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

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

Samuel C. Randazzo (Counsel of Record)
Frank P. Darr
Joseph E. Oliker
MCNEES WALLACE & NURICK LLC
21 East State Street, 17th 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

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

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

INDEX

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

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

I. INTRODUCTION

Q1. Please state your name and business address.

A1. My name is Kevin M. Murray. My business address is 21 East State Street, 17th Floor, Columbus, Ohio 43215-4228.

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

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

Q3. Please describe your educational background.

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

Q4. Please describe your professional experience.

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

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

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

Q6. What is the purpose of your testimony?

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

[1] In my testimony I will refer at times to AEP-Ohio as the Company.

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

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

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

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

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

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

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

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

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

I recommend that the Commission reject AEP-Ohio's Modified ESP and promptly direct AEP-Ohio to restore the use of RPM-based capacity pricing in all cases where a CRES provider is serving a retail consumer within AEP-Ohio's service area. I also suggest that the protracted debate that has occurred on the subject of this proceeding has, itself, stymied the ability for consumers to identify options to reduce their electric bills through "customer choice" and that the experience in this case strongly suggests that the Commission should turn to a competitive bid process ("CBP") to establish default generation supply prices.

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

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

FERC has increasingly relied upon competitive market forces to establish "just and reasonable" prices at the wholesale level in both the gas and electric sectors. As part of FERC's effort to remedy the anticompetitive electric industry structure which was dominated by vertically-integrated investor-owned electric utilities, FERC required electric utilities to move to open access, comparable and non-discriminatory transmission service and encouraged vertically-integrated electric utilities that owned generating plants to transfer operational control of their high voltage transmission facilities to independent RTOs such as PJM Interconnection LLC ("PJM"). When Ohio enacted its electric restructuring legislation in 1999, the legislation similarly included a requirement that owners of transmission facilities transfer control of such facilities to an RTO.[2] Again, FERC's directives and policy announcements were part of FERC's effort to remedy undue discrimination in the operation of transmission facilities that occurred because vertically-integrated utilities used their operation and control of their transmission facilities to favor their generation assets.

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

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

[2] Section 4928.12, Ohio Revised Code.

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

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

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

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

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

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

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

[3] Section 4928.12, Ohio Revised Code.

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

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

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

CSP and OP filed their ETPs in Commission Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP. At this time, AEP-Ohio's parent, American Electric Power or "AEP", was changing its traditional regulated utility model to move towards an energy trading business model with an international scope focused on multiple energy commodities and physical and financial products or services. As a result, the corporate separation plans filed by OP and CSP were a bit different than other EDUs. More specifically, OP and CSP proposed to maintain ownership and control of generation in the existing OP and CSP entities and transfer the "wires business" (transmission and distribution) to new entities. This aspect of CSP's and OP's corporate separation plans is identified in the attached pages of the pre-filed testimony of CSP's and OP's witness William Forrester that are attached to my testimony as Exhibit KMM-2. AEP's corporate separation plans in Texas and Ohio and their relationship to the move to an energy trading business model are also described in the prospectus which AEP issued in 2002. The 2002 prospectus is attached to my testimony as Exhibit KMM-3.

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

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

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

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

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

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

A12. Yes. In public statements and throughout the lengthy debate in this proceeding and the litigation in Case No. 10-2929-EL-UNC, AEP-Ohio has claimed that it cannot move promptly to market-based pricing for generation capacity service or use a competitive bidding process to establish default generation service supply prices that are part of the SSO until the AEP System Integration Agreement (often referred to as the AEP Pool Agreement) is terminated or restructured and until it unwinds the fixed resource requirement ("FRR") election which AEPSC (not AEP-Ohio) made in 2007. These claims are without merit since the initial Commission-approved OP and CSP corporate separation plans did not involve transferring generating assets. In other words, unlike the FirstEnergy operating companies that AEP-Ohio's witness Robert Powers refers to at page 7 of his testimony, the CSP and OP transition plans proposals approached corporate separation differently. Instead of transferring generating assets to a non-regulated affiliate, OP and CSP proposed transferring ownership and control of the distribution and transmission function segments to new, structurally separated entities. I believe the differences between the CSP/OP approach and the approach followed by the FirstEnergy operating companies is related to AEP's plans at the time to focus on the energy trading business to capture value from the competitive wholesale market from the relatively low book cost generating assets owned or controlled by CSP and OP. In any event, I know of no reason why moving forward with the type of corporate separation initially proposed by and approved for CSP and OP might need to be delayed until the subsequent FRR election made by AEPSC is terminated or until the AEP East System Integration Agreement is terminated or modified.

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

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

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

[4] *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).

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

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

A14. No.

Q15. Why not?

A15. Like many of the vertically-integrated electric utilities that adopted the energy trading business model made infamous by companies like Enron, AEP's pursuit of that model did not go well. As the negative financial consequences of the energy trading business model rippled through the electricity industry and the broader energy industry, and Wall Street turned sour on the energy trading approach, AEP abruptly discontinued its pursuit of the international energy trading business model and declared that it was returning to a business model that focused on a traditionally regulated and vertically-integrated electric utility business model. A copy of a press release issued by AEP on October 10, 2002 announcing it was substantially reducing its energy trading activities is attached to my testimony as Exhibit KMM-5. It is my opinion that AEP's rather precarious pursuit of the energy trading model and its subsequent abrupt distancing itself from that business model so as to portray itself to Wall Street as a stable, vertically-integrated and traditionally regulated electric utility caused AEP-Ohio to not implement the corporate separation plans approved by the Commission in the ETP cases for CSP and OP, and to reverse course on plans to obtain EWG status as authorized by the Commission in Case No. 01-3289-EL-UNC. Nonetheless, it is my understanding that SB 3 and the Commission's rules require that the distribution, transmission and generation functions be looked at as though they are three separate and unrelated lines of business.

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

A16. No. In fact, the FirstEnergy operating companies positively responded to the Commission's support of RSPs even though they transferred ownership and control of their generating assets to a separate unregulated affiliate in compliance with their Commission-approved corporate separation plans. As in the case of the FirstEnergy operating companies, implementation of the corporate separation plans by CSP and OP may have involved securing FERC approval of generation supply contracts between the EDUs and the affiliated generation entities to assemble a sensible rate stabilization plan. But, corporate separation plan implementation would not have thwarted the opportunity for RSPs unless AEP demanded otherwise.

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

A17. PJM's capacity market is intended to ensure the adequate availability of necessary resources that can be called upon to ensure the reliability of the grid. In this context, it is important to understand that this reliability is for the entire footprint of PJM, not just the distribution service area of AEP-Ohio. Each load serving entity ("LSE") within PJM is responsible for contributing owned or controlled capacity resources to the common pool of resources that are available to PJM to satisfy PJM's reliability objective. These capacity resources include electric generating plants, eligible energy efficiency resources and demand response resources. The pool of capacity resources committed to PJM is available to and dispatched by PJM to satisfy the reliability objective within PJM's footprint. Beyond these committed resources, PJM also has other tools that PJM can use in emergencies to affect the performance of resources that did not volunteer to participate through the preferred market-based structure that relies on bids supplied by parties that own or control capacity resources. PJM's capacity market structure provides transparent information on the value of capacity, energy and ancillary services to enable forward market signals to support infrastructure investment. The capacity market design also provides a forward mechanism to evaluate the ongoing reliability requirements in a transparent manner, providing opportunities for the integration of distributed and central station generation, demand response, energy efficiency, and transmission options to maintain and enhance reliability while achieving scale and scope economies within the PJM footprint

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

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

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

A18. Yes. RPM is intended to provide a forward price signal for capacity resources (all capacity resources) and LSE obligations that also reflects PJM's regional transmission expansion planning process. RPM can also have a locational nature to the pricing signal. RPM relies upon a multi-auction structure designed to procure resource commitments to satisfy the **region's** unforced capacity obligation through a base residual auction ("BRA"), incremental auctions ("IAs") and bilateral market transactions.

Q19. How does RPM operate?

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

For each delivery year, PJM determines a peak load forecast. PJM then calculates an installed reserve margin for the entire PJM region. The installed reserve margin is defined as the level of installed reserves in excess of the forecast peak load needed to maintain the desired reliability index of ten years, on average, per occurrence (loss of load expectation of one occurrence every ten years) after emergency procedures to invoke load management. The installed reserve margin is calculated based upon probabilistic studies. PJM then calculates the region's forecast pool requirement, which represents the quantity of unforced capacity resources needed recognizing the pool-wide equivalent average forced outage rate and the expected performance of demand response resources.

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

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

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

Q20. How are capacity charges billed under RPM?

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

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

A21. Yes. PJM's capacity market also allows LSEs an alternative method of satisfying their capacity resource obligation to the PJM pool. This alternative is known as the FRR alternative. FRR permits an LSE the option to submit an FRR capacity plan (to be reviewed and approved by PJM) to satisfy the shared responsibility of all LSEs to commit capacity resources and as an alternative to the requirement to participate in the periodic RPM competitive bidding process or auctions, which feature a variable capacity resource requirement. American Electric Power Service Corporation ("AEPSC"), acting on behalf of the affiliated AEP East operating companies made an FRR election in 2007. AEP-Ohio itself is not a stand-alone FRR entity. The ESP application submitted in this proceeding does not identify the relationship between AEPSC or identify the contractual or other obligations that AEP-Ohio may have as a result of AEPSC's FRR election.

Q22. How was PJM's capacity market created?

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

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

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

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

> FERC Statutes and Regulations ¶31,233 (October 20, 2006) ("*Order 688*"), the FERC found that both MISO and PJM are independently administered, auction-based day-ahead and real-time wholesale markets for the sale of electric energy. The FERC also found that the existence of wholesale markets for long-term sales of capacity and electric energy is satisfied by the existence of long-term bilateral contracts for sales of capacity and energy and is a sufficient indication of a market. *Order 688* ¶117.
>
> The PJM energy market provides substantial benefits to the region based on its ability for utilities and customers to access a larger number of generation resources to fulfill load requirements while utilizing a robust transmission system. PJM's methodology results in the least cost generating units serving the load requirements, subject to any transmission constraints. This method is similar to the one performed by AEP for its system prior to joining PJM. PJM, however, provides access to additional generating units and the capability of importing generation from MISO without paying additional transmission rates. The resulting dispatch price provides transparent economic signals that guide short- and long-run decisions by participants and regulators.

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

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

A24. Yes. On November 1, 2010, AEPSC, on behalf of OP and CSP, submitted an application to FERC in Docket No. ER11-1995-000 and subsequently re-submitted an application in Docket No. ER11-2183-000 seeking to establish what AEPSC characterized as a cost-based charge for capacity supplied to CRES suppliers providing competitive generation service to retail load within the AEP-Ohio service area. In its FERC application, AEPSC asserted that its sudden proposal to change the basis for establishing prices for capacity is consistent with Section D.8 of Schedule 8.1 of the PJM Reliability Assurance Agreement ("RAA") which AEP-Ohio signed when it became a transmission-owner member of PJM. Section D.8 of the RAA provides, in relevant part:

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

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

[5] 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").

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

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

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

However, in response to applications for rehearing, the Commission subsequently rejected the Stipulation on February 23, 2012 finding that it was not consistent with the public interest. The Commission's rejection of the Stipulation resulted in capacity prices for CRES providers serving customers in AEP-Ohio's service area reverting to the state compensation mechanism (i.e., the status quo RPM-based prices). In rejecting the Stipulation, the Commission directed AEP-Ohio to notify the Commission whether AEP-Ohio would modify or withdraw its original ESP application. Subsequently, the Commission granted a motion by AEP-Ohio in Case No. 10-2929-EL-UNC to re-establish, on an interim basis, a two-tiered pricing structure for capacity, but only through May 31, 2012, with capacity prices thereafter reverting to RPM-based prices. The re-established two-tiered capacity charge retained opportunities for RPM-based pricing to remain in cases where CRES providers served customers (including "mercantile customers") through eligible community aggregation programs.

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

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

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

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

A27. AEP-Ohio is proposing to roll environmental costs currently collected through a rider into base generation rates and fix the base generation rates at that level through December 31, 2014. An alternative energy rider would be established to recover a portion of the costs of alternative energy resources. AEP-Ohio has proposed a generation resource rider ("GRR") as a non-bypassable placeholder rider to recover costs associated with the Turning Point Solar facility, with any charges to be recovered through the rider to be approved by the Commission in a separate proceeding. The fuel adjustment clause ("FAC") would continue, albeit presumably with some modifications as a result of proposed energy-only auctions for a portion of the SSO load. AEP-Ohio is proposing to increase the interruptible rate credit under Rate IRP-D to $8.21 per kW-month, with the revenue reduction associated with the higher level of credit being recovered through a non-bypassable RSR.[6] A non-bypassable RSR is proposed to guarantee the total revenues AEP-Ohio receives through the combination of base generation revenues, capacity charges to CRES providers and the RSR. A two-tiered capacity pricing structure is proposed. For the first 21% of shopping load in 2012, the first 31% of shopping load in 2013 and the first 41% of shopping load in 2014, AEP-Ohio would impose a capacity charge of $145.79 per MW-day on a CRES provider. In 2012, non-mercantile customers in communities that approved governmental aggregation initiatives in the November 2011 general election, or in prior elections, will be eligible for additional allotments of capacity at the rate of $145.79 per MW-day. For any additional shopping load beyond the first pricing tier in any year, AEP-Ohio proposes a capacity charge of $255 MW-day be paid by a CRES provider.

[6] 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.

II. APPROPRIATE CHARGES FOR CAPACITY

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

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

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

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

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

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

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

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

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

SB 3 contained policy objectives and established the process by which the evolution to reliance upon competitive markets would occur for competitive services such as generation supply. As discussed earlier, Ohio's implementation of SB 3 required the unbundling or separation of the three major functions (generation or production, transmission and distribution) associated with retail electric service into separate competitive and non-competitive service components with separate prices for such unbundled components.

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

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

[7] 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

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

---

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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Because FirstEnergy's Ohio EDUs do not own generating assets, two integration auctions ("IA") were conducted to obtain capacity resources for the 2011-2012 and 2012-2013 delivery years. The 2011-2012 FRR IA cleared 12,583.2 MW of unforced capacity in the RTO at a resource clearing price of $108.89 per MW-day. The 2012-2013 FRR IA cleared 13,038.7 MW of unforced capacity in the RTO at a resource clearing price of $20.46 per MW-day. These capacity prices are very close to capacity prices from the larger BRA for the same delivery years. Bidders in the auctions to obtain SSO generation supply for FirstEnergy were required to rely upon capacity secured in the two IAs and reflect this in their offer prices for the 2011-2012 and 2012-2013 delivery years. For the 2013-2014 delivery year, bidders in the auctions to obtain SSO generation supply for FirstEnergy will use capacity secured through PJM's capacity auctions. Thus, the clearing price of $44.76 per MWH in the January 24, 2012 auction reflects bidders paying the FirstEnergy EDUs $20.46 per MW-day for capacity in the 2012-2013 delivery year, and paying the BRA clearing price for capacity of $27.73 per MW-day for the 2013-2014 delivery year.

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

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

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

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

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

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

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

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

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

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

[END CONFIDENTIAL TESTIMONY].

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

A40. Yes, in addition to my earlier discussion of AEP-Ohio's use of and reliance upon PJM's RPM to support its pricing proposals and policy advocacy here in Ohio, it is also relying on RPM in several adjoining or nearby states to identify appropriate capacity compensation. A number of American Electric Power EDUs in other states in the PJM region offer retail customers experimental rates or rates under pilot programs that reflect PJM real-time prices. For example, Kentucky Power offers customers an experimental real-time pricing rate, Tariff R.T.P., a copy of which is attached to my testimony as Exhibit KMM-10. Under this Kentucky Power rate schedule, the price charged to customers includes a component for capacity. The price reflected for capacity in the rates charged to Kentucky Power customers is based upon the prevailing RPM prices.

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

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

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

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

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

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

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

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

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

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

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

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

[9] 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.

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

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

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

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

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

> **WHEREAS**, each Party to this Agreement is a Load Serving Entity within the PJM Region;
>
> **WHEREAS**, each Party is committing to share its Capacity Resources with the other Parties to reduce the overall reserve requirements for the Parties while maintaining reliable service; and
>
> **WHEREAS**, each Party is committing to provide mutual assistance to the other Parties during Emergencies;
>
> **WHEREAS**, each Party is committing to coordinate its planning of Capacity Resources to satisfy the Reliability Principles and Standards;
>
> **WHEREAS**, the Parties previously have entered into similar commitments related to sub-regions of the PJM Region through the East RAA, the West RAA, or the South RAA;
>
> **WHEREAS**, the Parties desire, on a phased basis, to replace the East RAA, West RAA, and South RAA with a single reliability assurance agreement among all Load-Serving Entities in the PJM Region; and

> **NOW THEREFORE**, for and in consideration of the covenants and mutual agreements set forth herein and intending to be legally bound hereby, the Parties agree as follows:[10]

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

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

I would also note that Exhibit KMM-23[11], an internal AEP memorandum, states that:

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

[10] Exhibit KMM-15 at 4.

[11] 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.

III. CAPACITY BILLING

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

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

The Commission should require AEP-Ohio to document to customers and CRES providers that the PLC factor it is assigning to customers corresponds with the customers' PLC value recognized by PJM.[12]

IV. ESP VERSUS MRO

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

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

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

[12] 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.

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

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

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

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

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

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

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 30-31 (December 14, 2011).

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

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

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

[13] *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).

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

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

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

A52. Yes. There are numerous flaws in Ms. Thomas' analysis. The methodology utilized by Ms. Thomas for her analysis relies exclusively upon administratively-determined market price estimates rather than the actual results from recent auctions in Ohio to establish SSO generation prices for other EDUs. Under these circumstances, I view the exclusive use of administratively-determined prices to be unreasonable given the availability of actual auction results and other readily available measures to check whether the administratively-determined price are reasonable.

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

[14] *Id.* at 7.

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

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

[15] 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.

[16] "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).

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

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

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

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

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

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

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

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

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

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

[17] 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).

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

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

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

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

Q56. Did you consider using supply offers for AEP-Ohio customers to benchmark Company witness Thomas' administratively-determined competitive benchmark prices?

A56. Yes. I considered this but decided it was not appropriate. As a result of the regulatory uncertainty in AEP-Ohio's service area regarding what capacity costs a CRES provider may or may not incur, and the confusions that AEP-Ohio has created in the administration of the two-tiered capacity pricing structure, I elected to not rely upon supply offers in AEP-Ohio's EDU service area.

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

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

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

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

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

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

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

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

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

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

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

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

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

A61. As explained earlier in my testimony, AEP-Ohio is an EDU with a generation business segment. If the vertically-integrated AEP-Ohio elected the FRR option, the generation business segment could negotiate a wholesale price under which it would sell capacity resources which must be designated under its FRR plan to potential suppliers in the CBP and bidders would reflect these prices in their bids. Alternatively, prospective bidders could obtain other capacity resources through ownership or bilateral contracts that they would substitute for currently designated capacity resources in the FRR plan.[18] Bidders would logically attempt to maximize the recovery of the capacity cost of such resources in their bids.

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

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

[18] 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.

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

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

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

A64. To derive the estimated market prices I began with AEP-Ohio witness Thomas' estimated market prices that reflect capacity priced at $145.79. I then adjusted the capacity component of the price downward to reflect the capacity component Ms. Thomas estimated based upon RPM prices, as shown on Exhibit LJT-1, page 2 of 3, of her prior testimony filed in support of the Stipulation in this proceeding. At the time my testimony was prepared, capacity prices for the June 2015 through May 2016 delivery period were not known because the BRA will not occur in May 2012 until after my testimony is filed. Therefore, I assumed capacity prices at the level for the prior delivery year. Other than modifying the capacity cost component of the estimated market prices, I made no other adjustments. This is conservative (favorable to AEP-Ohio's position) as other cost components of Ms. Thomas' administratively-estimated prices, such as the load shaping and following component and the transaction risk adder, move up or down in relationship to the overall price. I held these cost components equal to the levels estimated at a capacity price of $145.79 per MW-day, notwithstanding the known reduction in capacity prices that result from the RPM process.

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

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

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

A66. Yes. Because the CBP for generation supply for FirstEnergy's SSO load did not include the requirement for winning bidders to supply alternative energy resources or credits, I adjusted the market price upwards to reflect the cost of the alternative energy requirement in the competitive benchmark price reflected in the testimony of Ms. Thomas. This requires an upward adjustment of $.54 per MWH in 2012, $.79 per MWH in the January 2013 through May 2014 period, and $1.03 per MWH in the June 2014 through May 2015 period. Ms. Thomas did not provide an estimate of the cost of alternative energy requirements for June 2015 through May 2016. I escalated the price upward by $1.28 per MWH in the June 2015 through May 2016 period to reflect alternative energy requirements.

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

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

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

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

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

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

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

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

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

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

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

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

Second, the $330 million Modified ESP disadvantage only captures the impacts of the RSR on non-shopping customers. AEP-Ohio proposed that the RSR be non-bypassable and payable by shopping customers as well. Based upon the assumed level of shopping reflected in AEP-Ohio witness Allen's testimony, as shown on Exhibit KMM-21, the RSR will collect $198 million in transition revenue from shopping customers between June 1, 2012 and May 31, 2015. The effect of the RSR on non-shopping customers is a cost of the Modified ESP and must be recognized for purposes of comparing it to an MRO.

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

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

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

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

A75. AEP-Ohio has not supplied the details regarding showing how AEP-Ohio plans to conduct the limited auction for 5% of the SSO load and recover the winning bidder's cost from SSO customers. However, in response to discovery, attached as Exhibit KMM-22, AEP-Ohio indicated it plans to flow the costs of the 5% energy-only bid through the FAC and make no other changes to base SSO rates for distribution, transmission and generation. If that is the case, the only way that the limited energy-only SSO bid will not require an overall price increase to SSO customers is if the cleared bid price is lower than AEP-Ohio's FAC rate. The market price estimates presented in this case suggest that the results of the energy-only auction will likely be above the FAC rate and thereby increase the cost of the ESP as compared to the MRO and make rates less stable and predictable as well.

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

The administratively-determined market price estimates developed by AEP-Ohio witness Thomas support a similar conclusion. For example, the non-capacity portion of her competitive benchmark price for the June 2012 through May 2013 delivery year ranges from $44.07 to $50.52 per MWH and the non-capacity portion of the competitive benchmark price for the June 2013 through May 2014 delivery year ranges from $47.07 to $53.95 per MWH, significantly higher than AEP-Ohio's expected FAC rate of $36.10 per MWH.[20]

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

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

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

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

[20] 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.

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

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

> The first application filed under this section by an electric distribution utility that, as of July 31, 2008, directly owns, in whole or in part, operating electric generating facilities that had been used and useful in this state shall require that a portion of that utility's standard service offer load for the first five years of the market rate offer be competitively bid under division (A) of this section as follows: ten per cent of the load in year one, not more than twenty per cent in year two, thirty per cent in year three, forty per cent in year four, and fifty per cent in year five. Consistent with those percentages, the commission shall determine the actual percentages for each year of years one through five. The standard service offer price for retail electric generation service under this first application shall be a proportionate blend of the bid price and the generation service price for the remaining standard service offer load, which latter price shall be equal to the electric distribution utility's most recent standard service offer price, adjusted upward or downward as the commission determines reasonable, relative to the jurisdictional portion of any known and measurable changes from the level of any one or more of the following costs as reflected in that most recent standard service offer price:
>
> (1) The electric distribution utility's prudently incurred cost of fuel used to produce electricity;
>
> (2) Its prudently incurred purchased power costs;
>
> (3) Its prudently incurred costs of satisfying the supply and demand portfolio requirements of this state, including, but not limited to, renewable energy resource and energy efficiency requirements;
>
> (4) Its costs prudently incurred to comply with environmental laws and regulations, with consideration of the derating of any facility associated with those costs. In making any adjustment to the most

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

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

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

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

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

[21] *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).

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

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

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

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

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

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

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

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

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

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

V. CONCLUSION

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

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

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

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

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

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

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

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

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

A83. No, I do not agree.

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

Second, AEP-Ohio has previously used market-based prices and competitive bidding to establish default generation supply costs in the case of the pricing structure applicable to Ormet Primary Aluminum Corporation[22] and the former Ohio customers of Monongahela Power Company.[23] In both cases, AEP-Ohio claimed that it did not have adequate generation resources to supply generation to these new loads and that a competitive bidding process was the appropriate means of identifying the cost of such supply that was passed on to customers. And, in its first proposed ESP, AEP-Ohio also proposed to use a CBP to establish an escalating portion of the default generation supply price. As I described earlier, AEP-Ohio's comments in Commission Case No. 07-796-EL-ATA, *et al.*, strongly endorsed the use of a CBP to set default generation supply prices. These actual or proposed AEP-Ohio uses of competitive bidding to set default generation supply prices demonstrate that AEP-Ohio's current position regarding the alleged barriers to the use of competitive bidding is very different than the position AEP-Ohio took in prior Commission proceedings.

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

---

[22] *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).

[23] *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).

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

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

Q84. Does this conclude your testimony?

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, 29th 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
Elizabeth.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, 18th 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, 15th 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@ohiopovertylaw.org
jmaskovyak@ohiopovertylaw.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
lmcalister@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, 29th 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
mhpetricoff@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
mhpetricoff@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
mhpetricoff@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
mhpetricoff@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@kmklaw.com
dmeyer@kmklaw.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 KORENERGY

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.con
james.rubin@snrdenton.com
thomas.millar@snrdenton.com

Arthur Beeman
SNR Denton US LLP
525 Market Street, 26th 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
whit@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
djmichalski@hahnlaw.com

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

Larry F. Eisenstat
Richard Lehfeldt
Robert L. Kinder, Jr.
Dickstein Shapiro LLP
1825 Eye St. NW
Washington, DC 20006
eisenstatl@dicksteinshapiro.com
lehfeldtr@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, 6th 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, 12th 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. 99-1729-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. 99-1730-EL-ETP

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

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

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
WILLIAM R. FORRESTER
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name and business address.

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

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

A. I am the Director of Ohio Regulatory Affairs.

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

I graduated in June, 1965 from The Ohio State University with the degree of Bachelor of Science in Business Administration. Immediately following graduation, I became an employee of Columbus and Southern Ohio Electric Company (subsequently acquired by AEP), and from that time until 1976 my responsibilities included the preparation of reports, financial forecasts, internal audits and special financial studies. I was Manager of the Reports and Studies Area of the Accounting Department from 1976 to November, 1977. In November, 1977 I was appointed Assistant Director of Rates and Regulations and in April, 1978 I was appointed Director of Rates and Regulations. In January, 1996 I was appointed Director of Ohio Regulatory Affairs. Also, I have been a Certified Public Accountant since 1988.

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

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

Q. For whom are you testifying in this proceeding?

A. OPCO and CSP.

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

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

Purpose of Testimony

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

A. The purpose of my testimony is to:

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

existing base rate levels). Company Witness Pyle will sponsor the state and local tax changes brought about by the passage of Am. Sub. S. B. No. 3 and certain adjustments to taxes other than income taxes and state and municipal income taxes resulting from the implementation of new and/or revised tax statutes applicable to public utilities in Ohio.

3. Sponsor the Universal Service Fund Rider (PIPP replacement) and the Energy Efficiency Fund Rider (Revolving Efficiency Loan Fund/DSM).

4. Sponsor the Corporate Separation Plan including Code of Conduct. In this regard, I am also sponsoring Part B of the rules, with the exceptions that Company Witness Pena will cover the financial considerations concerning the Corporate Separation Plan including Part B, §(G)(3), and Company Witness Knorr is testifying to the requirements for separate accounting including Part B, §(G)(2), and the Cost Allocation Manual (CAM) requirements including Part B, §(J)(1)-(9).

5. Support OPCO and CSP's participation in the Statewide Consumer Education Plan and Part E; and to explain the customer education campaign goals and objectives, and how CSP and OPCO will structure, implement and manage the customer education campaign in accordance with Am. Sub. S. B. No. 3. I will also sponsor CSP and OPCO's share of the Statewide Consumer Education Plan implementation costs.

6. Sponsor CSP and OPCO's Shopping Incentive Plan including Part H.

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.

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

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

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

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

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

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

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

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

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

A. CSP and OPCO are proposing to include recovery of its stranded generation-related regulatory assets over the ten-year transition period provided for in Am. Sub. S. B. No. 3. The Companies have determined the amount of amortization of their stranded generation-related regulatory assets that was included in each Company's last base rate case filing. These amounts of recovery of regulatory assets were included in the transition charge during the Market Development Period (the first five years). The remaining unrecovered balances of these stranded generation-related regulatory assets at December 31, 2005, were divided by the estimated KWH to be delivered over the remaining five years of the ten-year transition period, to determine the transition charge for the period January 1, 2006, through December 31, 2010.

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

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

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

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

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

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

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

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

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

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

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

A. Yes. First I want to discuss new regulatory assets that CSP and OPCO want the Commission to establish through the Transition Plan proceedings. These new regulatory assets are: the cost resulting from SFAS 106 (Post-Retirement Benefits) Transition Obligation; the cost, mandated by Am. Sub. S. B. No. 3, for consumer education on electric restructuring; the cost of the development and operation of the operational support systems that the electric distribution service provider must have to allow electric consumers to choose their supplier of electric generation service; and the cost of CSP and OPCO Transition Plan filings including the public notices required and the necessary hearings on both Companies' transition filings.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. There are two suggestions to handling these expenses. The first is that the Company will provide revised estimates for these expenses two weeks prior to the start of hearings on the transition filings. The second is that in the year 2004 when the Commission is reviewing the regulatory assets, these expenses can be adjusted to reflect the actual expenses associated with the operational support systems and the actual transition filing expenses.

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

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

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

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

A. The Companies are proposing the "revenues lost" approach. Under that approach, stranded costs are calculated by subtracting the competitive market value of the power the customer would have purchased from the revenues that the customer would have paid had it stayed on the utility's generation system. Therefore, the Companies are proposing that the difference between the lower market price and the unbundled generation rate be included in the transition charge to provide recovery for the stranded generation asset costs. Company Witness Landon demonstrates that calculating the future economic value of the generation assets is very difficult. The calculation of the difference between the lower market price and the unbundled generation rate is a much simpler calculation and it provides the Companies an opportunity to recover those stranded generation asset costs. Moreover, as the Federal Energy Regulatory Commission has stated "the revenues lost approach is the fairest and most efficient way to balance the competing interests of those involved."

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

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

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

Unbundled Rate Schedules – Tax Recovery Methodology

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

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

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

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

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

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

A. The following taxes should be included as adjustments in the computation of unbundled rates of CSP and OPCO: gross receipts tax, personal property taxes, kilowatt-hour tax, Ohio franchise tax, deferred state income taxes, municipal income taxes, and deferred municipal income taxes.

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

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

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

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

Schedule of Effective Dates for Rate Riders

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

A. The rate rider for the elimination of the gross receipts tax should be effective May 1, 2002. The rate rider for the reduction in personal property taxes should be effective January 1, 2001. The rate rider for the new kilowatt-hour tax should be effective May 1, 2001. The rate rider for the Ohio franchise tax, including deferred state income taxes, should be effective January 1, 2001. Company Witness Pyle explains why the effective date for the Ohio Franchise Tax should be January 1, 2001 rather than January 1, 2002. The rate rider for municipal income taxes, including deferred municipal income taxes, should be effective January 1, 2002.

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

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

Universal Service Fund Rider (PIPP Replacement)

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

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

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

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

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

A. Yes. EXHIBIT NO. ___ WRF-1 shows the estimated unrecovered PIPP balances for CSP and OPCO.

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

A. The starting point is the Total Aged PIPP bills as of September 30, 1999. This is the amount of PIPP billings that are greater than the amount of payments received from PIPP customers. To this amount the estimated PIPP aged bills for the period October 1, 1999 through June 30, 2000 were added. The estimated arrears credits were then added and the estimated reinstatements were subtracted to arrive at the estimated cumulative total aged PIPP bills as of June 30, 2000. The next step was to take the cumulative total PIPP Rider billed as of September 30, 1999. To this was added the estimated PIPP rider billed for the period October 1, 1999 through June 30, 2000. The difference between estimated cumulative total aged PIPP bills and the estimated cumulative total PIPP rider is the estimated unrecovered PIPP balances. CSP's unrecovered PIPP balance is $18,951,773 and OPCO's unrecovered PIPP balance is $8,757,482.

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

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

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

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

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

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

A. CSP had $2 million of DSM expense built into base rates and OPCO had approximately $3.0 million of DSM expense built into base rates. These amounts, less the low-income DSM expense that was included in the Universal Service Fund rider, were used to develop the Energy Efficiency Fund Rider. Company Witness Thomas has included both the Universal Service Fund rider and the Energy Efficiency Fund rider in Schedule UNB-1.

Corporate Separation Plan Including Code of Conduct

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

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

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

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

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

A. The transmission and distribution services offered to customers include engineering analysis, emergency repairs, rebuilds and upgrades on customer-owned electric equipment, meter and laboratory services, power quality improvements and safety training. The Companies have provided these services to customers for many years.

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

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

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

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

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

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

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

Q. What is the timeline for the separation plan?

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

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

A. FERC approval is required of the generation supply agreements from OPCO and CSP to their respective distribution subsidiaries at their unbundled generation rates to enable these subsidiaries to provide default service during the Market Development Period. In addition, any other sales for resale by the AEP operating companies to a CRS or the distribution subsidiaries would also be subject to FERC jurisdiction.

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

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

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

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

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

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

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

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

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

Statewide Consumer Education Plan

Nature of the Customer Education Campaign

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

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

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

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

General Plan

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

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

Q. How will the campaign be managed?

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

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

A. A single statewide advisory group will consist of a representative of the Commission staff, the Ohio Consumers' Counsel, the utilities, and an energy marketer. Representatives of certain customer classes will also be included. The individuals will have the necessary skills and experience to contribute meaningful and credible input to the group, and demonstrate an effective background, skills and experience in public relations, advertising, communications or consumer education. The group will be advisory in nature only; however, its recommendations will be given full consideration commensurate with its professional expertise. The group will not be a decision-making body. Recommendations of the group will be applicable in the same manner to local territory-specific campaigns as well. A service territory-specific group similar in size and make-up to the state group will also be convened for CSP and OPCO.

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

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

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

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

Q. How will the campaign employ research?

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

Q. What is the timeline for the campaign?

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

Q. What tactics will the campaign include?

A. The campaign will rely heavily on public relations tactics at the outset, and use paid advertising in the third quarter of 2000 that will raise awareness and refer people to more detailed information sources (e.g., web site, brochure, call center). The public relations tactics include, but are not limited to, direct mail, media relations, special events, speakers' bureau, collateral material, web site, and call center. We will also leverage our partnerships with community-based agencies and organizations and trade organizations. These tactics will be deployed at the state and local levels.

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

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

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

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

CSP and OPCO Shopping Incentive Plan

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

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

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

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

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

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

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

A. No. The Commission's rules, by even giving the impression that the shopping incentive may increase, have created an impediment to customers shopping for an alternative supplier. I believe some customers will refrain from shopping during the first year because they believe they will get a larger discount by waiting until the second or third year. For example, here in Columbus there is a mega hardware store that is going out of business. HQ's going out of business sale started with discounts of 20% to 30%. The HQ discounts then increased after about one month to the 40% to 50% range. The discounts are now in the range of 60% to 70%. Customers, shopping at HQ, may decide to wait for the larger discount before purchasing the item that they want. These customers face the risk that the hardware item that they want to purchase may be sold out before the discount reaches the level they desire.

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

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

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

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

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

In addition, Am. Sub. S. B. No. 3 makes special provisions for governmental aggregators. These provisions allow municipalities, counties and townships to provide aggregation services for their citizens for the purchase of electricity. Just the fact that these provisions were included in Am. Sub. S. B. No. 3 indicates that some parties felt that this would be a significant avenue to provide customer choice to the citizens of Ohio. To what extent this governmental aggregation will be used to switch customers to alternative suppliers is unknown. This unique provision has not been included in any other state's restructuring laws, to the best of my knowledge. Therefore, I cannot draw on any other state's experience to forecast the amount of customer switching that will occur because of governmental aggregation. However, the logical assumption is that the General Assembly did not provide this opportunity in vain. The political leadership of the state must have expected some governmental aggregation to occur.

Q. Does this conclude your testimony?

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	(465,921)	
Estimated Additional Recovery		5,206,997
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	2,103,942	
Estimated Cumulative Total PIPP Rider		33,687,859
Total PIPP Unrecovered as of 6/30/2000		$18,951,773

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	(710,829)	
Estimated Additional Recovery		5,418,771
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	3,059,100	
Estimated Cumulative Total PIPP Rider		61,097,258
Total PIPP Unrecovered as of 6/30/2000		$8,757,482

EXHIBIT NO. ___ WRF-2

OPCO/CSP CORPORATE SEPARATION PLAN

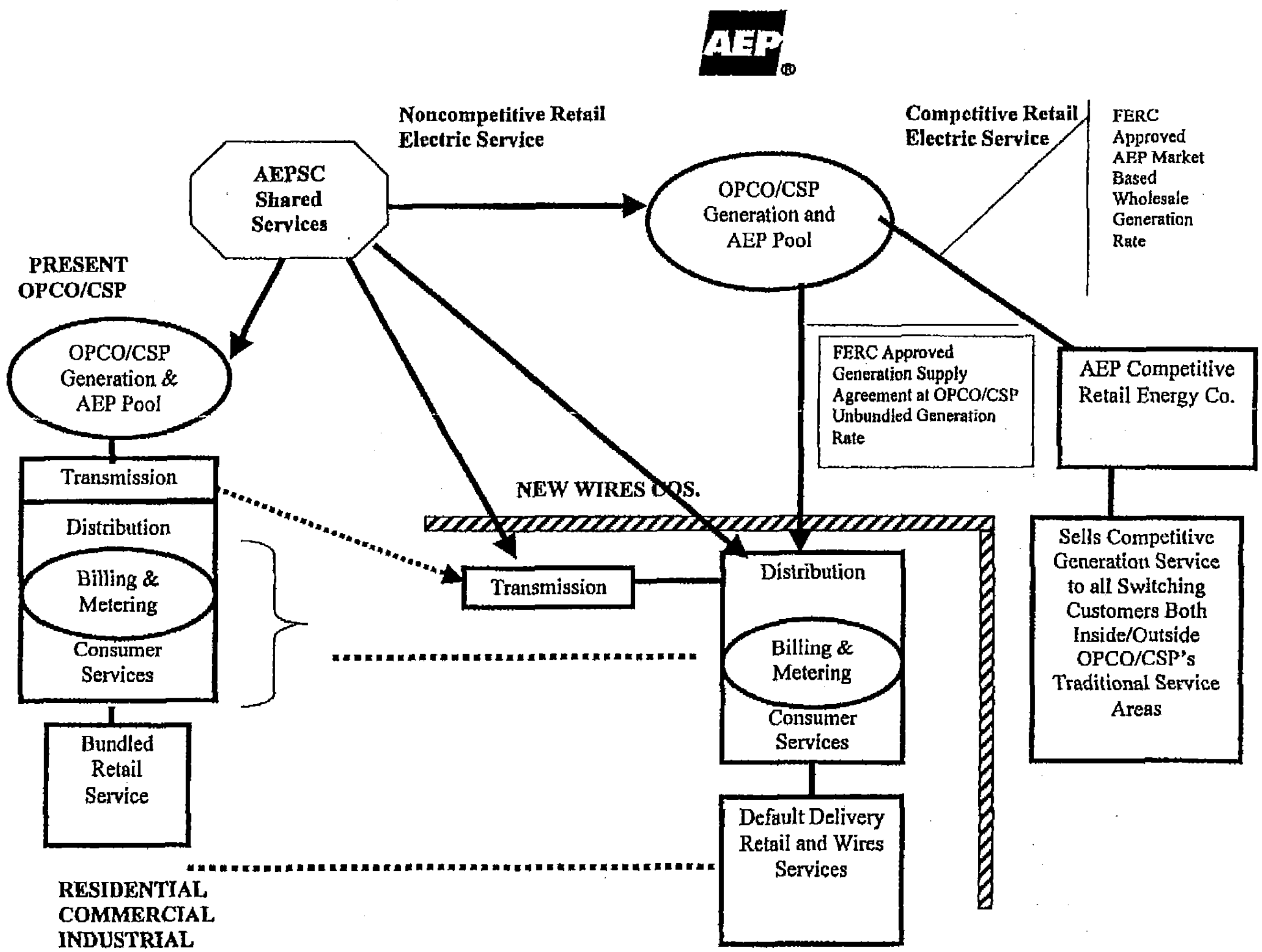

EXHIBIT NO.__ WRF-3
Page 1 of 1

CSP AND OPCO'S
CUSTOMER CHOICE EDUCATION PROGRAM
COST RESPONSIBILITY

		CSP *	OPCO *	CSP	OPCO	TOTAL AEP OHIO
1/1/00 - 12/31/01	$16,000,000	13.88%	15.17%	$2,220,800	$2,427,200	$4,648,000
1/1/02 - 12/31/05	$17,000,000	13.88%	15.17%	$2,359,600	$2,578,900	$4,938,500
TOTAL	$33,000,000			$4,580,400	$5,006,100	$9,586,500

* 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
(OOO)

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

EXHIBIT NO. _____ WRF-4
Page 2 of 2

OHIO POWER COMPANY
PROJECTED TRANSITION PLAN FILING EXPENSES
(OOO)

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

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)

OHIO NEWSPAPER SERVICES INC.
A SUBSIDIARY OF THE OHIO NEWSPAPER ASSOCIATION

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

1335 Dublin Road • Suite 216-B • Columbus, Ohio 43215 • Phone: 614-486-6677

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

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

ADVERTISING ESTIMATE
December 7, 1999

ORDER #: 99122A00-005442

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: 7652					
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

ORDER #: 99122A00-005442

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

ORDER #: 99122400-005442

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
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: 11625					
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					
Steubenville - Herald Star Steubenville OH (Jefferson)					
4X16.00	SAU	23.43	1499.52	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 25500 Sun: 28800					
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		769.68	50539.52		

19,926.60 ÷ 2 = 9,964.80
Total Paid Circulation 818159   40,574.72 X 1.0638 = 43,163.39

Total Insertions	39	
Gross Advertising	50539.52	Current Thru 12/28/99
Net Billed	42958.59	
Total Misc	0.00	

2000 Estimate
$53,765.44 gross
$45,700.62 Net.

Total Billed 42958.59

$\frac{53765.44}{50,539.52}$ = 6.38% price increase year 2000

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

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

ADVERTISING ESTIMATE
December 7, 1999

ORDER #: 99122AC0-005443

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	1025.28	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	1505.92	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	592.00	12/08/99	Half page ad
Daily 6-12.5-21.50 Circ: 8100					
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					
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					
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					
Georgetown - News Democrat Georgetown OH (Brown)					
4X16.00	SAU	5.50	352.00	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	752.00	12/08/99	Half page ad
Daily 8-0.0-21.50 Circ: 5500					
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					
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					
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					
London - Madison Press London OH (Madison)					
4X16.00	SAU	8.05	515.20	12/08/99	Half page ad
Daily 6-9.3-21.50 Circ: 6500					
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: 12536					
Marysville - Journal Tribune Marysville OH (Union)					
4X16.00	SAU	7.85	502.40	12/08/99	Half page ad
Daily 6-10.0-21.50 Circ: 6101					

WP-EXHIBIT NO. ___ WRF-4

ORDER #: 99122AC0-005443

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
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	652.16	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		

19,929.60 ÷ 2 = 9964.80

Total Paid Circulation 458141 — 17,095.68 x 1.0638 = 18,186.38

Total Insertions 24
Gross Advertising 27060.48
Net Billed 23001.41
Total Misc 0.00

} Current Thru 12/28/99

2000 Estimate – price increase
$28,787.74 gross
$24,469.57 Net

Total Billed 23001.41

$\frac{28,787.74}{27,060.48}$ = 6.38% price increase year 2000

JOB NO OSCAR
PGM NO X943

COLUMBUS SOUTHERN POWER COMPANY
PUCO 94 COLUMN OSCAR REPORT
09-99

10/19/99

COL	COUNTS	DOLLARS	DESC
COL 01:01	507,540		Total number of Residental customers
COL 01:02	16,450	2.8%	number of Residental accounts on 4(B) Payment Plan - ACTIVE
COL 01:03		25,250,353.71	Total dollar amount of active PIP customers
COL 01:04	11,077		number of Residental accounts on 4(A) Payment Plan
COL 01:05		1,911,077.42	Total dollar amount of arrearages of customers in 01:04
COL 01:06	56,019		Total number of Residental 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	13,015		number of Secondary Heating source customers in 01:02
COL 02:03	4,060		number of Continuous PIP Customers
COL 02:04	106		number of New PIP customers
COL 02:05	12,212		number of Readmitted PIP customers
COL 03:01	6,560		number of Inactive PIP customers - deferred PIPP balan
COL 03:02	1,539		number of Final PIP customers
COL 03:03	31		number of 03:01 customers because of income ineligibili
COL 03:04	501		number of 03:01 customers because of reverification
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	4,057		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		21,420,240.65	dollar amount of deferred arrears of active PIP

WP-________ WRF-1
Page 1 of 2

48

JOB N[illegible]OSCAR
PGM NO[illegible]CSX943

OHIO POWER COM[illegible]
PUCO 94 COLUMN OSCA[illegible]ORT
09-99

10/19/99

COL	COUNTS	DOLLARS	DESC
01.01	596,052		Total number of Residental customers
01.02	28,684	3.54	Number of Residental accounts on 4(B) Payment Plan - ACTIVE
01.03		28,866,712.11	Total dollar amount of active PIP customers
01.04	5,329		Number of Residental 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 Residental 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	16,698		Number of Readmitted PIP customers
03.01	7,831		Number of Inactive PIP customers - deferred PIPP balan
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 he
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	1,084		Number of PIPP graduates, last third 12 months
04.01		25,113,432.96	Dollar amount of deferred arrears of active PIPP

WP-________ WRF-1

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

Item Type - DIS_CASEDOCS

Case Number :	99-1729
CaseTitle :	COLUMBUS SOUTHERN POWER CO.
DateFiled :	12/30/1999
Party :	
DocumentType :	APP
Other :	4/29/2003 3:51:53 PM
InDate: :	2003-04-29-16.12.16.000000
User ID :	scanner1
PageCount :	202
DocItemId :	Z2UIO2ZEGLIWTXG0
DocItemIdNew :	