

**PUBLIC VERSION**

**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.	)	

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**DIRECT TESTIMONY OF KEVIN M. MURRAY  
ON BEHALF OF INDUSTRIAL ENERGY USERS-OHIO**

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Samuel C. Randazzo (Counsel of Record)  
Frank P. Darr  
Joseph E. Olier  
MCNEES WALLACE & NURICK LLC  
21 East State Street, 17<sup>th</sup> Floor  
Columbus, OH 43215-4228  
Telephone: (614) 469-8000  
Telecopier: (614) 469-4653  
sam@mwncmh.com  
fdarr@mwncmh.com  
joliker@mwncmh.com

**May 4, 2012**

**Attorneys for Industrial Energy Users-Ohio**

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**1 I. INTRODUCTION**

**2 Q1. Please state your name and business address.**

3 A1. My name is Kevin M. Murray. My business address is 21 East State Street, 17<sup>th</sup>  
4 Floor, Columbus, Ohio 43215-4228.

**5 Q2. By whom are you employed and in what position?**

6 A2. I am a Technical Specialist for McNees Wallace & Nurick LLC ("McNees") and  
7 the Executive Director of the Industrial Energy Users-Ohio ("IEU-Ohio"). I am  
8 providing testimony on behalf of IEU-Ohio.

**9 Q3. Please describe your educational background.**

1 A3. I graduated from the University of Cincinnati in 1982 with a Bachelor of Science  
2 degree in Metallurgical Engineering.

3 **Q4. Please describe your professional experience.**

4 A4. I have been employed by McNees for 14 years where I focus on helping  
5 IEU-Ohio members address issues that affect the price and availability of utility  
6 services. I have also been actively involved, on behalf of commercial and  
7 industrial customers, in the formation of regional transmission operators ("RTOs")  
8 and the organization of regional electricity markets from both the supply-side and  
9 demand-side perspective. I serve as an end-use customer sector representative  
10 on the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"  
11 or "MISO") Advisory Committee and I have been actively involved in MISO  
12 working groups that focus on various issues since 1999. Prior to joining McNees,  
13 I was employed by the law firm of Kegler, Brown, Hill & Ritter ("KBH&R") in a  
14 similar capacity. Prior to joining KBH&R, I spent 12 years with The Timken  
15 Company, a specialty steel and roller bearing manufacturer. While at The  
16 Timken Company, I worked within a group that focused on meeting the electricity  
17 and natural gas requirements for facilities in the United States. I also spent  
18 several years in supervisory positions within The Timken Company's steelmaking  
19 operations.

20 **Q5. Have you previously testified before the Public Utilities Commission of**  
21 **Ohio ("Commission")?**

1 A5. Yes. The proceedings before the Commission in which I have submitted expert  
2 testimony are identified in Exhibit KMM-1.

3 **Q6. What is the purpose of your testimony?**

4 A6. The purpose of my testimony is to address whether it would be appropriate to  
5 establish two-tiered capacity pricing to be paid by competitive retail electric  
6 service ("CRES") providers that acquire retail customers that receive distribution  
7 service from Ohio Power Company ("OP") and Columbus Southern Power  
8 Company ("CSP"), now both merged as Ohio Power Company and doing  
9 business as AEP-Ohio.<sup>1</sup> For the reasons discussed in my testimony, based upon  
10 the facts and circumstances as well as policy and legal considerations, the  
11 Commission should not approve AEP-Ohio's request to establish a two-tiered  
12 capacity pricing structure. I also recommend that the Commission reject the  
13 proposed retail stability rider ("RSR"). The combination of the two-tiered capacity  
14 pricing structure, coupled with the RSR, is designed to transfer business and  
15 financial risk associated with the separate competitive generation business of  
16 AEP-Ohio to non-shopping retail customers, shopping retail customers and  
17 CRES providers, and provide AEP-Ohio's generation business with a  
18 discriminatory and non-comparable advantage. The two-tiered capacity charge  
19 scheme is also an unreasonable and, based on advice of counsel, unlawful  
20 proposal to obtain transition revenue long after the opportunity to advance a  
21 transition revenue claim ended both by law and a result of AEP-Ohio's prior  
22 commitments. Since the RSR proposal is linked in part to the operation of the

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<sup>1</sup> In my testimony I will refer at times to AEP-Ohio as the Company.

1 two-tiered capacity charge scheme, the fundamental defects in the two-tiered  
2 capacity charge scheme are also embedded in the RSR. The non-bypassable  
3 nature of the RSR also results in the imposition of revenues and risks related to  
4 AEP-Ohio's separate generation business on AEP-Ohio's distribution service  
5 customers thereby improperly tying the relationship between AEP-Ohio's  
6 generation supply and non-competitive retail services.

7 I also recommend that the Commission find the modified electric security plan  
8 ("Modified ESP") is not more favorable in the aggregate than a market rate option  
9 ("MRO") because the Modified ESP is much more expensive than the MRO  
10 option. Based upon the assumed standard service offer ("SSO") load reflected in  
11 the workpapers of AEP-Ohio witness William A. Allen, which I believe  
12 significantly overstates likely shopping levels if the AEP-Ohio above market  
13 capacity pricing requests are entertained, the Modified ESP is less favorable than  
14 an MRO by \$330 million between June 2012 and December 2014 for SSO  
15 customers. During the period between January 2014 and May 2014 when AEP-  
16 Ohio proposes to conduct an energy-only auction to secure SSO generation  
17 supply, the Modified ESP is less favorable than an MRO by an additional \$77  
18 million for SSO customers.

19 My ESP versus MRO analysis only reflects the costs to SSO customers.  
20 However, the significantly above market capacity price that AEP-Ohio is  
21 proposing to levy on shopping customers is an additional cost of the Modified  
22 ESP. Exhibit WAA-4 to the testimony of AEP Ohio witness Allen shows that  
23 under the Modified ESP and based upon the switching levels assumed in Mr.

1 Allen's testimony, AEP-Ohio expects to collect \$1,204 million in capacity revenue  
2 from CRES providers between June 2012 and May 2015 that will be reflected in  
3 the prices CRES providers charge their customers. If CRES providers were  
4 compensating AEP-Ohio at the reliability pricing model ("RPM") price, which  
5 reflects prevailing market prices, I estimate that AEP-Ohio would collect capacity  
6 revenue of approximately \$434 million if RPM-based capacity prices were paid  
7 by CRES providers and their customers. The difference of \$770 million is an  
8 additional cost to consumers of the Modified ESP and is a source of transition  
9 revenues to AEP Ohio.

10 Additionally, my ESP versus MRO analysis only captures the impacts of the RSR  
11 on non-shopping customers because the analysis examines the prices the  
12 customers pay under an ESP versus what they would pay under an MRO. AEP-  
13 Ohio has proposed that the RSR be non-bypassable and payable by shopping  
14 customers as well. Based upon the assumed level of shopping reflected in AEP-  
15 Ohio witness Allen's testimony, the RSR will collect \$198 million in transition  
16 revenues from shopping customers between June 1, 2012 and May 31, 2015.

17 Further, as discussed in the testimony of IEU-Ohio witness Joseph G. Bowser,  
18 the excessive carrying charge proposed by AEP-Ohio in the Modified ESP  
19 version of the phase-in recover rider ("PIRR") results in an additional cost of the  
20 ESP that is not captured in my ESP versus MRO price analysis because the  
21 analysis examines the prices the customers pay under an ESP versus what they  
22 would pay under an MRO. The additional cost of the Modified ESP's proposed

1 PIRR is at least \$186 million based upon Mr. Bowser's net present value  
2 analysis.

3 When all of the additional costs of the Modified ESP are properly recognized, it is  
4 less favorable in the aggregate than an MRO by over \$1.5 billion for the period  
5 between June 2012 and May 2015.

6 Should the Commission consider adoption of any two-tiered capacity charge  
7 structure, I also describe the type of rate design that the Commission should  
8 require AEP-Ohio to adopt and I describe the information I recommend that the  
9 Commission require AEP-Ohio to provide so that it is possible for consumers and  
10 CRES providers to identify if the capacity charge billing determinants are correct.  
11 My recommended rate design is necessary to satisfy comparability and non-  
12 discrimination requirements and helps to reduce some of the confusion  
13 associated with the very confusing two-tiered structure. Requiring AEP-Ohio to  
14 provide the information I identify regarding the specification of capacity charge  
15 billing determinants is necessary to facilitate "apples-to-apples" comparisons and  
16 verify the accuracy of the amount of any capacity charge bill that a customer or  
17 CRES provider may incur regardless of the level of the capacity charge.

18 I recommend that the Commission reject AEP-Ohio's Modified ESP and promptly  
19 direct AEP-Ohio to restore the use of RPM-based capacity pricing in all cases  
20 where a CRES provider is serving a retail consumer within AEP-Ohio's service  
21 area. I also suggest that the protracted debate that has occurred on the subject  
22 of this proceeding has, itself, stymied the ability for consumers to identify options



1 to reduce their electric bills through “customer choice” and that the experience in  
2 this case strongly suggests that the Commission should turn to a competitive bid  
3 process (“CBP”) to establish default generation supply prices.

4 **Q7. How do the issues raised by AEP-Ohio in this proceeding relate to efforts**  
5 **to develop competitive markets for electricity?**

6 A7. The significance of the issues raised by AEP-Ohio’s application in this  
7 proceeding can be better understood by looking more broadly at what has  
8 happened at the state and federal level to restructure the electric industry to  
9 address the anticompetitive structure of the industry and to allow competitive  
10 markets to serve the public interest in reasonable rates and reliable service. This  
11 broader history includes background information on determinations that have  
12 been made by the Federal Energy Regulatory Commission (“FERC”).

13 FERC has increasingly relied upon competitive market forces to establish “just  
14 and reasonable” prices at the wholesale level in both the gas and electric  
15 sectors. As part of FERC’s effort to remedy the anticompetitive electric industry  
16 structure which was dominated by vertically-integrated investor-owned electric  
17 utilities, FERC required electric utilities to move to open access, comparable and  
18 non-discriminatory transmission service and encouraged vertically-integrated  
19 electric utilities that owned generating plants to transfer operational control of  
20 their high voltage transmission facilities to independent RTOs such as PJM  
21 Interconnection LLC (“PJM”). When Ohio enacted its electric restructuring  
22 legislation in 1999, the legislation similarly included a requirement that owners of

1 transmission facilities transfer control of such facilities to an RTO.<sup>2</sup> Again,  
2 FERC's directives and policy announcements were part of FERC's effort to  
3 remedy undue discrimination in the operation of transmission facilities that  
4 occurred because vertically-integrated utilities used their operation and control of  
5 their transmission facilities to favor their generation assets.

6 Over time, the role of RTOs has expanded, subject to FERC's supervision and  
7 regulation, beyond the operation and control of transmission assets to remedy  
8 the anticompetitive industry structure. Today, RTOs are responsible for  
9 maintaining real time reliability of the electric grid and do so in coordination with  
10 regional electricity markets. Instead of allowing vertically-integrated electric  
11 utilities such as AEP-Ohio and its affiliates to use control over "bottleneck"  
12 functions to favor their own assets and services, FERC mandated open access  
13 transmission services and authorized the creation of RTOs to facilitate the  
14 separation of ownership and control over the transmission and generation  
15 functions.

16 Under FERC's supervision, RTOs have done much to break the hold of vertically-  
17 integrated utilities' control over monopoly or "bottleneck" functions such as  
18 transmission and have increasingly introduced market-based approaches to  
19 maintain reliability in ways that better check the abuses that occurred in the  
20 anticompetitive vertically-integrated industry structure. The RTOs are managing  
21 the operation of regional electricity markets to secure scale and scope

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<sup>2</sup> Section 4928.12, Ohio Revised Code.

1 economies with independent market-monitoring oversight to determine if, and  
2 when, RTO or FERC intervention is needed to address anticompetitive behavior  
3 or circumstances where competition is not adequate to produce just and  
4 reasonable rates. For example, PJM began operating a regional electricity  
5 market in 1997. Currently, PJM coordinates the movement of wholesale  
6 electricity in all or parts of thirteen states and the District of Columbia.

7 These regional electricity markets typically include a number of products  
8 associated with the generation of electricity. Within PJM, the FERC-approved  
9 and regulated market structure includes separate products for capacity and  
10 energy as well as various ancillary services which include, for example,  
11 regulation and synchronized reserves.

12 The development and operation of regional electricity markets has also evolved  
13 over time with corresponding changes in the market rules established by the  
14 RTOs. Various stakeholders affected by changes in market rules often disagree  
15 as to whether market rule changes are appropriate, with FERC acting as the  
16 arbiter when disagreements arise. The capacity market rules in PJM have been  
17 a source of significant and frequent stakeholder disagreement.

18 **Q8. You have described the efforts at the federal level to separate ownership**  
19 **and control of bottleneck functions within the vertically-integrated electric**  
20 **utility industry segment known as the wholesale or sale for resale market.**  
21 **Before discussing the structure and purpose of PJM's capacity market,**

1       **please describe the means by which Ohio approached separation of**  
2       **ownership and control of such functions in the retail segment.**

3    A8.   The separation of ownership and control objective can be seen in numerous  
4       aspects of Ohio's approach to restructuring the retail electric market so that retail  
5       customers can exercise "customer choice" for the services or functions declared  
6       by the law or found by the Commission to be "competitive retail electric services".  
7       For example, Amended Substitute Senate Bill 3 ("SB 3") requires entities owning  
8       or operating transmission facilities to participate in RTOs that, like PJM,  
9       independently separate ownership and control of transmission functions from  
10      generation functions and maintain reliability within a broad region including  
11      Ohio.<sup>3</sup> As I understand SB 3, the provision of generation supply to retail  
12      customers was declared to be and is a competitive service and the Commission  
13      has authority to declare that other services are competitive. For services which  
14      are non-competitive, the Commission retained traditional ratemaking authority to  
15      authorize utilities to bill and collect for non-competitive services unless the  
16      Commission's authority is preempted.

17      In the case of competitive services, it is my understanding that SB 3 preserved  
18      the Commission's ability to approve prices for default service provided by an  
19      electric distribution company ("EDU") such as AEP-Ohio through the SSO but  
20      precludes the Commission from regulating rates and charges for competitive  
21      services provided by CRES providers based on the traditional rate base, rate of  
22      return model. It is also my understanding that SB 3 precludes an EDU from

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<sup>3</sup> Section 4928.12, Ohio Revised Code.

1 providing a competitive and non-competitive service unless the competitive  
2 service is provided through a structurally separate entity. In addition to  
3 essentially separating the distribution, transmission and generation functions of a  
4 vertically-integrated investor-owned electric utility, it is my understanding that SB  
5 3 requires EDUs to implement corporate separation plans approved by the  
6 Commission to guard against the challenges associated with the vertically-  
7 integrated and anticompetitive industry structure that predated electric industry  
8 restructuring.

9 **Q9. What type of corporate separation plan was approved for AEP-Ohio?**

10 A9. It is my understanding that SB 3 made the corporate separation requirements  
11 effective prior to the January 1, 2001 effective date of customer choice. It also  
12 required the Commission to review and address the EDU's corporate separation  
13 plan as part of the service and rate unbundling process that took place in the  
14 electric transition plan ("ETP") process.

15 CSP and OP filed their ETPs in Commission Case Nos. 99-1729-EL-ETP and  
16 99-1730-EL-ETP. At this time, AEP-Ohio's parent, American Electric Power or  
17 "AEP", was changing its traditional regulated utility model to move towards an  
18 energy trading business model with an international scope focused on multiple  
19 energy commodities and physical and financial products or services. As a result,  
20 the corporate separation plans filed by OP and CSP were a bit different than  
21 other EDUs. More specifically, OP and CSP proposed to maintain ownership  
22 and control of generation in the existing OP and CSP entities and transfer the

1 “wires business” (transmission and distribution) to new entities. This aspect of  
2 CSP’s and OP’s corporate separation plans is identified in the attached pages of  
3 the pre-filed testimony of CSP’s and OP’s witness William Forrester that are  
4 attached to my testimony as Exhibit KMM-2. AEP’s corporate separation plans in  
5 Texas and Ohio and their relationship to the move to an energy trading business  
6 model are also described in the prospectus which AEP issued in 2002. The 2002  
7 prospectus is attached to my testimony as Exhibit KMM-3.

8 **Q10. Did the Commission approve the corporate separation plans proposed by**  
9 **CSP and OP in the ETP cases?**

10 A10. Yes, the Commission issued an order in the ETP cases on September 28, 2000  
11 in which the Commission approved a settlement that resolved issues in the ETP  
12 cases for CSP and OP. The proposed corporate separation plans were  
13 approved as part of the ETP cases.

14 **Q11. Did OP and CSP implement the approved corporate separation plans?**

15 A11. No. When OP and CSP submitted an application on February 9, 2004 in Case  
16 No. 04-169-EL-UNC to establish a rate stabilization plan (“RSP”), they requested  
17 Commission authorization to continue functional corporate separation rather than  
18 proceeding to structurally separate during the rate stabilization period. The  
19 Commission’s January 26, 2005 order in case No. 04-169-EL-UNC accepted this  
20 provision of the RSP.

1 Subsequently, in their applications to establish initial electric security plans (Case  
2 Nos. 08-917-EL-SSO and 08-918-EL-SSO) CSP and OP requested the  
3 Commission modify their corporate separation plans such that generation assets  
4 remain functionally separate but that CSP and OP retain their distribution and  
5 transmission assets. The applications also stated that upon the expiration of  
6 functional separation, CSP's and OP's generating assets would be transferred or  
7 sold. In its March 18, 2009 order approving the proposed electric security plans,  
8 the Commission directed the Companies to seek Commission approval of  
9 modifications to their corporate separation plans in another proceeding in  
10 accordance with then recently promulgated Commission rules. On June 1, 2009,  
11 OP and CSP submitted applications for approval of corporate separation plans  
12 that again acknowledged that functional separation was interim in nature and that  
13 Ohio law required legal separation of their competitive and non-competitive  
14 businesses. After conducting an audit on June 2, 2010, the Commission  
15 accepted the corporate separation applications submitted in Case No. 09-464-  
16 EL-UNC.

17 **Q12. As it relates to the issues in this proceeding, does the Commission's prior**  
18 **approval of OP's and CSP's proposal to leave ownership and control of**  
19 **generating assets in OP and CSP and transfer ownership and control of the**  
20 **wires business to new entities have any significance?**

21 A12. Yes. In public statements and throughout the lengthy debate in this proceeding  
22 and the litigation in Case No. 10-2929-EL-UNC, AEP-Ohio has claimed that it  
23 cannot move promptly to market-based pricing for generation capacity service or

1 use a competitive bidding process to establish default generation service supply  
2 prices that are part of the SSO until the AEP System Integration Agreement  
3 (often referred to as the AEP Pool Agreement) is terminated or restructured and  
4 until it unwinds the fixed resource requirement ("FRR") election which AEPSC  
5 (not AEP-Ohio) made in 2007. These claims are without merit since the initial  
6 Commission-approved OP and CSP corporate separation plans did not involve  
7 transferring generating assets. In other words, unlike the FirstEnergy operating  
8 companies that AEP-Ohio's witness Robert Powers refers to at page 7 of his  
9 testimony, the CSP and OP transition plans proposals approached corporate  
10 separation differently. Instead of transferring generating assets to a non-  
11 regulated affiliate, OP and CSP proposed transferring ownership and control of  
12 the distribution and transmission function segments to new, structurally  
13 separated entities. I believe the differences between the CSP/OP approach and  
14 the approach followed by the FirstEnergy operating companies is related to  
15 AEP's plans at the time to focus on the energy trading business to capture value  
16 from the competitive wholesale market from the relatively low book cost  
17 generating assets owned or controlled by CSP and OP. In any event, I know of  
18 no reason why moving forward with the type of corporate separation initially  
19 proposed by and approved for CSP and OP might need to be delayed until the  
20 subsequent FRR election made by AEPSC is terminated or until the AEP East  
21 System Integration Agreement is terminated or modified.



1 **Q13. Did AEP-Ohio also seek Exempt Wholesale Generator (“EWG”) status for**  
2 **its generating assets subsequent to the approval of its corporate**  
3 **separation plans in the ETP process?**

4 A13. Yes. On December 21, 2011, CSP and OP filed an application in Case No. 01-  
5 3289-EL-UNC at the Commission requesting the Commission make certain  
6 findings pursuant to 15 U.S.C. §79z-5a(c) of the Public Utility Holding Company  
7 Act of 1935 (“PUHCA”). In 2002, CSP and OP, as well as other AEP operating  
8 company affiliates, were moving forward with plans to structurally separate their  
9 generation businesses. Because the corporate separation plans approved  
10 during the ETP cases contemplated the distribution and transmission businesses  
11 being moved out of CSP and OP, with the generation assets remaining, CSP and  
12 OP were seeking EWG status for their generating assets. It is my understanding  
13 that before EWG status could be granted, PUHCA required each state  
14 commission having jurisdiction over retail rates for an entity seeking EWG status  
15 for generating plant that was included in rate base for the retail jurisdiction to  
16 make a determination that EWG status would benefit consumers, was in the  
17 public interest and would not violate the law. The application stated:

18 The transactions underlying this Application are being undertaken  
19 because of the requirements of SB3 to separate control of the  
20 generating plants from the regulated wires businesses. The  
21 Corporate separation requirements in SB3 help effectuate the  
22 policy set forth in Ohio Rev. Code Section 4928.02, Ohio Rev.  
23 Code, which is create a robust competitive marketplace, which is in  
24 the public interest and will benefit consumers.<sup>4</sup>

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<sup>4</sup> *Application of Ohio Power Company and the Columbus Southern Power Company for Certain Findings Under 15 U.S.C. §79z and 17CFR §250.53, Case No. 01-3289-EL-UNC, Application at 5-6 (December 21, 2001).*

1 Then Executive Vice President Henry W. Fayne subsequently submitted a letter  
2 addressed to then Chairman Alan R. Schriber in the proceeding affirming that  
3 AEP would continue to provide CSP and OP the necessary equity capital to  
4 enable them to satisfy their obligation under Ohio law, including the provision of  
5 adequate, safe and reliable transmission and distribution service. A copy of Mr.  
6 Fayne's letter is attached to my testimony as Exhibit KMM-4. In the letter, CSP  
7 and OP also committed to promptly notify the Commission staff if a major rating  
8 agency downgraded either company's senior bond ratings and obligated CSP  
9 and OP to submit a plan to restore their bond ratings with any plan modifications  
10 required by the Commission. The Commission's October 17, 2002 order that  
11 provided the requested EWG findings was specifically conditioned on these  
12 conditions and commitments.

13 **Q14. Did AEP-Ohio separate its distribution and transmission businesses and**  
14 **obtain EWG status for its generating assets following the PUCO's approval**  
15 **of the application in Case No. 01-3289-EL-UNC?**

16 A14. No.

17 **Q15. Why not?**

18 A15. Like many of the vertically-integrated electric utilities that adopted the energy  
19 trading business model made infamous by companies like Enron, AEP's pursuit  
20 of that model did not go well. As the negative financial consequences of the  
21 energy trading business model rippled through the electricity industry and the  
22 broader energy industry, and Wall Street turned sour on the energy trading

1 approach, AEP abruptly discontinued its pursuit of the international energy  
2 trading business model and declared that it was returning to a business model  
3 that focused on a traditionally regulated and vertically-integrated electric utility  
4 business model. A copy of a press release issued by AEP on October 10, 2002  
5 announcing it was substantially reducing its energy trading activities is attached  
6 to my testimony as Exhibit KMM-5. It is my opinion that AEP's rather precarious  
7 pursuit of the energy trading model and its subsequent abrupt distancing itself  
8 from that business model so as to portray itself to Wall Street as a stable,  
9 vertically-integrated and traditionally regulated electric utility caused AEP-Ohio to  
10 not implement the corporate separation plans approved by the Commission in  
11 the ETP cases for CSP and OP, and to reverse course on plans to obtain EWG  
12 status as authorized by the Commission in Case No. 01-3289-EL-UNC.  
13 Nonetheless, it is my understanding that SB 3 and the Commission's rules  
14 require that the distribution, transmission and generation functions be looked at  
15 as though they are three separate and unrelated lines of business.

16 **Q16. If AEP-Ohio would have implemented the corporate separation plans**  
17 **proposed to and approved by the Commission, would that have meant that**  
18 **it would not have been possible for AEP-Ohio to come forward with an RSP**  
19 **proposal as the Commission encouraged in 2003?**

20 A16. No. In fact, the FirstEnergy operating companies positively responded to the  
21 Commission's support of RSPs even though they transferred ownership and  
22 control of their generating assets to a separate unregulated affiliate in  
23 compliance with their Commission-approved corporate separation plans. As in

1 the case of the FirstEnergy operating companies, implementation of the  
2 corporate separation plans by CSP and OP may have involved securing FERC  
3 approval of generation supply contracts between the EDUs and the affiliated  
4 generation entities to assemble a sensible rate stabilization plan. But, corporate  
5 separation plan implementation would not have thwarted the opportunity for  
6 RSPs unless AEP demanded otherwise.

7 **Q17. Now, returning to the PJM capacity market, please explain why PJM**  
8 **operates a capacity market?**

9 A17. PJM's capacity market is intended to ensure the adequate availability of  
10 necessary resources that can be called upon to ensure the reliability of the grid.  
11 In this context, it is important to understand that this reliability is for the entire  
12 footprint of PJM, not just the distribution service area of AEP-Ohio. Each load  
13 serving entity ("LSE") within PJM is responsible for contributing owned or  
14 controlled capacity resources to the common pool of resources that are available  
15 to PJM to satisfy PJM's reliability objective. These capacity resources include  
16 electric generating plants, eligible energy efficiency resources and demand  
17 response resources. The pool of capacity resources committed to PJM is  
18 available to and dispatched by PJM to satisfy the reliability objective within PJM's  
19 footprint. Beyond these committed resources, PJM also has other tools that PJM  
20 can use in emergencies to affect the performance of resources that did not  
21 volunteer to participate through the preferred market-based structure that relies  
22 on bids supplied by parties that own or control capacity resources. PJM's  
23 capacity market structure provides transparent information on the value of

1 capacity, energy and ancillary services to enable forward market signals to  
2 support infrastructure investment. The capacity market design also provides a  
3 forward mechanism to evaluate the ongoing reliability requirements in a  
4 transparent manner, providing opportunities for the integration of distributed and  
5 central station generation, demand response, energy efficiency, and transmission  
6 options to maintain and enhance reliability while achieving scale and scope  
7 economies within the PJM footprint

8 Within the PJM region, RPM is the means by which PJM's market-based  
9 approach addresses the regional reliability objective. The goal of RPM is to align  
10 capacity pricing with system, region-wide, reliability requirements and to provide  
11 transparent information to all market participants far enough in advance of  
12 transactions so as to allow time for a proactive positive performance response to  
13 the information. The fundamental elements of the RPM structure are:

- 14 • Locational capacity pricing to recognize and quantify the locational  
15 value of capacity;
- 16 • A variable resource requirement mechanism to adjust price based  
17 on the level of resources procured;
- 18 • Forward commitment of supply by generation, demand resources  
19 and qualified transmission upgrades cleared in a multi-auction  
20 structure; and
- 21 • A reliability backstop mechanism to ensure that sufficient  
22 generation, transmission and demand response solutions will be  
23 available to preserve system reliability.

24 **Q18. Is providing forward prices for capacity one of the functions of RPM?**

25 A18. Yes. RPM is intended to provide a forward price signal for capacity resources  
26 (all capacity resources) and LSE obligations that also reflects PJM's regional  
27 transmission expansion planning process. RPM can also have a locational

1 nature to the pricing signal. RPM relies upon a multi-auction structure designed  
2 to procure resource commitments to satisfy the region's unforced capacity  
3 obligation through a base residual auction ("BRA"), incremental auctions ("IAs")  
4 and bilateral market transactions.

5 **Q19. How does RPM operate?**

6 A19. BRAs are held each May three years in advance of each delivery year, which  
7 runs from June 1 through the following May 31. Subsequent to the BRA, up to  
8 three IAs are held to procure additional resources, if necessary, and to adjust  
9 commitments to reflect known changes in market requirements prior to the  
10 delivery year. The auction results produce locational capacity charges that are  
11 allocated among LSEs through a locational reliability charge. The existence of  
12 this locational element in the PJM market structure is a byproduct of the pooled-  
13 resources approach that PJM has adopted to satisfy reliability objectives within  
14 the PJM region.

15 For each delivery year, PJM determines a peak load forecast. PJM then  
16 calculates an installed reserve margin for the entire PJM region. The installed  
17 reserve margin is defined as the level of installed reserves in excess of the  
18 forecast peak load needed to maintain the desired reliability index of ten years,  
19 on average, per occurrence (loss of load expectation of one occurrence every ten  
20 years) after emergency procedures to invoke load management. The installed  
21 reserve margin is calculated based upon probabilistic studies. PJM then  
22 calculates the region's forecast pool requirement, which represents the quantity

1 of unforced capacity resources needed recognizing the pool-wide equivalent  
2 average forced outage rate and the expected performance of demand response  
3 resources.

4 Prior to conducting BRAs, PJM assesses the need to create locational  
5 deliverability areas (“LDAs”). LDAs are load pockets within the PJM footprint in  
6 which transmission import capacity is constrained, therefore requiring the use of  
7 internal capacity resources within the LDAs to satisfy the region-wide reliability  
8 objective. The areas within PJM that are not LDAs are referred to as the balance  
9 of the RTO zone. Depending on supply and demand conditions, price separation  
10 may occur for LDAs from the balance of the RTO zone when the BRA is  
11 conducted.

12 The BRA is structured to obtain sufficient capacity resources to satisfy the  
13 projected pool requirement scaled to reflect normal weather. The BRA relies  
14 upon a downward sloping demand curve called the variable resource  
15 requirement curve. The use of the variable resource requirement curve may  
16 result in the procurement of capacity resources in excess of the reliability  
17 objective if the total cost of resource procurement for the LDAs or balance of the  
18 RTO zone is lower at the higher level of reliability than it would be at the target  
19 reliability objective. After the BRA and prior to the delivery year, PJM conducts  
20 three IAs. The IAs are conducted to allow for replacement resource procurement  
21 and increases and decreases in the reliability objective resulting from, for  
22 example, a change in load forecast. The results from all of the auctions are  
23 mathematically weighted to determine a final zonal capacity price.

1 Once all auctions have been concluded, the final zonal capacity obligation is  
2 determined. This is done through the use of a final zonal scaling factor that is  
3 used to determine an LSE's daily unforced capacity obligation.

4 **Q20. How are capacity charges billed under RPM?**

5 A20. For settlement purposes, each PJM electric distribution company ("EDC") is  
6 responsible for allocating its normalized previous summer's peak (measured  
7 based on five coincident peaks) to each customer in the zone (both wholesale  
8 and retail). According to PJM's business practice manuals, the process used by  
9 an EDC to allocate peak load contributions to its customers is supposed to be  
10 based upon rules negotiated with the EDC's regulators. To assist in performing  
11 these allocations, PJM publishes information, known as the five coincident peaks  
12 or 5CP, for each summer, typically by mid-October. The 5CP reflects the five  
13 highest non-holiday weekday RTO unrestricted daily peaks from the summer. An  
14 individual customer's usage during those five hours is known as the peak load  
15 contribution or PLC.

16 **Q21. Do LSEs have options other than participation in the periodic capacity**  
17 **auctions conducted by PJM?**

18 A21. Yes. PJM's capacity market also allows LSEs an alternative method of satisfying  
19 their capacity resource obligation to the PJM pool. This alternative is known as  
20 the FRR alternative. FRR permits an LSE the option to submit an FRR capacity  
21 plan (to be reviewed and approved by PJM) to satisfy the shared responsibility of  
22 all LSEs to commit capacity resources and as an alternative to the requirement to



1 participate in the periodic RPM competitive bidding process or auctions, which  
2 feature a variable capacity resource requirement. American Electric Power  
3 Service Corporation (“AEPSC”), acting on behalf of the affiliated AEP East  
4 operating companies made an FRR election in 2007. AEP-Ohio itself is not a  
5 stand-alone FRR entity. The ESP application submitted in this proceeding does  
6 not identify the relationship between AEPSC or identify the contractual or other  
7 obligations that AEP-Ohio may have as a result of AEPSC’s FRR election.

8 **Q22. How was PJM’s capacity market created?**

9 A22. RPM and the FRR option are byproducts of a FERC-approved settlement  
10 negotiated by many parties in a case in which PJM proposed changes to its  
11 market rules. That settlement, which was signed by AEPSC on behalf of all the  
12 AEP operating companies in PJM, was accepted by FERC on December 22,  
13 2006. *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006).

14 **Q23. Has AEPSC and AEP-Ohio supported RPM as reasonable?**

15 A23. Yes. AEPSC and AEP-Ohio operated pursuant to the RPM rules for a number of  
16 years without objection. Indeed, AEP-Ohio strongly defended the PJM market  
17 rules and RPM in proceedings before this Commission. For example, in 2007,  
18 AEP-Ohio argued that Ohio was part of a robust regional energy market and  
19 urged the Commission to move forward with a CBP for the provision of SSO  
20 generation service:

21 The competitive significance of RTOs is well recognized. In *New*  
22 *PURPA Section 210(m) Regulations Applicable to Small Power*  
23 *Production and Cogeneration Facilities*, Docket No. RM06-10-000,

1 FERC Statutes and Regulations ¶31,233 (October 20, 2006)  
2 (“Order 688”), the FERC found that both MISO and PJM are  
3 independently administered, auction-based day-ahead and real-  
4 time wholesale markets for the sale of electric energy. The FERC  
5 also found that the existence of wholesale markets for long-term  
6 sales of capacity and electric energy is satisfied by the existence of  
7 long-term bilateral contracts for sales of capacity and energy and is  
8 a sufficient indication of a market. *Order 688* ¶117.

9  
10 The PJM energy market provides substantial benefits to the region  
11 based on its ability for utilities and customers to access a larger  
12 number of generation resources to fulfill load requirements while  
13 utilizing a robust transmission system. PJM's methodology results  
14 in the least cost generating units serving the load requirements,  
15 subject to any transmission constraints. This method is similar to  
16 the one performed by AEP for its system prior to joining PJM. PJM,  
17 however, provides access to additional generating units and the  
18 capability of importing generation from MISO without paying  
19 additional transmission rates. The resulting dispatch price provides  
20 transparent economic signals that guide short- and long-run  
21 decisions by participants and regulators.

22 Case No. 07-796-EL-ATA, *et al.*, *Reply Comments of Columbus Southern Power*  
23 *Company and Ohio Power Company* at 4-5 (October 12, 2007). In fact, in its  
24 initial comments in that proceeding, AEP-Ohio indicated that if a CBP were held  
25 to obtain SSO generation for AEP-Ohio's load, given AEP-Ohio's FRR status,  
26 AEP-Ohio would sell capacity to winning bidders at the RPM clearing price until  
27 such time as AEP-Ohio could terminate its FRR status. Case No. 07-796-EL-  
28 ATA, *et al.*, *Comments of Columbus Southern Power Company and Ohio Power*  
29 *Company* at 5 (September 5, 2007).

30 **Q24. Has AEPSC and AEP-Ohio modified its opinion on the reasonableness of**  
31 **RPM?**

32 A24. Yes. On November 1, 2010, AEPSC, on behalf of OP and CSP, submitted an  
33 application to FERC in Docket No. ER11-1995-000 and subsequently re-

1 submitted an application in Docket No. ER11-2183-000 seeking to establish what  
2 AEPSC characterized as a cost-based charge for capacity supplied to CRES  
3 suppliers providing competitive generation service to retail load within the AEP-  
4 Ohio service area. In its FERC application, AEPSC asserted that its sudden  
5 proposal to change the basis for establishing prices for capacity is consistent with  
6 Section D.8 of Schedule 8.1 of the PJM Reliability Assurance Agreement (“RAA”)  
7 which AEP-Ohio signed when it became a transmission-owner member of PJM.  
8 Section D.8 of the RAA provides, in relevant part:

9 In a state regulatory jurisdiction that has implemented retail choice,  
10 the FRR Entity must include in its FRR Capacity Plan all load,  
11 including expected load growth, in the FRR Service Area,  
12 notwithstanding the loss of any such load to or among alternative  
13 retail LSEs. In the case of load reflected in the FRR Capacity Plan  
14 that switches to an alternative retail LSE, **where the state**  
15 **regulatory jurisdiction requires switching customers or the**  
16 **LSE to compensate the FRR Entity for its FRR capacity**  
17 **obligations, such state compensation mechanism will prevail.**  
18 In the absence of a state compensation mechanism, the applicable  
19 alternative retail LSE shall compensate the FRR Entity at the  
20 capacity price in the unconstrained portions of the PJM Region, as  
21 determined in accordance with Attachment DD to the PJM Tariff,  
22 provided that the FRR Entity may, at any time, make a filing with  
23 FERC under Sections 205 of the Federal Power Act proposing to  
24 change the basis for compensation to a method based on the FRR  
25 Entity’s cost or such other basis shown to be just and reasonable,  
26 and a retail LSE may at any time exercise its rights under Section  
27 206 of the FPA.<sup>5</sup>

28 On December 8, 2010, the Commission issued an entry in Case No. 10-2929-EL-  
29 UNC confirming capacity supplied to CRES providers serving customers in the  
30 AEP-Ohio service area would be priced based upon the prevailing RPM

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<sup>5</sup> PJM Interconnection, L.L.C., Rate Schedule FERC No. 44, *Reliability Assurance Agreement Among Load Serving Entities in the PJM Region*, Schedule 8.1, §D.8 at 111 (“Fixed Resource Requirement Alternative”), effective July 14, 2011 (emphasis added) (“Exhibit KMM-15”).

1 mechanism, the status quo at that time. The entry directed interested parties to  
2 file comments on an appropriate state compensation mechanism. The  
3 Commission subsequently established a procedural schedule for an evidentiary  
4 hearing commencing on October 4, 2011.

5 **Q25. What occurred after the Commission established a schedule for an**  
6 **evidentiary hearing commencing on October 4, 2011?**

7 A25. On September 7, 2011, a strongly contested stipulation and recommendation  
8 ("Stipulation") was submitted in these proceedings. The Stipulation provided for  
9 a two-tiered structure to price capacity for CRES providers, with some capacity  
10 priced at prevailing market prices and any remaining capacity priced at \$255 per  
11 megawatt-day ("MW-day"). The Commission adopted the Stipulation with  
12 modifications on December 14, 2011.

13 However, in response to applications for rehearing, the Commission  
14 subsequently rejected the Stipulation on February 23, 2012 finding that it was not  
15 consistent with the public interest. The Commission's rejection of the Stipulation  
16 resulted in capacity prices for CRES providers serving customers in AEP-Ohio's  
17 service area reverting to the state compensation mechanism (i.e., the status quo  
18 RPM-based prices). In rejecting the Stipulation, the Commission directed AEP-  
19 Ohio to notify the Commission whether AEP-Ohio would modify or withdraw its  
20 original ESP application. Subsequently, the Commission granted a motion by  
21 AEP-Ohio in Case No. 10-2929-EL-UNC to re-establish, on an interim basis, a  
22 two-tiered pricing structure for capacity, but only through May 31, 2012, with

1 capacity prices thereafter reverting to RPM-based prices. The re-established  
2 two-tiered capacity charge retained opportunities for RPM-based pricing to  
3 remain in cases where CRES providers served customers (including “mercantile  
4 customers”) through eligible community aggregation programs.

5 After rejecting the September 7, 2011 Stipulation, the Commission also set a  
6 procedural schedule to resume Case No. 10-2929-EL-UNC. Issues in Case No.  
7 10-2929-EL-UNC are being litigated as of the date this testimony is due to be  
8 filed with the Commission and it is unclear when the Commission may address  
9 those issues.

10 **Q26. Did AEP-Ohio elect to modify its original ESP application?**

11 A26. Yes. On March 30, 2012, AEP-Ohio submitted a modified application and  
12 supporting testimony. The modified application, or Modified ESP, differs  
13 substantially from the original application. In its Modified ESP, AEP-Ohio claims  
14 that each of the major components of the Modified ESP is critical to AEP-Ohio’s  
15 future and need to be addressed in order for AEP-Ohio to continue a transition to  
16 a fully competitive auction-based SSO.

17 **Q27. What are the significant components of the Modified ESP?**

18 A27. AEP-Ohio is proposing to roll environmental costs currently collected through a  
19 rider into base generation rates and fix the base generation rates at that level  
20 through December 31, 2014. An alternative energy rider would be established to  
21 recover a portion of the costs of alternative energy resources. AEP-Ohio has

1 proposed a generation resource rider (“GRR”) as a non-bypassable placeholder  
2 rider to recover costs associated with the Turning Point Solar facility, with any  
3 charges to be recovered through the rider to be approved by the Commission in  
4 a separate proceeding. The fuel adjustment clause (“FAC”) would continue,  
5 albeit presumably with some modifications as a result of proposed energy-only  
6 auctions for a portion of the SSO load. AEP-Ohio is proposing to increase the  
7 interruptible rate credit under Rate IRP-D to \$8.21 per kW-month, with the  
8 revenue reduction associated with the higher level of credit being recovered  
9 through a non-bypassable RSR.<sup>6</sup> A non-bypassable RSR is proposed to  
10 guarantee the total revenues AEP-Ohio receives through the combination of  
11 base generation revenues, capacity charges to CRES providers and the RSR. A  
12 two-tiered capacity pricing structure is proposed. For the first 21% of shopping  
13 load in 2012, the first 31% of shopping load in 2013 and the first 41% of shopping  
14 load in 2014, AEP-Ohio would impose a capacity charge of \$145.79 per MW-day  
15 on a CRES provider. In 2012, non-mercantile customers in communities that  
16 approved governmental aggregation initiatives in the November 2011 general  
17 election, or in prior elections, will be eligible for additional allotments of capacity  
18 at the rate of \$145.79 per MW-day. For any additional shopping load beyond the  
19 first pricing tier in any year, AEP-Ohio proposes a capacity charge of \$255 MW-  
20 day be paid by a CRES provider.

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<sup>6</sup> In other words, customers served under Rate IRP-D will see a decrease in their overall bill, but the reduced revenues will be paid for by other customers through the RSR.

1    **II.     APPROPRIATE CHARGES FOR CAPACITY**

2    **Q28. Do you believe that AEP-Ohio's proposal to establish two-tiered pricing for**  
3       **capacity utilized by CRES providers to serve retail load within the AEP-**  
4       **Ohio service area is reasonable?**

5    A28. No. There are multiple reasons why approval of AEP-Ohio's proposal would  
6       result in unreasonable if not unlawful outcomes and, more broadly speaking, go  
7       against the structural reforms and policy objectives that are part and parcel of the  
8       effort to remedy an anticompetitive electric industry structure.

9       First, establishing a two-tiered pricing structure for capacity would be contrary to  
10      the state's policies and would uniquely provide an unwarranted subsidy to AEP-  
11      Ohio's generation business segment, to the detriment of its competitors and  
12      shopping and non-shopping customers alike.

13      Second, it also appears that the proposed two-tiered CRES capacity price is  
14      designed to allow AEP-Ohio to capture most of the generation service bill  
15      reduction benefits that consumers would see by switching to a competitive  
16      supplier, including the affiliated CRES provider AEP Retail Energy Partners LLC.

17      Third, charging CRES providers the proposed two-tiered price for capacity would  
18      not result in the generation capacity service and price applied to CRES providers  
19      being comparable to the charge for capacity embedded in the default generation  
20      supply price embedded in the SSO.

1 Fourth, as IEU-Ohio witness J. Edward Hess explains in his testimony, AEP-  
2 Ohio's application in this proceeding is really a belated, and as I understand it  
3 based on the advice of counsel, illegal request to obtain "transition revenue" well  
4 after the opportunity to submit such a claim expired. I also understand that this  
5 "transition revenue" claim was submitted by AEP-Ohio long after it surrendered  
6 its right to submit such a claim and to impose a transition charge on shopping  
7 customers.

8 **Q29. Is the proposed two-tiered pricing for capacity a request for additional**  
9 **transition revenues?**

10 A29. Yes. It may be helpful to provide some additional context to help explain my  
11 answer.

12 Ohio made the move to "customer choice" in 1999 with the passage of SB 3. At  
13 the time, there were parallel federal efforts to restructure the wholesale electric  
14 market and address the anticompetitive electric industry structure. These  
15 initiatives were rooted in the view that competitive markets could do a better job  
16 of advancing the public interest in reasonable prices, reliable service and  
17 innovation than traditional regulation.

18 SB 3 contained policy objectives and established the process by which the  
19 evolution to reliance upon competitive markets would occur for competitive  
20 services such as generation supply. As discussed earlier, Ohio's implementation  
21 of SB 3 required the unbundling or separation of the three major functions  
22 (generation or production, transmission and distribution) associated with retail



1 electric service into separate competitive and non-competitive service  
2 components with separate prices for such unbundled components.

3 SB 3 established a “transition period” beginning on January 1, 2001 and ending  
4 on December 31, 2010. Within the transition period, SB 3 created a five-year  
5 market development period (“MDP”) during which incumbent investor-owned  
6 utilities and customers had the opportunity to prepare for and transition to a  
7 competitive market. SB 3 directed the Commission to structure transition plans  
8 with the objective of obtaining at least 20% customer switching by the mid-point  
9 of the MDP, which could end no later than December 31, 2005.

10 The evolutionary approach to restructuring the retail investor-owned electric  
11 industry in Ohio, accompanied by the completion of the transitional tasks, served  
12 two important objectives. The first objective was to provide customers with  
13 certain price protections from the dysfunction that is often associated with new  
14 and immature markets until such time as the retail market was mature enough to  
15 produce “reasonable” prices. The General Assembly protected customers by  
16 specifying that the total price of electricity in effect in October 1999 would define  
17 the total price envelope within which the individual or unbundled generation,  
18 transmission and distribution prices would be established through the transition  
19 plan process.<sup>7</sup> SB 3 also provided residential customers an immediate benefit in  
20 the form of a 5% discount.

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<sup>7</sup> The total bundled price for each electric rate schedule established the total rate cap, which is then divided between the functional components (generation, transmission, and distribution). Ohio provided, in Section 4928.34(A)(6), Ohio Revised Code, that such rate cap was subject to adjustment for changes in taxes, costs related to the establishment of a universal service fund (“USF”), and a temporary rider

1 The second consequence of the SB 3 structure protected incumbent EDUs  
2 during the MDP (and the balance of the transition period) from potential revenue  
3 loss that might otherwise be caused by an abrupt exposure to a new and  
4 immature market. In 2001, price offers for competitive retail service were  
5 relatively low and the transition structure protected EDUs from revenue and  
6 earnings erosion. Each EDU was also provided an opportunity to protect itself in  
7 the event the EDU judged the revenue from unbundled generation prices to be  
8 above the revenue that it could obtain from providing generation services in the  
9 competitive market. The right to pursue this protection required an EDU to file a  
10 claim with the Commission for “transition revenue” (i.e., the positive difference  
11 between the unbundled default supply generation prices and prices available to  
12 the EDU for generation services provided in the market —sometimes called  
13 “stranded costs”) as part of the ETP filings. If the EDU’s unbundled default  
14 supply generation service prices yielded revenue less than that available in the  
15 market, this “stranded benefit” was netted against the transition revenue claim.  
16 The net, legitimate and verifiable amount of any allowable generation-related  
17 transition revenue claim had to be collected by December 31, 2010. OP’s and  
18 CSP’s ETP cases were ultimately resolved through stipulations approved by the  
19 Commission. In the stipulations, OP and CSP agreed to forego claims for  
20 recovery of above-market generation costs (generation transition costs or  
21 “GTC”). *In the Matter of the Applications of Columbus Southern Power Company*  
22 *and Ohio Power Company for Approval of Their Electric Transition Plans and for*

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established by Section 4928.61, Ohio Revised Code. Thus, the rate cap was not an absolute cap on the total charges paid by customers during the MDP.

1        *Receipt of Transition Revenues*, Case Nos. 99-1729-EL-ETP and 99-1730-EL-  
2        ETP, Opinion and Order at 16 (September 28, 2000). IEU-Ohio witness Mr.  
3        Hess also discusses this history.

4        Shortly after the Stipulation was filed on September 7, 2011 in Case Nos. 11-  
5        346-EL-SSO, *et al.*, AEP-Ohio issued a press release that described the effect of  
6        the settlement as follows:

7                After a decade of legislative and regulatory changes to Ohio's  
8                market for electricity, this agreement allows an appropriate  
9                transition to a fully competitive electricity generation environment  
10               for AEP in the state.<sup>8</sup>

11        AEP-Ohio has continued to maintain that it is seeking an additional transition in  
12        this case as well. Both in its application, as well as in the direct testimony of  
13        Robert P. Powers, AEP-Ohio has stated it would like the Commission to approve  
14        a transition plan in order for AEP-Ohio to move to a fully competitive market.  
15        During this additional transition, that I understand has no basis in law, if the  
16        Commission approves AEP-Ohio's Modified ESP application, customers will be  
17        economically blocked from obtaining competitive retail electric services (such as  
18        generation supply) from CRES providers, or their savings from switching to a  
19        CRES provider will be very limited, thereby allowing AEP-Ohio to collect, largely  
20        on a non-bypassable basis, the revenues produced by its SSO rates. In fact, the  
21        RSR is designed to ensure that the total revenue AEP-Ohio collects from the  
22        combination of base generation charges, CRES capacity charges and RSR  
23        revenue equals a predetermined result. In other words, AEP-Ohio wants the

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<sup>8</sup> The press release is available via the Internet at <http://www.aep.com/newsroom/newsreleases/?id=1712> (last accessed March 28, 2012).

1 Modified ESP to produce a guaranteed level of generation revenue irrespective  
2 of shopping levels, a result that is arguably more than the transition revenue  
3 opportunity provided by SB 3, at a point in time long past the deadline for AEP-  
4 Ohio to collect transition revenue.

5 **Q30. Is the proposed RSR a source of transition revenue?**

6 A30. Yes. As previously noted, the RSR is designed as a tracking mechanism that will  
7 automatically adjust to provide AEP-Ohio a guaranteed level of generation  
8 revenue. IEU-Ohio witness Hess discusses why the RSR is contrary to Ohio  
9 policy and law in his testimony and should not be approved.

10 **Q31. Are there differences between the transition in SB 3 and the additional**  
11 **transition proposed by AEP-Ohio?**

12 A31. Yes. Broadly speaking, the SB 3 transition provided customers with electric bill  
13 predictability and certainty while giving customers the opportunity to do better by  
14 shopping. Residential customers were given a 5% discount off of the unbundled  
15 generation price. The FAC was eliminated. SB 3's transition did not shift  
16 revenue responsibility within or between rate groups.

17 In contrast, the transition resulting from AEP-Ohio's two-tiered capacity structure,  
18 coupled with the non-bypassable RSR, will economically limit shopping. So, the  
19 transition clearly protects AEP-Ohio but it does not contain the balanced, pro  
20 "customer choice" transition that was created in SB 3.

1 **Q32. How would the two-tiered pricing structure for capacity subsidize**  
2 **generation service for AEP-Ohio?**

3 A32. It would allow AEP-Ohio to impose and collect generation-related revenue from a  
4 currently higher than market charge on CRES providers who seek to serve load  
5 in the AEP-Ohio service area, when various AEP-Ohio affiliates are actively  
6 acquiring load at both the wholesale and retail level in other electric utility service  
7 areas while relying upon market-based priced capacity in order to do so. This is  
8 fundamentally unfair -- to AEP-Ohio customers, the broader PJM region and to  
9 CRES providers.

10 **Q33. Have AEP-Ohio affiliates participated in recent auctions to acquire**  
11 **generation to serve SSO load in Ohio?**

12 A33. Yes, several times, including on two recent occasions. Most recently, AEP-Ohio  
13 affiliates participated in an auction held December 14, 2011 to acquire SSO  
14 generation supply for Duke Energy Ohio ("Duke") customers and in a January 24,  
15 2012 auction to acquire SSO generation supply for customers of FirstEnergy's  
16 EDUs, which are The Cleveland Electric Illuminating Company, the Ohio Edison  
17 Company and The Toledo Edison Company. Both auctions required bidders to  
18 supply energy, capacity, losses and ancillary services necessary to provide SSO  
19 generation supply.

**Q34. What were the results of those auctions?**

A34. The December 14, 2011 auction produced a clearing price of \$49.72 per megawatt-hour ("MWH") for the January 1, 2012 to May 31, 2013 delivery year, \$51.10 per MWH for the January 1, 2012 to May 31, 2014 delivery year, and \$57.08 per MWH for the January 1, 2012 to May 31, 2015 delivery year. A summary of the auction results is included as Exhibit KMM-6. The January 24, 2012 auction produced a clearing price of \$44.76 per MWH for the June 1, 2012 to May 31, 2014 delivery year.

**Q35. Did AEP-Ohio affiliates participate in these auctions?**

A35. Yes. As shown on Exhibit KMM-6, in the December 14, 2011 auction, AEP Energy Partners, Inc. won a total of 5 tranches and AEPSC won 6 tranches. As shown on Exhibit KMM-7, in the January 24, 2012 auction, AEP Energy Partners, Inc. won 2 tranches and AEPSC won 2 tranches.

**Q36. How do bidders in the Duke and FirstEnergy SSO auctions acquire and pay for capacity and reflect those costs in their bids?**

A36. Both FirstEnergy and Duke are presently FRR entities in PJM. As a result, bidders were required to obtain and pay for capacity from the FirstEnergy operating companies or Duke for their respective auctions.

The FirstEnergy EDUs do not own any electric generation so their FRR election was executed differently than how AEP-Ohio participates in FRR. When FirstEnergy made the commitment to join PJM, the BRAs for the 2011-2012 and

1 2012-2013 delivery years had already occurred. Thus, it was necessary to  
2 establish a transition mechanism for FirstEnergy.

3 The transition plan developed for FirstEnergy established a two-year FRR to  
4 allow FirstEnergy to synchronize with PJM's normal RPM cycle. FirstEnergy's  
5 transition plan to enter PJM required it to obtain the necessary capacity  
6 resources for the 2011-2012 and 2012-2013 delivery years and include those  
7 capacity resources in an FRR plan submitted to PJM prior to each delivery year.  
8 The transition plan provided that FirstEnergy would participate in the BRA for the  
9 2013-2014 delivery year. The BRA for the 2013-2014 delivery year ("RTO  
10 locational deliverability area" or "RTO LDA") cleared at a price of \$27.73 per MW-  
11 day.

12 Because FirstEnergy's Ohio EDUs do not own generating assets, two integration  
13 auctions ("IA") were conducted to obtain capacity resources for the 2011-2012  
14 and 2012-2013 delivery years. The 2011-2012 FRR IA cleared 12,583.2 MW of  
15 unforced capacity in the RTO at a resource clearing price of \$108.89 per MW-  
16 day. The 2012-2013 FRR IA cleared 13,038.7 MW of unforced capacity in the  
17 RTO at a resource clearing price of \$20.46 per MW-day. These capacity prices  
18 are very close to capacity prices from the larger BRA for the same delivery years.  
19 Bidders in the auctions to obtain SSO generation supply for FirstEnergy were  
20 required to rely upon capacity secured in the two IAs and reflect this in their offer  
21 prices for the 2011-2012 and 2012-2013 delivery years. For the 2013-2014  
22 delivery year, bidders in the auctions to obtain SSO generation supply for  
23 FirstEnergy will use capacity secured through PJM's capacity auctions. Thus,

1 the clearing price of \$44.76 per MWH in the January 24, 2012 auction reflects  
2 bidders paying the FirstEnergy EDUs \$20.46 per MW-day for capacity in the  
3 2012-2013 delivery year, and paying the BRA clearing price for capacity of  
4 \$27.73 per MW-day for the 2013-2014 delivery year.

5 Duke also is operating under an FRR election but, similar to AEP-Ohio, it owns  
6 generating assets. Duke designated the capacity resources held to serve SSO  
7 load under its FRR plan submitted to PJM. Bidders participating in the Duke  
8 SSO auctions acquire capacity and pay Duke at prevailing market prices for  
9 capacity, the final clearing price established under RPM. The bid prices from the  
10 December 14, 2011 auction reflect BRA capacity costs of \$110.00 per MW-day  
11 for the 2011-2012 delivery year, \$16.46 per MW-day for the 2012-2013 delivery  
12 year, \$27.73 per MW-day for 2013-2014 delivery year, and \$125.99 per MW-day  
13 for the 2014-2015 delivery year. Thus, when AEP-Ohio affiliates compete at the  
14 wholesale or retail level to serve customers in other areas of Ohio, they rely upon  
15 capacity priced at prevailing market prices, or RPM.

16 **Q37. Are AEP-Ohio affiliates competing to serve retail customers throughout**  
17 **Ohio?**

18 A37. Yes. AEP Retail Energy, a non-regulated affiliate, is currently offering to serve  
19 customers throughout Ohio in regions open to retail customer choice. I have  
20 included, as Exhibit KMM-8, supply offers and the associated terms and  
21 conditions for residential customers as of March 15, 2012. AEP Retail Energy is  
22 also offering to supply commercial and industrial customers.



1 **Q38. When AEP Retail Energy acquires retail load, how do PJM's rules require**  
2 **AEP Retail Energy to obtain and pay for capacity?**

3 A38. The answer varies slightly depending on service areas due to FRR status and  
4 prior decisions of this Commission. For customers provided distribution service  
5 by the FirstEnergy EDUs or Duke, the process is very similar to how capacity is  
6 supplied to bidders in the SSO auction. As CRES providers acquire load in these  
7 service areas, they compensate the FRR entity for capacity at the same prices  
8 discussed earlier in my testimony that were relied upon by SSO bidders.

9 Dayton Power and Light ("DP&L") is not operating under an FRR plan. For EDUs  
10 in retail access states not under an FRR plan, CRES providers acquire and/or  
11 release capacity as they gain or lose load and pay for capacity at prevailing  
12 market prices - RPM. Thus, other than in AEP-Ohio's service area, when its  
13 affiliate AEP Retail Energy competes to serve customers, it obtains and pays for  
14 capacity based upon market-based rates, or RPM, and other generation  
15 suppliers receive market-based, rather than based on some form of "cost-based"  
16 arbitrary price for capacity used to serve retail customers.

17 When AEP Retail Energy serves customers in AEP-Ohio's service territory, the  
18 price for capacity will differ on an interim basis under the two-tiered pricing  
19 structure for capacity discussed earlier in my testimony. As things presently  
20 stand, the price for capacity will be either the RPM, market-based price or \$255  
21 per MW-day, based upon the Commission's March 7, 2012 entry in Case No. 10-  
22 2929-EL-UNC.

1 It is fundamentally unfair and contrary to Ohio's pro-competition policies to allow  
2 AEP-Ohio's affiliates to serve non AEP-Ohio EDU customers in other areas of  
3 Ohio while paying RPM market-based prices for capacity, but require CRES  
4 providers attempting to serve AEP-Ohio EDU customers to pay a much higher  
5 rate for capacity. The much higher ("cost-based" or arbitrary) price for capacity  
6 also amounts to a subsidy to AEP-Ohio's supposedly corporately separated  
7 generation business as it is significantly higher than prevailing market prices for  
8 capacity.

9 **Q39. Are there other indicators that RPM clearing prices are representative of**  
10 **prevailing market prices for capacity?**

11 A39. Yes. As previously mentioned, FirstEnergy's integration into PJM involved a  
12 transition plan to synchronize with the regular schedule developed to establish  
13 prices through the RPM mechanism. These capacity clearing prices from the  
14 FirstEnergy transitional auctions are very similar to the prevailing capacity prices  
15 in the BRA for the unconstrained region of PJM for the same delivery year, which  
16 were \$110.00 per MW-day for the 2011-2012 delivery year and \$16.46 per MW-  
17 day for the 2012-2013 delivery year. AEP-Ohio provides service within this  
18 unconstrained PJM region. When an FRR entity is located in the unconstrained  
19 portion of the PJM region, the RPM auction clearing price generally indicates the  
20 value of capacity that can be substituted for capacity located anywhere else in  
21 that unconstrained region. Thus, the transitional FRR IAs conducted for the  
22 FirstEnergy operating companies are representative of the broader relevant

1 market conditions and pricing outcomes in the unconstrained region of PJM,  
2 which includes AEP-Ohio. [BEGIN CONFIDENTIAL TESTIMONY]

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12 [END CONFIDENTIAL TESTIMONY].

13 **Q40. Has American Electric Power, through its other operating companies,**  
14 **recognized RPM prices as an appropriate market-based means of valuing**  
15 **capacity in other jurisdictions?**

16 A40. Yes, in addition to my earlier discussion of AEP-Ohio's use of and reliance upon  
17 PJM's RPM to support its pricing proposals and policy advocacy here in Ohio, it  
18 is also relying on RPM in several adjoining or nearby states to identify

1 appropriate capacity compensation. A number of American Electric Power EDUs  
2 in other states in the PJM region offer retail customers experimental rates or  
3 rates under pilot programs that reflect PJM real-time prices. For example,  
4 Kentucky Power offers customers an experimental real-time pricing rate, Tariff  
5 R.T.P., a copy of which is attached to my testimony as Exhibit KMM-10. Under  
6 this Kentucky Power rate schedule, the price charged to customers includes a  
7 component for capacity. The price reflected for capacity in the rates charged to  
8 Kentucky Power customers is based upon the prevailing RPM prices.

9 Indiana Michigan Power ("I&M") offers a similar experimental real-time pricing,  
10 Tariff R.T.P. in both its Indiana and Michigan rate zones. I have attached a copy  
11 of I&M's Tariff R.T.P. for the Indiana rate zone to my testimony as Exhibit KMM-  
12 11 and a copy of the I&M Tariff R.T.P. for the Michigan rate zone to my testimony  
13 as Exhibit KMM-12. In both instances, the capacity component of the rate  
14 charged to I&M customers is based upon the prevailing RPM prices.

15 Appalachian Power Company offers its customers in Virginia two dynamic pricing  
16 pilot rates, Schedule DP-1 and Schedule DP-2, which are attached to my  
17 testimony as Exhibit KMM-13. Schedule DP-1 allows eligible customers to have  
18 usage for the generation component of their bills charged based upon prices  
19 established in PJM's market. The capacity component of the rate is based on  
20 prevailing RPM prices.

21 Schedule DP-2 is perhaps more interesting in that it allows customers with  
22 eligible qualifying facilities to sell electricity energy and capacity to Appalachian

1 Power Company, with the rates based upon PJM's market. In other words, when  
2 Appalachian Power Company is purchasing capacity, the appropriate price is  
3 based upon prevailing RPM prices.

4 Thus, even in other states like Michigan that have adopted some form of  
5 "customer choice", or states that continue to rely upon rate base, rate of return  
6 economic regulation to establish retail electric prices, the AEP operating  
7 companies are using PJM's RPM to establish capacity-related prices.

8 **Q41. Are AEP-Ohio's proposed capacity prices to be charged CRES providers**  
9 **comparable to the charge for capacity embedded in the default generation**  
10 **supply SSO prices?**

11 A41. No. There is no explicit capacity charge in the SSO rates. Further, as shown on  
12 Exhibit KMM-14, when specifically requested in Case No. 10-2929-EL-UNC to  
13 identify the capacity component of its SSO rates, AEP-Ohio could not or chose  
14 not to do so. Thus, it is impossible to identify whether the proposed capacity  
15 charges that AEP-Ohio wants to impose on CRES providers is comparable to the  
16 capacity-related charge embedded in the default generation supply portion of the  
17 SSO prices.

18 **Q42. Why does comparability between the capacity-related charge that AEP-**  
19 **Ohio wants to impose on CRES providers and the capacity-related charge**  
20 **embedded in the default generation supply portion of the SSO prices**  
21 **matter?**

1 A42. AEP-Ohio has proposed a two-tiered pricing structure for capacity that by its very  
2 nature creates non-comparable capacity prices between customers depending  
3 on whether a shopping customer is in the first or second pricing tier for capacity.  
4 At the same time, AEP-Ohio has continued to maintain that the default  
5 generation supply prices are not based on cost and are not subject to  
6 examination based on a cost-based methodology.<sup>9</sup> This results in a situation in  
7 which it is impossible to establish comparable rates for capacity.

8 Also, even if AEP-Ohio's default generation supply price reflected the capacity  
9 rates AEP-Ohio proposes to charge to CRES providers, the structure of the  
10 default generation supply rate is very different than the unbundled per megawatt  
11 day rate design that applies to a CRES provider. In other words, the rate design  
12 between the two is not comparable and the structural differences make it  
13 impossible for a customer to develop a meaningful comparison, on an apples to  
14 apples basis, between the default generation supply price and pricing offers  
15 available from competitive suppliers.

16 **Q43. With regard to the non-comparable rate structures between the SSO pricing**  
17 **and the proposed two-tiered capacity prices for CRES providers, how could**  
18 **the structural non-comparability be remedied?**

19 A43. Assume the SSO residential rate totals \$0.08 per kWh and that the embedded  
20 capacity portion of this rate was \$0.02 per kWh. If the wholesale capacity price

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<sup>9</sup> An AEP-Ohio memorandum dated November 4, 2011 that discussed the need for an impairment analysis for the AEP East generating fleet, which was produced in response to an interrogatory and is attached to my testimony as Exhibit KMM-23, demonstrates that AEP-Ohio views its Ohio SSO generation rates as market-based rather than cost-based.

1 to CRES providers serving residential load in AEP-Ohio's service area was  
2 unbundled to show a separate and comparable capacity charge within the SSO  
3 structure, AEP-Ohio would be economically indifferent to shopping from a  
4 capacity revenue standpoint. In other words, it would obtain the same  
5 ("comparable") compensation for providing capacity generation service to a non-  
6 shopping customer as when the same customer elects to obtain service from a  
7 CRES provider.

8 However, under this same example, if the embedded capacity portion of the  
9 default generation supply price within the SSO was \$0.02 per kWh and the  
10 wholesale capacity price charged to CRES providers was set at \$0.04 per kWh,  
11 the results would not be comparable and the comparability violation would allow  
12 AEP-Ohio to bias customer choice in favor of the generation assets under its  
13 ownership or control, the structural problem that electric industry restructuring  
14 was designed to remedy. It is also my understanding that the rate levels and rate  
15 structures as between the default service option and the capacity pricing that  
16 applies to CRES providers must be comparable and non-discriminatory. In this  
17 proceeding, AEP-Ohio has presented no evidence to demonstrate that the prices  
18 for capacity to be charged CRES providers are comparable to the default  
19 generation supply service and price of the SSO.

20 **Q44. Are capacity resources that AEP-Ohio commits in an FRR capacity plan**  
21 **dedicated to serve AEP-Ohio customers?**

1 A44. No. As already discussed, the notion that capacity resources in PJM are  
2 dedicated to specific customers or load is an absolute fiction, irrespective of  
3 whether an LSE elects the FRR option or participates in RPM auctions.

4 PJM's RAA, which is included in my testimony as Exhibit KMM-15, contains the  
5 RPM rules. The RAA is a contract which has been filed with and approved by  
6 the FERC and that is executed by any party that is an LSE in PJM. An LSE in  
7 PJM includes not just an EDU, but any entity that by franchise, law or contract  
8 serves retail customers. Thus, an LSE in PJM includes any Ohio CRES provider.  
9 The RAA is a mutual assistance agreement, which is evidenced by the "whereas"  
10 provisions of the RAA that identifies the purpose of the agreement:

11 **WHEREAS**, each Party to this Agreement is a Load Serving Entity  
12 within the PJM Region;

13 **WHEREAS**, each Party is committing to share its Capacity  
14 Resources with the other Parties to reduce the overall reserve  
15 requirements for the Parties while maintaining reliable service; and

16 **WHEREAS**, each Party is committing to provide mutual assistance  
17 to the other Parties during Emergencies;

18 **WHEREAS**, each Party is committing to coordinate its planning of  
19 Capacity Resources to satisfy the Reliability Principles and  
20 Standards;

21 **WHEREAS**, the Parties previously have entered into similar  
22 commitments related to sub-regions of the PJM Region through the  
23 East RAA, the West RAA, or the South RAA;

24 **WHEREAS**, the Parties desire, on a phased basis, to replace the  
25 East RAA, West RAA, and South RAA with a single reliability  
26 assurance agreement among all Load-Serving Entities in the PJM  
27 Region; and



1                   **NOW THEREFORE**, for and in consideration of the covenants and  
2                   mutual agreements set forth herein and intending to be legally  
3                   bound hereby, the Parties agree as follows:<sup>10</sup>

4                   As the RAA clearly states, capacity resources in PJM are dedicated to the needs  
5                   of the PJM pool in total, and are not dedicated to the loads of specific LSEs. The  
6                   mutual assistance nature of the RAA is designed to reduce the overall level of  
7                   capacity resources that each LSE would need to hold in the absence of the  
8                   sharing of capacity resources in order to achieve a targeted level of reliability (at  
9                   least a loss of load probability of no more than one day in 10 years).

10                  The commitment to share capacity resources pursuant to the RAA again  
11                  illustrates the fundamental unfairness of allowing AEP-Ohio's retail marketing  
12                  affiliate to serve customers in other areas of Ohio, relying upon capacity owned  
13                  by other generation owners and paying them RPM prices for capacity, while  
14                  competitors attempting to serve AEP-Ohio customers would be burdened with  
15                  above market capacity charges under the Modified ESP.

16                  I would also note that Exhibit KMM-23<sup>11</sup>, an internal AEP memorandum, states  
17                  that:

18                         "[t]he non-cost based rate generation assets [of AEP-Ohio] are not  
19                         operated separately, but are coordinated and dispatched with  
20                         generation assets owned by the other East cost-based regulated  
21                         operating companies (APCo, KYPCo and I&M). The costs and

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<sup>10</sup> Exhibit KMM-15 at 4.

<sup>11</sup> Exhibit KMM-23 also describes the internal accounting that is used to reflect the unbundled services in Ohio: "As information, the Retail sales related to generation are unbundled from the total rate charged customers in one of two ways, depending on the way the billing rates are designed. For an unbundled rate company (OPCO, CSP, APCO-VA and I&M-MI), the billing rates are entered into the MACSS system for G, T and D. Unbundled revenue reports provide the billed and unbilled revenues that support the journal entries to unbundle the revenues."

benefits of the generation assets are shared among all of the East operating companies in the Interconnection Agreement (Agreement). The output of the Ohio Companies' generation plants is available to fulfill the continuing native load obligations of those jurisdictions through the Power Pool Agreements. Due to the nature of electrical energy and the operation of the plants through the Pool, it is impossible to match cash inflows from the sales to cash outflows from either purchased or generated power by unit of by plant."

Thus, AEP's own internal treatment of the AEP-Ohio generating plants is inconsistent with the notion that AEP-Ohio's generating plants are dedicated to satisfying FRR or other generating requirements of the retail customers within AEP-Ohio's distribution service area.

**Q45. What is your overall recommendation on the two-tiered capacity pricing structure and the proposed RSR?**

A45. The Commission should not approve the two-tiered capacity pricing structure and the prices for generation capacity service provided to CRES providers should be based on the RPM mechanism that was in place through December 31, 2011. The results of the RPM auctions including those in which [BEGIN CONFIDENTIAL TESTIMONY]

[END CONFIDENTIAL TESTIMONY] I discuss in my testimony, show that the RPM-based method of pricing capacity provides appropriate compensation to AEP-Ohio's generation business segment based on a market-based valuation of generation capacity. The Commission should also reject the proposed RSR.

1     **III.     CAPACITY BILLING**

2     **Q46.   Should the Commission require AEP-Ohio to provide customers and CRES**  
3           **providers additional information to verify they are being billed**  
4           **appropriately for capacity?**

5     A46.   Yes.   As previously noted, each PJM EDC is responsible for allocating its  
6           normalized previous summer's peak to each customer in the zone (both retail  
7           and wholesale). To assure that capacity resources are appropriately allocated to  
8           shopping and non-shopping customers and that the allocation process does not  
9           discriminate, a transparent process is necessary.

10          The Commission should require AEP-Ohio to document to customers and CRES  
11          providers that the PLC factor it is assigning to customers corresponds with the  
12          customers' PLC value recognized by PJM.<sup>12</sup>

13     **IV.     ESP VERSUS MRO**

14     **Q47.   What finding must the Commission make before it can approve an ESP?**

15     A47.   It is my understanding that before the Commission can approve an ESP it is  
16           required to find that the ESP is more favorable in the aggregate than an MRO.

17     **Q48.   Did the Company evaluate whether the ESP is more favorable in the**  
18           **aggregate than an MRO?**

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<sup>12</sup> Each PJM EDC is responsible for allocating the previous summer's weather normalized peak to end-use customers in the zone (both retail and wholesale) and for providing this information to PJM by December 31 prior to the start of the delivery year.

1 A48. Yes. In her testimony in support of the Modified ESP, AEP-Ohio witness Laura J.  
2 Thomas describes her comparison of the SSO results under an MRO, using  
3 administratively-determined competitive benchmark prices she developed, to an  
4 SSO under the proposed Modified ESP. The results of this comparison for  
5 planning years 2012/2013, 2013/2014 and 2014/2015 are presented on Exhibit  
6 LJT-1, page 2 of 3. For purposes of portraying the MRO SSO outcome, Ms.  
7 Thomas uses administratively-determined competitive benchmark prices of  
8 \$69.36 per MWH for planning year 2012/2013, \$71.09 per MWH for planning  
9 year 2013/2014 and \$74.34 per MWH for planning year 2014/2015. In addition,  
10 page 1 of Exhibit LJT-1 summarizes what Ms. Thomas characterizes as  
11 quantifiable and non-quantifiable benefits of the Modified ESP, with the  
12 quantifiable benefits totaling \$960,622,505.

13 **Q49. Have you identified any errors or shortcomings in the ESP versus MRO**  
14 **analysis performed by AEP-Ohio witness Thomas?**

15 A49. Yes. In addition to the flaws in her analysis regarding the pricing impacts of the  
16 Modified ESP versus MRO, which I discuss later in my testimony, Ms. Thomas  
17 relies upon calculations performed by AEP-Ohio witness Allen to suggest that the  
18 Modified ESP provides \$988,700,00 in benefits because of the proposal to  
19 provide CRES providers with “discounted” generation capacity service prices.  
20 The math behind the \$988,700,000 “benefit” shows that it is the difference in  
21 revenue between the two-tiered capacity price proposed in the Modified ESP and  
22 the revenue produced by a so called “cost-based” rate for capacity equivalent to  
23 \$355 per MW-day. In other words, the “discounted” capacity benefit that AEP-

Ohio attributes to the Modified ESP assumes that but for the proposed two-tiered capacity prices of \$145.79 per MW-day and \$255 per MW-day, the price for generation capacity service embedded in an MRO SSO would be \$355 per MW-day. By assuming that things would be worse and that AEP-Ohio would be permitted another opportunity to collect above-market generation revenue (transition revenue) when retail customers shop but for the two-tiered capacity pricing proposal, AEP-Ohio then claims that the Modified ESP is better than the MRO.

**Q50. Do you agree with Company witness Thomas' claim that the two-tiered capacity pricing proposal can be counted as a benefit for purposes of comparing the SSO under the MRO option with the SSO under the ESP option?**

A50. No, for several reasons. First, AEP-Ohio has never received regulatory approval from any regulator (either this Commission or FERC) to impose a \$355 per MW-Day charge on CRES providers. In fact, as discussed earlier in my testimony, the interim capacity charges authorized by the Commission in Case No. 10-2929-EL-UNC are lower for the first tier of capacity than AEP-Ohio's current proposal (priced at prevailing RPM prices) and more customers are eligible for the RPM-based first tier of the capacity pricing structure through governmental aggregation programs. Additionally, the interim capacity charges authorized by the Commission are due to revert to prices based upon prevailing market rates or RPM on June 1, 2012. Therefore, characterizing a discount to a capacity price that is higher than any rate AEP-Ohio has ever been authorized to charge a

1 CRES provider as a benefit that can be counted for purposes of comparing the  
2 Modified ESP to an MRO has no factual support and it ignores the capacity  
3 pricing that is currently in place.

4 More fundamentally, the question of whether charging CRES providers higher  
5 than market prices of capacity can be counted as an ESP benefit simply because  
6 the price was lower than what AEP-Ohio would like to charge has been  
7 addressed by the Commission. The Commission directly confronted this issue  
8 when it issued its December 14, 2011 order approving the (now rejected)  
9 Stipulation in this proceeding. In support of its effort to secure approval of the  
10 Stipulation, AEP-Ohio argued, as it has again here, that the two-tiered capacity  
11 pricing proposal in the Stipulation provided capacity to CRES providers at a  
12 discount which was a benefit that had to be counted in the ESP versus MRO  
13 analysis. The Commission correctly concluded otherwise and pointed at other  
14 flaws in the ESP versus MRO analysis that AEP-Ohio witness Thomas has  
15 included in the ESP versus MRP analysis once again:

16 [W]e believe the Signatory Parties and AEP-Ohio cannot claim the  
17 discounted capacity price to CRES providers as a benefit. As Mr.  
18 Fortney appropriately stated in his testimony, AEP-Ohio's  
19 requested capacity price in its application was never certain, and  
20 therefore, it cannot be considered as either a benefit or meaningful  
21 number for the purposes of conducting the statutory test (Tr. X at  
22 1707-1708).

23 *In the Matter of the Application of Columbus Southern Power Company and Ohio*  
24 *Power Company for Authority to Establish a Standard Service Offer Pursuant to*  
25 *Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Case*  
26 *Nos. 11-346-EL-SSO, et al., Opinion and Order at 30-31 (December 14, 2011).*

1 The fact that AEP-Ohio has chosen to completely disregard the explicit finding  
2 and guidance provided by the Commission in its December 14 Opinion and  
3 Order on this issue reinforces the conclusion that AEP-Ohio has not presented  
4 the Commission with a credible analysis of the Modified ESP in this case.

5 The latest claim that “discounted” capacity pricing is a benefit under the Modified  
6 ESP is even more ludicrous when the effects of the RSR are recognized for  
7 purposes of conducting the MRO versus ESP analysis. As discussed in the  
8 testimony of AEP-Ohio witness Allen, under AEP-Ohio's proposal any change in  
9 the level of capacity pricing up or down will translate into a dollar for dollar  
10 change in the level of the RSR.<sup>13</sup> As Mr. Allen states in his testimony, a \$10 per  
11 MW-day decrease in the capacity charge will cause a corresponding \$33 million  
12 increase in the RSR revenue requirement over the term of the Modified ESP, and  
13 a \$10 per MW-day increase in the capacity charge will cause a corresponding  
14 \$33 million decrease in the RSR revenue requirement over the term of the  
15 Modified ESP. Thus, the RSR is designed to act a backstop to guarantee AEP-  
16 Ohio a target level of generation revenue irrespective of what level of capacity  
17 pricing may ultimately be approved.

18 **Q51. If capacity pricing cannot be counted as a benefit, consistent with the**  
19 **Commission’s prior Opinion and Order in this proceeding and the reasons**

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<sup>13</sup> *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case Nos. 11-346-EL-SSO, et al., Direct Testimony of William A. Allen at 14-15 (March 30, 2012).

1           **you have discussed, how do the ESP versus MRO results summarized on**  
2           **Exhibit LJT-1, page 1 of 3 change?**

3   A51. Notwithstanding the additional flaws in Company witness Thomas' analysis which  
4       I discuss later in my testimony, and if Ms. Thomas' analysis is only corrected to  
5       remove the improper "discounted" capacity assumption, the Modified ESP is less  
6       favorable than the assumed MRO alternative by \$28,077,495, a swing of just  
7       under \$1 billion. This fundamental defect in Ms. Thomas' ESP versus MRO  
8       analysis shows that AEP-Ohio has not come forward with evidence to  
9       demonstrate the Modified ESP meets the "more favorable in the aggregate test"  
10      required for ESP approval. And, the almost \$1 billion swing in the results of the  
11      ESP versus MRO test highlights the significantly excessive above-market burden  
12      that the Modified ESP would, if approved, impose on electric consumers and the  
13      high degree of sensitivity that Ms. Thomas' analysis has to adjustments that are  
14      needed to better reflect the market prices essential to the ESP versus MRO  
15      comparison.

16   **Q52. Have you identified any other flaws in the analysis performed by Company**  
17   **witness Thomas?**

18   A52. Yes. There are numerous flaws in Ms. Thomas' analysis. The methodology  
19      utilized by Ms. Thomas for her analysis relies exclusively upon administratively-  
20      determined market price estimates rather than the actual results from recent  
21      auctions in Ohio to establish SSO generation prices for other EDUs. Under  
22      these circumstances, I view the exclusive use of administratively-determined



1 prices to be unreasonable given the availability of actual auction results and  
2 other readily available measures to check whether the administratively-  
3 determined price are reasonable.

4 Additionally, the methodology used by Ms. Thomas to develop the  
5 administratively-determined competitive benchmark price is unreasonable and  
6 unreliable in many aspects. The assumed capacity costs reflected in the  
7 competitive benchmark price are based upon the so called “cost-based” capacity  
8 charge of \$355 per MW-day requested by AEP-Ohio in Case No. 10-2929-EL-  
9 UNC. The resulting capacity price that Ms. Thomas applies to calculate the  
10 results of a CBP used on the MRO option grossly overstates the capacity price  
11 that would apply to the CBP associated with the MRO option. As a result, the  
12 competitive benchmark prices in Ms. Thomas’ analysis, for purposes of  
13 portraying the MRO results, are too high by a very large margin. For the January  
14 2015 to May 2015 delivery period, Ms. Thomas assumes that bidders for the  
15 energy only SSO CBP proposed as part of the Modified ESP are subject to  
16 capacity charges of \$355 per MW-Day, which conflicts with the testimony of  
17 AEP-Ohio witness Allen.<sup>14</sup> Further, Company witness Thomas also fails to  
18 recognize that AEP-Ohio’s current ESP includes distribution rate riders  
19 (gridSMART and the Enhanced Service Reliability Rider) that were approved  
20 pursuant to the single issue ratemaking provision of Section 4928.143(B)(2)(h),  
21 Ohio Revised Code. In projecting the cost of the Modified ESP, she also ignores  
22 the distribution investment rider (“DIR”) proposed as part of the Modified ESP. I

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<sup>14</sup> *Id.* at 7.

1 have been advised by counsel that an MRO does not permit the inclusion of  
2 similar charges. Therefore, the ESP versus MRO comparison must recognize  
3 the economic benefits that customers would receive under the MRO option from  
4 elimination of these riders, something that Ms. Thomas' analysis fails to do.

5 Additionally, AEP-Ohio has proposed to include the GRR as a non-bypassable  
6 placeholder rider to be used to potentially collect costs associated with the  
7 Turning Point Solar Project. Ms. Thomas assumes zero cost for this rider in her  
8 ESP versus MRO analysis.<sup>15</sup> I have been advised by counsel that OP and CSP  
9 could not include this placeholder rider under an MRO and even if includable  
10 under the MRO option, it could not be included as a non-bypassable charge. It is  
11 improper and unreasonable to omit the potential effect of the GRR for the  
12 purpose of comparing the Modified ESP to the MRO. In its December 14, 2011  
13 Opinion and Order in this proceeding, the Commission found that the projected  
14 effect of the GRR had to be quantified and included to properly perform the ESP  
15 versus MRO analysis.<sup>16</sup>

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<sup>15</sup> In supplemental testimony filed on May 2, 2012, Ms. Thomas testifies that the GRR should not affect the ESP versus MRO analysis based upon advice from counsel that Rider GRR would be available under either an ESP or an MRO. However, Ms. Thomas further testifies that if the Commission determines Rider GRR is only available under an ESP, the additional cost of the GRR is \$8,377,000 over the term of the Modified ESP.

<sup>16</sup> "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 (Tr. X at 1694-1695)." *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case Nos. 11-346-EL-SSO *et al.*, Opinion and Order at 30 (December 14, 2011).

1 Ms. Thomas fails to account for an increase in the SSO price that is likely to  
2 occur as a result of the AEP-Ohio proposal to conduct a limited energy-only  
3 competitive bid for 5% of the SSO load beginning six months after a final order in  
4 this proceeding. This error understates the cost of the Modified ESP.

5 AEP-Ohio witness Thomas presents two alternative scenarios in her analysis.  
6 The first focuses solely on the January 2015 to May 2015 delivery period. Here  
7 again, Ms. Thomas' alternative scenario, as presented on Exhibit LJT-3, page 1  
8 of 1, reflects an assumed capacity cost of \$355 per MW-Day for the January  
9 2015 through May 2015 delivery period, which differs from AEP-Ohio's Modified  
10 ESP proposal, thereby making Ms. Thomas' analysis defective and meaningless.

11 Ms. Thomas' second alternative scenario, as shown on Exhibit LJT-5, assumes  
12 an amalgamation that mixes the assumed prices of customers receiving SSO  
13 service with the assumed prices paid by customers being served by CRES  
14 providers. As I discuss later in my testimony, I don't believe this analysis is  
15 proper. It does not provide an accurate or meaningful comparison of the ESP  
16 versus MRO, and should be disregarded by the Commission.

17 AEP-Ohio witness Thomas' analysis of the ESP versus the MRO also is  
18 defective because it includes an apparent error in the current transmission cost  
19 recovery "G" component shown on all of her exhibits. The value that appears in  
20 her exhibits does not tie to the values supported by the workpapers of David M.  
21 Roush, as shown on Exhibit KMM-16.

1 **Q53. Are there other reasons the Commission should not rely upon AEP-Ohio's**  
2 **and Ms. Thomas' competitive benchmark analysis?**

3 A53. Yes. It is not reasonable to rely exclusively upon administratively-determined  
4 estimates of competitive power prices for purposes of portraying the MRO option  
5 when actual auction results for Ohio SSO load are readily available and more  
6 reliable. On August 25, 2010, the Commission approved an ESP for Ohio Edison  
7 Company, The Cleveland Electric Illuminating Company and The Toledo Edison  
8 Company (collectively "FirstEnergy") in Case No. 10-388-EL-SSO. The  
9 FirstEnergy ESP is for a three-year term beginning June 1, 2011 and continuing  
10 through May 31, 2014. A key feature of the ESP is that all of the generation  
11 supply required to provide the SSO to FirstEnergy's retail customers is obtained  
12 through a CBP. The auction schedule, including the number of tranches secured  
13 in each auction and the associated delivery periods, is shown on Exhibit KMM-  
14 17. Three of the scheduled auctions have been completed to date, securing  
15 tranches associated with all three years of FirstEnergy's ESP. In the present  
16 circumstances, it is unreasonable to use administratively-determined price  
17 estimates to portray the MRO option in view of the actual CBP information that is  
18 readily available for at least a portion of the period covered by the Modified ESP.  
19 For periods after June 1, 2014, it is appropriate to consider administratively-  
20 determined market price estimates in conjunction with the results of SSO  
21 auctions since comparable bids prices do not yet exist, or as the Commission  
22 has done in other circumstances such as those associated with the FirstEnergy  
23 RSPs, subject the Modified ESP to a CBP test.

1 **Q54. Are there other tools to evaluate whether Ms. Thomas' administratively-**  
2 **estimated benchmark prices used to portray the MRO option are**  
3 **reasonable?**

4 A54. Yes. The administratively-estimated benchmark prices can be compared to  
5 actual supply offers. There are several active suppliers in Ohio that publish offer  
6 prices and plans on their websites and allow electronic enrollment. I have  
7 included, as Exhibit KMM-18, a sample of current offers. FirstEnergy Solutions is  
8 offering residential customers of Ohio Edison 6% off of the customer's price to  
9 compare ("PTC") through June 2014. The result from the January auction for  
10 FirstEnergy SSO load discussed earlier in my testimony is blended with the  
11 results from prior auctions. Beginning June 1, 2012 through May 31, 2013, the  
12 PTC for FirstEnergy customers will be \$53.37 per MWH,<sup>17</sup> and the FirstEnergy  
13 Solutions offer for 6% off the PTC is equivalent to \$50.17 per MWH.

14 AEP Retail Energy Partners LLC is offering FirstEnergy residential customers a  
15 24-month fixed price of 5.69 cents per kWh.

16 As shown on Exhibit KMM-18, in the Duke service area, both FirstEnergy  
17 Solutions and Direct Energy are offering residential customer rates as low as  
18 \$56.90 per MWH with contract terms through March 2014, or 12 months,  
19 respectively. AEP Retail Energy Partners LLC is offering residential customers a  
20 fixed price of 5.79 cents per kWh through May 2014. In all instances, these

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<sup>17</sup> A Commission press release announcing the results of the latest FirstEnergy SSO auction and the blended rate to become effective June 1, 2012 is posted at:  
<http://www.puco.ohio.gov/puco/index.cfm/media-room/media-releases/firstenergy-customers-can-expect-lower-electricity-prices-beginning-this-summer/> (last accessed April 12, 2012).

1 prices are considerably lower than the administratively-determined competitive  
2 benchmark prices developed by Company witness Thomas for similar delivery  
3 periods.

4 **Q55. Why are the January 2012 FirstEnergy auction results much lower than**  
5 **current street offers for residential customers?**

6 A55. The market dynamics differ between CBP auctions and street offers for  
7 residential customers. The CBP relies upon a descending clock auction in which  
8 bidders have to lower their offer prices in each round in order to stay in  
9 contention for prospective business. Bidders know they must lower their prices  
10 in each auction round to meet or beat other bidders in order to secure any  
11 business.

12 Retail generation supply street offers, particularly in nascent markets for  
13 residential customers, are often priced in order to beat the default generation  
14 supply price to compare or “PTC”, rather than totally reflecting underlying market  
15 fundamentals. Other competitive offers may provide an additional check on  
16 street offers.

17 **Q56. Did you consider using supply offers for AEP-Ohio customers to**  
18 **benchmark Company witness Thomas’ administratively-determined**  
19 **competitive benchmark prices?**

20 A56. Yes. I considered this but decided it was not appropriate. As a result of the  
21 regulatory uncertainty in AEP-Ohio’s service area regarding what capacity costs  
22 a CRES provider may or may not incur, and the confusions that AEP-Ohio has

1 created in the administration of the two-tiered capacity pricing structure, I elected  
2 to not rely upon supply offers in AEP-Ohio's EDU service area.

3 **Q57. What are the results of the most recent FirstEnergy SSO auctions?**

4 A57. As I noted previously in my testimony, the auction held January 24, 2012  
5 obtained SSO generation supply for the two-year delivery period of June 1, 2012  
6 through May 31, 2014 at a price of \$44.76 per MWH. AEP-Ohio affiliates were  
7 winning bidders in the auction.

8 **Q58. Why are the prices resulting from the FirstEnergy SSO auctions held in**  
9 **January 2012 significantly lower than prices resulting from the Duke SSO**  
10 **auctions in December 2011?**

11 A58. Electricity prices are significantly influenced by the underlying prices of essential  
12 inputs such as fuel (coal, natural gas and oil) used in fossil-fueled generating  
13 facilities. The United States has seen a prolific growth in natural gas production  
14 in recent years due to shale gas development. Natural gas storage inventories  
15 were at record levels at the beginning of winter and a warmer than normal winter  
16 resulted in all-time record high natural gas storage inventories at the end of the  
17 winter heating season. These underlying fundamentals have put downward  
18 pressure on natural gas prices in the spot and forward market and natural gas  
19 prices are at ten year lows. Low natural gas prices have prompted some  
20 switching to natural gas generating facilities from coal-fired generating capacity  
21 and the reduced coal demand has put downward pressure on coal prices as well.

1 As a result of these changing fundamentals, wholesale electricity prices have  
2 declined by approximately 30% since December, 2011.

3 **Q59. Has AEP-Ohio witness Thomas made additional errors that result in the**  
4 **capacity component of the benchmark price she uses for purposes of**  
5 **portraying the MRO option being overstated?**

6 A59. Yes. To derive the competitive benchmark price used in her analysis, rather than  
7 assuming all capacity was priced at prevailing market prices, Ms. Thomas  
8 assumed that capacity prices were set at the \$355 per MW-day rate AEP-Ohio  
9 has requested in Case No. 10-2929-EL-UNC.

10 **Q60. Why is AEP-Ohio witness Thomas' utilization of the \$355 per MW-day**  
11 **capacity cost incorrect?**

12 A60. There are several reasons. First, Ms. Thomas is relying upon the so-called state  
13 compensation mechanism that appears in PJM's RAA to derive the capacity  
14 prices reflected in her competitive benchmark price which is used to portray the  
15 MRO option. The state compensation mechanism results from Schedule 8.1,  
16 Section D.8 of PJM's RAA, which provides (emphasis added):

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



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

10 Ms. Thomas fails to recognize that under an MRO, which provides for generation  
11 prices to be established pursuant to a CBP, the CBP bidders are engaged in a  
12 wholesale transaction to provide generation service to the EDU responsible for  
13 providing the SSO, and the EDU remains the LSE under PJM's tariff. Thus, the  
14 state compensation mechanism reflected in PJM's tariff would not be applicable  
15 to bidders in an MRO CBP because the MRO CBP is a wholesale transaction  
16 subject to the jurisdiction of FERC. Thus, the \$355 per MW-day premise for her  
17 estimated capacity prices is incorrect even if a \$355 per MW-day capacity price  
18 is assumed to apply to CRES providers though the FRR state compensation  
19 mechanism route. Additionally, as previously noted, no regulatory agency has  
20 ever approved a \$355 per MW-day charge for capacity. Thus, there is no basis  
21 to rely upon the \$355 per MW-day rate in any event.

22 **Q61. How would capacity be priced if a competitive bid was conducted if AEP-**  
23 **Ohio were assumed to be an FRR entity?**

24 A61. As explained earlier in my testimony, AEP-Ohio is an EDU with a generation  
25 business segment. If the vertically-integrated AEP-Ohio elected the FRR option,  
26 the generation business segment could negotiate a wholesale price under which  
27 it would sell capacity resources which must be designated under its FRR plan to

1 potential suppliers in the CBP and bidders would reflect these prices in their bids.  
2 Alternatively, prospective bidders could obtain other capacity resources through  
3 ownership or bilateral contracts that they would substitute for currently  
4 designated capacity resources in the FRR plan.<sup>18</sup> Bidders would logically  
5 attempt to maximize the recovery of the capacity cost of such resources in their  
6 bids.

7 **Q62. Would potential bidders in the MRO CBP process likely be willing to pay**  
8 **the Company \$355 per MW-day for capacity?**

9 A62. No. While potential bidders may be willing to obtain capacity from AEP-Ohio's  
10 generation segment, there is no good or rational reason to assume that such  
11 bidders would be willing to pay much more for capacity than they would pay  
12 based on prevailing market prices. As previously discussed, market prices for  
13 capacity are readily identifiable from the transparent BRAs that have been  
14 conducted by PJM as well as the FRR integration auctions conducted for  
15 FirstEnergy. Additionally, and as I discussed at page 23-24 of my testimony,  
16 when advocating for a statewide CBP for SSO load in 2007, AEP-Ohio indicated  
17 that if the Commission directed that a statewide bid be conducted, AEP-Ohio  
18 would sell capacity to winning bidders at RPM prices until such time as it could  
19 terminate its FRR status.

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<sup>18</sup> Schedule 8.1 Section G of PJM's RAA allows an LSE that selects the FRR option to substitute capacity resources as necessary to cure deficiencies or avoid penalty charges.

1 **Q63. Have you derived market price estimates for the term of AEP-Ohio's**  
2 **Modified ESP based upon the results of the competitive bids conducted to**  
3 **obtain SSO generation supply for FirstEnergy?**

4 A63. Yes. Based upon the results of the recent auctions to solicit SSO generation  
5 supply for FirstEnergy, I selected a price of \$44.76 per MWH as an appropriate  
6 market price estimate for the June 2012 to May 2014 delivery period. For the  
7 period of June 2014 through May 2015, in the interest of simplicity, I started with  
8 the administratively-determined market price estimate of \$74.34 used by Ms.  
9 Thomas and then reduced her assumed price to \$60.22 per MWH to reflect  
10 known capacity prices based upon RPM. For the period of June 2015 through  
11 May 2016, and in the interest of simplicity, I assumed a market price estimate of  
12 \$63.46 per MWH, which is the market price for this delivery period reflected in  
13 Ms. Thomas' workpapers, similarly adjusted downward to reflect known RPM-  
14 based capacity prices. The calculations supporting these estimates are shown  
15 on Exhibit KMM-19.

16 **Q64. How did you develop your estimated market prices for the June 2014**  
17 **through May 2016 delivery periods?**

18 A64. To derive the estimated market prices I began with AEP-Ohio witness Thomas'  
19 estimated market prices that reflect capacity priced at \$145.79. I then adjusted  
20 the capacity component of the price downward to reflect the capacity component  
21 Ms. Thomas estimated based upon RPM prices, as shown on Exhibit LJT-1,  
22 page 2 of 3, of her prior testimony filed in support of the Stipulation in this

1 proceeding. At the time my testimony was prepared, capacity prices for the June  
2 2015 through May 2016 delivery period were not known because the BRA will  
3 not occur in May 2012 until after my testimony is filed. Therefore, I assumed  
4 capacity prices at the level for the prior delivery year. Other than modifying the  
5 capacity cost component of the estimated market prices, I made no other  
6 adjustments. This is conservative (favorable to AEP-Ohio's position) as other  
7 cost components of Ms. Thomas' administratively-estimated prices, such as the  
8 load shaping and following component and the transaction risk adder, move up  
9 or down in relationship to the overall price. I held these cost components equal  
10 to the levels estimated at a capacity price of \$145.79 per MW-day,  
11 notwithstanding the known reduction in capacity prices that result from the RPM  
12 process.

13 **Q65. Did the CBP used to secure generation supply for FirstEnergy's SSO load**  
14 **require winning bidders to supply advanced energy resources or credits?**

15 A65. No. FirstEnergy plans to conduct a separate request for proposals to obtain  
16 renewable energy credits to satisfy its statutory obligations.

17 **Q66. Did you make any adjustments to your market price estimate to reflect**  
18 **differences associated with the responsibility to provide advanced energy**  
19 **resources or credits?**

20 A66. Yes. Because the CBP for generation supply for FirstEnergy's SSO load did not  
21 include the requirement for winning bidders to supply alternative energy  
22 resources or credits, I adjusted the market price upwards to reflect the cost of the

1 alternative energy requirement in the competitive benchmark price reflected in  
2 the testimony of Ms. Thomas. This requires an upward adjustment of \$.54 per  
3 MWH in 2012, \$.79 per MWH in the January 2013 through May 2014 period, and  
4 \$1.03 per MWH in the June 2014 through May 2015 period. Ms. Thomas did not  
5 provide an estimate of the cost of alternative energy requirements for June 2015  
6 through May 2016. I escalated the price upward by \$1.28 per MWH in the June  
7 2015 through May 2016 period to reflect alternative energy requirements.

8 **Q67. Are there any other factors that are necessary to consider in the**  
9 **comparison of the expected results of an MRO versus AEP-Ohio's Modified**  
10 **ESP?**

11 A67. Yes. AEP-Ohio has two distribution riders that were approved as part of the  
12 underlying and current ESPs. These riders are the gridSMART Rider and the  
13 Enhanced Service Reliability Rider. Based upon discussions with counsel, it is  
14 my understanding that these riders were approved pursuant to Section  
15 4928.143(B)(2)(h), Ohio Revised Code. I have been advised by counsel that the  
16 single issue distribution ratemaking provision of Section 4928.143(B)(2)(h), Ohio  
17 Revised Code, is not available under an MRO and that, under an MRO, the SSO  
18 price is a proportional blend of the bid price and the generation service price for  
19 the remaining SSO load. Therefore, the ESP versus MRO comparison must  
20 recognize the elimination of the gridSMART Rider and the Enhanced Service  
21 Reliability Rider that would occur under an MRO. The Modified ESP, if  
22 approved, would also allow the Company to implement the DIR and the Storm  
23 Damage Recovery Mechanism. The ESP versus MRO comparison must

1 recognize the elimination of these riders for the purpose of specifying the cost of  
2 the MRO alternative.

3 **Q68. Does the ESP versus MRO comparison performed by AEP-Ohio witness**  
4 **Thomas recognize the costs associated with the proposed GRR?**

5 A68. No. The Modified ESP includes a provision to establish a non-bypassable GRR  
6 as a placeholder rider with an initial charge of zero. The Modified ESP would  
7 allow AEP-Ohio to seek recovery through subsequent proceedings of the cost of  
8 the Turning Point Solar project and a new MR6 unit. On July 1, 2011, the  
9 Company filed supplemental testimony indicating it had reached definitive  
10 agreements with the Turning Point Solar project developer. Company witness  
11 Phillip J. Nelson provided supplemental testimony that includes the projected  
12 revenue requirement for the project.<sup>19</sup> However, Ms. Thomas does not address  
13 or recognize the costs associated with the GRR in her ESP versus MRO  
14 analysis, disregarding the Commission's prior guidance on this issue which I  
15 discussed earlier in my testimony.

16 **A69. Is it necessary to recognize the costs associated with the GRR in the ESP**  
17 **versus MRO comparison?**

18 A69. Yes. I have been advised by counsel that an ESP permits, under certain  
19 circumstances and provided statutory criteria are met, a provision for a non-

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<sup>19</sup>*In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Case Nos. 11-346-EL-SSO, et al., Supplemental Testimony of Philip J. Nelson, Exhibit PJN-5, page 2 (May 2, 2012).*

bypassable charge to recover the costs associated with new generating facilities approved by the Commission as part of an ESP. However, there is no similar provision that allows such a non-bypassable charge under an MRO.

**A70. Are the costs associated with the RSR additional costs under an ESP?**

A70. Yes. I have been advised by counsel that there is no lawful authority for the proposed RSR. However, if the RSR is approved, it would be an additional cost that must be recognized in the ESP versus MRO analysis.

**A71. Did you perform a comparison of the expected results of an MRO versus AEP-Ohio's Modified ESP using the adjusted market prices you have described in your testimony?**

A71. Yes. I analyzed multiple scenarios due to how AEP-Ohio has structured its Modified ESP. First, I examined the delivery periods between June 1, 2012 and December 31, 2014. I examined these delivery periods because they are prior to the proposed energy-only auctions to secure generation supply for SSO load on and after January 1, 2015, and due to the caveats regarding the ESP versus MRO comparison for the January 2015 to May 2015 delivery period that I discuss later in my testimony. After making the adjustments discussed in my testimony and shown on Exhibit KMM-20, the ESP is less favorable than the MRO by \$7.64 per MWH or \$137 million in the June 2012 through May 2013 delivery period, \$9.53 per MWH or \$132 million in the June 2013 through May 2014 delivery period, and \$7.47 per MWH or \$61 million in the June 2014 through December 2014 delivery period. Using the assumed SSO load reflected in AEP-Ohio

1 witness Allen's workpapers, which I believe significantly overstates likely  
2 shopping if the AEP-Ohio above-market capacity pricing requests are  
3 entertained, the ESP is less favorable than an MRO by \$330 million over this 31-  
4 month period.

5 **Q72. What are the results of your ESP versus MRO analysis for the period**  
6 **January 2015 to May 2015 and June 2015 to May 2016?**

7 A72. The ESP is less favorable than an MRO by \$13.53 per MWH between January  
8 2015 and May 2015. Using the assumed SSO volumes reflected in AEP-Ohio  
9 witness Allen's testimony and workpapers, the Modified ESP costs \$77 million  
10 more than the MRO for the period. This is in addition to the \$333 million higher  
11 cost of the ESP for the June 2012 through December 2014 period I discuss  
12 earlier in my testimony.

13 For the June 2015 through May 2016 delivery year, the Modified ESP is less  
14 favorable than an MRO by \$2.08 per MWH. Assuming the same SSO volumes  
15 as the prior delivery year, the Modified ESP costs \$29 million more than the  
16 MRO. This is in addition to the \$330 million higher cost of the ESP for the June  
17 2012 through December 2014 period I discuss earlier in my testimony.

18 **Q73. Are there additional costs of the Modified ESP that are not reflected in**  
19 **finding that the Modified ESP is less favorable than the MRO by \$330**  
20 **million?**



1 A73. Yes. The \$330 million only reflects the cost disadvantage to SSO or non-  
2 shopping customers. However, there are three categories of additional costs of  
3 the Modified ESP that customers will experience and must be recognized for  
4 purposes of comparing the Modified ESP to an MRO. First, an additional cost of  
5 the Modified ESP is the above market capacity costs that AEP Ohio wants to levy  
6 on shopping customers. Exhibit WAA-4 to the testimony of AEP Ohio witness  
7 Allen shows that under the Modified ESP, and based upon the switching levels  
8 assumed in Mr. Allen's testimony, AEP-Ohio expects to collect \$1,204 million in  
9 capacity revenue from CRES providers between June 2012 and May 2015 that  
10 will be reflected in the prices CRES providers charge their customers. If CRES  
11 providers were compensating AEP-Ohio at RPM, which reflects prevailing market  
12 prices, I estimate that Mr. Allen's \$1,204 million would drop to \$434 million in  
13 capacity revenues between June 2012 and May 2015. The difference of \$770  
14 million is an additional cost to consumers of the Modified ESP and is a source of  
15 transition revenue to AEP-Ohio. I have prepared Exhibit KMM-21 which shows  
16 the derivation of the additional \$770 million cost to shopping customers that will  
17 result if the Modified ESP is approved.

18 Second, the \$330 million Modified ESP disadvantage only captures the impacts  
19 of the RSR on non-shopping customers. AEP-Ohio proposed that the RSR be  
20 non-bypassable and payable by shopping customers as well. Based upon the  
21 assumed level of shopping reflected in AEP-Ohio witness Allen's testimony, as  
22 shown on Exhibit KMM-21, the RSR will collect \$198 million in transition revenue  
23 from shopping customers between June 1, 2012 and May 31, 2015. The effect

1 of the RSR on non-shopping customers is a cost of the Modified ESP and must  
2 be recognized for purposes of comparing it to an MRO.

3 Third, as discussed in the testimony of IEU-Ohio witness Bowser, the excessive  
4 carrying cost and other improper accounting treatment associated with AEP-  
5 Ohio's proposed PIRR should be considered an additional cost of the Modified  
6 ESP that is not reflected in my computation of the \$330 million ESP  
7 disadvantage. The additional cost of the version of the PIRR included in the  
8 Modified ESP is, based upon net present value analysis, at least \$186 million.

9 **Q74. Does your analysis understate how much the Modified ESP fails the better**  
10 **in the aggregate test between June 2012 and December 2014?**

11 A74. That is likely so based upon my understanding of the Company's plans to  
12 conduct an energy-only auction for 5% of the SSO load no later than six months  
13 after the Commission issues a final order in this proceeding.

14 **Q75. How does AEP-Ohio plan to conduct this initial limited auction for 5% of**  
15 **the SSO load and recover the bidder's cost from SSO customers?**

16 A75. AEP-Ohio has not supplied the details regarding showing how AEP-Ohio plans to  
17 conduct the limited auction for 5% of the SSO load and recover the winning  
18 bidder's cost from SSO customers. However, in response to discovery, attached  
19 as Exhibit KMM-22, AEP-Ohio indicated it plans to flow the costs of the 5%  
20 energy-only bid through the FAC and make no other changes to base SSO rates  
21 for distribution, transmission and generation. If that is the case, the only way that

1 the limited energy-only SSO bid will not require an overall price increase to SSO  
2 customers is if the cleared bid price is lower than AEP-Ohio's FAC rate. The  
3 market price estimates presented in this case suggest that the results of the  
4 energy-only auction will likely be above the FAC rate and thereby increase the  
5 cost of the ESP as compared to the MRO and make rates less stable and  
6 predictable as well.

7 The winning bid in the January 2012 FirstEnergy SSO auction was \$44.76 per  
8 MWH for the delivery period of June 2012 through May 2014. As shown on  
9 Exhibit KMM-19, the implicit capacity prices reflected in these bids (based upon  
10 capacity priced at RPM) range from \$3.19 to \$5.78 per MWH for 2012 and \$1.35  
11 to \$2.33 per MWH for the January 2013 through May 2014 period . If these  
12 implicit capacity prices are subtracted from the cleared bid price of \$44.76, it  
13 produces an implicit residual energy bid ranging from \$38.98 to \$43.41 per  
14 MWH. AEP-Ohio's FAC reflected in the Modified ESP is \$36.10 per MWH. This  
15 and the generation related ancillary service costs of \$2.91 per MWH total \$39.01.  
16 This indicates the plan to bid out 5% of the SSO load and flow the bid cost  
17 through the FAC will result in higher ESP prices than what is reflected on Exhibit  
18 KMM-20.

19 The administratively-determined market price estimates developed by AEP-Ohio  
20 witness Thomas support a similar conclusion. For example, the non-capacity  
21 portion of her competitive benchmark price for the June 2012 through May 2013  
22 delivery year ranges from \$44.07 to \$50.52 per MWH and the non-capacity  
23 portion of the competitive benchmark price for the June 2013 through May 2014

1 delivery year ranges from \$47.07 to \$53.95 per MWH, significantly higher than  
2 AEP-Ohio's expected FAC rate of \$36.10 per MWH.<sup>20</sup>

3 All of these factors suggest the proposed energy-only auction provision in the  
4 Modified ESP for 5% of the SSO load will result in higher costs to SSO  
5 customers and those higher costs are not reflected in my ESP versus MRO  
6 analysis.

7 **Q76. Are there additional flaws in the ESP versus MRO analysis performed by**  
8 **AEP-Ohio witness Thomas?**

9 A76. Yes. Ms. Thomas' testimony, beginning at page 19, states that there are two  
10 options to evaluate the ESP versus MRO for the January 2015 through May 2015  
11 delivery period and both methods produce equivalent results. Ms. Thomas  
12 asserts that because AEP-Ohio is assumed to have divested all of its generating  
13 assets by January 1, 2015, the legacy ESP price to be blended with the CBP  
14 would equal and flow through to customers through the FAC. Her reasoning  
15 includes an incorrect assumption.

16 AEP-Ohio, in its vertically-integrated form, has proposed to transfer its generation  
17 assets to a non-regulated affiliate as part of its ESP application in this case.  
18 Whether that actually happens, and the timeframe associated with those events,  
19 will likely be a function of subsequent orders of the Commission and the  
20 discretion exercisable by AEP-Ohio and its affiliates. However, what we are

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<sup>20</sup> Depending on the product definition in the energy-only auction, AEP-Ohio may also avoid the SSO generation related ancillary service cost of \$2.91 per MWH currently recovered through the transmission cost recovery rider.

1       trying to evaluate in the ESP versus MRO comparison context is the MRO  
2       alternative. In other words, for purposes of portraying the MRO alternative, any  
3       potential transfer of generating assets by AEP-Ohio is irrelevant.

4       It is my understanding that an MRO for an EDU that owns generating assets as  
5       of July 31, 2008 is required to reflect a blending of bid results with legacy ESP  
6       rates. Specifically, Section 4928.142(D), Ohio Revised Code, provides:

7               The first application filed under this section by an electric  
8               distribution utility that, as of July 31, 2008, directly owns, in whole  
9               or in part, operating electric generating facilities that had been used  
10              and useful in this state shall require that a portion of that utility's  
11              standard service offer load for the first five years of the market rate  
12              offer be competitively bid under division (A) of this section as  
13              follows: ten per cent of the load in year one, not more than twenty  
14              per cent in year two, thirty per cent in year three, forty per cent in  
15              year four, and fifty per cent in year five. Consistent with those  
16              percentages, the commission shall determine the actual  
17              percentages for each year of years one through five. The standard  
18              service offer price for retail electric generation service under this  
19              first application shall be a proportionate blend of the bid price and  
20              the generation service price for the remaining standard service offer  
21              load, which latter price shall be equal to the electric distribution  
22              utility's most recent standard service offer price, adjusted upward or  
23              downward as the commission determines reasonable, relative to  
24              the jurisdictional portion of any known and measurable changes  
25              from the level of any one or more of the following costs as reflected  
26              in that most recent standard service offer price:

27              (1) The electric distribution utility's prudently incurred cost of fuel  
28              used to produce electricity;

29              (2) Its prudently incurred purchased power costs;

30              (3) Its prudently incurred costs of satisfying the supply and demand  
31              portfolio requirements of this state, including, but not limited to,  
32              renewable energy resource and energy efficiency requirements;

33              (4) Its costs prudently incurred to comply with environmental laws  
34              and regulations, with consideration of the derating of any facility  
35              associated with those costs. In making any adjustment to the most

1 recent standard service offer price on the basis of costs described  
2 in division (D) of this section, the commission shall include the  
3 benefits that may become available to the electric distribution utility  
4 as a result of or in connection with the costs included in the  
5 adjustment, including, but not limited to, the utility's receipt of  
6 emissions credits or its receipt of tax benefits or of other benefits,  
7 and, accordingly, the commission may impose such conditions on  
8 the adjustment to ensure that any such benefits are properly  
9 aligned with the associated cost responsibility. The commission  
10 shall also determine how such adjustments will affect the electric  
11 distribution utility's return on common equity that may be achieved  
12 by those adjustments. The commission shall not apply its  
13 consideration of the return on common equity to reduce any  
14 adjustments authorized under this division unless the adjustments  
15 will cause the electric distribution utility to earn a return on common  
16 equity that is significantly in excess of the return on common equity  
17 that is earned by publicly traded companies, including utilities, that  
18 face comparable business and financial risk, with such adjustments  
19 for capital structure as may be appropriate. The burden of proof for  
20 demonstrating that significantly excessive earnings will not occur  
21 shall be on the electric distribution utility. Additionally, the  
22 commission may adjust the electric distribution utility's most recent  
23 standard service offer price by such just and reasonable amount  
24 that the commission determines necessary to address any  
25 emergency that threatens the utility's financial integrity or to ensure  
26 that the resulting revenue available to the utility for providing the  
27 standard service offer is not so inadequate as to result, directly or  
28 indirectly, in a taking of property without compensation pursuant to  
29 Section 19 of Article I, Ohio Constitution. The electric distribution  
30 utility has the burden of demonstrating that any adjustment to its  
31 most recent standard service offer price is proper in accordance  
32 with this division.

33 If an MRO is accepted by the Commission, it is my understanding that beginning  
34 in the second year the Commission may prospectively alter the blending  
35 percentages in order to mitigate any abrupt or significant change in rates.  
36 Mathematically, for a company like AEP-Ohio that owns generating assets, this  
37 means the shortest time period to get to a 100% bid result under an MRO is six  
38 years, a fact acknowledged by AEP-Ohio in its application.

1 AEP-Ohio witness Thomas assumes, for the purposes of her analysis, that under  
2 the MRO scenario AEP-Ohio would likewise divest all of its generating assets by  
3 January 1, 2015. I don't believe the Commission would approve an MRO  
4 coupled with a plan to divest legacy generating assets in such a way as to allow  
5 an EDU to effectively bypass the blending requirements of Section 4928.142(D),  
6 Ohio Revised Code.

7 **Q77. Is Ms. Thomas' assumption about accelerating the MRO's blending**  
8 **requirement consistent with prior treatment of the ESP portion of the MRO**  
9 **price under Section 4928.142(D), Ohio Revised Code?**

10 A77. No. In 2010, Duke Energy Ohio ("Duke"), an EDU with generating assets as of  
11 July 31, 2008, filed a proposed MRO requesting the Commission approve an  
12 accelerated blending period that would result in a CBP for 100% of SSO load  
13 after 2 ½ years. After conducting an evidentiary hearing, the Commission  
14 dismissed Duke's MRO application as non-compliant with the law, finding an  
15 initial MRO application under the circumstances was required to reflect the longer  
16 blending period required by the statute.<sup>21</sup> Based upon this precedent, the  
17 Commission would not authorize an MRO as envisioned by Ms. Thomas. I think  
18 it is far more likely the Commission would require an MRO to reflect blending as  
19 required by the statute and this is the scenario that should be reflected in the  
20 ESP versus MRO analysis. I have reflected that approach on Exhibit KMM-20 in

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<sup>21</sup> *In the Matter of the Application of Duke Energy Ohio, Inc. for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for a Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service*, Case No. 10-2586-EL-SSO, Opinion and Order (February 23, 2011).

1 the column illustrating January 2015 to May 2015 rates. My Exhibit KMM-20  
2 shows that Ms. Thomas' accelerated blending assumption which she used to  
3 portray the results of the MRO overstates the cost of the MRO option.

4 **Q78. Are there other caveats that must be taken into account when analyzing the**  
5 **ESP versus MRO during the January 2015 to May 2015 delivery period?**

6 A78. Yes. Ignoring for the moment the shortcomings in AEP-Ohio's witness Thomas'  
7 blending theories, there is a more fundamental flaw in her analysis for the  
8 January 2015 to May 2015 delivery period. Ms. Thomas assumes a capacity  
9 price of \$355 per MW-Day (Exhibit LJT-3, page 1 of 1, line 7), which is  
10 significantly different than the capacity price of \$255 per MW-day for bidders in  
11 the limited energy-only SSO auction proposed by AEP-Ohio witness Allen in his  
12 testimony. An additional concern with AEP-Ohio's ESP versus MRO analysis for  
13 the January 2015 to May 2015 delivery period is that AEP-Ohio has provided no  
14 information on how the auction prices will be translated into retail rates for SSO  
15 customers. Thus, even if one assumes that the Modified ESP is more favorable  
16 than the MRO during this five-month period (which it is not), there is no evidence  
17 in this proceeding that the CBP process, when translated into retail SSO rates,  
18 will not produce significant rate shocks and cost shifts on an inter- and intra-class  
19 basis. In the absence of such evidence, there is no basis to conclude that the  
20 resulting Modified ESP SSO retail rates will be just and reasonable.



1 **Q79. Do you recommend the Commission evaluate the June 2015 to May 2016 delivery**  
2 **year as part of its overall ESP versus MRO analysis?**

3 A79. It is not necessary for the Commission to evaluate the June 2015 to May 2016  
4 delivery year in order to reach a conclusion that the Modified ESP is not more  
5 favorable in the aggregate than an MRO. However, it is clear AEP-Ohio is  
6 seeking Commission approval to conduct a CBP for the entire SSO load (energy  
7 and capacity) beginning June 1, 2015 through the Modified ESP proposal,  
8 although AEP-Ohio is attempting to delay review of many of the important details  
9 associated with the CBP to a future Commission proceeding. In a companion  
10 application to this proceeding, AEP-Ohio is requesting approval to transfer its  
11 generating assets to an affiliated company. AEP-Ohio has notified PJM that  
12 AEP-Ohio will participate in RPM capacity auctions beginning with the June 2015  
13 through May 2016 delivery year. Similar to FirstEnergy, if AEP-Ohio transfers its  
14 generating assets to an affiliate, the only readily apparent option to obtain SSO  
15 generation supply thereafter, irrespective of whether AEP-Ohio is operating  
16 under an ESP or MRO, would be through a CBP. Therefore, I think it is  
17 reasonable and appropriate for the Commission to consider the likely results of a  
18 100% CBP process for SSO generation for the June 2015 through May 2016  
19 delivery period as part of its consideration of the Modified ESP.

20 AEP-Ohio is pointing, in this application, to the early transition to a 100% CBP for  
21 SSO load as one of the benefits of its application in this proceeding.

1 If AEP-Ohio is pointing to the 100% CBP for SSO load as one of the benefits of  
2 its application in this proceeding that the Commission should recognize, I believe  
3 it is necessary to analyze this aspect of the Modified ESP and identify the likely  
4 rate impact to customers for the June 2015 to May 2016 delivery year, at a point  
5 in time in which many industry experts expect electricity prices to rise due to the  
6 impact from tightening environmental regulations.

7 Analyzing the June 2015 to May 2016 delivery year requires some of the same  
8 caveats I have previously identified in my testimony. For example, we don't  
9 know how the CBP prices will be translated into retail SSO rates. However, at a  
10 macro level (EDU) we can evaluate directionally what the expected results will  
11 be. Assuming the competitive benchmark prices reflected in Company witness  
12 Thomas' workpapers and after making the appropriate adjustments to the prices  
13 to reflect known capacity prices based upon RPM, the resulting SSO bid price  
14 would be \$63.46 per MWH and this price can be compared to the blending rate  
15 that would result under an MRO, assuming continued ownership of generating  
16 assets as shown on Exhibit KMM-20. My analysis indicates that an MRO that  
17 blends bid prices with legacy ESP rates rather than the Modified ESP's  
18 accelerated blending MRO would be more favorable to SSO customers than an  
19 MRO where the SSO price is determined entirely through a CBP in the June  
20 2015 to May 2016 delivery year.

21 **Q80. Can you critique the alternative ESP versus MRO analysis conducted by**  
22 **AEP-Ohio witness Thomas and reflected in Exhibits LJT-4 and LJT-5?**

1 A80. Yes. The alternative analysis performed by Ms. Thomas is defective and  
2 meaningless. To perform her alternative ESP versus MRO analysis, Ms.  
3 Thomas weighted generation supply prices she assumed customers will be  
4 paying to CRES providers (subject to capacity prices of \$145.79 per MW-day and  
5 \$255 per MW-Day) with the prices she estimates for customers that remain as  
6 SSO load under the Modified ESP. This is nonsensical. The rates that  
7 customers pay CRES providers are irrelevant in the ESP versus MRO test. The  
8 required test involves a comparison of the SSO rates under the MRO option and  
9 the ESP option.

## 10 **V. CONCLUSION**

11 **Q81. What are your conclusions regarding AEP-Ohio's request for a two-tiered**  
12 **capacity charge?**

13 A81. A two-tiered capacity charge would subsidize AEP-Ohio's generation to the  
14 detriment of customers and competitors and is inconsistent with the state's  
15 policies of the electric industry restructuring required to enable competitive  
16 markets for electricity generation service. AEP-Ohio's proposal for pricing CRES  
17 provider capacity amounts to an untimely attempt to seek "transition revenue" in  
18 circumstances where AEP-Ohio previously agreed that it would not do so.

19 A two-tiered capacity charge that uniquely applies to CRES providers is also  
20 inconsistent with how AEP-Ohio has, for its benefit, historically determined CRES  
21 provider capacity prices and how other affiliated AEP operating companies are  
22 establishing the capacity price for ratemaking purposes.

1 As IEU-Ohio witness Hess' testimony explains, the proposed RSR is also an  
2 unlawful subsidy flowing from noncompetitive service (distribution) to a  
3 competitive service (generation) contrary to the state's policies and Commission  
4 precedent.

5 It is my understanding that whatever prices the Commission may establish for  
6 services provided to consumers as well as CRES providers, they must be  
7 comparable and non-discriminatory.

8 **Q82. What are your conclusions and recommendations regarding the ESP**  
9 **versus MRO test?**

10 A82. I recommend the Commission find the Modified ESP is less favorable than an  
11 MRO. Therefore, I recommend that the Commission reject AEP-Ohio's Modified  
12 ESP and promptly direct AEP-Ohio to restore the use of RPM-based capacity  
13 pricing in all cases where a CRES provider is serving a retail consumer within  
14 AEP-Ohio's service area. I would also suggest that the protracted debate that  
15 has occurred on the subject of this proceeding has, itself, stymied the ability for  
16 consumers to identify options to reduce their electric bills through "customer  
17 choice" and that the experience in this case strongly suggests that the  
18 Commission should turn to a CBP to establish default generation supply prices.

19 **Q83. In your answer to question 82, you suggest that the Commission should**  
20 **use a CBP to establish default generation supply prices. AEP-Ohio has**  
21 **claimed that it cannot move to a CBP to set default generation supply**  
22 **prices until the current pool agreements are modified, corporate separation**

1        **is complete, AEP-Ohio discontinues its FRR status and, perhaps, other**  
2        **things happen. Do you agree that competitive bidding must be put off as**  
3        **AEP-Ohio has claimed?**

4        A83. No, I do not agree.

5        First, it is my understanding that the FRR option provides the FRR entity with the  
6        opportunity to accelerate termination of its FRR status as a result of regulatory  
7        determinations made by a state regulatory authority. Specifically, Section  
8        8.1(C)(3) of PJM's RAA states "in the event of a State Regulatory Structural  
9        Change, a Party may elect, or terminate its election of, the FRR Alternative  
10       effective as to any Delivery Year by providing written notice of such election or  
11       termination to the Office of the Interconnection in good faith as soon as the Party  
12       becomes aware of such State Regulatory Structural Change but in any event no  
13       later than two months prior to the Base Residual Auction for such Delivery Year."  
14       Thus, there is an opportunity to accelerate termination of the FRR status.  
15       Additionally, as previously noted, AEP-Ohio has represented to the Commission  
16       its FRR status would not interfere with a state-directed CBP and in order to  
17       expeditiously proceed with a CBP, AEP-Ohio would sell capacity to winning  
18       bidders at prevailing RPM prices.

19       Second, AEP-Ohio has previously used market-based prices and competitive  
20       bidding to establish default generation supply costs in the case of the pricing

1 structure applicable to Ormet Primary Aluminum Corporation<sup>22</sup> and the former  
2 Ohio customers of Monongahela Power Company.<sup>23</sup> In both cases, AEP-Ohio  
3 claimed that it did not have adequate generation resources to supply generation  
4 to these new loads and that a competitive bidding process was the appropriate  
5 means of identifying the cost of such supply that was passed on to customers.  
6 And, in its first proposed ESP, AEP-Ohio also proposed to use a CBP to  
7 establish an escalating portion of the default generation supply price. As I  
8 described earlier, AEP-Ohio's comments in Commission Case No. 07-796-EL-  
9 ATA, *et al.*, strongly endorsed the use of a CBP to set default generation supply  
10 prices. These actual or proposed AEP-Ohio uses of competitive bidding to set  
11 default generation supply prices demonstrate that AEP-Ohio's current position  
12 regarding the alleged barriers to the use of competitive bidding is very different  
13 than the position AEP-Ohio took in prior Commission proceedings.

14 With regard to corporate separation, it is my understanding that corporate  
15 separation has been a requirement since SB 3 was enacted and that AEP-Ohio's  
16 original corporate separation plan called for AEP-Ohio to transfer the "wires  
17 business" to a new regulated entity. This approved corporate separation plan

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<sup>22</sup>*Columbus Southern Power Company's and Ohio Power Company's Application to Set the 2007 Generation Market Price for Ormet's Hannibal Facilities*, PUCO Case No. 06-1504-EL-UNC, Columbus Southern Power Company's and Ohio Power Company's Ormet-Related 2007 Generation Market Price Submission (December 26, 2006). See, also, *Columbus Southern Power Company's and Ohio Power Company's Application to Set the 2007 Generation Market Price for Ormet's Hannibal Facilities*, PUCO Case No. 06-1504-EL-UNC, Entry (June 27, 2007); and *Columbus Southern Power Company's and Ohio Power Company's Application to Set the 2008 Generation Market Price for Ormet's Hannibal Facilities*, PUCO Case No. 07-1317-EL-UNC, Columbus Southern Power Company's and Ohio Power Company's Ormet-Related 2008 Generation Market Price Submission (December 27, 2007).

<sup>23</sup> *In the Matter of the Transfer of Monongahela Power Company's Certified Territory in Ohio to the Columbus Southern Power Company*, PUCO Case No. 05-765-EL-UNC, Opinion and Order (November 9, 2005).

1 was not implemented by AEP-Ohio. Nonetheless, AEP-Ohio's distribution,  
2 transmission and generation functions must be considered as separate  
3 businesses subject to safeguards to prevent subsidies and other inappropriate  
4 transfers between competitive and non-competitive functions. The vertically-  
5 integrated core of AEP-Ohio's Modified ESP – a core that is designed to  
6 subsidize and protect AEP-Ohio's competitive generation function – is  
7 fundamentally inconsistent with the role of AEP-Ohio as an electric distribution  
8 utility, the structural reforms undertaken to promote customer choice and the  
9 state policy favoring customer choice and precluding the use of distribution  
10 service to collect, directly or indirectly, for generation related services.

11 If, as AEP-Ohio now claims, a CBP has to be ignored as an obvious and, I  
12 believe, preferred answer to the question of how to set default generation supply  
13 prices, then I believe it is even more imperative to set CRES provider capacity  
14 prices based on RPM because an RPM-based capacity price will allow the CBP  
15 used to establish the RPM capacity prices to impose a market-based check on  
16 AEP-Ohio's non cost-based default generation supply prices.

17 **Q84. Does this conclude your testimony?**

18 A84. Yes.

## CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Direct Testimony of Kevin M. Murray on Behalf of Industrial Energy Users-Ohio* was served upon the following parties of record this 4th day of May 2012, via electronic transmission, hand-delivery or first class U.S. mail, postage prepaid.

/s/ Samuel C. Randazzo

Samuel C. Randazzo

Matthew J. Satterwhite  
Steven T. Nourse  
Anne M. Vogel  
American Electric Power Service Corporation  
1 Riverside Plaza, 29<sup>th</sup> Floor  
Columbus, OH 43215  
mjsatterwhite@aep.com  
stnourse@aep.com  
amvogel@aep.com

Daniel R. Conway  
Christen M. Moore  
Porter Wright Morris & Arthur  
41 S. High Street  
Columbus, OH 43215  
dconway@porterwright.com  
cmoore@porterwright.com

**ON BEHALF OF COLUMBUS SOUTHERN POWER  
COMPANY AND OHIO POWER COMPANY**

Dorothy K. Corbett  
Amy B. Spiller  
Jeanne W. Kingery  
139 East Fourth Street  
1303-Main  
Cincinnati, OH 45202  
Dorothy.Corbett@duke-energy.com  
Amy.spiller@duke-energy.com  
Jeanne.kingery@duke-energy.com

**ON BEHALF OF DUKE ENERGY RETAIL SALES, LLC  
AND DUKE ENERGY COMMERCIAL ASSET  
MANAGEMENT, INC.**

Robert A. McMahon  
Eberly McMahon LLC  
2321 Kemper Lane, Suite 100  
Cincinnati, OH 45206

Rocco D'Ascenzo  
Elisabeth Watts  
Duke Energy Ohio, Inc.  
139 East Fourth Street - 1303-Main  
Cincinnati, OH 45202  
Elisabeth.watts@duke-energy.com  
Rocco.d'ascenzo@duke-energy.com

**ON BEHALF OF DUKE ENERGY OHIO, INC.**

David F. Boehm  
Michael L. Kurtz  
Boehm, Kurtz & Lowry  
36 East Seventh Street Suite 1510  
Cincinnati, OH 45202  
dboehm@BKLLawfirm.com  
mkurtz@BKLLawfirm.com

**ON BEHALF OF THE OHIO ENERGY GROUP**

Gregory J. Poulos  
EnerNOC, Inc.  
101 Federal Street, Suite 1100  
Boston, MA 02110  
gpoulos@enernoc.com

**ON BEHALF OF ENERNOC, INC.**



Kyle L. Kern  
Terry L. Etter  
Maureen R. Grady  
Office of the Ohio Consumers' Counsel  
10 W. Broad Street, 18<sup>th</sup> Floor  
Columbus, OH 43215-3485  
kern@occ.state.oh.us  
etter@occ.state.oh.us  
grady@occ.state.oh.us

**ON BEHALF OF THE OFFICE OF THE OHIO  
CONSUMERS' COUNSEL**

Richard L. Sites  
General Counsel & Senior Director of Health  
Policy  
Ohio Hospital Association  
155 East Broad Street, 15<sup>th</sup> Floor  
Columbus, OH 43215-3620  
ricks@ohanet.org

Thomas J. O'Brien  
BRICKER & ECKLER, LLP  
100 South Third Street  
Columbus, OH 43215-4291  
tobrien@bricker.com

**OH BEHALF OF OHIO HOSPITAL ASSOCIATION**

Mark S. Yurick  
Zachary D. Kravitz  
Taft Stettinius & Hollister  
65 East State Street, Suite 1000  
Columbus, OH 43215  
myurick@taftlaw.com  
zkravitz@cwslaw.com

**ON BEHALF OF THE KROGER CO.**

Terrence O'Donnell  
Christopher Montgomery  
BRICKER & ECKLER LLP  
100 South Third Street  
Columbus, OH 43215-4291  
todonnell@bricker.com  
cmontgomery@bricker.com

**ON BEHALF OF PAULDING WIND FARM II LLC**

Mark A. Hayden  
FirstEnergy Service Company  
76 South Main Street  
Akron, OH 44308  
haydenm@firstenergycorp.com

James F Lang  
Laura C. McBride  
N. Trevor Alexander  
CALFEE, HALTER & GRISWOLD LLP  
1400 KeyBank Center  
800 Superior Ave.  
Cleveland, OH 44114  
jlang@calfee.com  
lmcbride@calfee.com  
talexander@calfee.com

David A. Kutik  
Jones Day  
North Point  
901 Lakeside Avenue  
Cleveland, OH 44114  
dakutik@jonesday.com

Allison E. Haedt  
Jones Day  
P.O. Box 165017  
Columbus, OH 43216-5017  
aehaedt@jonesday.com

John N. Estes III  
Paul F. Wight  
Skadden, Arps, Slate, Meagher & Flom LLP  
1440 New York Ave., N.W.  
Washington, DC 20005  
jestes@skadden.com  
paul.wight@skadden.com

**ON BEHALF OF FIRSTENERGY SOLUTIONS CORP.**

Michael R. Smalz  
Joseph V. Maskovyak  
Ohio Poverty Law Center  
555 Buttles Avenue  
Columbus, OH 43215  
msmalz@ohiopoveritylaw.org  
jmaskovyak@ohiopoveritylaw.org

**ON BEHALF OF THE APPALACHIAN PEACE AND  
JUSTICE NETWORK**

Lisa G. McAlister  
Matthew W. Warnock  
Thomas O'Brien  
BRICKER & ECKLER LLP  
100 South Third Street  
Columbus, OH 43215-4291  
lmcaster@bricker.com  
mwarnock@bricker.com  
tobrien@bricker.com

**ON BEHALF OF OMA ENERGY GROUP**

Jay E. Jadwin  
American Electric Power Service Corporation  
1 Riverside Plaza, 29<sup>th</sup> Floor  
Columbus, OH 43215  
jejadwin@aep.com

**ON BEHALF OF AEP RETAIL ENERGY PARTNERS  
LLC**

M. Howard Petricoff  
Stephen M. Howard  
Vorys, Sater, Seymour and Pease LLP  
52 E. Gay Street  
P.O. Box 1008  
Columbus, OH 43215-1008  
mhpeticoff@vorys.com  
smhoward@vorys.com

**ON BEHALF OF PJM POWER PROVIDERS GROUP  
AND THE RETAIL ENERGY SUPPLY ASSOCIATION**

Glen Thomas  
1060 First Avenue, Ste. 400  
King of Prussia, PA 19406  
gthomas@gtpowergroup.com

Laura Chappelle  
4218 Jacob Meadows  
Okemos, MI 48864  
laurac@chappelleconsulting.net

**ON BEHALF OF PJM POWER PROVIDERS GROUP**

M. Howard Petricoff  
Michael Settineri  
Vorys, Sater, Seymour and Pease LLP  
52 E. Gay Street  
P.O. Box 1008  
Columbus, OH 43215-1008  
mhpeticoff@vorys.com  
mjsettineri@vorys.com

William L. Massey  
Covington & Burling, LLP  
1201 Pennsylvania Ave., NW  
Washington, DC 20004  
wmassey@cov.com

Joel Malina  
Executive Director  
COMPLETE Coalition  
1317 F Street, NW  
Suite 600  
Washington, DC 20004  
malina@wexlerwalker.com

**ON BEHALF OF THE COMPETE COALITION**

Henry W. Eckhart  
1200 Chambers Road, Suite 106  
Columbus, OH 43212  
henryeckhart@aol.com

Christopher J. Allwein  
Williams, Allwein and Moser, LLC  
1373 Grandview Ave., Suite 212  
Columbus, OH 43212  
callwein@williamsandmoser.com

**ON BEHALF OF THE NATURAL RESOURCES  
DEFENSE COUNCIL AND THE SIERRA CLUB**

M. Howard Petricoff  
Michael J. Settineri  
Stephen M. Howard  
Vorys, Sater, Seymour and Pease LLP  
52 East Gay Street  
P.O. Box 1008  
Columbus, OH 43216-1008  
mhpeticoff@vorys.com  
mjsettineri@vorys.com  
smhoward@vorys.com

**ON BEHALF OF CONSTELLATION NEWENERGY,  
INC., CONSTELLATION ENERGY COMMODITIES  
GROUP, INC. , DIRECT ENERGY SERVICES, LLC**

Gary A Jeffries  
Assistant General Counsel  
Dominion Resources Services, Inc.  
501 Martindale Street, Suite 400  
Pittsburgh, PA 15212-5817  
Gary.A.Jeffries@aol.com

**ON BEHALF OF DOMINION RETAIL, INC.**

David I. Fein  
Vice President, Energy Policy – Midwest  
Constellation Energy Group, Inc.  
Cynthia Fonner Brady  
Senior Counsel  
Constellation Energy Resources LLC  
550 West Washington Blvd., Suite 300  
Chicago, IL 60661  
david.fein@constellation.com  
cynthia.brady@constellation.com

**ON BEHALF OF CONSTELLATION NEWENERGY, INC.  
AND CONSTELLATION ENERGY COMMODITIES  
GROUP, INC.**

Jeanine Amid Hummer  
Thomas K. Lindsey  
*City of Upper Arlington*

Pamela A. Fox  
*City of Hilliard*

C. Todd Jones,  
Christopher L. Miller,  
Gregory H. Dunn  
Asim Z. Haque  
Ice Miller LLC  
250 West Street  
Columbus, OH 43215  
pfox@hillardohio.gov  
christopher.miller@icemiller.com  
gregory.dunn@icemiller.com  
asim.haque@icemiller.com  
jhummer@uaoh.net  
tlindsey@uaoh.net

**ON BEHALF OF THE CITY OF HILLIARD, OHIO, THE  
CITY OF GROVE CITY, OHIO AND THE ASSOCIATION  
OF INDEPENDENT COLLEGES AND UNIVERSITIES OF  
OHIO, THE CITY OF UPPER ARLINGTON**

Sandy I-ru Grace  
Assistant General Counsel  
Exelon Business Services Company  
101 Constitution Ave., NW  
Suite 400 East  
Washington, DC 20001  
sandy.grace@exeloncorp.com

M. Howard Petricoff  
Vorys, Sater, Seymour and Pease LLP  
52 East Gay Street/P.O. Box 1008  
Columbus, OH 43216-1008  
mhpeticoff@vorys.com

David M. Stahl  
Eimer Stahl Klevorn & Solberg LLP  
224 South Michigan Avenue, Suite 1100  
Chicago, IL 60604  
dstahl@eimerstahl.com

**ON BEHALF OF EXELON GENERATION COMPANY,  
LLC**

Kenneth P. Kreider  
David A. Meyer  
Keating Muething & Klekamp PLL  
One East Fourth Street  
Suite 1400  
Cincinnati, OH 45202  
kpkreider@kmlaw.com  
dmeyer@kmlaw.com

Holly Rachel Smith  
Holly Rachel Smith, PLLC  
Hitt Business Center  
3803 Rectortown Road  
Marshall, VA 20115  
holly@raysmithlaw.com

Steve W. Chriss  
Manager, State Rate Proceedings  
Wal-Mart Stores, Inc.  
Bentonville, AR 72716-0550  
Stephen.Chriss@wal-mart.com

**ON BEHALF OF WAL-MART STORES EAST, LP AND  
SAM'S EAST, INC.**

Barth E. Royer (Counsel of Record)  
Bell & Royer Co., LPA  
33 South Grant Avenue  
Columbus, OH 43215-3927  
BarthRoyer@aol.com

Tara C. Santarelli  
Environmental Law & Policy Center  
1207 Grandview Ave., Suite 201  
Columbus, OH 43212  
tsantarelli@elpc.com

**ON BEHALF OF THE ENVIRONMENTAL LAW &  
POLICY CENTER**

Nolan Moser  
Trent A. Dougherty  
Camille Yancy  
Cathryn Loucas  
Ohio Environmental Council  
1207 Grandview Avenue, Suite 201  
Columbus, OH 43212-3449  
nolan@theoec.org  
trent@theoec.org  
camille@theoec.org  
cathy@theoec.org.

**ON BEHALF OF THE OHIO ENVIRONMENTAL  
COUNCIL**

Robert Korandovich  
KOREnergy  
P.O. Box 148  
Sunbury, OH 43074  
korenergy@insight.rr.com

**ON BEHALF OF KOREENERGY**

Douglas G. Bonner  
Emma F. Hand  
Keith C. Nusbaum  
Clinton A. Vince  
Daniel D. Barnowski  
James Rubin  
Thomas Millar  
SNR Denton US LLP  
1301 K Street NW  
Suite 600, East Tower  
Washington, DC 20005  
doug.bonner@snrdenton.com  
emma.hand@snrdenton.com  
keith.nusbaum@snrdenton.com  
clinton.vince@snrdenton.com  
daniel.barnowski@snrdenton.com  
james.rubin@snrdenton.com  
thomas.millar@snrdenton.com

Arthur Beeman  
SNR Denton US LLP  
525 Market Street, 26<sup>th</sup> Floor  
San Francisco, CA 941-5-2708  
arthur.beeman@snrdenton.com

**ON BEHALF OF ORMET PRIMARY ALUMINUM CORPORATION**

Jay L. Kooper  
Katherine Guerry  
Hess Corporation  
One Hess Plaza  
Woodbridge, NJ 07095  
jkooper@hess.com  
kguerry@hess.com

**ON BEHALF OF HESS CORPORATION**

Allen Freifeld  
Samuel A. Wolfe  
Viridity Energy, Inc.  
100 West Elm Street, Suite 410  
Conshohocken, PA 19428  
afreifeld@viridityenergy.com  
swolfe@viridityenergy.com

Jacqueline Lake Roberts,  
Counsel of Record  
101 Federal Street, Suite 1100  
Boston, MA 02110  
jroberts@enernoc.com

**ON BEHALF OF CPOWER, INC., VIRIDITY ENERGY, INC., ENERGYCONNECT INC., COMVERGE INC., ENERWISE GLOBAL TECHNOLOGIES, INC., AND ENERGY CURTAILMENT SPECIALISTS, INC.**

Benita Kahn  
Lija Kaleps-Clark  
Vorys Sater, Seymour and Pease LLC  
52 East Gay Street, P.O. Box 1008  
Columbus, OH 43216-1008  
bakahn@vorys.com  
lkalepsclark@vorys.com

**ON BEHALF OF OHIO CABLE TELECOMMUNICATIONS ASSOCIATION**

Mark A. Whitt  
Melissa L. Thompson  
Whitt Sturtevant LLP  
PNC Plaza, Suite 2020  
155 East Broad Street  
Columbus, OH 43215  
whitt@whitt-sturtevant.com  
thompson@whitt-sturtevant.com

Vincent Parisi  
Matthew White  
Interstate Gas Supply, Inc.  
6100 Emerald Parkway  
Dublin, OH 43016  
vparisi@igsenergy.com  
mswhite@igsenergy.com

**ON BEHALF OF INTERSTATE GAS SUPPLY, INC.**

Dane Stinson  
BAILEY CAVALIERI LLC  
10 West Broad Street, Suite 2100  
Columbus, OH 43215

**ON BEHALF OF THE OHIO ASSOCIATION OF SCHOOL BUSINESS OFFICIALS, THE OHIO SCHOOL BOARDS ASSOCIATION, THE OHIO SCHOOLS COUNCIL AND THE BUCKEYE ASSOCIATION OF SCHOOL ADMINISTRATORS**

Chad A. Endsley  
Chief Legal Counsel  
Ohio Farm Bureau Federation  
280 North High Street, P.O. Box 182383  
Columbus, OH 43218-2383  
cendsley@ofbf.org.

**ON BEHALF OF THE OHIO FARM BUREAU FEDERATION**

Brian P. Barger  
Brady, Coyle & Schmidt, LTD  
4052 Holland-Sylvania Rd.  
Toledo, OH 43623  
bpbarger@bcslawyers.com

**ON BEHALF OF THE OHIO CONSTRUCTION  
MATERIALS COALITION**

Diem N. Kaelber  
Robert J Walter  
10 West Broad Street, Suite 1300  
Columbus, OH 43215  
kaelber@buckleyking.com  
walter@buckleyking.com

**ON BEHALF OF OHIO RESTAURANT ASSOCIATION**

Judi L. Sobecki  
Randall V. Griffin  
The Dayton Power and Light Company  
1065 Woodman Drive  
Dayton, OH 45432  
Judi.sobecki@dplinc.com  
Randall.griffin@dplinc.com

**ON BEHALF OF THE DAYTON POWER AND LIGHT  
COMPANY**

Sara Reich Bruce  
Ohio Automobile Dealers Association  
655 Metro Place South, Suite 270  
Dublin, OH 43017  
sbruce@oada.com

**ON BEHALF OF THE OHIO AUTOMOBILE DEALERS  
ASSOCIATION**

Joseph M. Clark  
Direct Energy Services LLC  
And Direct Energy Business LLC  
6641 North High Street, Suite 200  
Worthington, OH 43085  
jmclark@vectren.com

**ON BEHALF OF DIRECT ENERGY SERVICES, LLC  
AND DIRECT ENERGY BUSINESS, LLC**

Todd M. Williams  
Williams Allwein and Moser, LLC  
Two Maritime Plaza-Third Floor  
Toledo, OH 43604  
toddm@wamenergylaw.com

**ON BEHALF OF THE OHIO BUSINESS COUNCIL FOR  
A CLEAN ECONOMY**  
Matthew R. Cox

Matthew Cox Law, Ltd.  
4145 St. Theresa Blvd.  
Avon, OH 44011  
matt@matthewcoxlaw.com

**ON BEHALF OF THE COUNCIL OF SMALLER  
ENTERPRISES (COSE)**

Carolyn S. Flahive  
Philip B. Sineneng  
THOMPSON HINE LLP  
41 S. High Street, Suite 1700  
Columbus, OH 43215  
Carolyn.Flahive@ThompsonHine.com  
Philip.Sineneng@ThompsonHine.com

**ON BEHALF OF BORDER ENERGY ELECTRIC  
SERVICES, INC.**

Randy J. Hart  
Rob Remington  
David J. Michalski  
200 Public Square, Suite 2800  
Cleveland, OH 44114-2316  
rhart@hahnlaw.com  
rrremington@hahnlaw.com  
djnichalski@hahnlaw.com

**ON BEHALF OF SUMMIT ETHANOL, LLC AND  
FOSTORIA ETHANOL, LLC**

Larry F. Eisenstat  
Richard Lehfelt  
Robert L. Kinder, Jr.  
Dickstein Shapiro LLP  
1825 Eye St. NW  
Washington, DC 20006  
eisenstatl@dicksteinshapiro.com  
lehfelttr@dicksteinshapiro.com  
kinderr@dicksteinshapiro.com

**ON BEHALF OF CPV POWER DEVELOPMENT, INC.**

William Wright  
Werner Margard  
Thomas Lindgren  
John H. Jones  
Assistant Attorneys' General  
Public Utilities Section  
180 East Broad Street, 6<sup>th</sup> Floor  
Columbus, OH 43215  
john.jones@puc.state.oh.us  
werner.margard@puc.state.oh.us  
thomas.lindgren@puc.state.oh.us  
william.wright@puc.state.oh.us

**ON BEHALF OF THE PUBLIC UTILITIES COMMISSION OF OHIO**

Greta See  
Jon Tauber  
Attorney Examiner  
Greta See  
Jon Tauber  
Attorney Examiner  
Public Utilities Commission of Ohio  
180 East Broad Street, 12<sup>th</sup> Floor  
Columbus, OH 43215

**ATTORNEY EXAMINERS**

**Exhibit KMM-1**

## **Exhibit KMM-1**

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

*In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan, PUCO Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, et al.*

*In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan, and the Sale or Transfer of Certain Generating Assets, Case No. 08-917-EL-SSO and In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan, PUCO Case No. 08-918-EL-SSO (remand phase).*

*In the Matter of the Application of Columbus Southern Power for Approval of its Program Portfolio Plan and Request for Expedited Consideration, PUCO Case No. 09-1089-EL-POR.*

*In the Matter of the Application of Ohio Power Company for Approval of its Program Portfolio Plan and Request for Expedited Consideration, PUCO Case No. 09-1090-EL-POR.*

*In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service, PUCO Case No. 09-906-EL-SSO.*

*In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, PUCO Case No. 08-935-EL-SSO.*

*In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service, PUCO Case No. 08-936-EL-SSO.*

*In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets, PUCO Case No. 08-917-EL-SSO.*

*In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan, PUCO Case No. 08-918-EL-SSO.*

*In the Matter of the Application of Duke Energy Ohio for Approval of an Electric Security Plan, PUCO Case No. 08-920-EL-SSO.*

*In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Electric Security Plan, PUCO Case No. 08-1094-EL-SSO.*



**Exhibit KMM-2**

# Large Filing Separator Sheet

Case Number: 99-1729-EL-ETP  
99-1730-EL-ETP

File Date: 12/30/99

Section: 1 of 12

Number of Pages: 202

Description of Document: Appl./Testimony of  
Forrester, Kahn & Landon

EXHIBIT NO. \_\_\_\_\_

BEFORE  
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus  
Southern Power Company for Approval of  
Electric Transition Plan and Application for  
Receipt of Transition Revenues

Case No. 99-<sup>1729</sup>\_\_\_-EL-ETP

In the Matter of the Application of Ohio  
Power Company for Approval of  
Electric Transition Plan and Application for  
Receipt of Transition Revenues

Case No. 99-<sup>1730</sup>\_\_\_-EL-ETP

DIRECT TESTIMONY OF  
WILLIAM R. FORRESTER  
ON BEHALF OF  
COLUMBUS SOUTHERN POWER COMPANY  
AND  
OHIO POWER COMPANY

RECORDED  
DEC 8 1999  
FBI

INDEX TO DIRECT TESTIMONY OF  
WILLIAM R. FORRESTER  
PUCO CASE NOS. 99-\_\_\_-EL-ETP and  
99-\_\_\_-EL-ETP

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1  
2  
3 BEFORE  
4 THE PUBLIC UTILITIES COMMISSION OF OHIO  
5 DIRECT TESTIMONY OF  
6 WILLIAM R. FORRESTER  
7 ON BEHALF OF  
8 COLUMBUS SOUTHERN POWER COMPANY  
9 CASE NO. 99-\_\_\_-EL-ETP  
10 AND  
11 OHIO POWER COMPANY  
12 CASE NO. 99-\_\_\_-EL-ETP

13 **Personal Data**

14 Q. Please state your name and business address.

15 A. My name is William R. Forrester. My business address is 1 Riverside Plaza,  
16 Columbus, Ohio 43215.

17 Q. What is your position in the American Electric Power (AEP) System.

18 A. I am the Director of Ohio Regulatory Affairs.

19 Q. Please briefly describe your educational background and business experience.

20 I graduated in June, 1965 from The Ohio State University with the degree of  
21 Bachelor of Science in Business Administration. Immediately following  
22 graduation, I became an employee of Columbus and Southern Ohio Electric  
23 Company (subsequently acquired by AEP), and from that time until 1976 my  
24 responsibilities included the preparation of reports, financial forecasts, internal  
25 audits and special financial studies. I was Manager of the Reports and Studies  
26 Area of the Accounting Department from 1976 to November, 1977. In  
27 November, 1977 I was appointed Assistant Director of Rates and Regulations and  
28 in April, 1978 I was appointed Director of Rates and Regulations. In January,

1           1996 I was appointed Director of Ohio Regulatory Affairs. Also, I have been a  
2           Certified Public Accountant since 1988.

3    Q.    What are your duties as Director of Ohio Regulatory Affairs?

4    A.    My duties include the supervision and direction of the Regulatory Affairs  
5           Department in the American Electric Power Ohio State Office, which has the  
6           responsibility for rate and regulatory matters affecting Ohio Power Company  
7           (OPCO) as well as affecting Columbus Southern Power Company (CSP). Both  
8           OPCO and CSP are operating subsidiaries of AEP.

9    Q.    For whom are you testifying in this proceeding?

10   A.    OPCO and CSP.

11   Q.    Have you previously submitted testimony as a witness before any regulatory  
12           commission?

13   A.    Yes. In addition to previous testimonies before this Commission, I have testified  
14           on behalf of CSP before the Federal Energy Regulatory Commission (FERC).

15

16   **Purpose of Testimony**

17   Q.    What is the purpose of your testimony in this proceeding?

18   A.    The purpose of my testimony is to:

- 19           1.    Sponsor an overview of OPCO and CSP's Transition Plan filing including  
20                   the recovery of transition costs.
- 21           2.    Sponsor the Tax Recovery Methodology in the Unbundled Rate Schedules  
22                   (i.e., provide the basis for the utilization of tariff riders regarding the  
23                   increase or decrease of state or local taxes included in CSP and OPCO's

- 1 existing base rate levels). Company Witness Pyle will sponsor the state  
2 and local tax changes brought about by the passage of Am. Sub. S. B. No.  
3 3 and certain adjustments to taxes other than income taxes and state and  
4 municipal income taxes resulting from the implementation of new and/or  
5 revised tax statutes applicable to public utilities in Ohio.
- 6 3. Sponsor the Universal Service Fund Rider (PIPP replacement) and the  
7 Energy Efficiency Fund Rider (Revolving Efficiency Loan Fund/DSM).
- 8 4. Sponsor the Corporate Separation Plan including Code of Conduct. In this  
9 regard, I am also sponsoring Part B of the rules, with the exceptions that  
10 Company Witness Pena will cover the financial considerations concerning  
11 the Corporate Separation Plan including Part B, §(G)(3), and Company  
12 Witness Knorr is testifying to the requirements for separate accounting  
13 including Part B, §(G)(2), and the Cost Allocation Manual (CAM)  
14 requirements including Part B, §(J)(1)-(9).
- 15 5. Support OPCO and CSP's participation in the Statewide Consumer  
16 Education Plan and Part E; and to explain the customer education  
17 campaign goals and objectives, and how CSP and OPCO will structure,  
18 implement and manage the customer education campaign in accordance  
19 with Am. Sub. S. B. No. 3. I will also sponsor CSP and OPCO's share of  
20 the Statewide Consumer Education Plan implementation costs.
- 21 6. Sponsor CSP and OPCO's Shopping Incentive Plan including Part H.
- 22

## List of Exhibits

Q. Please note the exhibits you are sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

### Description

1. EXHIBIT NO. \_\_\_ WRF-1 CSP and OPCO's Projected PIPP Unrecovered Balances as of 6/30/2000.
2. EXHIBIT NO. \_\_\_ WRF-2 which is a graphic representation of the planned Corporate Separation.
3. EXHIBIT NO. \_\_\_ WRF-3, CSP and OPCO's Customer Choice Education Program Cost Responsibility based on the number of customers as of December 31, 1997, for CSP and OPCO.
4. EXHIBIT NO. \_\_\_ WRF-4, CSP and OPCO's Projected Transition Plan Filing Expenses.

Q. Were these schedules prepared by you or under your supervision?

A. Yes.

## Overview of the OPCO and CSP Transition Plan Filing Including the Recovery of Transition Costs

Q. Would you please provide an overview of CSP and OPCO's Transition Plan filing?

A. Yes. Both Companies' filings were prepared from the Commission transition rules and consumer education plan. In order to provide a clear understanding of the Companies' filings the Companies have responded where applicable, to each rule and to the consumer education plan. By preparing the filings in this manner all parties will be able to relate each of the Companies' responses to the specific rules and to the plan.



1 Q. Are CSP and OPCO requesting transition costs to be included in the unbundled  
2 rates?

3 A. Yes. CSP and OPCO are requesting that Regulatory Assets and Stranded Costs  
4 be included in the unbundled rates.

5 Q. Why are the Companies requesting that they be permitted to recover regulatory  
6 assets as part of their transition costs?

7 A. Regulatory assets represent expenses that should have been included in the  
8 determination of rates that customers would pay for electric service, but for a  
9 variety of reasons, were not included in the determination of prior and/or existing  
10 rates. As a result, these expenses were deferred as regulatory assets for recovery  
11 through inclusion in future rates. Customers have been paying lower rates  
12 because of the deferral of these past expenses as regulatory assets for recovery in  
13 future rates. That is why the Companies refer to regulatory assets, such as the  
14 regulatory asset related to SFAS 109 balances, as "Customer Receivables" for  
15 future recovery.

16 Q. Can you give a specific example of a regulatory asset that resulted in lower  
17 current rates for customers?

18 A. Yes. In CSP's last rate case, Case No. 91-418-EL-AIR, CSP had requested that  
19 the Zimmer embedded interest incurred after the in-service date of Zimmer but  
20 prior to the effective date of the rates resulting from that case, be included in the  
21 rates determined in that proceeding. The Commission did not include that  
22 embedded interest in those rates, but authorized CSP to defer that expense to be  
23 included in CSP's next general rate proceeding. CSP's customers have been

1 paying lower rates than they would have paid had the Zimmer embedded interest  
2 been included in the determination of the current rates.

3 Q. How does Am. Sub. S. B. No. 3 change how the Companies will recover the  
4 regulatory assets?

5 A. Am Sub. S. B. No. 3 removes Commission regulation of the rate associated with  
6 generation. Because of this, the Companies will not be able to recover generation  
7 related prior period expenses deferred for recovery as regulatory assets in future  
8 regulated rates, i.e. "Customer Receivables". Therefore the Companies are  
9 requesting the Commission's authority to charge a transition charge to recover  
10 these stranded generation-related regulatory assets over the ten-year transition  
11 period.

12 Q. Would you please describe the Companies' proposal to recover its stranded  
13 generation-related regulatory assets in their Transition Plan filings?

14 A. CSP and OPCO are proposing to include recovery of its stranded generation-  
15 related regulatory assets over the ten-year transition period provided for in Am.  
16 Sub. S. B. No. 3. The Companies have determined the amount of amortization of  
17 their stranded generation-related regulatory assets that was included in each  
18 Company's last base rate case filing. These amounts of recovery of regulatory  
19 assets were included in the transition charge during the Market Development  
20 Period (the first five years). The remaining unrecovered balances of these  
21 stranded generation-related regulatory assets at December 31, 2005, were divided  
22 by the estimated KWH to be delivered over the remaining five years of the ten-

1 year transition period, to determine the transition charge for the period January 1,  
2 2006, through December 31, 2010.

3 Q. Why are CSP and OPCO proposing to recover stranded generation-related  
4 regulatory assets over the full ten-year transition period allowed by Am. Sub.  
5 S. B. No. 3?

6 A. Because of the significant balances of stranded generation related regulatory  
7 assets both Companies have, and the relatively small amount of amortization of  
8 those regulatory assets included in current rates, it was determined that utilizing  
9 the full ten-year period would be the best way to keep the transition charge  
10 associated with regulatory assets as low as possible. In addition, by including  
11 only the amount of amortization of regulatory assets that are in current rates in the  
12 initial five-year Market Development Period, development of a competitive  
13 generation market will be assisted because of a lower transition charge.

14 Q. Were CSP and OPCO's regulatory assets prudently incurred?

15 A. Yes. Based upon previous Commission orders and the accounting practices  
16 contained in those orders, as detailed in Company Witness McCoy's testimony,  
17 all of the regulatory assets recorded on both Companies' books have been  
18 prudently incurred.

19 Q. Have the regulatory assets included in CSP and OPCO's transition filings been  
20 directly assigned or allocated to the Companies' retail electric generation and are  
21 they legitimate, net, verifiable costs to provide service to consumers in the State  
22 of Ohio?

1 A. Yes. The stranded generation-related regulatory assets included for recovery in  
2 this transition filing have either been directly assigned or allocated to the retail  
3 electric generation of CSP or OPCO. Further, they are legitimate, net, verifiable  
4 costs to provide service to consumers in the State of Ohio.

5 Q. Are these stranded generation-related regulatory assets of CSP and OPCO  
6 unrecoverable in a competitive market?

7 A. Yes. Based upon Company Witness Landon's testimony regarding stranded  
8 costs, it is clear that it is highly unlikely that either CSP or OPCO would be able  
9 to recover any of those regulatory assets in a competitive market.

10 Q. But for Am. Sub. S. B. No. 3, would CSP and OPCO have otherwise been entitled  
11 to an opportunity to recover their regulatory assets on a going forward basis under  
12 Commission regulation?

13 A. Yes. Based upon an extensive history of regulation by the Commission and the  
14 past practices employed by the Commission in rate setting proceedings, it is clear  
15 that CSP and OPCO would have been entitled to an opportunity to recover the  
16 regulatory assets that both Companies have on their books.

17 Q. Do CSP and OPCO have other projected transition costs that the Companies are  
18 seeking to recover in their transition charges?

19 A. Yes. First I want to discuss new regulatory assets that CSP and OPCO want the  
20 Commission to establish through the Transition Plan proceedings. These new  
21 regulatory assets are: the cost resulting from SFAS 106 (Post-Retirement  
22 Benefits) Transition Obligation; the cost, mandated by Am. Sub. S. B. No. 3, for  
23 consumer education on electric restructuring; the cost of the development and

1 operation of the operational support systems that the electric distribution service  
2 provider must have to allow electric consumers to choose their supplier of electric  
3 generation service; and the cost of CSP and OPCO Transition Plan filings  
4 including the public notices required and the necessary hearings on both  
5 Companies' transition filings.

6 Q. Why should SFAS 106, Transition Obligation, be set up as a regulatory asset?

7 A. Company Witness McCoy explains why these costs should be included as new  
8 regulatory assets to afford a reasonable opportunity under the Transition Plan  
9 filing rules for recovery of these mandated expenses in the future.

10 Q. Why should the consumer education expenses mandated by Am. Sub. S. B. No. 3  
11 be setup as a regulatory asset?

12 A. The costs associated with the consumer education on electric restructuring are  
13 new legislatively mandated incremental costs that CSP and OPCO must spend  
14 during the Market Development Period. These costs must be established as new  
15 regulatory assets to afford a reasonable opportunity under the Transition Plan  
16 filing rules for recovery of these mandated expenses in the future.

17 Q. Please state why the development and operation costs related to the operational  
18 support systems should be a new regulatory asset?

19 A. The operational support systems that are necessary to allow customers to choose  
20 an alternative generation supplier are new incremental costs of implementing  
21 legislatively created customer choice in Ohio. The only way that there will be a  
22 reasonable opportunity under the Transition Plan filing rules to recover those  
23 costs is if the Commission makes these costs new regulatory assets. Company

1           Witness Laine explains what will be required in the operational support systems  
2           and estimates the developmental and operational costs of those systems.

3    Q.    Why have CSP and OPCO included the expenses for filing their Transition Plans  
4           as new regulatory assets?

5    A.    CSP and OPCO have included the expenses of filing the Transition Plans as new  
6           regulatory assets in order to have a reasonable opportunity to recover these  
7           incremental expenses. The Transition Plan filing expenses are similar to rate case  
8           expenses that have been included in base rate case proceedings for as long as I  
9           can remember. There is, however, one significant difference between rate case  
10          expenses and Transition Plan filing expenses: CSP and OPCO had the ability to  
11          make the determination of if and when a rate case would be filed. Neither  
12          Company has the option to not file a Transition Plan filing. Both Companies are  
13          required by Am. Sub. S. B. No. 3 to make the transition filings, and therefore, the  
14          expenses associated with the Transition Plan filings should be recoverable as new  
15          regulatory assets.

16   Q.    What incremental expenses are included in the estimated Transition Plan filing  
17          expenses?

18   A.    EXHIBIT NO. \_\_\_\_ WRF-4 shows the detail of the estimated incremental  
19          Transition Plan filing expenses. The item for the Commission Required Notice is  
20          the estimated cost of the Commission's required Transition Plan filing notice.  
21          The Companies have retained outside counsel to assist the Companies in all  
22          aspects of the Transition Plan filings. The Companies have hired an outside  
23          expert to provide calculations of the uneconomic generation assets. The

1 Commission has hired a consultant to assist the Staff in an economic valuation of  
2 the generating assets in Ohio and the Companies will have to pay a share of the  
3 cost of that consultant. All of these expenses are incremental expenses and do not  
4 include any Company labor.

5 Q. Are all of the amounts of these new regulatory assets final expenses that should be  
6 used in the determination of the rates?

7 A. No. The SFAS 106, Transition Obligation for Post-Retirement Benefits can be  
8 considered a final expense number. The estimates for the consumer education can  
9 also be considered a final expense number. However, as is indicated in Company  
10 Witness Laine's testimony, the estimate for the cost of the operational support  
11 systems is just an estimate of one possible way of providing those operational  
12 support systems. Company Witness Laine states that the Company is looking at  
13 different ways to provide those operational support systems which could  
14 significantly change the estimated costs of those systems. The estimates that I  
15 have included for the transition filing expenses are just estimates. The actual  
16 transition filing expenses will most likely be somewhat different than those  
17 estimates.

18 Q. How should the actual expenses of the operational support systems and the  
19 transition filing expenses be reflected in the rates?

20 A. There are two suggestions to handling these expenses. The first is that the  
21 Company will provide revised estimates for these expenses two weeks prior to the  
22 start of hearings on the transition filings. The second is that in the year 2004  
23 when the Commission is reviewing the regulatory assets, these expenses can be

1 adjusted to reflect the actual expenses associated with the operational support  
2 systems and the actual transition filing expenses.

3

4 The Company's intention is to assure that it has the opportunity to recover the  
5 incremental costs of the transition to a competitive generation supply. This  
6 recovery should be of the actual costs whether those actual costs are greater or  
7 lower than the estimates included in this filing. The Commission can provide a  
8 "true-up" mechanism that will make sure that the distribution customers only pay  
9 the actual incremental costs of this transition.

10 Q. What other transition costs are CSP and OPCO proposing in their Transition Plan  
11 filings?

12 A. CSP and OPCO are proposing that stranded generation asset costs be included in  
13 the transition charges.

14 Q. What method of determination of stranded generation asset costs to be included in  
15 the transition charge are the Companies proposing?

16 A. The Companies are proposing the "revenues lost" approach. Under that approach,  
17 stranded costs are calculated by subtracting the competitive market value of the  
18 power the customer would have purchased from the revenues that the customer  
19 would have paid had it stayed on the utility's generation system. Therefore, the  
20 Companies are proposing that the difference between the lower market price and  
21 the unbundled generation rate be included in the transition charge to provide  
22 recovery for the stranded generation asset costs. Company Witness Landon  
23 demonstrates that calculating the future economic value of the generation assets is



1 very difficult. The calculation of the difference between the lower market price  
2 and the unbundled generation rate is a much simpler calculation and it provides  
3 the Companies an opportunity to recover those stranded generation asset costs.  
4 Moreover, as the Federal Energy Regulatory Commission has stated "the  
5 revenues lost approach is the fairest and most efficient way to balance the  
6 competing interests of those involved."

7 Q. What market price have you used in this transition filing to calculate the stranded  
8 generation asset costs to be included in the transition charge?

9 A. The market price of 24.69 was taken from Company Witness Landon's EXHIBIT  
10 NO. \_\_\_ JHL-2 for the year 2001. Company Witness Thomas adjusted that  
11 market price to reflect the appropriate load factors and losses for each tariff for  
12 CSP and OPCO. The resulting market price of each tariff is then compared to  
13 each tariff's unbundled generation rate. For each tariff where the market price is  
14 below the unbundled generation rate a transition charge for the difference would  
15 be applied through a tariff rider.

16

17 A representative market price and adjustments to reflect individual tariff  
18 schedules should be determined before the start of each year in the Market  
19 Development Period to determine the transition charge to be applied during the  
20 following year.

1     **Unbundled Rate Schedules – Tax Recovery Methodology**

2     Q.     Which tax changes in Am. Sub. S. B. No. 3 will affect CSP and OPCO and what  
3             are the effective dates?

4     A.     The following taxes will change with respect to CSP and OPCO as of the  
5             indicated effective dates:

6	Kilowatt Hour Tax	Begins	05/01/01
7	Public Utility Excise Tax (Gross Receipts)	Ends	04/30/02
8	Property Tax Reduction	Effective	01/01/01
9	Ohio Franchise Tax	Begins	01/01/02
10	Municipal Income Tax	Begins	01/01/02

11

12    Q.     Which taxes specifically addressed in Am. Sub. S. B. No. 3 relate to unbundled  
13             rates?

14    A.     Ohio Revised Code (ORC) Section 4928.34 indicates that unbundled rates shall  
15             be adjusted for any changes in the taxation of electric utilities and retail electric  
16             service resulting from the passage of Am. Sub. S. B. No. 3. ORC Section 4928.35  
17             provides that the unbundled rate schedules should reflect tax law changes that  
18             have a material effect on utilities or if utilities receive any refund as a result of the  
19             resolution of utility property valuation litigation.

20    Q.     Which tax changes meet the criteria established in ORC Sections 4928.34 and  
21             should be reflected as adjustments in the computation of unbundled rates of CSP  
22             and OPCO?

23    A.     The following taxes should be included as adjustments in the computation of

1 unbundled rates of CSP and OPCO: gross receipts tax, personal property taxes,  
2 kilowatt-hour tax, Ohio franchise tax, deferred state income taxes, municipal  
3 income taxes, and deferred municipal income taxes.

4 Q. What methodology do you recommended to reflect tax changes imposed by the  
5 deregulation legislation?

6 A. Separate rate riders are recommended to capture the tax changes resulting from  
7 the elimination of the gross receipts tax, reduction in personal property taxes, and  
8 introduction of the kilowatt-hour tax. Separate rate riders are also recommended  
9 for the introduction of the Ohio franchise tax and addition of the municipal  
10 income taxes, including adoption of deferred state and local income tax  
11 accounting resulting from restructuring.

12 Q. Why are you recommending that CSP and OPCO use separate rate riders for these  
13 tax changes?

14 A. Because of the different effective dates of the various tax changes, the best way to  
15 implement those tax changes is through separate rate riders with varying effective  
16 dates. In addition, many of these tax changes have to have estimates of the  
17 amount of the tax change. By using separate rate riders, any required adjustment  
18 to the tax change can be made easily.

19

#### 20 **Schedule of Effective Dates for Rate Riders**

21 Q. When do you propose that the rate riders should take effect?

22 A. The rate rider for the elimination of the gross receipts tax should be effective May  
23 1, 2002. The rate rider for the reduction in personal property taxes should be

1 effective January 1, 2001. The rate rider for the new kilowatt-hour tax should be  
2 effective May 1, 2001. The rate rider for the Ohio franchise tax, including deferred  
3 state income taxes, should be effective January 1, 2001. Company Witness Pyle  
4 explains why the effective date for the Ohio Franchise Tax should be January 1,  
5 2001 rather than January 1, 2002. The rate rider for municipal income taxes,  
6 including deferred municipal income taxes, should be effective January 1, 2002.

7 Q. Why are you proposing an effective date of May 1, 2002 for the gross receipts  
8 rider?

9 A. The final privilege year for the gross receipts tax begins May 1, 2001 and ends  
10 April 30, 2002. The final measurement period for the gross receipts tax ends  
11 April 30, 2001. For financial purposes, the tax is amortized to expense ratably  
12 over the privilege year and not the measurement year. ORC Section  
13 4928.34(A)(6) states that, "(t)o the extent such total annual amount of the tax-  
14 related adjustment is greater than or less than the comparable amount of the total  
15 annual tax reduction experienced by the electric utility as a result of the  
16 provisions of Am. Sub. S. B. No. 3 of the 123<sup>rd</sup> General Assembly, such  
17 difference shall be addressed by the Commission through accounting procedures,  
18 refunds, or an annual surcharge or credit to customers, or through other  
19 appropriate means, to avoid placing the financial responsibility for the difference  
20 upon the electric utility or its shareholders." Selecting May 1, 2002 as the  
21 effective date of the gross receipts rider is the only way by which the Commission  
22 can avoid placing the financial responsibility for the difference in the amount of  
23 the tax-related adjustments on the utilities or their shareholders.

1

2 **Universal Service Fund Rider (PIPP Replacement)**

3 Q. How have CSP and OPCO determined the Universal Service Fund rider that has  
4 been included in each Company's unbundled rates?

5 A. Both CSP and OPCO took the PIPP riders that are currently in effect and added to  
6 those rates the low-income DSM program expenses built into base rates. This  
7 treatment is set forth in Am. Sub. S. B. No. 3.

8 Q. Do the Companies' current PIPP rates include a recovery of prior unrecovered  
9 PIPP balances?

10 A. No. Both CSP and OPCO's current PIPP rates include only the amount that was  
11 intended to recover the ongoing PIPP expenses.

12 Q. Will CSP and OPCO have unrecovered PIPP balances on July 1, 2000 when the  
13 PIPP program is turned over to the Department of Development (DOD)?

14 A. Yes. EXHIBIT NO. \_\_\_\_ WRF-1 shows the estimated unrecovered PIPP balances  
15 for CSP and OPCO.

16 Q. Would you explain how these estimated unrecovered balances were calculated?

17 A. The starting point is the Total Aged PIPP bills as of September 30, 1999. This is  
18 the amount of PIPP billings that are greater than the amount of payments received  
19 from PIPP customers. To this amount the estimated PIPP aged bills for the period  
20 October 1, 1999 through June 30, 2000 were added. The estimated arrears credits  
21 were then added and the estimated reinstatements were subtracted to arrive at the  
22 estimated cumulative total aged PIPP bills as of June 30, 2000. The next step was  
23 to take the cumulative total PIPP Rider billed as of September 30, 1999. To this

1 was added the estimated PIPP rider billed for the period October 1, 1999 through  
2 June 30, 2000. The difference between estimated cumulative total aged PIPP bills  
3 and the estimated cumulative total PIPP rider is the estimated unrecovered PIPP  
4 balances. CSP's unrecovered PIPP balance is \$18,951,773 and OPCO's  
5 unrecovered PIPP balance is \$8,757,482.

6 Q. What treatment is being proposed for these unrecovered PIPP balances?

7 A. As shown in Part F, CSP and OPCO have included these unrecovered PIPP  
8 balances in their stranded generation-related regulatory asset balances as of  
9 December 31, 2000.

10 Q. Have the Companies received any new rules regarding the Universal Service Fund  
11 from the DOD?

12 A. Yes. The Companies have met with the DOD and have provided PIPP information  
13 to the DOD. On December 9, 1999 the Companies received a proposed set of rules  
14 from DOD and a workshop was held on December 16, 1999. The Companies will  
15 continue to work with DOD on the new rules and if the final rules require changes,  
16 this testimony will be supplemented as necessary.

17

18 **Energy Efficiency Fund Rider (Revolving Efficiency Loan Fund/DSM)**

19 Q. How have CSP and OPCO developed the Energy Efficiency Fund Rider to fund  
20 the Revolving Efficiency Loan Fund?

21 A. CSP had \$2 million of DSM expense built into base rates and OPCO had  
22 approximately \$3.0 million of DSM expense built into base rates. These amounts,  
23 less the low-income DSM expense that was included in the Universal Service Fund

1 rider, were used to develop the Energy Efficiency Fund Rider. Company Witness  
2 Thomas has included both the Universal Service Fund rider and the Energy  
3 Efficiency Fund rider in Schedule UNB-1.

4 **Corporate Separation Plan Including Code of Conduct**

5 Q. How do the Companies intend to meet the corporate separation requirement of  
6 Am. Sub. S. B. No. 3 and the Commission Rules on Corporate Separation?

7 A. Part B in the Companies' Transition Plan Filing fully sets forth responses to the  
8 Commission's Rules. OPCO and CSP plan to establish new transmission  
9 subsidiaries and new distribution subsidiaries. These new subsidiaries will own  
10 and operate all of the transmission and distribution assets currently owned by  
11 OPCO and CSP.

12 Q. Will the new distribution subsidiaries be electric utilities and the providers of  
13 default service?

14 A. Yes. These new distribution subsidiaries will provide default service under the  
15 unbundled existing tariffs of OPCO and CSP.

16 Q. In Part B, the Companies state that the new transmission and new distribution  
17 subsidiaries will continue to provide transmission and distribution services to  
18 industrial and commercial customers and to municipal electric systems and rural  
19 electric cooperatives. Would you please explain what type of transmission and  
20 distribution services the Companies provide to these customers?

21 A. The transmission and distribution services offered to customers include  
22 engineering analysis, emergency repairs, rebuilds and upgrades on customer-  
23 owned electric equipment, meter and laboratory services, power quality

1 improvements and safety training. The Companies have provided these services to  
2 customers for many years.

3 Q. What are the benefits of the new transmission and new distribution subsidiaries  
4 continuing to offer these services?

5 A. All of these services are extensions of the Companies' core transmission and  
6 distribution services. By continuing to offer these services the new transmission  
7 and new distribution subsidiaries can fill in the valleys in the core work, thereby  
8 allowing maximum utilization of labor and equipment. This allows the  
9 transmission and distribution subsidiaries to staff skilled personnel for peak  
10 workloads, such as large-scale outages, without incurring the corresponding full  
11 expense burden. All payments received by the transmission and distribution  
12 subsidiaries for providing these transmission and distribution services to customers  
13 are credited to the cost of providing the core transmission and distribution services.  
14 Benefits from these services is reflected in the current rates which the Companies  
15 have unbundled in this Transition Plan filing.

16 Q. Are there any other unique services that will be moved to the new transmission and  
17 new distribution subsidiaries?

18 A. Yes. CSP and OPCO have storage water heater rental programs that will be  
19 moved to the new distribution subsidiaries. The Companies plan to phase-out the  
20 storage water heater rental program during the Market Development Period. The  
21 storage water heater rental program no longer is appropriate when there is a  
22 competitive market for generation services. The Companies will not market any  
23 new storage water heater rentals and will phase-out the rental program during the



1 Market Development Period. This should provide all current storage water heater  
2 rental customers ample time to transition to some other means of meeting their hot  
3 water requirements.

4 Q. Could you explain further how this corporate separation will meet the requirements  
5 of Am. Sub. S. B. No. 3?

6 A. EXHIBIT NO. \_\_\_\_ WRF-2 is a graphic representation of the planned corporate  
7 separation. The left side of this exhibit shows how CSP and OPCO currently are  
8 organized. The rest of this exhibit shows how the planned corporate separation  
9 will be organized. CSP and OPCO will continue to own and operate the  
10 generation assets. The two new subsidiaries of each Company will own and  
11 operate the transmission and distribution assets, respectively. AEP may also create  
12 a competitive retail electric supply (CRS) affiliate shown on this exhibit as AEP  
13 Competitive Retail Energy Co. The black and white single-hatched line on this  
14 exhibit shows the separation between the electric utility (i.e., the wires companies)  
15 and the unregulated generation and competitive retail electric supply affiliate.

16 Q. What is the timeline for the separation plan?

17 A. The required regulatory approvals at the FERC and the SEC to accomplish the  
18 proposed corporate separation plan will be sought during the year 2000. After  
19 receiving the required approvals, the new transmission and distribution  
20 subsidiaries for OPCO and CSP will be established.

21 Q. What FERC approval is required in connection with this separation plan?

22 A. FERC approval is required of the generation supply agreements from OPCO and  
23 CSP to their respective distribution subsidiaries at their unbundled generation rates

1 to enable these subsidiaries to provide default service during the Market  
2 Development Period. In addition, any other sales for resale by the AEP operating  
3 companies to a CRS or the distribution subsidiaries would also be subject to FERC  
4 jurisdiction.

5 Q. Is there any chance that this proposed corporate separation plan could change?

6 A. Yes. It is possible that there could be changes to the proposed corporate separation  
7 plan. If there are any changes to the corporate separation plan, this testimony and  
8 Part B to the Transition Plan Filing will be amended and filed as soon as possible.

9 Q. Please describe CSP and OPCO's Code of Conduct.

10 A. CSP and OPCO will adopt the Code of Conduct as set forth in the rules that were  
11 issued November 30, 1999. Part B provides detailed responses to the questions  
12 posed by the Commission's rules regarding how the Companies will comply with  
13 the Code of Conduct.

14 Q. How will CSP and OPCO communicate the Code of Conduct to affected  
15 employees?

16 A. CSP and OPCO intend to develop a three-phase approach to educating employees  
17 about the Code of Conduct and the corporate separation rules. The first phase will  
18 be a message to alert employees of the requirement of Am. Sub. S. B. No. 3 and  
19 the Code of Conduct. In particular the employees will be notified that they are  
20 prohibited from any transfer of any information in advance of implementation of  
21 the corporate separation plan that would be prohibited once that plan is in effect.  
22 This will be completed by January 1, 2000. The second phase will be to train any  
23 CRS employees concerning the requirements of the corporate separation rules.

1 The third phase will be to provide detailed training to all affected electric utility  
2 employees regarding the corporate separation rules. Phases two and three of the  
3 training will be completed prior to January 1, 2001.

4 Q. How will OPCO and CSP monitor employees' compliance with the corporate  
5 separation rules?

6 A. AEP's Internal Audit Department will have the responsibility for monitoring  
7 compliance with the corporate separation rules. The Company Response to Part B,  
8 §(H)(3) provides details as to the primary areas to be reviewed by the Internal  
9 Audit Department.

10

#### 11 **Statewide Consumer Education Plan**

12

##### **Nature of the Customer Education Campaign**

13 Q. Please describe the customer education campaign required by Am. Sub. S. B. No.  
14 3?

15 A. The customer education campaign will provide objective, useful information to  
16 Ohio's electric customers who will have the option to choose electric suppliers  
17 beginning January 1, 2001. The campaign will raise awareness of choice, and  
18 provide information about how to choose a supplier.

19 Q. What are the effective dates for the customer education campaign?

20 A. The campaign to educate customers during the Market Development Period will  
21 begin in 2000, and continue through the Market Development Period for CSP and  
22 OPCO.

## General Plan

1

2 Q. What is the general strategy for educating customers about electric choice?

3 A. CSP and OPCO, working with the state's other electric utilities through The Ohio  
4 Electric Utility Institute (OEUI) will support and implement a statewide and a  
5 coordinated local-territory campaign. The statewide campaign will be managed  
6 by the Commission Staff on a day-to-day basis. The local campaigns conducted  
7 by CSP and OPCO will dovetail with the statewide campaign, using the same  
8 messages tailored for specific audiences and platforms.

9 Q. How will the campaign be managed?

10 A. The campaign will be managed on a day-to-day basis by the Commission Staff.  
11 An advisory group, consisting of selected members, will review materials and  
12 recommend action; however, its recommendations will not be binding. CSP and  
13 OPCO will work with the statewide campaign to disseminate the same  
14 information as well as more in-depth information, to customers in their service  
15 territories.

16 Q. How will the advisory group be selected, managed and utilized?

17 A. A single statewide advisory group will consist of a representative of the  
18 Commission staff, the Ohio Consumers' Counsel, the utilities, and an energy  
19 marketer. Representatives of certain customer classes will also be included. The  
20 individuals will have the necessary skills and experience to contribute meaningful  
21 and credible input to the group, and demonstrate an effective background, skills  
22 and experience in public relations, advertising, communications or consumer  
23 education. The group will be advisory in nature only; however, its

1 recommendations will be given full consideration commensurate with its  
2 professional expertise. The group will not be a decision-making body.  
3 Recommendations of the group will be applicable in the same manner to local  
4 territory-specific campaigns as well. A service territory-specific group similar in  
5 size and make-up to the state group will also be convened for CSP and OPCO.

6 Q. How will an advertising agency/public relations firm be chosen and managed?

7 A. The Commission staff will submit a Request for Proposals to full-service  
8 advertising and public relations firms or, in the alternative, an advertising firm  
9 and a public relations firm. The statewide campaign advisory group will review  
10 the responses and narrow the field to at most ten agencies. The Commission will  
11 select the successful bidding firm. Commission staff will be the primary contact  
12 for the agency.

13 Q. What audiences will CSP and OPCO target for education efforts?

14 A. CSP and OPCO will specifically target residential customers, and small- and mid-  
15 sized commercial customers, elected officials, community leaders and civic  
16 organizations, trade associations and consumer groups. Industrial customers have  
17 special needs that will be addressed on an individual basis. A particular effort  
18 will target low-income, special needs and hard-to-reach customers in the service  
19 territories. CSP and OPCO will also target community-based organizations, with  
20 the intent of working with them to reach their constituents with the campaign  
21 messages.

22 Q. How will the campaign employ research?

1 A. Statewide research will be conducted by an independent agency to determine the  
2 baseline level of customer awareness prior to the start of the campaign. Research  
3 will be repeated every six months to determine changes in awareness. After the  
4 initial baseline survey, and once the education campaign has started, research will  
5 also be used to gauge the level of knowledge of choice and how to select an  
6 electricity supplier. Information from the research will be used to fine-tune  
7 messages and tactics.

8 Q. What is the timeline for the campaign?

9 A. The RFP will be issued by the Commission during the first quarter of 2000.  
10 Research will be conducted spring 2000, and campaign and message development  
11 will follow closely after that. Internet pages and web site linkages will be  
12 developed shortly upon completion of the message development. Some  
13 community-based activities – e.g., speaker engagements, fair participation, local  
14 news releases/letters to editors/op eds – will begin second quarter, 2000.  
15 Campaign paid mass-media advertising will begin the third quarter. The  
16 campaign for the remainder of the Market Development Period will be developed  
17 third/fourth quarter 2000.

18 Q. What tactics will the campaign include?

19 A. The campaign will rely heavily on public relations tactics at the outset, and use  
20 paid advertising in the third quarter of 2000 that will raise awareness and refer  
21 people to more detailed information sources (e.g., web site, brochure, call center).  
22 The public relations tactics include, but are not limited to, direct mail, media  
23 relations, special events, speakers' bureau, collateral material, web site, and call

1 center. We will also leverage our partnerships with community-based agencies  
2 and organizations and trade organizations. These tactics will be deployed at the  
3 state and local levels.

4 Q. What will the CSP and OPCO territory-specific consumer education plans  
5 include?

6 A. Because the territory-specific campaign will mirror the statewide campaign, and  
7 because the primary research has not been conducted and the statewide campaign  
8 has not been developed, it is not possible to present a detailed territory-specific  
9 consumer education campaign with objectives, strategies and tactics; messages; a  
10 timeline; and a line-item budget. The goal will be to conduct a statewide and a  
11 territory-specific campaign that: 1. Raises consumer awareness of customer  
12 choice; 2. Generates consumer interest in customer choice; 3. Builds consumer  
13 knowledge of how customer choice works and how to participate; 4. Provides  
14 accurate, objective information; 5. Minimizes consumer confusion; and 6.  
15 Reaches special-interest populations. CSP and OPCO will be responsible for  
16 spending up to \$2.2 million and up to \$2.4 million, respectively, for the period  
17 starting January 1, 2000 through December 31, 2001, and \$2.4 million and \$2.6  
18 million, respectively, through the remaining Market Development Period. See  
19 EXHIBIT NO. \_\_\_ WRF-3 for CSP and OPCO's Customer Choice Education  
20 Program Cost Responsibility.

21 Q. Who will be working with OEUI on the statewide campaign and will be the "point  
22 person" for the CSP and OPCO territory-specific campaigns?

23 A. Debra Strohmaier, APR, Ohio Corporate Communications Manager.

1   **CSP and OPCO Shopping Incentive Plan**

2   Q.   What are CSP and OPCO proposing for the shopping incentive?

3   A.   The shopping incentives that the Companies are proposing are set forth in Part H  
4       §(A) which I am sponsoring. These shopping incentives represent the lower of  
5       the estimated market cost of electric energy or the unbundled generation rate of  
6       the current tariffs.

7   Q.   Shouldn't the shopping incentive be greater than this?

8   A.   No. The shopping incentive or to use another term "the price to compare" should  
9       be the lower of the estimated market cost or the unbundled generation rate.  
10       Customer Choice in Ohio should start with the price to compare to allow  
11       customers an opportunity to choose an alternative supplier on the real economics  
12       of the electricity purchase.

13  Q.   Wouldn't a larger shopping incentive cause more customers to switch to an  
14       alternative supplier?

15  A.   Probably. The bigger someone makes the savings the more you will induce  
16       customers to switch suppliers, all other things being equal. However, the real  
17       goal of customer choice should be to have customers make good economic  
18       decisions on their supply of KWH.

19  Q.   Are you proposing that the shopping incentive be increased in the second and  
20       third years, if needed?

21  A.   No. The Commission's rules, by even giving the impression that the shopping  
22       incentive may increase, have created an impediment to customers shopping for an  
23       alternative supplier. I believe some customers will refrain from shopping during



1 the first year because they believe they will get a larger discount by waiting until  
2 the second or third year. For example, here in Columbus there is a mega  
3 hardware store that is going out of business. HQ's going out of business sale  
4 started with discounts of 20% to 30%. The HQ discounts then increased after  
5 about one month to the 40% to 50% range. The discounts are now in the range of  
6 60% to 70%. Customers, shopping at HQ, may decide to wait for the larger  
7 discount before purchasing the item that they want. These customers face the risk  
8 that the hardware item that they want to purchase may be sold out before the  
9 discount reaches the level they desire.

10

11 With the purchase of electricity, customers who believe that larger discounts will  
12 be coming in the future most likely will wait. These customers know that they do  
13 not face any risk of the electricity being sold out before the larger discounts come.  
14 The Commission's rule should have only indicated that an examination of  
15 customer switching behavior would be conducted after one year and after two  
16 years. That is what CSP and OPCO are proposing be done in Part H, §(C).

17 Q. Do CSP and OPCO believe that customers will switch to alternative suppliers  
18 with the proposed shopping incentives?

19 A. Yes. The customer survey included in Part H indicates there are even customers  
20 who say they will switch to an alternative supplier even if they have to pay more  
21 than what they are paying to CSP and OPCO. This indicates to me that customers  
22 will switch with the proposed shopping incentives.

23

1 OPCO has, already, had a large industrial customer choose to switch to an  
2 alternative supplier. This customer has unique circumstances in its service  
3 location that has allowed it to choose an alternative supplier prior to January 1,  
4 2001. This customer represents over 500 MW of OPCO's industrial load that has  
5 switched to an alternative supplier.

6  
7 In addition, the DOD is taking over the PIPP program July 1, 2000. In the  
8 Columbia Gas Choice program in Toledo, Ohio, the PIPP customers' gas service  
9 was aggregated and bid out very successfully. I anticipate that the DOD will  
10 aggregate the electric service for the PIPP customers for the State of Ohio and bid  
11 out that service in a manner similar to what was done in Toledo. This would  
12 mean that 2.8% of CSP's residential customers and 3.5% of OPCO's residential  
13 customers have switched to an alternative supplier. (See attached  
14 WP-\_\_\_WRF-1).

15  
16 In addition, Am. Sub. S. B. No. 3 makes special provisions for governmental  
17 aggregators. These provisions allow municipalities, counties and townships to  
18 provide aggregation services for their citizens for the purchase of electricity. Just  
19 the fact that these provisions were included in Am. Sub. S. B. No. 3 indicates that  
20 some parties felt that this would be a significant avenue to provide customer  
21 choice to the citizens of Ohio. To what extent this governmental aggregation will  
22 be used to switch customers to alternative suppliers is unknown. This unique  
23 provision has not been included in any other state's restructuring laws, to the best

1 of my knowledge. Therefore, I cannot draw on any other state's experience to  
2 forecast the amount of customer switching that will occur because of  
3 governmental aggregation. However, the logical assumption is that the General  
4 Assembly did not provide this opportunity in vain. The political leadership of the  
5 state must have expected some governmental aggregation to occur.

6 Q. Does this conclude your testimony?

7 A. Yes.

EXHIBIT NO. \_\_WRF-1  
Page 1 of 2

Columbus Southern Power Company  
Projected PIPP Unrecovered Balance as of 6/30/2000

Cumulative Total Aged Bills as of 9/1999		\$47,432,635
Estimated Aged Bills 10/99 thru 6/2000	5,445,605	
Estimated Arrears Credits	227,313	
Estimated Reinstatements	<u>(465,921)</u>	
Estimated Additional Recovery		<u>5,206,997</u>
Estimated Cumulative Total Aged Bills		52,639,632
Cumulative Total PIPP Rider as of 9/1999	31,583,917	
Estimated PIPP Rider Bills 10/99 thru 6/2000	<u>2,103,942</u>	
Estimated Cumulative Total PIPP Rider		<u>33,687,859</u>
Total PIPP Unrecovered as of 6/30/2000		<u>\$18,951,773</u>

EXHIBIT NO. \_\_WRF-1  
Page 2 of 2

Ohio Power Company  
Projected PIPP Unrecovered Balance as of 6/30/2000

Cumulative Total Aged Bills as of 9/1999		\$64,435,969
Estimated Aged Bills 10/99 thru 6/2000	6,015,755	
Estimated Arrears Credits	113,845	
Estimated Reinstatements	<u>(710,829)</u>	
Estimated Additional Recovery		<u>5,418,771</u>
Estimated Cumulative Total Aged Bills		69,854,740
Cumulative Total PIPP Rider as of 9/1999	58,038,158	
Estimated PIPP Rider Bills 10/99 thru 6/2000	<u>3,059,100</u>	
Estimated Cumulative Total PIPP Rider		<u>61,097,258</u>
Total PIPP Unrecovered as of 6/30/2000		<u><u>\$8,757,482</u></u>

EXHIBIT NO. \_\_\_ WRF-2

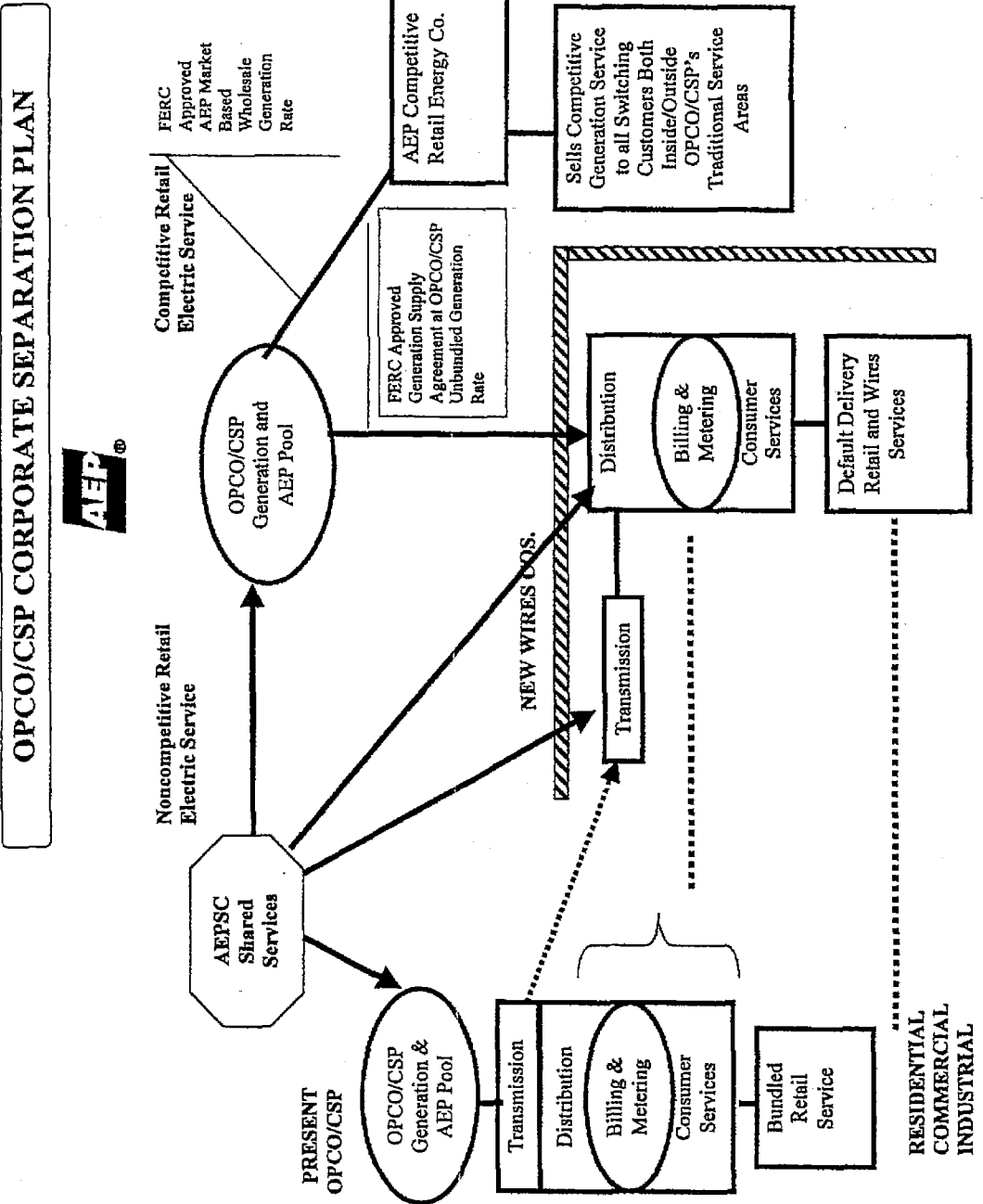


EXHIBIT NO. \_\_ WRF-3  
Page 1 of 1

CSP AND OPCO'S  
CUSTOMER CHOICE EDUCATION PROGRAM  
COST RESPONSIBILITY

	<u>CSP *</u>	<u>OPCO *</u>	<u>CSP</u>	<u>OPCO</u>	<u>TOTAL AEP OHIO</u>
<u>1/1/00 - 12/31/01</u>	\$16,000,000	13.88%	\$2,220,800	\$2,427,200	\$4,648,000
<u>1/1/02 - 12/31/05</u>	\$17,000,000	13.88%	\$2,359,600	\$2,578,900	\$4,938,500
<b>TOTAL</b>	<u>\$33,000,000</u>		<u>\$4,580,400</u>	<u>\$5,006,100</u>	<u>\$9,586,500</u>

\* Based upon number of customers as of 12/31/97.

EXHIBIT NO. \_\_\_\_ WRF-4  
Page 1 of 2

COLUMBUS SOUTHERN POWER COMPANY  
PROJECTED TRANSITION PLAN FILING EXPENSES  
(000)

Commission Required Notice	\$ 18
Outside Counsel	500
Transcripts	18
Expert Witnesses	125
Commission Staff Consultant	60
Other Major Expenses	<u>35</u>
Total	\$ <u>756</u>



EXHIBIT NO. \_\_\_\_ WRF-4  
Page 2 of 2

OHIO POWER COMPANY  
PROJECTED TRANSITION PLAN FILING EXPENSES  
(000)

Commission Required Notice	\$ 43
Outside Counsel	500
Transcripts	18
Expert Witnesses	125
Commission Staff Consultant	65
Other Major Expenses	<u>35</u>
Total	\$ <u>786</u>

WP-EXHIBIT NO. \_\_\_ WRF-4

Page 1 of 7

COLUMBUS SOUTHERN COMPANY / OHIO POWER COMPANY  
PROJECTED TRANSITION PLAN FILING EXPENSES  
( 000 )

Commission Required Notice	\$18 (CSP) / 43 (OP)
Outside Counsel	500
Transcripts	18
Expert Witnesses	125
Commission Staff Consultant	\$60 (CSP) / 65 (OP)
Other Major Expenses	35
Printing and Mailing Notice	0
Copying Documents	0
Total	\$ 756 (CSP) / 786 (OP)

Commission Required Notice (see Pages 2-7)

Legal – Outside Counsel (per Forrester/ PWMA estimate @ \$1,000,000/2 )

Legal – Transcripts (94-996 Case @ \$15,128 x 3% inflation x 5 years)

Expert Witnesses (per Forrester @ \$250,000/2)

Other Major Expenses (94-996 Case @ \$29,941 x 3% inflation x 5 years)

Printing and Mailing Notice (94-996 Case @ \$ 0)

Copying Documents (94-996 Case @ \$ 0)

WP-EXHIBIT NO. \_\_\_ WRF-4

Page 2 of 7



## FAX MEMO

From Susan Bowles

December 7, 1999

TO: Deb Strohmaier - AEP  
Fax: 628-4631  
FROM: Susan Bowles

re: 1/2 page quote

Deb:

Here is your estimate for the half page ad. I have separated the quotes for Ohio Power and Columbus Southern Power. Rates will be good through Dec. 28th. I have estimated rates should this ad run after this date. The only cost not included would be for overnight charges should we need to ship the artwork using Airborne Express or Fed Ex.

Also, there are several "half page ad sizes" to choose from depending on your information. I used a 4 column by 16" ad for your estimate. Actual dimensions for this size are 8 5/8" x 16". You could also run this as a 6x10.5 (13"x10") if a more horizontal layout would work better.

Please give me a call if you have any questions.

Page 1 of 6

Ohio Newspaper Service  
1335 Dublin Rd., Suite 215 B  
Columbus, OH 43215

WP-EXHIBIT NO. WRF-4  
Page 3 of 7

ADVERTISING ESTIMATE  
December 7, 1999

ORDER #: S9122A00-005442

Page 1

Deb Strohmaier  
AEP Service Corporation  
1 Riverside Plaza  
Columbus, OH 43215  
614-223-1403

CLIENT: Ohio Power  
P. O. #: PUCO 1/2 page quote  
POSITION:  
COPY: camera-ready from AEP

AD SIZE	RATE TYPE	RATE (\$)	TOTAL (\$)	RUN DATE	CAPTION
Ashland - Times Gazette	Ashland OH (Ashland)				
4X16.00	SAU	13.10	838.40	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 11851				
Athens - Messenger	Athens OH (Athens)				
4X16.00	SAU	16.02	1025.28	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 13009 Sun: 15723				
Bellefontaine - Examiner	Bellefontaine OH (Logan)				
4X16.00	SAU	9.29	594.56	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 10300				
Bowling Green - Sentinel Tribune	Bowling Green OH (Wood)				
4X16.00	SAU	11.55	739.20	12/08/99	Half page ad
Daily 6-12.5-21.00	Circ: 12634				
Bucyrus - Telegraph Forum	Bucyrus OH (Crawford)				
4X16.00	SAU	12.42	794.88	12/08/99	Half page ad
Daily 6-12.5-21.00	Circ: 7552				
Cambridge - Daily Jeffersonian	Cambridge OH (Guernsey)				
4X16.00	SAU	15.31	979.84	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 13002 Sun: 13035				
Canton - Repository	Canton OH (Stark)				
4X16.00	SAU	52.57	3364.48	12/08/99	Half page ad
Daily 6-21.5-21.50	Circ: 62500 Sun: 82000				
Columbus - Dispatch	Columbus OH (Franklin)				
4X16.00	SAU	157.05	10051.20	12/08/99	Half page ad
Daily 6-12.5-21.00	Circ: 254346 Sun: 391396				
Coshocton - Tribune	Coshocton OH (Coshocton)				
4X16.00	SAU	13.73	878.72	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 7742 Sun: 8109				
Defiance - Crescent News	Defiance OH (Defiance)				
4X16.00	SAU	11.20	716.80	12/08/99	Half page ad
Daily 6-12.5-21.00	Circ: 16499 Sun: 17146				
Delaware - Gazette	Delaware OH (Delaware)				
4X16.00	SAU	11.35	726.40	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 7975				
Dover/New Phil. - Times Reporter	New Philadelphia OH (Tuscarawas)				
4X16.00	SAU	27.53	1761.92	12/08/99	Half page ad
Daily 6-12.5-22.50	Circ: 24466 Sun: 26792				
Et. Liverpool - Review	East Liverpool OH (Columbianna)				
4X16.00	SAU	16.34	1045.76	12/08/99	Half page ad
Daily 6-0.0-21.50	Circ: 11148				
Findlay - Courier	Findlay OH (Hancock)				
4X16.00	SAU	17.13	1096.32	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 23422				

WP-EXHIBIT NO. \_\_\_ WRF-4

Page 4 of 7

Page 2

ORDER #: 99122400-005442

Deb Strohmaier  
AEP Service Corporation  
1 Riverside Plaza  
Columbus, OH 43215  
614-223-1403

CLIENT: Ohio Power  
P. O. #: PUCO -72 page quote  
POSITION:  
COPY: camera-ready from AEP

AD SIZE	RATE TYPE	RATE (\$)	TOTAL (\$)	RUN DATE	CAPTION
Fremont - News Messenger Fremont OH (Sandusky)					
4X16.00	SAU	22.30	1427.20	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 13947					
Gallipolis - Daily Tribune Gallipolis OH (Gallia)					
4X16.00	SAU	7.20	460.80	12/08/99	Half page ad
Daily 6-12.5-21.25 Circ: 5579 Sun: 11825					
IN/WINCHESTER - NEWS GAZETTE WINCHESTER IN					
4X16.00	SAU	8.72	558.08	12/08/99	Half page ad
DAILY 0-0.0-0.00 Circ: 4018					
Ironton - Tribune Ironton OH (Lawrence)					
4X16.00	SAU	10.95	700.80	12/08/99	Half page ad
Tu-Su 6-12.5-21.50 Circ: 7500 Sun: 8000					
Kenton - Times Kenton OH (Hardin)					
4X16.00	SAU	8.50	544.00	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 7200					
Lancaster - Eagle Gazette Lancaster OH (Fairfield)					
4X16.00	SAU	22.23	1422.72	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 17000 Sun: 17000					
Lima - News LIMA OH (Allen)					
4X16.00	SAU	29.10	1862.40	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 35093 Sun: 44477					
Logan - News Logan OH (Hocking)					
4X16.00	SAU	8.90	569.60	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 4544					
Mansfield - News Journal Mansfield OH (Richland)					
4X16.00	SAU	30.40	1945.60	12/08/99	Half page ad
Daily 6-12.5-21.00 Circ: 36000 Sun: 46000					
Marietta - Times Marietta OH (Washington)					
4X16.00	SAU	18.30	1171.20	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 12535					
Marion - The Star Marion OH (Marion)					
4X16.00	SAU	20.92	1338.88	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 15609 Sun: 16556					
Martins Ferry - Times Leader Martins Ferry OH (Belmont)					
4X16.00	SAU	24.61	1575.04	12/08/99	Half page ad
Daily 6-12.5-22.00 Circ: 19813 Sun: 22243					
Mount Vernon - News Mount Vernon OH (Knox)					
4X16.00	SAU	10.19	652.16	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 10122					
New Lexington - Perry County Tribune New Lexington OH (Perry)					
4X16.00	SAU	8.96	573.44	12/08/99	Half page ad
Wed. 9-10.0-21.50 Circ: 4500					
Newark - Advocate Newark OH (Licking)					
4X16.00	SAU	26.15	1673.60	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 23250 Sun: 23750					
Paulding - Paulding Progress Paulding OH (Paulding)					
4X16.00	SAU	5.00	320.00	12/08/99	Half page ad
Wed. 6-12.4-21.50 Circ: 4300					

WP-EXHIBIT NO.      WRF-4

Page 5 of 7

Page 3

7P3ER #: 99122400-005442

Deb Strohmaier  
AEP Service Corporation  
Riverside Plaza  
Columbus, OH 43215  
614-223-1403

CLIENT: Ohio Power  
P. O. #: POC-1/2 page quote  
POSITION:  
COPY: camera-ready from SEP

AD SIZE	RATE TYPE	RATE (\$)	TOTAL (\$)	RUN DATE	CAPTION
Pomeroy - Daily Sentinel	Pomeroy OH (Maigs)				
4X16.00	SAU	6.50	415.00	12/08/99	Half page ad
Daily 6-12.5-21.25	Circ: 4780 Sun: 11625				
Portsmouth - Times	Portsmouth OH (Scioto)				
4X16.00	SAU	18.95	1212.90	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 17084 Sun: 16317				
Staubenville - Herald Star	Staubenville OH (Jefferson)				
4X16.00	SAU	23.43	1499.52	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 25500 Sun: 28200				
Tiffin - Advertiser Tribune	Tiffin OH (Seneca)				
4X16.00	SAU	15.22	974.08	12/08/99	Half page ad
Daily 6-11.4-21.50	Circ: 11200 Sun: 11750				
Upper Sandusky - Chief Union	Upper Sandusky OH (Wyandot)				
4X16.00	SAU	6.00	384.00	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 4650				
Van Wert - Times Bulletin	Van Wert OH (Van Wert)				
4X16.00	SAU	13.75	880.00	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 7500				
Wapakoneta - Daily News	Wapakoneta OH (Auglaize)				
4X16.00	SAU	9.66	618.24	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 5300				
Wooster - Daily Record	Wooster OH (Wayne)				
4X16.00	SAU	23.00	1472.00	12/08/99	Half page ad
Daily 6-12.5-21.50	Circ: 22778 Sun: 22869				
Zanesville - Times Recorder	Zanesville OH (Muskingum)				
4X16.00	SAU	26.15	1673.60	12/08/99	Half page ad
Daily 6-12.5-21.00	Circ: 21911 Sun: 21929				

\* 2496.00 19926.60 ÷ 2 = 769.68 50539.52  
Total Paid Circulation 818159 9964.80  
40574.72 × 1.0638 = 43163.37

Total Insertions	39	} Current Thru 12/28/99	2000 Estimate
Gross Advertising	50539.52		\$53,765.49 gross
Net Billed	42958.59		
Total Misc	0.00		\$45,700.62 Net.

Total Billed	42958.59
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$$\frac{53,765.44}{50,539.52} = 1.0738 \text{ price increase year 2000}$$

Ohio Newspaper Service  
1335 Dublin Rd., Suite 216 S  
Columbus, OH 43215

WP-EXHIBIT NO. WRF-4  
Page 6 of 7

ADVERTISING ESTIMATE  
December 7, 1999

ORDER #: 99122AC0-005443

Page 1

Deb Strohmaier  
AEP Service Corporation  
1 Riverside Plaza  
Columbus, OH 43215  
614-223-1403

CLIENT: Columbus Southern Power  
P. O. #: PUCO 1/2 page ad  
POSITION:  
COPY: camera-ready from AEP

AD SIZE	RATE TYPE	RATE (\$)	TOTAL (\$)	RUN DATE	CAPTION
• Athens - Messenger Athens OH (Athens)	4X16.00 SAU	16.02	<u>1025.28</u>	12/08/99	Half page ad
	Daily 6-12.5-21.50 Circ: 13009 Sun: 15723				
Chillicothe - Gazette Chillicothe OH (Ross)	4X16.00 SAU	23.53	<u>1505.92</u>	12/08/99	Half page ad
	Daily 6-12.5-21.50 Circ: 16182 Sun: 19548				
Circleville - Herald Circleville OH (Pickaway)	4X16.00 SAU	9.25	<u>592.00</u>	12/08/99	Half page ad
	Daily 6-12.5-21.50 Circ: 2100				
• Columbus - Dispatch Columbus OH (Franklin)	4X16.00 SAU	157.05	<u>10051.20</u>	12/08/99	Half page ad
	Daily 6-12.5-21.00 Circ: 254346 Sun: 391396				
Delaware - Gazette Delaware OH (Delaware)	4X16.00 SAU	11.35	<u>726.40</u>	12/08/99	Half page ad
	Daily 6-12.5-21.50 Circ: 7975				
Gallipolis - Daily Tribune Gallipolis OH (Gallia)	4X16.00 SAU	7.20	<u>450.80</u>	12/08/99	Half page ad
	Daily 6-12.5-21.25 Circ: 5579 Sun: 11825				
Georgetown - News Democrat Georgetown OH (Brown)	4X16.00 SAU	5.50	<u>352.00</u>	12/08/99	Half page ad
	THUR 6-10.5-21.00 Circ: 5000				
Hillsboro - Times Gazette Hillsboro OH (Highland)	4X16.00 SAU	11.75	<u>752.00</u>	12/08/99	Half page ad
	Daily 8-0.0-21.50 Circ: 5500				
• Ironton - Tribune Ironton OH (Lawrence)	4X16.00 SAU	10.95	<u>700.60</u>	12/08/99	Half page ad
	Tu-Su 6-12.5-21.50 Circ: 7500 Sun: 8000				
• Lancaster - Eagle Gazette Lancaster OH (Fairfield)	4X16.00 SAU	22.23	<u>1422.72</u>	12/08/99	Half page ad
	Daily 6-12.5-21.50 Circ: 17000 Sun: 17000				
• Logan - News Logan OH (Hocking)	4X16.00 SAU	8.90	<u>569.60</u>	12/08/99	Half page ad
	Daily 6-12.5-21.50 Circ: 4544				
London - Madison Press London OH (Madison)	4X16.00 SAU	8.05	<u>515.20</u>	12/08/99	Half page ad
	Daily 6-9.3-21.50 Circ: 6500				
• Marietta - Times Marietta OH (Washington)	4X16.00 SAU	18.30	<u>1171.20</u>	12/08/99	Half page ad
	Daily 6-12.5-21.50 Circ: 12535				
Marysville - Journal Tribune Marysville OH (Union)	4X16.00 SAU	7.85	<u>502.40</u>	12/08/99	Half page ad
	Daily 6-10.0-21.50 Circ: 6101				

WP-EXHIBIT NO. WRF-4

ORDER #: 99122AC0-005443

Page 7 of 7

Page 2

Deb Strohmaier  
AEP Service Corporation  
1 Riverside Plaza  
Columbus, OH 43215  
614-223-1403

CLIENT: Columbus Southern Power  
P. O. #: PUCO 172 page ad  
POSITION:  
COPY: camera-ready from AEP

AD SIZE	RATE TYPE	RATE (\$)	TOTAL (\$)	RUN DATE	CAPTION
McConnelsville - Morgan County Herald McConnelsville OH (Morgan)					
4X16.00	SAU	7.00	448.00	12/08/99	Half page ad
Wed. 5-21.5-21.00 Circ: 4753					
• Mount Vernon - News Mount Vernon OH (Knox)					
4X16.00	SAU	10.19	552.16	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 10122					
Mt. Sterling - Tribune London OH (Madison)					
4X16.00	SAU	4.19	268.16	12/08/99	Half page ad
Monday 6-0.0-21.50 Circ: 6900					
• New Lexington - Perry County Tribune New Lexington OH (Perry)					
4X16.00	SAU	8.96	573.44	12/08/99	Half page ad
Wed. 9-10.0-21.50 Circ: 4500					
• Newark - Advocate Newark OH (Licking)					
4X16.00	SAU	26.15	1673.60	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 23250 Sun: 23750					
• Pomeroy - Daily Sentinel Pomeroy OH (Meigs)					
4X16.00	SAU	6.50	416.00	12/08/99	Half page ad
Daily 6-12.5-21.25 Circ: 4780 Sun: 11825					
• Portsmouth - Times Portsmouth OH (Scioto)					
4X16.00	SAU	18.95	1212.80	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 17084 Sun: 16317					
• Waverly - News Watchman Waverly OH (Pike)					
4X16.00	SAU	6.88	440.32	12/08/99	Half page ad
Sun/Wed 6-12.4-21.50 Circ: 3298					
Wellston - Telegram Wellston OH (Jackson)					
4X16.00	SAU	8.82	564.48	12/08/99	Half page ad
Wed. 8-9.9-21.50 Circ: 5000					
West Union - The Defender West Union OH (Adams)					
4X16.00	SAU	7.25	464.00	12/08/99	Half page ad
Wed 6-11.5-21.00 Circ: 8583					

\* 1536.00 422.82 27060.48  
 $19,929.00 \div 2 =$   
 Total Paid Circulation 458141  $\frac{9964.50}{17095.62} \times 1.0638 = 18,186.38$

Total Insertions  
 Gross Advertising  
 Net Billed  
 Total Misc

24  
 27060.48  
 23001.41  
 0.00

} Current  
 Thru 12/28/99

2000 Estimate - price increase.  
 \$28,787.74 gross  
 \$24,469.57 Net

Total Billed 23001.41

$\frac{28,787.74}{24,469.57} = 1.1764$  price increase year 2000



COL	COUNTS	DOLLARS	DESC
COL 01:01	587,540		Total number of Residential customers
COL 01:02	16,458	2,870	number of Residential accounts on 4(B) Payment Plan - ACTIVE
COL 01:03		25,258,353.71	Total dollar amount of active PIP customers
COL 01:04	11,877		number of Residential accounts on 4(A) Payment Plan
COL 01:05		1,911,877.42	Total dollar amount of arrearages of customers in 01:04
COL 01:06	56,819		Total number of Residential accounts in arrears 60+ days
COL 01:07		7,733,353.97	Total dollar amount of 1.06 arrearages
COL 02:01	2,643		number of Primary Heating source customers in 01:02
COL 02:02	13,815		number of Secondary Heating source customers in 01:02
COL 02:03	4,060		number of Continuous PIP Customers
COL 02:04	186		number of New PIP customers
COL 02:05	12,212		number of Reenrolled PIP customers
COL 03:01	6,558		number of Inactive PIP customers - deferred PIP balen
COL 03:02	1,539		number of Final PIP customers
COL 03:03	31		number of 03:01 customers because of income ineligibility
COL 03:04	591		number of 03:01 customers because of reactivation
COL 03:05	6,026		number of 03:01 customers other - 03:01 minus 03:03
COL 03:06	111		number of 03:02 resulting from non-payment disconnects
COL 03:07	4,857		number of customers, 50% poverty, 3% PIPS, secondary he
COL 03:08	14		number of customers on PIPP balanced payment plan
COL 03:09	12		number of PIPP GRADUATES, first 12 months
COL 03:10	553		number of PIPP GRADUATES, second 12 months
COL 03:11	1,496		number of PIPP GRADUATES, last third 12 months
COL 04:01		21,428,246.65	dollar amount of deferred arrears of active PIP

COL	COUNTS	DOLLARS	DESC
01.01	596,052		Total Number of Residential customers
01.02	20,684	3.54	Number of Residential accounts on 4(B) Payment Plan - ACTIVE
01.03		28,066,712.11	Total dollar amount of active PIP customers
01.04	5,329		Number of Residential accounts on 4(A) Payment Plan
01.05		633,583.25	Total dollar amount of arrearages of customers in 01.04
01.06	59,674		Total number of Residential accounts in arrears 60+ days
01.07		3,993,242.16	Total dollar amount of 1.06 arrearages
02.01	4,489		Number of Primary Heating source customers in 01.02
02.02	16,195		Number of Secondary Heating source customers in 01.02
02.03	3,702		Number of Continuous PIP Customers
02.04	284		Number of New PIP customers
02.05	16,498		Number of Readmitted PIP customers
03.01	7,831		Number of Inactive PIP customers - deferred PIPP balon
03.02	701		Number of Final PIP customers
03.03	132		Number of 03.01 customers because of income ineligibili
03.04	733		Number of 03.01 customers due to reverif. - PIPP gradua
03.05	6,966		Number of 03.01 customers other - 03.01 minus 03.03
03.06	171		Number of 03.02 resulting from non-payment disconnects
03.07	6,042		Number of customers, 50% poverty, 3% PIPP, secondary ha
03.08	25		Number of customers on PIPP balanced payment plan
03.09	48		Number of PIPP graduates, first 12 months
03.10	246		Number of PIPP graduates, second 12 months
03.11	1,884		Number of PIPP graduates, last third 12 months
04.01		25,113,432.96	Dollar amount of deferred arrears of active PIPP

EXHIBIT NO. \_\_\_\_\_

BEFORE  
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus  
Southern Power Company for Approval of  
Electric Transition Plan and Application for  
Receipt of Transition Revenues

Case No. 99-\_\_-EL-ETP

In the Matter of the Application of Ohio  
Power Company for Approval of  
Electric Transition Plan and Application for  
Receipt of Transition Revenues

Case No. 99-\_\_-EL-ETP

DIRECT TESTIMONY OF  
EDWARD P. KAHN  
ON BEHALF OF  
COLUMBUS SOUTHERN POWER COMPANY  
AND  
OHIO POWER COMPANY

Item Index - document

1

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Summary: Testimony Public Version of Direct Testimony of Kevin Murray on behalf of Industrial Energy Users-Ohio (Part 1 of 3 - Testimony through Exhibit KMM-2) electronically filed by Ms. Vicki L. Leach-Payne on behalf of Randazzo, Samuel C. Mr.