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SECTION 2 of 2

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DESCRIPTION OF DOCUMENT
TESTIMONY - SCHNITZER - CONTINUED

AEP Ohio Understates the Proposed ESP Price

(Jan 2012 – May 2014)
[Contains RESTRICTED ACCESS CONFIDENTIAL Information]

Corrected Proposed ESP Price ($/MWH)	**Corrections**	
	Low	High
AEP Ohio Proposed ESP Price _a/	**59.82**	**59.82**
Less:		
2011 Full Fuel	32.86	32.86
2011 Environmental Compliance Costs	<u>0.90</u>	<u>0.90</u>
Market Comparable Base "g" Price	**26.06**	**26.06**
Plus: (Jan 2012- May 2014)		
Full Fuel _b/	[redacted]	[redacted]
Pool Termination or Modification _c/		
Environmental Investment (EICCR) _d/		
Facilites Closure Cost Recovery Rider (FCCR) _e/		
Carbon Capture and Sequestration Rider (CCSR) _f/		
Generation Resource Rider (GRR) _g/		
POLR Charge (POLR) _h/	2.84	2.84
NERC Compliance Cost Rider (NERCR)	*	*
Subtotal, Total Adjustments	43.83	47.43
Corrected Proposed ESP Price _i/	**69.89**	**73.49**
Total Correction to Proposed ESP Price	10.07	13.67

_a/ This price is used in Ms. Thomas' MRO price comparison shown in Exhibit LJT-2. Company witness Roush claims at 10 of his Direct Testimony that the Proposed ESP Price is "comparable to market generation prices;" however, this figure includes 2011 fuel and environmental costs held constant and is compared to estimated increasing market prices for the January 2012 through May 2014 delivery period.
_b/ Based on information contained in AEP Ohio Interrogatory Response, FES, Set 1, Attachment 1, RESTRICTED ACCESS CONFIDENTIAL.
_c/ Low case assumes financial impact of pool termination or modification does not occur during this ESP period. High case assumes that the financial impact of pool termination or modification begins January 1, 2014.
_d/ Low case is based on AEP Ohio's estimated environmental capital expenditures for 2012-2014. High case is based on accelerated retrofit schedule to comply with proposed EPA regulations.
_e/ Based on recovery of estimated closure costs for potential retirement candidates identified by AEP Ohio.
_f/ Based on Company's estimate of FEED study costs. Assumes CCS plant costs are not recovered during this ESP time period.
_g/ Based on the estimated cost of the proposed Turning Point Solar Project, but assumes that capacity replacement costs (*e.g.*, for "fully exposed" coal generation fleet) does not occur during the proposed ESP period.
_h/ AEP Ohio's estimate.
_i/ I have not included the impact of the Distribution Investment Rider in my analysis. To the extent that this rider would result in additional costs beyond what AEP Ohio could recover under an MRO, this would further increase the costs of the proposed ESP.
* Not yet estimated.

Q. COULD THE COSTS IMPOSED ON CUSTOMERS BE EVEN HIGHER THAN WHAT YOU HAVE ESTIMATED?

A. Certainly. It is important to recognize that I did not attempt to estimate all the costs and risks of the proposed generation-related riders. Furthermore, the economics associated with future generation investments, future plant closure costs, lost pool revenues, market revenues, and so forth are inherently uncertain, as I will discuss further in the next section of my testimony.

VIII. <u>THE PROPOSED ESP, IN ADDITION TO BEING MORE EXPENSIVE FOR CUSTOMERS, IS RISKIER FOR CUSTOMERS</u>

Q. MR. SCHNITZER, PLEASE EXPLAIN HOW AEP OHIO'S PROPOSED ESP EXPOSES CUSTOMERS TO SIGNIFICANT RISKS.

A. AEP Ohio's proposed ESP includes numerous riders that allocate significant risks to its customers. These riders require AEP Ohio's customers to pay for a wide variety of uncertain variable costs and fixed capital generation investment costs in the future, which would impact customer rates over the term of the proposed ESP and in many instances beyond the ESP period.

Q. WOULD EVERY POTENTIAL SSO SUPPLY PLAN EXPOSE CUSTOMERS TO THE SAME LEVEL OF UNCERTAINTY, OR RISKS, ASSOCIATED WITH THE COSTS OF THEIR SUPPLY?

A. No, the risks borne by customers can vary significantly between alternative SSO supply plans. There are numerous inherent risks that make the cost of SSO supply uncertain. They include generation plant costs and outages, fuel price uncertainty, regulatory uncertainty, unexpected weather patterns, changes in customer usage patterns, transmission line outages, locational basis differentials, unexpected economic growth levels, unanticipated ancillary services costs, and customer migration, to name a few. No procurement approach makes these risks disappear. SSO customers will still consume more energy on a hot summer day, and less on a cool day. Congestion charges between hub and load will vary based on generation patterns and grid characteristics. And customers will still have the right to leave SSO service when it is cheaper to do so,[162] and to return when that is their preference (subject to whatever switching restrictions are in place). In other words, the risks associated with SSO supply costs will exist regardless of the SSO plan that is chosen. The choice of SSO plan, however, affects who will bear these risks.

A key policy question for the Commission involves determining who is in the best position to bear many of these risks: AEP Ohio's retail customers, AEP Ohio's shareholders, or competitive suppliers of electricity.

Q. HOW DO THE RISKS THAT CUSTOMERS WOULD BEAR UNDER AEP OHIO'S PROPOSED ESP COMPARE WITH THE RISKS THAT CUSTOMERS WOULD BEAR UNDER AN ALTERNATIVE SSO APPROACH IN WHICH SSO SUPPLY IS PROCURED THROUGH COMPETITIVE SOLICITATIONS FOR FIXED-PRICE FULL REQUIREMENTS SUPPLY PRODUCTS?

A. AEP Ohio's proposed ESP clearly places the burden of significant potential costs and risks onto retail customers, largely due to the many riders that pass through numerous

[162] Unless the SSO supply plan effectively forecloses this choice as AEP Ohio's proposed ESP does – a topic discussed later in my testimony.

generation-related costs and risks. As a result, AEP Ohio's proposed ESP would create a great deal of cost uncertainty and potential rate instability for customers. In contrast, an SSO approach involving competitive solicitations for fixed-price full requirements supply products would provide greater price stability for customers, and would provide more protection for customers against these risks.

Q. PLEASE EXPLAIN HOW FIXED-PRICE FULL REQUIREMENTS PRODUCTS PROVIDE PRICE STABILITY AND PROTECT CUSTOMERS FROM FUTURE COSTS AND RISKS.

A. A fixed-price full requirements product obligates the seller of the product to satisfy a specified percentage of all of the SSO customers' supply requirements in every hour of the delivery period, regardless of the SSO customers' changes in energy consumption, and regardless of the extent to which customers switch to or from SSO service. The seller of the fixed-price full requirements product is paid a predetermined price per megawatt-hour for this service regardless of what future market prices or generation costs turn out to be. The seller is responsible for assuming, managing, and covering the financial costs and risks associated with electricity supply, while customers are provided the associated price stability and protection against adverse market and/or generation cost outcomes. In sum, sellers of fixed-price full requirements products must satisfy their obligation, regardless of how much market prices or generation costs may increase during the delivery period and regardless of the SSO load level. Yet if market prices decrease after the supply contracts are signed, then customers may elect service from a lower cost CRES supplier. Effectively, the fixed-price full requirements product price acts as a cap on rates because the product price for SSO supply is guaranteed, but customers can switch to CRES suppliers if they can find a better deal.

Furthermore, when fixed-price full requirements products are procured through competitive solicitations, bidders compete on the basis of the lowest price to provide the fixed-price full requirements product, and customers' rates are based on the lowest bid prices for the fixed-price full requirements products.

Q. WHY DOES AEP OHIO'S PROPOSED ESP PROVIDE MUCH LESS PROTECTION FOR CUSTOMERS THAN AN ALTERNATIVE IN WHICH SSO SUPPLY IS PROCURED THROUGH COMPETITIVE SOLICITATIONS FOR FIXED-PRICE FULL REQUIREMENTS SUPPLY?

A. Unlike a bidder in a competitive solicitation for fixed-price full requirements products, AEP Ohio seeks to ensure recovery of its generation costs from customers in the event that fuel costs increase, generation plants become uneconomic and are closed, environmental retrofits are made, new generation is built, new unforeseen expenses are incurred, and so forth and so on. Thus, AEP Ohio's plan clearly places the burden on customers to bear numerous unknown costs and potential risks that customers would not bear if the SSO supply were procured using a fixed-price full requirements competitive solicitation process.[163]

[163] For example, under AEP Ohio's proposal, if AEP Ohio were to make an investment decision that later turned out to be "uneconomic," customers could be required to pay for it in the proposed riders. These costs could be substantial and could last many years into the future, well beyond the term of the proposed ESP. Similarly, under AEP Ohio's proposed ESP, the utility is allowed to recover changes in fuel costs from its customers through the fuel adjustment mechanism. A supplier of a fixed-price full requirements product in a competitive bid process would not be allowed to pass through changes in fuel costs during the term of the delivery period.

Q. HOW DOES THE EXISTENCE OF AEP OHIO'S PROPOSED RIDERS AFFECT THE COMPARISON OF THE EXPECTED PRICES SHOWN IN MS. THOMAS' EXHIBIT LJT-2, EVEN AFTER MAKING THE CORRECTIONS THAT YOU HAVE IDENTIFIED?

A. Simply put, it is extremely difficult to look at the Proposed ESP Price and the Competitive Benchmark Price and obtain an "apples-to-apples" comparison, because the approaches involve very different risk exposures for customers. Under AEP Ohio's proposed ESP, the all-in customer rates would be very uncertain, and as a result, could involve significant additional costs, because AEP Ohio's proposed ESP involves a significant allocation of costs and risks to retail customers. In contrast, under the fixed-price competitive bid process in which solicitations are held for parties to provide full requirements supply to meet AEP Ohio's SSO load requirements, most of these uncapped costs and risks would be assumed by the full requirements suppliers, thereby protecting customers from these risks. In effect, Ms. Thomas' comparison is like comparing the price of an auto insurance policy with little or no coverage against the price of another insurance policy with significant coverage and protection for customers. These are very different products.

Q. WHAT DO YOU CONCLUDE REGARDING THE RISKS THAT CUSTOMERS WOULD BE FORCED TO BEAR UNDER AEP OHIO'S PROPOSED ESP DURING THE 29-MONTH TERM?

A. AEP Ohio's proposed ESP exposes customers to costs and risks that are significant. The financial stability benefits claimed by AEP Ohio are overstated. The proposed ESP, in addition to being more expensive for customers, is also riskier for customers. In contrast, an SSO supply approach involving competitive solicitations for fixed-price full requirements supply products would provide greater price stability and protection for customers throughout the term of the supply contract. Under such an approach, the proposed generation-related riders also could be eliminated.

IX. <u>THE PROPOSED ESP WITH NON-BYPASSABLE CHARGES FOR GENERATION-RELATED COSTS AND AN ABOVE-MARKET CAPACITY PRICE TO CRES SUPPLIERS WOULD STYMIE RETAIL COMPETITION AND DEPRIVE AEP OHIO'S CUSTOMERS OF A MEANINGFUL OPPORTUNITY TO SHOP</u>

Q. MR. SCHNITZER, DOES OHIO LAW RECOGNIZE THE IMPORTANCE OF THE DEVELOPMENT OF COMPETITIVE RETAIL ELECTRIC MARKETS?

A. Yes. While I am not an attorney, my understanding is that the development of competitive retail electric markets is an explicit policy goal under the law. Specifically, Ohio Revised Code, section 4928.02 states,

> "It is the policy of this state to do the following throughout this state: ...(B) Ensure the availability of unbundled and comparable retail electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective need; [and] (H) Ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates;"

Q. DO YOU BELIEVE AEP OHIO'S ESP PROPOSAL WILL SUPPORT A COMPETITIVE RETAIL MARKET?

A. No. There are two fundamental problems: a) AEP Ohio's proposed non-bypassable charges for generation-related costs, and b) AEP Ohio's proposed capacity price for retail suppliers.

Q. EXPLAIN THE FIRST PROBLEM.

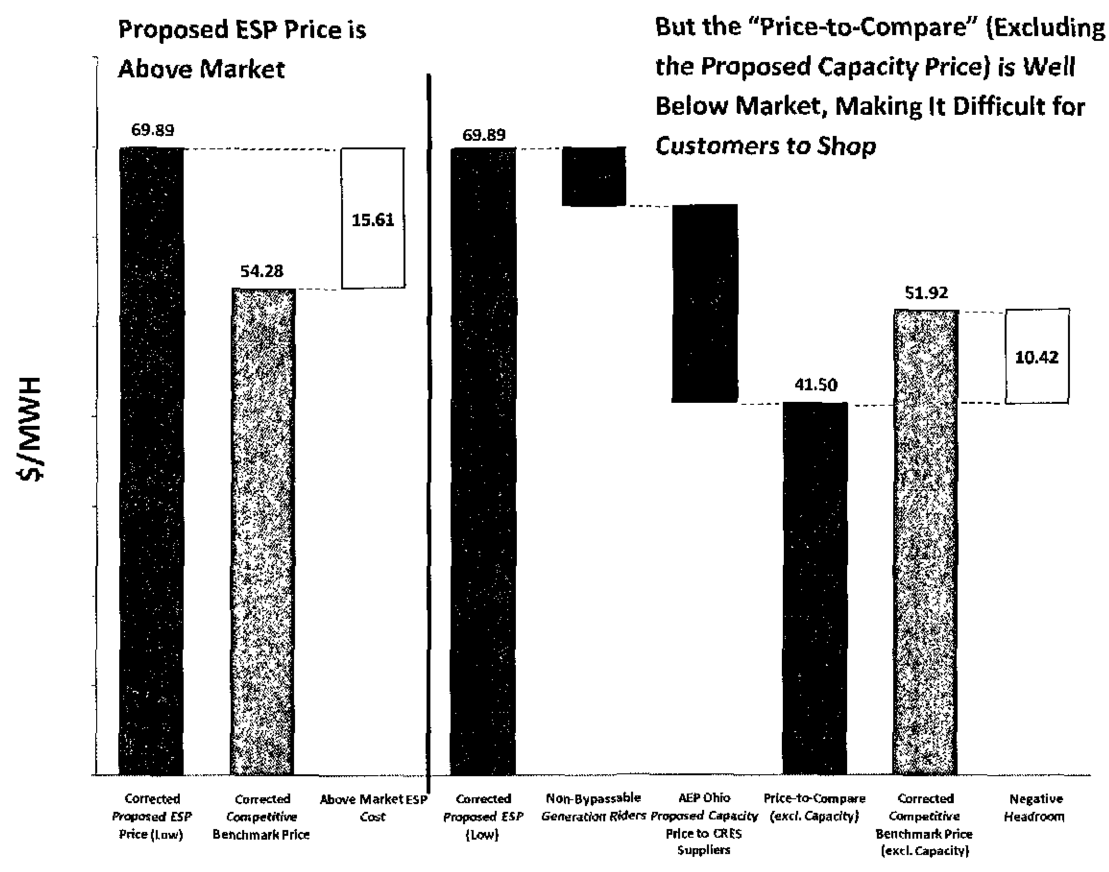
A. The many generation-related costs that AEP Ohio seeks to recover through non-bypassable riders will harm the development of competitive retail markets. As a policy matter, generation is a competitive service and generation-related costs should not be recovered through non-bypassable rates that apply to both shopping and non-shopping customers. Customers who shop should not have to pay twice for the same service. The Commission should avoid imposing AEP Ohio's generation-related costs on customers who do not take generation service from AEP Ohio.

Q. EXPLAIN THE SECOND PROBLEM.

A. The problem associated with the non-bypassable generation charges is further exacerbated by the proposal to force CRES suppliers to pay AEP Ohio's above-market capacity prices with limited opportunities to avoid these costs. AEP Ohio is attempting to recover its capacity costs from CRES providers who in turn must recover these costs from their customers, making AEP Ohio's capacity price similar to a non-bypassable charge. As a result, AEP Ohio's high capacity price proposal makes it very difficult for CRES providers to compete with the Proposed ESP Price. Even though the Proposed ESP Price is higher than the expected results of an MRO (as I showed earlier in my testimony), the combination of the proposed non-bypassable generation riders and the above-market capacity price will result in a total bypassable charge (or "Price-To-Compare" excluding capacity costs) that is significantly below market energy costs, making it very difficult for customers to shop for price savings.

In effect, this forces competitive retail suppliers to obtain market energy and ancillary services for less than AEP Ohio's Price-to-Compare (excluding capacity costs to CRES suppliers), in order to serve customers for less than the Proposed ESP Price. This is extremely unlikely – not because competitive suppliers cannot compete, but because AEP Ohio is "stacking the deck" against competitive markets by proposing that competitive retail suppliers pay high above-market capacity costs with no credit for market energy and other sources of revenue that the Company could otherwise recover when customers shop.

The Proposed ESP Design Stymies Retail Competition



Q. ABOVE YOU SHOW HOW AEP OHIO IS "STACKING THE DECK" AGAINST COMPETITIVE MARKETS USING YOUR CORRECTED FIGURES. CAN YOU ALSO ILLUSTRATE THIS USING AEP OHIO'S NUMBERS?

A. Yes. If I simply take AEP Ohio's Proposed ESP Price of $59.82 per MWH and then subtract AEP Ohio's proposed capacity price of $21.95 per MWH to CRES suppliers,[164] this results in a net cost of $37.87 per MWH. This figure effectively represents the non-capacity costs (fuel, variable O&M, etc.) embedded in the Proposed ESP Price. Meanwhile, Ms. Thomas estimates in Exhibit LJT-1 that the non-capacity market costs of serving these customers is about $58.87 per MWH. Her own analysis suggests that CRES suppliers can be expected to incur $58.87 per MWH in non-capacity market costs, but customers can avoid only $37.87 per MWH in AEP Ohio charges when they shop.

In other words, if I assume the Company's proposed capacity costs are included in the Proposed ESP Price and in the competitive market cost-to-serve, it is extremely unlikely that retail suppliers will be able to compete with the proposed ESP. In fact, Ms. Thomas' estimate of simple swap energy prices exceeds the non-capacity costs implicitly embedded in the Proposed ESP Price. This is before taking into account the other market supply costs that Ms. Thomas identifies in Exhibit LJT-1 (*e.g.*, basis, load following/shaping adjustment, ancillary services, alternative energy, losses, etc.). Clearly, the playing field is not level. CRES suppliers are at a distinct disadvantage under the proposed ESP design. Not because they cannot compete, but rather because AEP Ohio's proposed rules are such that competitive suppliers are not "allowed" to compete in an

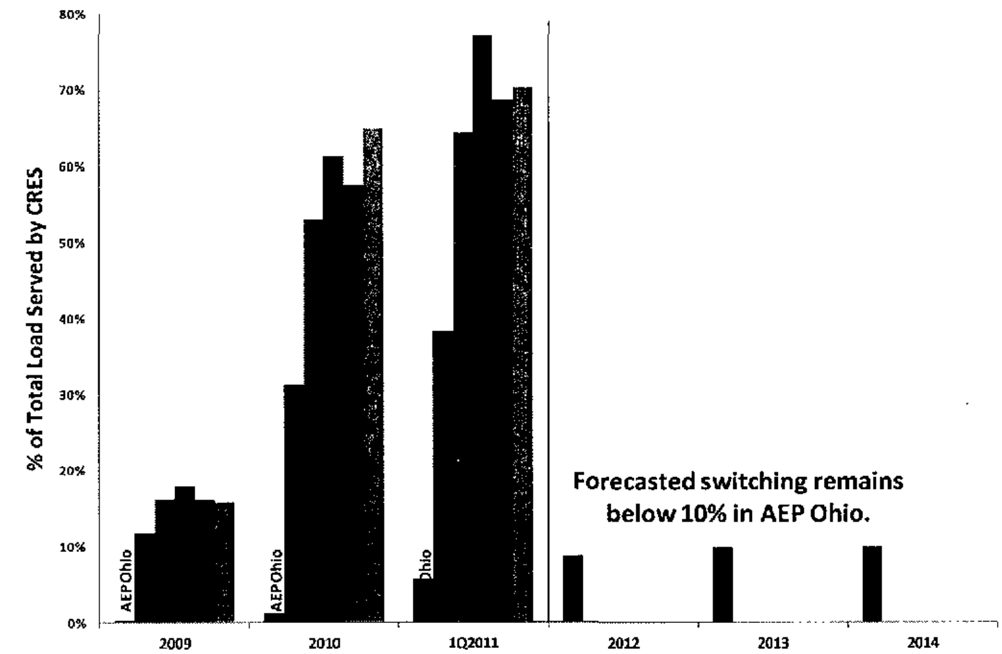
[164] This weighted average figure was calculated based on information contained in Exhibit LJT-1.

economic sense. This is why the capacity price being proposed by AEP Ohio "stacks the deck" against CRES suppliers.

Q. DOES AEP OHIO'S PROJECTED CUSTOMER SHOPPING FIGURES SUPPORT YOUR CONCLUSION THAT THE DEVELOPMENT OF RETAIL COMPETITION WILL LIKELY REMAIN STALLED IN THE AEP OHIO SERVICE TERRITORY DURING THE PROPOSED ESP PERIOD?

A. Yes. AEP Ohio witness Laura Thomas includes a forecast of retained and total load during the ESP supply period, based on an assumed level of shopping. As can be seen in the chart below, AEP Ohio's forecasted switching rates are well below the switching rates observed in Ohio's other service territories. This demonstrates that AEP Ohio's proposed ESP will not meaningfully contribute to the development of retail competition in AEP Ohio's service territory and is therefore not consistent with State policy.

Customer Switching at AEP Ohio is Well Below Other Ohio Utilities



Sources: Workpapers of L Thomas, PUCO Case No. 11-346-EL-SSO, pp. 7-8.
PUCO, Division of Planning & Market Analysis, Electric Customer Choice Switch Rates, 7/14/2011.

Furthermore, Ms. Thomas' figures show zero switching among residential customers for the duration of the ESP delivery period in AEP Ohio's service territory. This is contrasted with residential switching rates of 65% in the FirstEnergy Ohio Utilities' service territories and 32% in Duke's Ohio service territory.[165] Ms. Thomas' figures also show zero switching among industrial customers for the duration of the ESP delivery period in AEP Ohio's service territory. This is contrasted with industrial switching rates of 77% in the FirstEnergy Ohio Utilities' service territories, 95% in

[165] PUCO, Division of Planning & Market Analysis, Electric Customer Choice Switch Rates, March 2011 Report, Accessed 7/14/2011.

Duke's Ohio service territory, and 82% in Dayton Power & Light's service territory.[166] Clearly, AEP Ohio does not expect significant retail shopping to occur under its plan.

Q. IF AEP OHIO'S PROPOSED ESP IS APPROVED BY THE COMMISSION, WHAT DO YOU CONCLUDE ABOUT THE PROSPECTS FOR RETAIL COMPETITION IN AEP OHIO'S SERVICE AREA?

A. Retail competition will be severely limited and unfairly restricted, to the detriment of AEP Ohio's customers. The proposed ESP with non-bypassable charges for generation-related costs and an above-market capacity price to CRES suppliers would stymie retail competition and deprive AEP Ohio's customers of a meaningful opportunity to shop.

X. THE STRUCTURE THAT AEP OHIO IS PROPOSING COULD RESULT IN SERIOUS HARM TO CUSTOMERS AND PROVIDES AEP OHIO WITH AN INCENTIVE TO INVEST IN COSTLY GENERATION INVESTMENTS EVEN WHEN CHEAPER RESOURCE ALTERNATIVES EXIST IN THE MARKET

A. Non-Bypassable Generation Charges Coupled With the Ability of AEP Ohio to Retain Off-System Sales Energy Margins Provides AEP Ohio with an Incentive to Make Investments In Uneconomic Generation

Q. PLEASE EXPLAIN WHY AEP OHIO'S PROPOSED ESP WILL CREATE AN INCENTIVE FOR UNECONOMIC GENERATION INVESTMENTS?

A. Establishing non-bypassable riders without an appropriate comparison to more economic market alternatives will create an incentive for uneconomic investments. Customers will be responsible for paying for uneconomic investment and operating decisions made by AEP Ohio. Furthermore, the integration of this approach with the current treatment of off-

[166] PUCO, Division of Planning & Market Analysis, Electric Customer Choice Switch Rates, March 2011 Report, Accessed 7/14/2011.

system sales results in an additional benefit to AEP Ohio shareholders and may exacerbate this problem.

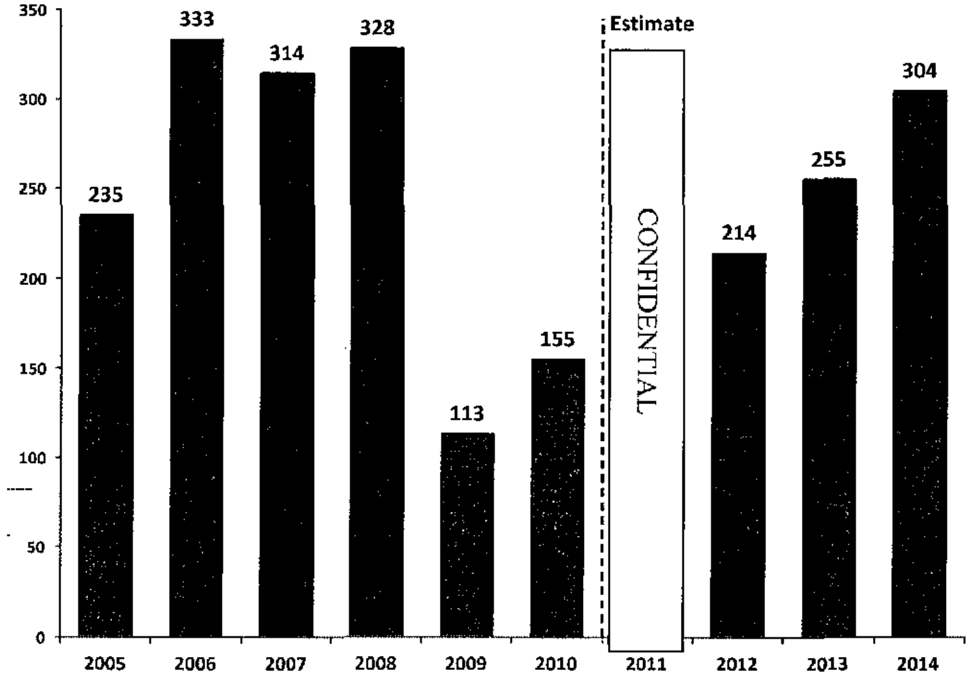
The electricity supply business is inherently risky, because the future is uncertain with respect to those things that will determine the future market price of electricity: load growth, fuel prices, environmental costs, new technology, and so forth. AEP Ohio's proposal improperly allocates risk (including the risk associated with technological choices, excess supply problems, and cost overruns) to consumers rather than to investors. Not surprisingly, the regulatory process significantly underestimates these risks when making long-term resource commitments because customers, and not investors, largely bear these risks. In these risky electricity markets, unfavorable and unforeseen investment outcomes are common. Unfortunately, in regulated markets, retail customers bear the responsibility of paying for those mistakes, while in competitive markets investors are responsible for the consequences of their decisions. Therefore, investors in competitive markets are more likely to respond quickly to changing market conditions than a regulated utility that can pass through its costs to retail customers.

Q. EXPLAIN HOW AEP OHIO'S PROPOSED ESP EXACERBATES THE INCENTIVE PROBLEM, GIVEN THE TREATMENT OF OFF-SYSTEM SALES MARGINS IN THE STATE OF OHIO.

A. In Ohio, unlike many of the other jurisdictions in which AEP operates, AEP's shareholders are permitted to retain all of the margins from AEP Ohio's off-system sales.[167] According to AEP Ohio's forecast, these margins are expected to be significant, totaling over $770 million pre-tax during the 2012-2014 period.

AEP Ohio Shareholders Retain Substantial Margins From Off-System Energy Sales

(Contains COMPETITIVELY-SENSITIVE CONFIDENTIAL Information)



2005 - 2010 from AEP Ohio's Interrogatory Response, OCC, Set 4, INT-139 and 2012 -2014 from OCC, Set 4, INT-140.
*2011: This information is COMPETITIVELY -SENSITIVE CONFIDENTIAL and is from AEP Ohio's Interrogatory Response, OCC, Set 1, RPD -24, Attachment 1.

The ability to sell excess energy and to allow shareholders to retain the margin from these sales provides an incentive for AEP Ohio to favor high cost, capital-intensive, low heat rate investments that enhance energy output even if lower cost supply options may exist. This incentive is exacerbated by AEP Ohio's proposed ESP because under the ESP customers are responsible for paying the capital costs of such generation investments through the proposed non-bypassable riders and above-market capacity price. In other words, customers pay for the capital and fixed O&M costs while AEP's shareholders

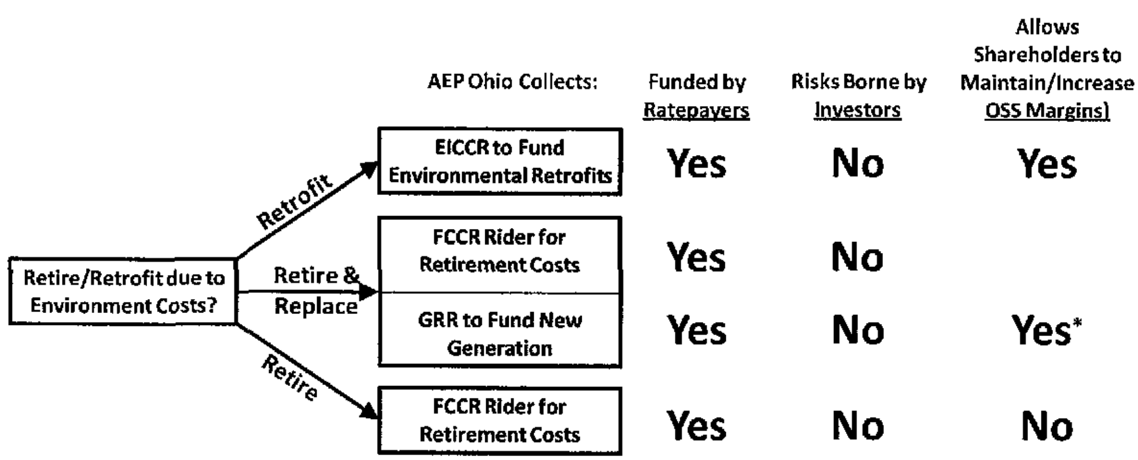
[167] AEP 2010 10-K, at 21.

retain the energy benefits of off-system sales. This provides an incentive for AEP Ohio to "overbuild," and can ultimately result in high costs and high rates for customers. As a result, the structure that AEP Ohio is proposing provides AEP Ohio with an incentive to invest in costly generation investments even when cheaper resource alternatives exist in the market and could result in serious harm to customers.

Q. PLEASE PROVIDE AN EXAMPLE OF HOW AEP OHIO'S PLAN ASYMMETRICALLY ALLOCATES THE RISKS AND BENEFITS OF CAPITAL INVESTMENTS BETWEEN CUSTOMERS AND INVESTORS.

A. Suppose AEP Ohio was deciding whether to a) retrofit an old existing coal unit to meet new environmental requirements, b) retire the coal plant and replace it with a new generation resource, or c) retire the coal plant with no capacity replacement. The decision can be conceptualized like this:

Overview of AEP Ohio Retrofit vs. Retire Decision



* Especially if new generation is more expensive baseload or intermediate capacity that produces more energy than a peaking unit.

In the first case, AEP Ohio's customers would pay for the environmental improvements via the proposed non-bypassable EICCR. At the same time, shareholders would be able to retain the margin from sales of any excess energy as a result of keeping the old coal unit in operation.

Under the second resource option, if AEP Ohio elected to retire the old coal unit, its customers would pay for the closure costs through the proposed non-bypassable FCCR rider. The capacity of the retired coal plant would be replaced by capacity from either an existing or new generation unit, the costs of which AEP Ohio may recover through the GRR. In any case, this second option could also result in excess energy for AEP Ohio to sell off-system.

Lastly, under the third option AEP Ohio would close the plant and recover the closure costs from its customers through the FCCR rider. Once the plant is retired, AEP Ohio would no longer be able to retain any of the margin from sales of any excess energy as a result of keeping the old coal unit in operation.

As can be seen, AEP Ohio has structured its proposed ESP to divorce risk from benefit. Although its ratepayers will bear the majority of the risks and costs, AEP's shareholders will avoid most of the risk while retaining the benefits of capital investments, especially those that enable AEP Ohio to maintain or increase off-system sales.

Q. CAN YOU PROVIDE AN ILLUSTRATION OF HOW AEP OHIO'S PROPOSED ESP MAY FAVOR UNNECESSARY, CAPITAL-INTENSIVE ENVIRONMENTAL RETROFITS?

A. Given options (a), (b), and (c) above, AEP Ohio has a strong economic incentive to choose capital-intensive options (a) or (b) in order to maintain or increase its off-system sales margins.[168]

For example, consider an uncontrolled (*e.g.*, no scrubber or mercury control) coal plant that currently (prior to new EPA regulation) is economic to operate. That is, the market value of energy and capacity revenues is greater than the "to-go" fuel and O&M costs.[169] The benefit of continued operation of the plant would accrue to non-shopping customers to the extent the output is used to serve AEP Ohio load and shareholders when the output results in off-system sales energy margins.

After EPA regulations and environmental compliance costs are added, the "to-go" costs with the retrofit could very well exceed the market value of the energy and capacity. This would suggest a negative margin or economic loss indicating that continued operation of the plant is uneconomic. Absent cost recovery via the non-bypassable EICCR, AEP Ohio would likely elect to shut this plant down.

But, with the non-bypassable EICCR in place, AEP Ohio could recover the cost of its retrofits from all shopping and non-shopping customers. In this case, customers pay the EICCR while shareholders preserve the pre-existing margin from excess energy sales. This results in an incentive to continue operation even though the overall economics suggest that the plant should be retired.

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[168] For illustrative purposes, it is assumed the replacement generation is actually needed. As I discuss separately, this replacement capacity may not be needed to serve AEP Ohio customers given the size of the projected reserve margins even if expected retirements occur.

[169] These are fuel and O&M costs not already incurred.

B. <u>Uneconomic Investments Would Increase Costs for AEP Ohio's Customers</u>

Q. HOW WOULD THE INCENTIVE FOR UNECONOMIC INVESTMENTS AFFECT CUSTOMERS?

A. Given that AEP Ohio estimates spending up to $2.8 billion in environmental capital expenditures through 2020[170] and could spend hundreds of millions of dollars on new generation to replace old coal units,[171] this incentive to invest in uneconomic generation, if unchecked by competitive market forces, could impose a significant burden on customers. If AEP Ohio's proposal to provide for ratepayer-funded generation investment is adopted, it could expose AEP Ohio's retail customers to considerable costs and risks for many years into the future, and significantly harm the development of competitive markets in Ohio and elsewhere. Large and potentially uneconomic investments in generation, once made by AEP Ohio, would need to be recovered from its customers for many years into the future (*i.e.*, creating a new round of "stranded generation costs" that otherwise would not be recoverable in competitive markets). Therefore, the Commission's decision on AEP Ohio's proposed ESP has significant implications for costs to customers and the financial impact of the decision in this case could extend decades into the future, well beyond the proposed 29-month ESP period. Furthermore, these costs directly impact the competitiveness of Ohio businesses, and the prospects for jobs in Ohio.[172] While AEP Ohio asks that it be allowed to ensure cost recovery of its investments in order to create jobs, there is no guarantee that it will make the "right" investments in the "right"

[170] AEP Ohio's Interrogatory Response, FES, Set 10, INT-10-2.

[171] See my earlier discussion regarding the GRR.

[172] Dr. Lesser's analysis shows that raising electricity costs for all Ohio consumers and foreclosing retail electric competition will cause the loss of thousands of jobs in Ohio. See discussion, AEP Ohio's "ESP Will Destroy Ohio Jobs, Not Create Them."

locations. In fact, AEP Ohio's testimony implies that it will only be able to make new environmental investments in AEP Ohio generating assets if it is ensured certain non-bypassable cost recovery.[173]

Q. WHAT ARE THE BENEFITS OF A COMPETITIVE GENERATION MARKET WITH RESPECT TO MAJOR CAPITAL INVESTMENT DECISIONS?

A. One of the most significant areas of potential savings from restructuring is more efficient long-term investments (sometimes referred to as "dynamic efficiency"). Competitive markets can provide significant improvements in resource planning and capital additions. Price signals, rather than administrative determinations, guide economic retirements and capacity improvements, economic new entry, and environmental compliance strategies. This will encourage the right amount of generating capacity with the appropriate levels of reliability, as well as the right mix of generating technologies in the right locations. Competition makes investors, rather than consumers, responsible for investment decisions with no assured recovery of the investment. All of this works to the benefit of customers. In a properly functioning competitive market, AEP Ohio's proposed generation-related riders are unnecessary.

[173] Direct Testimony of Joseph Hamrock on behalf of CSP and OPCo, at 23, lines 16-19.

XI. THE PROPOSED ESP WOULD HARM WHOLESALE COMPETITION AND PROVIDE SUBSIDIES TO AEP OHIO'S GENERATION BUSINESS

Q. HOW WILL THE PROPOSED ESP IMPACT WHOLESALE COMPETITION?

A. There are likely to be several effects. First, the incentive for uneconomic generation investment can lead to a) uneconomic retirement decisions (*i.e.*, continued operations of an existing facility even when the "to-go" costs exceed the market value of the energy and capacity), and b) uneconomic entry decisions (*e.g.*, new generation investment that cannot be recovered by market revenues). Both of these effects will tend to discourage the development of other more economic generation investments. Second, the non-bypassable cost recovery mechanisms will provide AEP Ohio's generation with an unfair competitive advantage. As previously discussed, uneconomic generation investment funded with non-bypassable cost recovery will increase costs to AEP Ohio's customers. Therefore, the proposed ESP would harm wholesale competition and provide subsidies to AEP Ohio's generation business.

Q. ARE MOST OTHER GENERATORS IN PJM ASSURED COST RECOVERY OF THEIR INVESTMENTS SIMILAR TO WHAT AEP OHIO IS PROPOSING IN THIS CASE?

A. No. The vast majority of other generators in the rest of PJM face the risks associated with their investment decisions without the safety net (at the expense of customers) that is being requested by AEP Ohio in the proposed ESP. AEP Ohio's plan would create an unlevel playing field for merchant generators in the region and could discourage the development of the lowest-cost generation investment. Unregulated merchant generators do not have the cost recovery assurances that AEP Ohio is seeking in this case. Their shareholders, not retail customers, bear the brunt of their investment decisions.

Q. DOES AEP OHIO HAVE EXPERIENCE WITH COST RECOVERY OF INVESTMENTS IN DEREGULATED MARKETS?

A. Yes. The 2010 10-K for AEP, CSP and OPCo, discussing estimated air quality environmental investments, states that, "We will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through our regulated rates." But they then add that, "We should be able to recover these expenditures through market prices in deregulated jurisdictions."[174]

XII. THE COMMISSION SHOULD REJECT AEP OHIO'S PROPOSED ESP, AND INSTEAD ADOPT A MODIFIED ESP BASED ON PROCUREMENT OF SSO SUPPLY THROUGH COMPETITIVE SOLICITATIONS OF FIXED-PRICE FULL REQUIREMENTS PRODUCTS

Q. HAS AEP OHIO SHOWN THAT ITS PROPOSED ESP IS SUPERIOR TO AN APPROACH INVOLVING FIXED-PRICE FULL REQUIREMENTS SSO SUPPLY PRODUCT SOLICITATIONS?

A. No, it has not. As described earlier in this testimony, AEP Ohio's analysis contains serious errors and is misleading. Correcting these errors, I show that a modified ESP that relies on fixed-price full requirements solicitations could result in an SSO price that is substantially less than the Proposed ESP Price, and at the same time, would not expose

[174] AEP, 2010 10-K, at 141; OPCo, 2010 10-K, at 141; CSP, 2010 10-K, at 124 (emphasis added).

customers to the significant risks associated with the Company's proposed riders during the term of the proposed ESP. As I noted earlier, adopting a modified ESP based on procurement of SSO supply through competitive solicitations of fixed-price full requirements products can be expected to result in SSO customer savings of about $1.6 to $2.0 billion over the proposed 29-month ESP period.[175]

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission reject AEP Ohio's proposed ESP and instead adopt a modified ESP that is based on procurement of supply through competitive solicitations of fixed-price full requirements products.

Q. PLEASE BRIEFLY REITERATE THE MAJOR BENEFITS OF THE FIXED-PRICE FULL REQUIREMENTS PRODUCT SOLICITATION APPROACH VIS-À-VIS AEP OHIO'S PROPOSED APPROACH.

A. In a procurement approach involving fixed-price full requirements solicitations, bidders compete on the basis of the lowest price to satisfy all aspects of the default service customers' load requirements at a fixed $/MWH price, regardless of how the load varies, and regardless of future market conditions or generation costs. In short, a fixed-price full requirements approach would allow non-shopping customers who do not choose a competitive retail supplier to obtain the benefits of wholesale competition.[176] At the same

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[175] These figures were based on forward energy prices at the time of the Company's filing. If I updated my analysis to reflect the forward price levels as of July 18, 2011 (just prior to filing this testimony), the modified ESP would still be expected to result in SSO customer savings of about $1.2 to $1.5 billion over the proposed 29-month ESP period.

[176] SSO customers can get the benefits of wholesale competition, even though they have not voluntarily chosen, or would not be able to choose (for reasons of poor credit, for example), a competitive retail supplier; as a result, this is

time, it would eliminate AEP Ohio's proposed riders that expose customers to significant costs and risks. Rather, these risks would be borne by experienced electricity market participants.

The use of a competitive process to procure a full-requirements product is designed to induce competitive bidding among suppliers. The competitiveness of the bidding process, coupled with the nature of the product that is being procured, will produce an outcome where the suppliers who can best manage their supply costs over time will be the winning bidders. The entities interested in these types of procurements typically are adept at managing supply portfolios that meet the load requirements of these types of customers. Those suppliers who are the best portfolio managers (in terms of handling the associated supply risks) will likely place the lowest bids in the competitive solicitation. Thus, the procurement process is intended to rely on the skills of the best portfolio managers to achieve the best prices for customers.

Q. IS THERE ANY BASIS FOR BELIEVING THAT A UTILITY HAS AN ADVANTAGE, WITH RESPECT TO MAKING GOOD DECISIONS REGARDING HOW TO MOST COST EFFECTIVELY SATISFY SSO SUPPLY OBLIGATIONS, OVER THE FULL REQUIREMENTS SUPPLIERS WHO WOULD COMPETE TO PROVIDE SSO SUPPLY AT THE LOWEST PRICE?

A. No. Rather than relying on AEP Ohio's judgment regarding how to satisfy its SSO supply obligations, participants in the full requirements solicitations would each make their own judgments about how best to supply the fixed-price full requirements product from the

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an effective way to get the benefits of wholesale competition to customers who do not or cannot choose a retail supplier.

wholesale markets. There are many choices for the would-be suppliers to make – for example, whether to make short-term or long-term purchases, whether or not to hedge fuel costs, whether to contract for the output of or buy an equity interest in generating assets. The procurement process would involve a competition among participants, including any competitive AEP Ohio affiliates, about who can best tap into the wholesale market on behalf of SSO customers. Bidders' expectations regarding the costs of some of the components of fixed-price full requirements supply may be similar because transparent markets exist for some of the components (*e.g.*, around-the-clock energy and capacity). However, bidders' assessments of other costs and risks (*e.g.*, those associated with customer migration, weather risk, transmission congestion, usage patterns, changes in laws and regulations, etc.) associated with providing fixed-price full requirements supply may be very different, their judgments regarding the best ways to manage these other costs and risks may be very different, and some bidders may be able to manage these costs and risks in a more cost-effective manner.

If the Commission were to reject AEP Ohio's proposed ESP and instead adopt an ESP that is based on procurement of supply through competitive solicitations of fixed-price full requirements products, customers would receive the benefits of two levels of wholesale competition: the competition among generating resources in the underlying wholesale market, and the competition among suppliers for how best to buy in that wholesale market. This should provide substantial benefits to AEP Ohio's customers, and is a superior approach to having AEP Ohio customers subject to the decisions of a single portfolio manager and assuming the risks associated with it. In addition, solicitations of fixed-price full requirements products would better support retail competition than the proposed ESP. This is due to the fact that SSO rates would be market-based and non-bypassable generation charges could be eliminated.

Q. ARE FIXED-PRICE FULL REQUIREMENTS SOLICITATIONS IN AN ESP FRAMEWORK USED ELSEWHERE IN OHIO TO SUPPLY SSO SERVICE?

A. Yes. On August 25, 2010, the Commission approved a stipulated three-year ESP for FirstEnergy's electric distribution utilities in Ohio in Case No. 10-388-EL-SSO. Among other things, the Commission-approved ESP establishes a competitive bid process by which retail generation rates are established for the time period, June 1, 2011 through May 31, 2014. Unlike AEP Ohio's ESP, under the FirstEnergy ESP, retail generation rates will be determined through a competitive bid process for fixed-price full requirements supply products for all of SSO supply. The competitive bid process is conducted by an independent bid manager every October and January beginning in 2010 and ending in 2013.

Q. ARE FIXED-PRICE FULL REQUIREMENTS SOLICITATIONS COMMON ELSEWHERE TO SUPPLY SSO SERVICE?

A. Yes. Utilities across many states have procured full requirements products through open solicitations, such as requests for proposals or auctions, in which bidders competing with one another indicate the prices at which they are willing to provide full requirements SSO supply. In fact, fixed-price full requirements product solicitations are by far the most prevalent form of SSO procurement in other restructured jurisdictions. Numerous state utility commissions in other jurisdictions recognize the public policy benefits associated with fixed-price full requirements products, especially in jurisdictions with retail access, and the value that these products provide in protecting customers from various risks, many of which are the risks to which AEP Ohio's proposal would expose customers. Examples of specific restructured states in which full requirements supply products are procured include: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Jersey, Ohio, Pennsylvania, Rhode Island, and Washington D.C.

In sum, this approach is by far the most prevalent form of default service procurement in other restructured jurisdictions, is an effective way to get the benefits of wholesale competition to customers who do not choose a retail supplier, and reinforces, rather than undermines, efficient wholesale competition.

Q. IS AEP OHIO AWARE OF FIXED-PRICE FULL REQUIREMENTS SOLICITATIONS IN OTHER STATES?

A. Yes. Ms. Thomas states on page 5 of her testimony that practices in Delaware, Maryland, New Jersey, Pennsylvania and Illinois were reviewed. In addition, she mentions FirstEnergy's competitive bid process for SSO service.

Q. HOW MIGHT AN ESP THAT RELIES ON SOLICITATIONS FOR FIXED-PRICE FULL REQUIREMENTS SUPPLY PRODUCTS BE IMPLEMENTED?

A. An ESP that relies on solicitations may look similar to the one that was approved by the Commission for the FirstEnergy Ohio Utilities. AEP Ohio could use multiple laddered solicitations to procure fixed-price full requirements slice of system products, so that the SSO supply portfolio will provide customers with stable rates and the supply portfolio will not need to turn over completely at any one point in time. Furthermore, this SSO supply approach will eliminate AEP Ohio's POLR charge, as well as the numerous non-bypassable generation-related riders included in AEP Ohio's proposed ESP because competitive fixed-price full requirements product suppliers would assume these costs and risks throughout the duration of each contract.

XIII. IF THE COMMISSION DOES NOT ADOPT THE ABOVE RECOMMENDATION, IT SHOULD, AS A MINIMUM, BEFORE ALLOWING ANY RECOVERY THROUGH A COST-BASED RIDER, SUBJECT ANY OTHERWISE ELIGIBLE SIGNIFICANT INVESTMENT IN GENERATION, WHETHER NEW, RETROFIT, OR ENVIRONMENTAL CONTROL, TO AN OPEN AND TRANSPARENT MARKET TEST AND REQUIRE OTHER CHANGES TO THE PROPOSED ESP

Q. IF THE COMMISSION DOES NOT ADOPT AN ESP BASED ON PROCUREMENT OF SUPPLY THROUGH COMPETITIVE SOLICITATIONS, WHAT WOULD YOU RECOMMEND?

A. The Commission should, as a minimum, require the following modifications to the proposed ESP:

- Before allowing recovery through a cost-based rider, subject any otherwise eligible significant investment in generation, whether new, retrofit, or environmental control, to an open and transparent market test;

- Ensure that AEP Ohio's proposed capacity price applicable to CRES suppliers is priced at market (RPM), or at least, no higher than a "maximum above-market" rate; and,

- Eliminate all non-bypassable riders for future generation investment and operating costs, or convert them to bypassable riders.

Q. MR. SCHNITZER, WHY IS AN OPEN AND TRANSPARENT MARKET TEST FOR SIGNIFICANT INVESTMENTS IN GENERATION APPROPRIATE?

A. First, let me be clear that I take no position as a matter of law as to whether AEP Ohio's proposed riders have satisfied all of the statutory criteria under either Revised Code sections 4928.143(B)(2)(b) or 4928.143(B)(2)(c). My point is that any such investments that AEP Ohio seeks to recover in cost-based riders should be subject to the test I describe below. That said, AEP Ohio has proposed a number of cost-based riders related to investment in generation, including the EICCR and the GRR. A basic regulatory principle for cost-based rates such as these riders is that the opportunity for return on and of investment in rates is limited to "prudently incurred" costs. Or, stated differently, only prudently incurred costs are recoverable in cost-based rates. In the context of the riders proposed by AEP Ohio, the most important element of the prudence determination is the determination that the decision to undertake a particular investment – whether an environmental retrofit or new generation construction – was prudent given the available alternatives. I refer to this aspect of prudence as "decisional prudence."

There are clearly alternatives for all of the investments which, under AEP Ohio's proposal, would be recovered on a cost basis through the EICCR or the GRR. For an environmental retrofit investment, one alternative is clearly to retire the facility and to purchase or build replacement capacity, and other alternatives include repowering and retirement without replacement. For a new generation investment, available alternatives include a power purchase agreement, procurement of a different type of capacity, and a combination of short-term purchases and construction at a later date. Thus, before any of these investment costs can be recovered in rates, the Commission must make a decisional prudence finding. It must find that the decision to undertake a particular investment, and not one of the available alternatives, was prudent.

Q. HOW SHOULD THE COMMISSION MAKE THIS DECISIONAL PRUDENCE DETERMINATION?

A. Under the circumstances present here, where the structure of the proposed riders combined with the treatment of off-system sales creates an incentive for AEP Ohio to undertake investments which will not benefit its customers, the assessment of decisional prudence takes on particular importance. The best way for the Commission to ensure that customers are being protected is to put each proposed investment to a market test, as described further below. The "best evidence" that a proposed investment in new or existing generation is prudent is that no market competitor will offer equivalent capacity and energy for a lower price.

Q. IS THIS MARKET TEST TO ESTABLISH DECISIONAL PRUDENCE CONSISTENT WITH THE PROVISIONS OF SECTION 4928.143(B) OF THE OHIO REVISED CODE?

A. Yes. Both Revised Code sections 4928.143(B)(2)(b) and (B)(2)(c) refer to "resource planning projections submitted by the electric distribution utility." Resource planning projections are much more than load forecasts – they involve a determination of the most economic portfolio of resources to meet the distribution utility's planning objectives, including an assessment of alternatives to the proposed investments. As discussed above, wholesale purchases of capacity and energy are clearly an alternative to all environmental retrofit and new construction proposals, so an assessment of the wholesale purchase option is properly a part of any determination of decisional prudence associated with these investments. So the only question, from a policy perspective, is how best to incorporate the wholesale purchase option in this assessment? The Commission could hear contrasting evidence of future wholesale market price forecasts, and expend enormous time and energy in the process. But this is clearly not the best approach when the market price can be directly observed through a solicitation of the type that I describe below. This is the best way for the Commission to make its required decisional prudence finding. To the extent it has the discretion to adopt this approach, it should do so.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY AN OPEN AND TRANSPARENT MARKET TEST.

A. If AEP Ohio was planning to make a certain investment in generation, it should be required to solicit competitive bids for an equivalent number of MW and/or MWH for a specified period of time in order to determine whether its proposed investment is least cost. The competitive bid should be for a similar product (in terms of energy output, capacity, etc.) for a similar term, similar strike price, and location as the investment being proposed by the utility. AEP Ohio then should compare the costs of its proposed utility investment to the market alternative. I would include in this analysis all "to go" or non-sunk costs – both capital and O&M costs. In business, this is the classic "make" vs. "buy" decision. Without testing the market in order to determine whether the "build" option is cheaper than the "buy" option or vice versa, the Commission cannot make a decisional prudence determination.

Q. ARE YOU SUGGESTING THAT THESE INVESTMENTS WOULD BE ONLY CONSIDERED OVER THE 29-MONTH ESP TERM?

A. No, not at all. If AEP Ohio were considering an investment with an expected life of fifteen years that would provide energy and capacity at a particular generation bus, the market test I am suggesting would then be a non-discriminatory, "head-to-head" comparison for a fifteen-year product with similar product attributes at the same location.

Q. WHY IS AN OPEN AND TRANSPARENT MARKET TEST IMPORTANT?

A. A transparent market test is necessary to ensure that the least-cost resource options are employed at the time of the investment decision, so that Ohio residential and business customers are not burdened with high-cost (*i.e.*, above market) generation for many years into the future. This will help avoid situations in which customers must incur stranded costs associated with future investments or long-term contracts.

Q. HAS AEP OHIO DEMONSTRATED THAT THERE IS A NEED FOR ADDITIONAL GENERATION RESOURCES TO SERVE AEP OHIO CUSTOMERS?

A. No, as I discussed earlier, AEP Ohio has significant reserve margins and does not need new generation dedicated to serve its AEP Ohio load.

Q. HAS AEP OHIO DEMONSTRATED THAT GENERATION INVESTMENTS MADE BY THE COMPANY ARE THE LOWEST COST ALTERNATIVE?

A. No, it has not. And as discussed above, the Company should be required to conduct a competitive market test to demonstrate that these generation investments are the lowest cost alternative.

Q. IN THIS PROCEEDING, HAS AEP OHIO PROVIDED EVIDENCE THAT THE PROPOSED TURNING POINT SOLAR PROJECT IS THE LOWEST COST ALTERNATIVE?

A. No. According to AEP Ohio, the Turning Point solar project (49.9MW) is expected to be the first project to be included in the GRR.[177] Rather than assume that the Solar Point Turning Project is economic, I believe the Commission should require AEP Ohio to design a competitive bid process for a similar product (in terms of energy and capacity) for a similar term and location. This would allow AEP Ohio to select the least-cost option for the benefit of its customers.

Q. WHAT DO YOU CONCLUDE ABOUT THE IMPORTANCE OF A MARKET TEST?

A. Under AEP Ohio's proposed ESP, the Company proposes numerous riders to recover the costs of generation-related investment and environmental compliance. These investment decisions are not subject to competitive market forces. AEP Ohio's ESP relies on non-bypassable riders to mitigate shareholder risks. A market test is needed to protect

[177] Direct Testimony of David Roush on behalf of CSP and OPCo, at 11, lines 7-9.

customers. A market test will ensure that AEP Ohio determines whether cheaper market alternatives exist before undertaking a major capital generation investment project.

Q. TURNING TO YOUR OTHER SUGGESTED MODIFICATIONS TO THE ESP, WHY SHOULD THE COMMISSION ENSURE THAT THE CAPACITY PRICE IS PRICED AT MARKET (RPM), OR AT LEAST, NO HIGHER THAN A "MAXIMUM ABOVE-MARKET" RATE, AND ELIMINATE ALL NON-BYPASSABLE RIDERS FOR FUTURE GENERATION INVESTMENT AND OPERATING COSTS OR CONVERT THEM TO BYPASSABLE RIDERS?

A. As I have discussed in detail above, the capacity price proposed by AEP Ohio far exceeds market prices and any reasonable "maximum above-market" capacity rate. Approving its proposed capacity price will stymie retail competition. I have also discussed in detail how the proposed non-bypassable generation charges will undermine both wholesale and retail competition.

The modifications I recommend are necessary to ensure fair and efficient competition at both the wholesale and retail levels. As a matter of public policy, generation-related charges should be bypassable, allowing customers to avoid these charges in the event that AEP Ohio's investment and operating decisions result in high costs for their customers relative to competitive alternatives. Likewise, AEP Ohio generation should not be given special treatment in terms of cost recovery that provides it with a competitive advantage relative to other generators in the market.

XIV. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR MAJOR CONCLUSIONS.

A. First, I conclude that the price of AEP Ohio's Proposed ESP is not more favorable than the expected price under an MRO, and AEP Ohio has not established that any other terms it proposes overcome that deficit to make the ESP more favorable in the aggregate than the expected results of an MRO. There are a number of reasons why AEP Ohio's proposed ESP price is not more favorable than the expected price under an MRO:

1. The Proposed ESP is more expensive for customers. There are numerous errors in AEP Ohio's calculations – errors that overstate the MRO price and errors and omissions that understate the Proposed ESP Price.

    - When these errors are corrected, AEP Ohio's Proposed ESP Price is about \$7 to \$9 per MWH higher than the alternative MRO price. Over its proposed term, AEP Ohio's ESP would cost its SSO customers \$700 million to \$1.0 billion more than an MRO.

    - In addition, the proposed ESP can be expected to result in a significant rate increase over current rates – an average total rate increase of 18% to 23%, even if transmission and distribution rates are held constant at 2011 levels throughout the ESP period. This rate increase will result in approximately \$1.6 to \$2.0 billion in additional costs to customers as compared to current rates.

2. In addition to being more expensive, the proposed ESP is riskier for customers. The proposed ESP contains numerous riders that allow rates to be adjusted upward

and the proposed ESP, therefore, does not provide the fixed price protection for customers that AEP Ohio claims.[178]

3. Thus, Mr. Hamrock's conclusion that "AEP Ohio's 2012-2014 ESP best serves the public interest by offering a price that is more favorable in the aggregate than the expected results under an MRO" is simply incorrect.[179] AEP Ohio's Proposed ESP Price is significantly higher than the expected price under an MRO – by $700 million to $1.0 billion over the term of the proposed ESP period. AEP Ohio has not quantified any significant benefits associated with the other elements of its plan, and has certainly not provided any evidence to suggest that any such benefits could overcome a $700 million to $1.0 billion pricing deficit.

Second, I conclude that the proposed ESP would also harm customers and undermine public policy in other ways.

1. The proposed ESP would stymie retail competition in the AEP Ohio service area. Retail suppliers would be unable to compete with AEP Ohio's SSO offering – not because of any shortcoming on the suppliers' part, but because the deck would be "stacked" against them. AEP Ohio would be allowed to impose a litany of non-bypassable riders for the recovery of generation costs. These riders would be collected from all shopping and non-shopping customers regardless of their

[178] There is a fundamental "night and day" difference between the "fixed price generation service" that AEP Ohio alleges it is offering in its proposed ESP and that provided by a fixed-price full requirements bidder in a competitive solicitation process. AEP Ohio's "fixed price generation service" is far from fixed. AEP Ohio can adjust its rates for changes in fuel costs, changes in environmental costs, changes in capital costs, changes in retirement costs, and a variety of other costs that could be recovered in the numerous riders that it proposes. On the other hand, a fixed-price full requirements bidder in a competitive bid process must manage a panoply of risks in order to honor its commitment to supply an unknown, fluctuating quantity of power at a fixed price. The fixed price is fixed throughout the term of the contract. This is not at all what AEP Ohio is proposing in this ESP.

[179] Direct Testimony of Joseph Hamrock on Behalf of CSP and OPCo, at 26, lines 22-23.

supplier. Thus, when an SSO customer switches to an alternative retail supplier, that customer would pay its new supplier's generation costs and would also still need to pay a portion of AEP Ohio's generation costs. Thus, customers would be forced to *pay twice* for these costs if they shop. Furthermore, the capacity price which AEP Ohio proposes to charge CRES suppliers and is included in the MRO test is far too high. In its approach to calculating this proposed capacity price, AEP Ohio failed to account for the revenue that the Company's generation would derive from market energy and other sources of revenue available to the Company (*i.e.*, costs that AEP Ohio could otherwise recover when a customer shops). These revenues should be an offset to the capacity price. The result of AEP Ohio's failure to credit these revenues is that the proposed capacity price would significantly overcompensate AEP Ohio. In fact, AEP Ohio's proposed capacity price is over nine times greater than the market clearing price for capacity in PJM's RPM during the proposed ESP period. The combination of the proposed non-bypassable generation charges imposed on all customers and the proposed above-market capacity price for CRES providers would deprive AEP Ohio's customers of any meaningful opportunity to shop and save money with other suppliers, all but ending retail competition in AEP Ohio's service area.

2. AEP Ohio's proposed ESP structure also could result in serious harm to customers beyond the term of the ESP. The subsidies that the ESP proposal would grant to AEP Ohio, in the form of the non-bypassable cost recovery mechanisms, would give the Company an incentive to make uneconomic investments in generation that customers would be forced to bear for years. For example, the proposed ESP

would require customers to pay for environmental and new capacity investments that may not be economic, without the ability to avoid these above-market costs by switching suppliers. At the same time, AEP Ohio would continue to retain off-system sales energy margins. Taken together, these features of the proposed ESP would provide AEP Ohio with an incentive to make costly generation investments even when cheaper resource alternatives exist in the market. Such uneconomic investments would increase costs for all of AEP Ohio's distribution customers far beyond the proposed 29-month ESP period.

3. The proposed ESP's non-bypassable riders for the recovery of generation-related costs would also harm wholesale competition by providing subsidies to AEP Ohio's generation business. In contrast, competitive generation suppliers are not entitled to these types of ratepayer-backed cost recovery guarantees. These non-bypassable charges would grant AEP Ohio a competitive advantage over other generators because AEP Ohio could force its customers to bear the risks associated with the uncertain and significant costs of AEP Ohio's generating assets and decisions, while competitive owners of generation must bear these risks themselves.

Q. PLEASE SUMMARIZE YOUR MAJOR RECOMMENDATIONS.

A. Given that AEP Ohio's proposed ESP price is not more favorable than the expected price under an MRO, and that the proposed ESP would also harm customers and undermine public policy in other ways, I support the following recommendations:

1. The Commission should reject AEP Ohio's proposed ESP and instead adopt a modified ESP based on procurement of SSO supply through competitive solicitations of fixed-price full requirements products. This type of ESP default service procurement, which has been approved by the Commission for the FirstEnergy Ohio Utilities, can be expected to result in \$16 to \$19 per MWH lower prices than AEP Ohio's Proposed ESP Price over the term of the ESP. The 18% to 23% rate increase that would result from AEP Ohio's ESP proposal could be avoided by adopting such a modified ESP based on procurement of SSO supply through competitive solicitations of fixed-price full requirements products, and SSO customers could save \$1.6 to \$2.0 billion over the 29-month ESP period relative to the proposed ESP. This recommendation, if adopted, could completely mitigate the proposed average total rate increase associated with AEP Ohio's proposal, and even result in a total rate decrease. Furthermore, this competitive solicitation model is by far the most prevalent form of default service procurement in other restructured jurisdictions, particularly for smaller customers, because it is an effective way to provide customers with the benefits of wholesale competition.

2. Alternatively, if the Commission does not adopt this recommendation, it should, at a minimum, require the following modifications to the proposed ESP to mitigate the harm that AEP Ohio's plan would impose on customers:

    - Before allowing recovery through a cost-based rider, subject any otherwise eligible significant investment in generation, whether new, retrofit, or environmental control, to an open and transparent market test;

- Ensure that AEP Ohio's proposed capacity price applicable to CRES suppliers is priced at market (RPM), or at least, no higher than a "maximum above-market" rate; and,

- Eliminate all non-bypassable riders for future generation investment and operating costs, or else convert them to bypassable riders that do not impose costs on the customers of competitive suppliers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does, although I reserve the right to file rebuttal testimony.

Exhibit MMS-1

Michael M. Schnitzer, Director

The NorthBridge Group
30 Monument Square
Concord, MA 017742

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

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

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

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

Exhibit MMS-2

Corrections to Total Generation Service Price

(Jan. 2012- May 2014)

[Contains RESTRICTED ACCESS CONFIDENTIAL Information]

Corrected Total Generation Service Price	**($/MWH)**	
	Low	High
Total Generation Service Price	**56.86**	**56.86**
Less:		
2011 Full Fuel	32.86	32.86
2011 Environmental Compliance Costs	0.90	0.90
2011 Base ESP "g" Rate	**23.10**	**23.10**
Plus: (Jan 2012- May 2014)		
Fuel	[redacted]	[redacted]
Environmental Investment (EICCR)		
POLR Charge	2.84	2.84
Subtotal, Total Adjustments	41.71	43.18
Corrected Total Generation Service Price	**64.81**	**66.28**
Total Corrections	7.95	9.42

Exhibit MMS-3

Responses to Interrogatories From Exelon Corp. (EXC)

EXC 1-002

RPD 3-012 (& attachment)
RPD 3-014 (& attachment)

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSES TO EXELON GENERATION COMPANY, LLC'S DISCOVERY REQUEST CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO FIRST SET

INTERROGATORY

INT-1-002. Please provide a detailed list of all the existing AEP East Power Pool Companies generation plants that the AEP East Power Pool Companies plan to retire, mothball or temporarily lay-up, and/or run on limited service and/or restricted operation (i.e., change the output at which the plant is operated) through May 31, 2014

RESPONSE:

Please see the Companies' response to part a of IEU INT-099 for the generating units the existing AEP East Power Pool Companies plan to retire by May 31, 2014. In addition, the existing AEP East Power Pool Companies have identified the following units to run on limited service (extended start-up status) which could continue through May 31, 2014:

Ohio Power Company - Sporn Units 4 & 5; Muskingum River Unit 4
Columbus Southern Power Company - Picway Unit 5
Appalachian Power Company - Clinch River Unit 3; Glen Lyn Units 5 & 6; Sporn Unit 3
Indiana Michigan Power Company - Tanners Creek Units 1 &2

In extended start-up mode, these units will remain off-line until needed to meet demand

Prepared By: Philip J. Nelson

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSES TO EXELON GENERATION COMPANY, LLC'S DISCOVERY REQUEST CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO THIRD SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-3-012. Please provide a copy of the confidential supplement to the AEP-East 2010 Integrated Resource Plan containing any business sensitive information excluded from the publicly-available AEP-East 2010 Integrated Resource Plan.

RESPONSE

See COMPETITIVELY-SENSITIVE CONFIDENTIAL Exelon RPD 3-012 Attachment 1.

Prepared By: Philip J. Nelson

See COMPETITIVELY SENSITIVE CONFIDENTIAL attachment, RPD 3-012 Attachment 1

COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSES TO
EXELON GENERATION COMPANY, LLC'S
DISCOVERY REQUEST
CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO
THIRD SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-3-014. Please provide all documents that contain an analysis, study, memo or report on the topic of Re-powering or Retro-fitting any generation unit owned by Columbus Southern Power or Ohio Power for the time period though the IRP planning term of 2020?

RESPONSE

See COMPETITIVELY-SENSITIVE CONFIDENTIAL Exelon RPD 3-014 Attachements 1-6.

Prepared By: Philip J. Nelson

See COMPETITIVELY SENSITIVE CONFIDENTIAL attachment, RPD 3-014 Attachment 4

Responses to Interrogatories
From First Energy Solutions (FES)

FES 1-001 (& attachment)
FES 5-018
FES 6-008 (& attachment)
FES 6-009 (& attachment)
FES 10-002 (& attachments)
FES 10-003
FES 10-005 (& attachment)
FES 10-009 (& attachment)

COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSES TO
FIRSTENERGY SOLUTIONS CORP.'S
DATA REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FIRST SET

INTERROGATORY

INT-001 What is Your estimate of the revenue that will be generated by each of the following provisions of the ESP in each year of the term of the ESP:

a) The Fuel Adjustment Clause ("FAC");
b) The Provider of Last Resort ("POLR") Rider;
c) The Environmental Investment Carrying Cost Rider ("EICCR");
d) The Carbon Capture and Sequestration Rider ("CCSR"); and, e) The Pool Termination and Modification Costs?

RESPONSE

a See COMPETITIVELY SENSITIVE CONFIDENTIAL Attachment 1
b. The requested data can be calculated by data provided by Company witness Roush's work papers.
c) See AEM-1 attached to the testimony of Company witness Moore for 2012
d) See Company witness Nelson's testimony at page 21 for the annual revenue requirement for the FEED study
e) Pool Termination and Modification costs are not expected to occur during this ESP period

Prepared By: Philip J. Nelson

See RESTRICTED ACCESS CONFIDENTIAL attachment, FES Attachment 1-001

COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
FIRSTENERGY SOLUTIONS
DISCOVERY REQUEST
CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO
FIFTH SET

INTERROGATORY

INT-5-018. In witness Nelson's testimony at 30:18, he states that the Pool Termination or Modification provision will be calculated by comparing "the lost AEP Pool capacity revenue to increases in net revenue related to new wholesale transaction or decreases in generation asset costs that result from the FERC proceedings related to the AEP Pool." Identify the mathematical calculation which will be used by AEP to make this determination.

RESPONSE:

The Company has not developed any mathematical calculation.

Prepared By: Philip J Nelson

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

INTERROGATORY

INT-6-8: Referring to OCC INT-096, please identify the monthly power pool capacity revenues received (or expenses incurred) by Ohio Power and CSP for each of 2009 and 2010, and the associated MWs sold (or purchased) to AEP pool members

RESPONSE:

The Company objects to this request as seeking information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence Without waiving the foregoing objection(s) or any general objection the Company may have, the Company states as follows.

For January 2009 to February 2010, see attachment FES 6-8 Attachment 1.

For March 2010 to December 2010, see response to OEG-INT-3-003.

Prepared By: Philip J. Nelson

CALCULATION OF MEMBER PRIMARY CAPACITY
SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,287,000	0.33178	8,677,000	(2,390,000)
KPCO	1,453,000	0.07094	1,855,300	(402,300)
I&M	5,122,000	0.18027	4,714,600	407,400
OPCO	8,450,000	0.23074	6,034,600	2,415,400
CSP	4,841,000	0.18627	4,871,500	(30,500)
TOTAL	26,153,000	1.00000	26,153,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,390,000)	*****	+	*****	(27,791,724)
KPCO	(402,300)	*****	+	*****	(4,678,080)
I&M	407,400	10.54	+	3.45	5,699,526
OPCO	2,415,400	8.43	+	2.8	27,124,942
CSP	(30,500)	*****	+	*****	(354,664)

EQUALIZATION CAPACITY RATE: 11.6283
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,289,000	0.34458	9,023,900	(2,734,900)
KPCO	1,453,000	0.06943	1,818,200	(365,200)
I&M	5,155,000	0.17686	4,631,600	523,400
OPCO	8,450,000	0.22638	5,928,400	2,521,600
CSP	4,841,000	0.18275	4,785,900	55,100
TOTAL	26,188,000	1.00000	26,188,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(2,734,900)	*****	+	*****	(31,944,237)
KPCO	(365,200)	*****	+	*****	(4,265,617)
I&M	523,400	10.54	+	3.26	7,222,920
OPCO	2,521,600	8.43	+	2.85	28,443,648
CSP	55,100	8.78	+	1.08	543,286

EQUALIZATION CAPACITY RATE: 11.6802
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,321,000	0.34458	9,034,900	(2,713,900)
KPCO	1,453,000	0.06943	1,820,400	(367,400)
I&M	5,155,000	0.17686	4,637,300	517,700
OPCO	8,450,000	0.22638	5,935,700	2,514,300
CSP	4,841,000	0.18275	4,791,700	49,300
TOTAL	26,220,000	1.00000	26,220,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(2,713,900)	*****	+	*****	(33,067,727)
KPCO	(367,400)	*****	+	*****	(4,476,614)
I&M	517,700	10.54	+	2.77	6,890,587
OPCO	2,514,300	8.43	+	3.55	30,121,314
CSP	49,300	8.78	+	2.02	532,440

EQUALIZATION CAPACITY RATE: 12.1846

(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

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Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY
SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,321,000	0.34458	9,034,900	(2,713,900)
KPCO	1,453,000	0.06943	1,820,400	(367,400)
I&M	5,155,000	0.17686	4,637,300	517,700
OPCO	8,450,000	0.22638	5,935,700	2,514,300
CSP	4,841,000	0.18275	4,791,700	49,300
TOTAL	26,220,000	1.00000	26,220,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,713,900)	*****	+	*****	(33,085,328)
KPCO	(367,400)	*****	+	*****	(4,478,997)
I&M	517,700	10.54	+	3.12	7,071,782
OPCO	2,514,300	8.43	+	3.48	29,945,313
CSP	49,300	8.78	+	2.32	547,230

EQUALIZATION CAPACITY RATE: 12.1911
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY
SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,321,000	0.34458	9,034,900	(2,713,900)
KPCO	1,453,000	0.06943	1,820,400	(367,400)
I&M	5,155,000	0.17686	4,637,300	517,700
OPCO	8,450,000	0.22638	5,935,700	2,514,300
CSP	4,841,000	0.18275	4,791,700	49,300
TOTAL	26,220,000	1.00000	26,220,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(2,713,900)	*****	+	*****	(34,734,275)
KPCO	(367,400)	*****	+	*****	(4,702,227)
I&M	517,700	10.54	+	3.31	7,170,145
OPCO	2,514,300	8.43	+	4.19	31,730,466
CSP	49,300	8.78	+	2.09	535,891

EQUALIZATION CAPACITY RATE: 12.7987

(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY
SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,321,000	0.34458	9,034,900	(2,713,900)
KPCO	1,453,000	0.06943	1,820,400	(367,400)
I&M	5,155,000	0.17686	4,637,300	517,700
OPCO	8,450,000	0.22638	5,935,700	2,514,300
CSP	4,841,000	0.18275	4,791,700	49,300
TOTAL	26,220,000	1.00000	26,220,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(2,713,900)	*****	+	*****	(33,094,019)
KPCO	(367,400)	*****	+	*****	(4,480,173)
I&M	517,700	10.54	+	3.26	7,144,260
OPCO	2,514,300	8.43	+	3.47	29,920,170
CSP	49,300	8.78	+	1.56	509,762

EQUALIZATION CAPACITY RATE: 12.1943
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,321,000	0.34694	9,096,800	(2,775,800)
KPCO	1,453,000	0.06990	1,832,800	(379,800)
I&M	5,155,000	0.17806	4,668,700	486,300
OPCO	8,450,000	0.22124	5,800,900	2,649,100
CSP	4,841,000	0.18386	4,820,800	20,200
TOTAL	26,220,000	1.00000	26,220,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,775,800)	*****	+	*****	(34,642,988)
KPCO	(379,800)	*****	+	*****	(4,740,041)
I&M	486,300	10.54	+	3.28	6,720,666
OPCO	2,649,100	8.43	+	3.82	32,451,475
CSP	20,200	8.78	+	1.66	210,888

EQUALIZATION CAPACITY RATE: 12.4804
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,321,000	0.35049	9,189,800	(2,868,800)
KPCO	1,453,000	0.07062	1,851,700	(398,700)
I&M	5,155,000	0.17908	4,695,500	459,500
OPCO	8,450,000	0.21406	5,612,600	2,837,400
CSP	4,841,000	0.18575	4,870,400	(29,400)
TOTAL	26,220,000	1.00000	26,220,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(2,868,800)	*****	+	*****	(35,386,102)
KPCO	(398,700)	*****	+	*****	(4,917,888)
I&M	459,500	10.54	+	3.43	6,419,215
OPCO	2,837,400	8.43	+	3.64	34,247,418
CSP	(29,400)	*****	+	*****	(362,643)

EQUALIZATION CAPACITY RATE: 12.3348
(This is the average $/kW rate paid by deficit members.)

NOTES:
* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,321,000	0.35084	9,199,000	(2,878,000)
KPCO	1,453,000	0.07069	1,853,500	(400,500)
I&M	5,155,000	0.17927	4,700,500	454,500
OPCO	8,450,000	0.21326	5,591,700	2,858,300
CSP	4,841,000	0.18594	4,875,300	(34,300)
TOTAL	26,220,000	1.00000	26,220,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(2,878,000)	*****	+	*****	(34,480,283)
KPCO	(400,500)	*****	+	*****	(4,798,246)
I&M	454,500	10.54	+	3.52	6,390,270
OPCO	2,858,300	8.43	+	3.22	33,299,195
CSP	(34,300)	*****	+	*****	(410,936)

EQUALIZATION CAPACITY RATE: 11.9806
(This is the average $/kW rate paid by deficit members.)

NOTES:

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Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY
SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,321,000	0.35600	9,334,300	(3,013,300)
KPCO	1,453,000	0.07173	1,880,800	(427,800)
I&M	5,155,000	0.18190	4,769,400	385,600
OPCO	8,450,000	0.21001	5,506,500	2,943,500
CSP	4,841,000	0.18036	4,729,000	112,000
TOTAL	26,220,000	1.00000	26,220,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(3,013,300)	*****	+	*****	(35,292,361)
KPCO	(427,800)	*****	+	*****	(5,010,477)
I&M	385,600	10.54	+	3.79	5,525,648
OPCO	2,943,500	8.43	+	2.95	33,497,030
CSP	112,000	8.78	+	2.65	1,280,160

EQUALIZATION CAPACITY RATE: 11.7122
(This is the average $/kW rate paid by deficit members.)

NOTES:

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** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,321,000	0.35600	9,334,300	(3,013,300)
KPCO	1,453,000	0.07173	1,880,800	(427,800)
I&M	5,155,000	0.18190	4,769,400	385,600
OPCO	8,450,000	0.21001	5,506,500	2,943,500
CSP	4,841,000	0.18036	4,729,000	112,000
TOTAL	26,220,000	1.00000	26,220,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(3,013,300)	*****	+	*****	(34,692,681)
KPCO	(427,800)	*****	+	*****	(4,925,341)
I&M	385,600	9.97	+	4	5,386,832
OPCO	2,943,500	8.37	+	2.85	33,026,070
CSP	112,000	8.76	+	2	1,205,120

EQUALIZATION CAPACITY RATE: 11.5132
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,333,000	0.35600	9,347,100	(3,014,100)
KPCO	1,453,000	0.07173	1,883,400	(430,400)
I&M	5,163,000	0.18190	4,776,000	387,000
OPCO	8,458,000	0.21001	5,514,000	2,944,000
CSP	4,849,000	0.18036	4,735,500	113,500
TOTAL	26,256,000	1.00000	26,256,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(3,014,100)	*****	+	*****	(40,532,338)
KPCO	(430,400)	*****	+	*****	(5,787,837)
I&M	387,000	9.97	+	6.52	6,381,630
OPCO	2,944,000	8.37	+	4.74	38,595,840
CSP	113,500	8.76	+	3.07	1,342,705

EQUALIZATION CAPACITY RATE: 13.4476

(This is the average $/kW rate paid by deficit members.)

NOTES:

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** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,353,000	0.35600	9,455,300	(3,102,300)
KPCO	1,453,000	0.07173	1,905,100	(452,100)
I&M	5,429,000	0.18190	4,831,300	597,700
OPCO	8,467,000	0.21001	5,577,900	2,889,100
CSP	4,858,000	0.18036	4,790,400	67,600
TOTAL	26,560,000	1.00000	26,560,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(3,102,300)	*****	+	*****	(40,966,960)
KPCO	(452,100)	*****	+	*****	(5,970,139)
I&M	597,700	10.01	+	4.46	8,648,719
OPCO	2,889,100	10.67	+	2.33	37,558,300
CSP	67,600	9.58	+	1.22	730,080

EQUALIZATION CAPACITY RATE: 13.2054
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,348,000	0.34793	9,250,700	(2,902,700)
KPCO	1,470,000	0.06944	1,846,300	(376,300)
I&M	5,430,000	0.18599	4,945,100	484,900
OPCO	8,483,000	0.21223	5,642,800	2,840,200
CSP	4,857,000	0.18441	4,903,100	(46,100)
TOTAL	26,588,000	1.00000	26,588,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,902,700)	*****	+	*****	(37,770,159)
KPCO	(376,300)	*****	+	*****	(4,896,445)
I&M	484,900	9.92	+	4.51	6,997,107
OPCO	2,840,200	10.6	+	2.17	36,269,354
CSP	(46,100)	*****	+	*****	(599,857)

EQUALIZATION CAPACITY RATE: 13.0121

(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

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

INTERROGATORY

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

RESPONSE:

See FES INT-6-009 Attachment 1

Prepared by: Philip J Nelson

AEP EAST SYSTEM
CAPACITY EQUALIZATION SETTLEMENT

[redacted]

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

AEP EAST SYSTEM
CAPACITY EQUALIZATION SETTLEMENT

[redacted]

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

AEP EAST SYSTEM
CAPACITY EQUALIZATION SETTLEMENT

[redacted]

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

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO FIRSTENERGY SOLUTIONS DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO TENTH SET

INTERROGATORY

INT-10-2. In a press release issued June 9, 2011, AEP issued a "Plan for Compliance With Proposed EPA Regulations," which stated, in part, that "The cost of AEP's compliance plan could range from $6 billion to $8 billion in capital investment through the end of the decade."

a. Please provide a detailed description of what portion of the $6 billion in capital investment referenced above pertains to Ohio Power Company and the Columbus Southern Power Company.

b. Please provide a detailed description of what portion of the $8 billion in capital investment referenced above pertains to Ohio Power Company and the Columbus Southern Power Company.

c. Please provide the specific amount of capital investment applicable to each of Ohio Power Company and the Columbus Southern Power Company, by year from 2011 to 2020 under the $6 billion capital investment scenario referenced above.

d. Please provide the specific amount of capital investment applicable to each of Ohio Power Company and the Columbus Southern Power Company, by year from 2011 to 2020 under the $8 billion capital investment scenario referenced above.

e. Please provide by generation plant, the plant name, the expected timing, and the specific milestones relating to each environmental investment under the $6 billion capital investment scenario referenced above, for each of Ohio Power Company and the Columbus Southern Power Company.

INT-10-2 (CONTINUED)

f. Please provide by generation plant, the plant name, the expected timing, and the specific milestones relating to any environmental investment under the $8 billion capital investment scenario referenced above, for each of Ohio Power Company and the Columbus Southern Power Company.

RESPONSE

a. and b. The $6 billion to $8 billion range AEP provided in its June 9, 2011 press release was based on setting bounds around a single base plan point estimate The point estimates for Columbus Southern Power and Ohio Power Company are $671.8 million and $1.89 billion, respectively (total of $2.56 billion for AEP Ohio Companies). The lower bounds are approximately $550 million for Columbus Southern Power and $1.55 billion for Ohio Power Company (total $2.1 billion for AEP Ohio Companies). The upper bounds are approximately $740 million for Columbus Southern Power and $2.06 billion for Ohio Power Company (total $2.8 billion for AEP Ohio Companies)

c. Please see FES INT 10-2 Attachment 1 for capital investment by year from 2012 through 2020; capital for these projects was not forecasted for 2011.

d. Please see FES INT 10-2 Attachment 2 for capital investment by year from 2012 through 2020; capital for these projects was not forecasted for 2011

e. Please see FES INT 10-2 CONFIDENTIAL Attachment 3

f. Please see FES INT 10-2 CONFIDENTIAL Attachment 4

Please note that these estimates provided in parts a through f. were prepared based on the best available information at the time without the benefit of detailed engineering. In addition, high demand for labor and materials due to a constrained compliance timeframe could result in actual costs different than these estimates. Finally, the comliance plan could change significantly depending on the final form of the proposed EPA regulations and regulatory approvals from state commissions.

Prepared By: Philip J. Nelson

2012-2020 AEP Ohio Generation Capital
(post-allocated, capital, owned-view, $000's, less AFUDC)
(data as of May 27, 2011)
Environmental Capital only

Operating Co	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
144 Columbus Southern Power	63,406	107,103	138,354	123,551	52,085	14,617	32,370	13,797	4,718	550,000
181 Ohio Power Co	80,409	331,262	346,729	216,029	241,895	167,455	102,109	33,725	26,756	1,546,370
Total	**143,815**	**438,365**	**485,083**	**339,580**	**293,980**	**182,072**	**134,479**	**47,522**	**31,474**	**2,096,370**

2012-2020 AEP Ohio Generation Capital
(post-allocated, capital, owned-view, $000's, less AFUDC)
(data as of May 27, 2011)
Environmental Capital only

Operating Co	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
144 Columbus Southern Power	85,310	144,102	186,150	166,233	70,078	19,666	43,552	18,563	6,348	740,000
181 Ohio Power Co	106,867	440,258	460,814	287,109	321,487	222,553	135,706	44,822	35,560	2,055,175
Total	**192,176**	**584,361**	**646,963**	**453,342**	**391,564**	**242,219**	**179,258**	**63,385**	**41,908**	**2,795,176**

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO FIRSTENERGY SOLUTIONS DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO TENTH SET

INTERROGATORY

INT-10-3. In his direct testimony at p. 30, Mr Nelson states that "the Company will compare the lost AEP Pool capacity revenue to increases in net revenue related to new wholesale transaction or decreases in generation asset costs that result from the FERC proceeding related to the AEP Pool." Does the Company propose to credit any incremental energy sales revenue against the lost AEP Pool capacity revenue as a result of pool termination or modification for the purpose of calculating the proposed Pool Termination or Modification Provision?

RESPONSE

Yes, if the pool termination or modification produces additional net sales revenue, including energy sales net revenue, that would not exist absent the termination or modification, the Company plans to factor such additional net sales revenue into the determination of whether the Company will avail itself of the Pool Termination or Modification Provision

Prepared By: Philip J. Nelson

COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
FIRSTENERGY SOLUTIONS
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
TENTH SET

INTERROGATORY

INT-10-5 Referencing OCC INT-134 (4th Set), please provide th

a) As of 12/31/2010, and

b) As of each unit's retirement date identified in Your LTFR.

RESPONSE

a) See FES 10-05 Attachment 1. While the Company keeps unit data separately for some specific plants or units, most of the property data for generating stations is by plant and property data that is common to all units is by plants. The amounts for Muskingum River Plant are for Units 1 to 4 which are kept together in one location. The Company has a separate location for Muskingum Unit 5 and Conesville Unit 3 in its property records. The totals for units do not include some common plant such as asset retirement obligations which are not maintained at separate locations

b) See a) above.

Prepared by: Thomas E Mitchell

Ohio Power Company
Muskingum Generating Plant Units 1 to 4, Original Cost, Accumulated Depreciation and Net Book Value
Electric Plant In Service Accounts 101 and 106, by General Ledger Account
At December 31, 2010

GL Acct	Plant Acct	Location	Original Cost	Accum. Depr.	Net Book Value
1010001	31000	Muskingum U 1-4	$241,167.00	$0.00	$241,167.00
1010001	31010	Muskingum U 1-4	$57,656.00	$0.00	$57,656.00
1010001	31100	Muskingum U 1-4	$27,209,889.95	$21,569,948.79	$5,639,941.16
1010001	31200	Muskingum U 1-4	$193,755,409.47	$108,949,608.69	$84,805,800.78
1010001	31400	Muskingum U 1-4	$57,706,109.11	$36,927,525.92	$20,778,583.19
1010001	31500	Muskingum U 1-4	$18,908,570.78	$8,495,636.35	$10,412,934.43
1010001	31600	Muskingum U 1-4	$8,466,360.59	$5,426,388.32	$3,039,972.27
1010001 Total			**$306,345,162.90**	**$181,369,108.07**	**$124,976,054.83**
1060001	31100	Muskingum U 1-4	$143,344.52	$12,611.28	$130,733.24
1060001	31200	Muskingum U 1-4	$2,684,046.06	$190,629.73	$2,493,416.33
1060001	31500	Muskingum U 1-4	$9,664.12	$530.99	$9,133.13
1060001	31600	Muskingum U 1-4	$79,639.70	$6,659.44	$72,980.26
1060001 Total			**$2,916,694.40**	**$210,431.44**	**$2,706,262.96**
Grand Total			**$309,261,857.30**	**$181,579,539.51**	**$127,682,317.79**

Ohio Power Company
Muskingum Generating Plant Units 1 to 4, By Plant Account
Electric Plant In Service Accounts 101 and 106 Combined
At December 31, 2010

Plant Acct	Location	Original Cost	Accum. Depr. Dec 2010	Monthly Depreciation Exp at Dec 2010
31000	Muskingum U 1-4	$241,167.00	$0.00	$0.00
31010	Muskingum U 1-4	$57,656.00	$0.00	$0.00
31100	Muskingum U 1-4	$27,353,234.47	$21,582,560.07	$96,178.01
31200	Muskingum U 1-4	$196,439,455.53	$109,140,238.42	$1,440,133.83
31400	Muskingum U 1-4	$57,706,109.11	$36,927,525.92	$173,701.13
31500	Muskingum U 1-4	$18,918,234.90	$8,496,167.34	$346,309.72
31600	Muskingum U 1-4	$8,546,000.29	$5,433,047.76	$50,555.21
		$309,261,857.30	**$181,579,539.51**	**$2,106,877.90**

Combines accounts 101 and 106 and indicates the monthly depreciation expense based on December 2010 actual.

Ohio Power Company
Muskingum Generating Plant Units 1 to 4, By Plant Account
Estimated Original Cost, Accumulated Depreciation and Net Book Value
At June 1, 2012 - the Estimated Retirement Date In the LTFR for Units 2 and 4

Plant Acct	Location	Original Cost	Estimated Accum. Depr. June 1, 2012	Estimated Net Book Value
31000	Muskingum U 1-4	$241,167.00	$0.00	$241,167.00
31010	Muskingum U 1-4	$57,656.00	$0.00	$57,656.00
31100	Muskingum U 1-4	$27,353,234.47	$23,217,586.24	$4,135,648.23
31200	Muskingum U 1-4	$196,439,455.53	$133,622,513.53	$62,816,942.00
31400	Muskingum U 1-4	$57,706,109.11	$39,880,445.13	$17,825,663.98
31500	Muskingum U 1-4	$18,918,234.90	$14,383,432.58	$4,534,802.32
31600	Muskingum U 1-4	$8,546,000.29	$6,292,486.33	$2,253,513.96
		$309,261,857.30	**$217,396,463.81**	**$91,865,393.49**

This calculation uses the accumulated depreciation at December 2010 and adds to that amount 17 months of monthly depreciation using the amount of monthly depreciation at December 2010. No additions or retirements of electric utility plant were estimated in making the above calculation of the estimated net book value at June 1, 2012.

Ohio Power Company
Muskingum Generating Plant Units 1 to 4, By Plant Account
Estimated Original Cost, Accumulated Depreciation and Net Book Value
At June 1, 2014 - the Estimated Retirement Date In the LTFR for Units 1 and 3

Plant Acct	Location	Original Cost	Estimated Accum. Depr. June 1, 2014	Estimated Net Book Value
31000	Muskingum U 1-4	$241,167.00	$0.00	$241,167.00
31010	Muskingum U 1-4	$57,656.00	$0.00	$57,656.00
31100	Muskingum U 1-4	$27,353,234.47	$25,525,858.48	$1,827,375.99
31200	Muskingum U 1-4	$196,439,455.53	$168,185,725.45	$28,253,730.08
31400	Muskingum U 1-4	$57,706,109.11	$44,049,272.25	$13,656,836.86
31500	Muskingum U 1-4	$18,918,234.90	$22,694,865.86	-$3,776,630.96
31600	Muskingum U 1-4	$8,546,000.29	$7,505,811.37	$1,040,188.92
		$309,261,857.30	**$267,961,533.41**	**$41,300,323.89**

This calculation uses the accumulated depreciation at December 2010 and adds to that amount 41 months of monthly depreciation using the amount of monthly depreciation at December 2010. No additions or retirements of electric utility plant were estimated in making the above calculation of the estimated net book value at June 1, 2014.

Ohio Power Company
Muskingum Generating Plant Units 1 to 4, By Plant Account
Estimated Original Cost, Accumulated Depreciation and Net Book Value
At December 31, 2014 - the Final Shutdown Dates for Units 2 and 4

Plant Acct	Location	Original Cost	Estimated Accum. Depr. Dec 31, 2014	Estimated Net Book Value
31000	Muskingum U 1-4	$241,167.00	$0.00	$241,167.00
31010	Muskingum U 1-4	$57,656.00	$0.00	$57,656.00
31100	Muskingum U 1-4	$27,353,234.47	$26,199,104.55	$1,154,129.92
31200	Muskingum U 1-4	$196,439,455.53	$178,266,662.26	$18,172,793.27
31400	Muskingum U 1-4	$57,706,109.11	$45,265,180.16	$12,440,928.95
31500	Muskingum U 1-4	$18,918,234.90	$25,119,033.90	-$6,200,799.00
31600	Muskingum U 1-4	$8,546,000.29	$7,859,697.84	$686,302.45
		$309,261,857.30	**$282,709,678.71**	**$26,552,178.59**

This calculation uses the accumulated depreciation at December 2010 and adds to that amount 48 months of monthly depreciation using the amount of monthly depreciation at December 2010. No additions or retirements of electric utility plant were estimated in making the above calculation of the estimated net book value at December 31, 2014. The retirement dates in the LTFR represent when the units capacity is assumed to be removed from the AEP East capacity mix. The units may be available for energy after the dates in the LTRF and Muskingum River Units 2 and 4 are expected to provide energy value until December 2014.

Columbus Southern Power Company
Conesville Generating Plant Unit 3, Original Cost, Accumulated Depreciation and Net Book Value
Electric Plant In Service Accounts 101 and 106, by General Ledger Account
At December 31, 2010

GL Acct	Plant Acct	Location	Original Cost	Accum. Depr.	Net Book Value
1010001	31100	Conesville Generating Plant Unit 3	$3,484,697.00	$3,174,612.07	$310,084.93
1010001	31200	Conesville Generating Plant Unit 3	$28,130,598.66	$23,380,533.29	$4,750,065.37
1010001	31400	Conesville Generating Plant Unit 3	$10,794,977.00	$9,289,217.77	$1,505,759.23
1010001	31500	Conesville Generating Plant Unit 3	$3,218,773.00	$2,913,560.55	$305,212.45
1010001	31600	Conesville Generating Plant Unit 3	$1,385,424.00	$1,207,645.32	$177,778.68
1010001 Total			**$47,014,469.66**	**$39,965,569.00**	**$7,048,900.66**
1060001	31200	Conesville Generating Plant Unit 3	$24,518.47	$4,446.88	$20,071.59
1060001 Total			**$24,518.47**	**$4,446.88**	**$20,071.59**
Grand Total			**$47,038,988.13**	**$39,970,015.88**	**$7,068,972.25**

Columbus Southern Power Company
Conesville Generating Plant Unit 3, By Plant Account
Electric Plant In Service Accounts 101 and 106 Combined
At December 31, 2010

Plant Acct	Location	Original Cost	Accum. Depr.	Monthly Depreciation Exp at Dec 2010
31100	Conesville Generating Plant Unit 3	$3,484,697.00	$3,174,612.07	$12,920.21
31200	Conesville Generating Plant Unit 3	$28,155,117.13	$23,384,980.17	$197,734.10
31400	Conesville Generating Plant Unit 3	$10,794,977.00	$9,289,217.77	$62,739.97
31500	Conesville Generating Plant Unit 3	$3,218,773.00	$2,913,560.55	$12,717.19
31600	Conesville Generating Plant Unit 3	$1,385,424.00	$1,207,645.32	$7,407.45
		$47,038,988.13	**$39,970,015.88**	**$293,518.92**

Combines accounts 101 and 106 and indicates the monthly depreciation expense based on December 2010 actual.

Columbus Southern Power Company
Estimated Original Cost, Accumulated Depreciation and Net Book Value
At June 1, 2012 - the Estimated Retirement Date In the LFTR for Unit 3

Plant Acct	Location	Original Cost	Estimated Accum. Depr. June 1, 2012	Estimated Net Book Value
31100	Conesville Generating Plant Unit 3	$3,484,697.00	$3,394,255.64	$90,441.36
31200	Conesville Generating Plant Unit 3	$28,155,117.13	$26,746,459.87	$1,408,657.26
31400	Conesville Generating Plant Unit 3	$10,794,977.00	$10,355,797.26	$439,179.74
31500	Conesville Generating Plant Unit 3	$3,218,773.00	$3,129,752.78	$89,020.22
31600	Conesville Generating Plant Unit 3	$1,385,424.00	$1,333,571.97	$51,852.03
		$47,038,988.13	**$44,959,837.52**	**$2,079,150.61**

This calculation uses the accumulated depreciation at December 2010 and adds to that amount 17 months of monthly depreciation using the amount of monthly depreciation at December 2010. No additions or retirements of electric utility plant were estimated in making the above calculation of the estimated net book value at June 1, 2012.

Columbus Southern Power Company
Estimated Original Cost, Accumulated Depreciation and Net Book Value
At December 31, 2012 - the Final Shutdown Date for Unit 3

Plant Acct	Location	Original Cost	Estimated Accum. Depr. Dec 31, 2012	Estimated Net Book Value
31100	Conesville Generating Plant Unit 3	$3,484,697.00	$3,484,697.11	-$0.11
31200	Conesville Generating Plant Unit 3	$28,155,117.13	$28,130,598.57	$24,518.56
31400	Conesville Generating Plant Unit 3	$10,794,977.00	$10,794,977.05	-$0.05
31500	Conesville Generating Plant Unit 3	$3,218,773.00	$3,218,773.11	-$0.11
31600	Conesville Generating Plant Unit 3	$1,385,424.00	$1,385,424.12	-$0.12
		$47,038,988.13	**$47,014,469.96**	**$24,518.17**

This calculation uses the accumulated depreciation at December 2010 and adds to that amount 24 months of monthly depreciation using the amount of monthly depreciation at December 2010. No additions or retirements of electric utility plant were estimated in making the above calculation of the estimated net book value at December 31, 2012. The retirement dates in the LTFR represent when the units capacity is assumed to be removed from the AEP East capacity mix. The unit may be available for energy after the dates in the LTRF and Conesville Unit 3 is expected to provide energy value until December 2012.

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO FIRSTENERGY SOLUTIONS DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO TENTH SET

INTERROGATORY

INT-10-9 Referencing the Direct Testimony of Thomas Mitchell at 12, lines 1-2, please provide the estimated "asset retirement obligations (ARO)" for Conesville 3, Muskingum River 2, and Muskingum River 4 as of the following dates:

a) As of 12/31/2010, and
b) As of each unit's retirement date identified in Your LTFR.

RESPONSE

a) See the ARO for the requested units in FES 10-09 Attachment 1. The ash Pond ARO amounts are not unit specific Therefore, the information is not available which would provide a unit specific ARO liability balance.

b) See FES 10-09 Attachment 1

Prepared by: Thomas E. Mitchell

Ohio Power Company
Muskingum River Generating Plant
Asset Retirement Obligation - Liability Balance
At June 1, 2014

Asset Retirement Obligation	Estimated June 1, 2014 Amount
ARO Muskingum River U 1 Asbestos	$510,853.31
ARO Muskingum River U0 Asbestos	$951,966.28
ARO Muskingum River U2 Asbestos	$680,288.62
ARO Muskingum River U3 Asbestos	$1,012,960.29
ARO Muskingum River U4 Asbestos	$1,088,242.04
ARO Muskingum River U5 Asbestos	$2,498,458.85
ASH#1 Muskingum Ash Pond	$1,281,481.45
ASH#2 Muskingum Ash Pond	$4,899,732.87
ASH#3 Muskingum Ash Pond	$751,700.80
ASH#4 Muskingum Ash Pond	$20,810,518.87
	$34,486,203.38

Ohio Power Company
Muskingum River Generating Plant
Asset Retirement Obligation - Liability Balance
At June 1, 2012

Asset Retirement Obligation	Estimated June 1, 2012 Amount
ARO Muskingum River U 1 Asbestos	$429,367.47
ARO Muskingum River U0 Asbestos	$848,783.59
ARO Muskingum River U2 Asbestos	$571,776.25
ARO Muskingum River U3 Asbestos	$851,383.71
ARO Muskingum River U4 Asbestos	$914,657.30
ARO Muskingum River U5 Asbestos	$2,119,910.68
ASH#1 Muskingum Ash Pond	$1,077,073.22
ASH#2 Muskingum Ash Pond	$4,118,179.85
ASH#3 Muskingum Ash Pond	$631,797.54
ASH#4 Muskingum Ash Pond	$17,491,047.42
	$29,053,977.03

Ohio Power Company
Muskingum River Generating Plant
Asset Retirement Obligation - Liability Balance
At December 31, 2010

Asset Retirement Obligation	Dec 2010 Amount
ARO Muskingum River U 1 Asbestos	$412,835.89
ARO Muskingum River U0 Asbestos	$778,804.65
ARO Muskingum River U2 Asbestos	$559,213.93
ARO Muskingum River U3 Asbestos	$761,282.43
ARO Muskingum River U4 Asbestos	$810,513.82
ARO Muskingum River U5 Asbestos	$1,895,800.34
ASH#1 Muskingum Ash Pond	$945,463.80
ASH#2 Muskingum Ash Pond	$3,614,972.44
ASH#3 Muskingum Ash Pond	$554,597.12
ASH#4 Muskingum Ash Pond	$15,353,786.53
	$25,687,270.95

Columbus Southern Power Company
Conesville Plant
Asset Retirement Obligation - Liability Balance
At June 1, 2012

Asset Retirement Obligation	Estimated June 1, 2012 Amount
ARO Conesville U0 Asbestos	$574,621.30
ARO Conesville U1 Asbestos	$812,898.08
ARO Conesville U2 Asbestos	$798,445.94
ARO Conesville U3 Asbestos	$646,135.26
ARO Conesville U4 Asbestos	$94,955.03
ARO Conesville U5 Asbestos	$113,131.95
ARO Conesville U6 Asbestos	$81,015.65
ASH#1 Conesville Ash Pond	$24,743,543.25
ASH#2 Conesville Ash Pond	$16,814,090.29
	$44,678,836.75

Columbus Southern Power Company
Conesville Plant
Asset Retirement Obligation - Liability Balance
At December 31, 2010

Asset Retirement Obligation	Dec 2010 Amount
ARO Conesville U0 Asbestos	$527,245.97
ARO Conesville U1 Asbestos	-$22,773.94
ARO Conesville U2 Asbestos	$434,276.18
ARO Conesville U3 Asbestos	$585,582.07
ARO Conesville U4 Asbestos	$80,627.22
ARO Conesville U5 Asbestos	$100,971.15
ARO Conesville U6 Asbestos	$71,585.63
ASH#1 Conesville Ash Pond	$22,484,828.73
ASH#2 Conesville Ash Pond	$17,183,664.45
	$41,446,007.46

Responses to Interrogatories
From Industrial Energy Users (IEU)

IEU 1-013
IEU 1-022
IEU 1-023
IEU 1-034
IEU 2-073
IEU 2-082
IEU 2-090
IEU 2-091 (& attachment)
IEU 2-092 (& attachment)
IEU 2-100
IEU 3-113
IEU 3-129

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO FIRST SET

INTERROGATORY

INT-013. Has CSP or OP prepared any estimates of the annual revenues or rates to be collected through the Alternative Energy Rider in 2012, 2013, or 2014?

RESPONSE

No.

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO FIRST SET

INTERROGATORY

INT-022. Has CSP or OP prepared any estimates of the annual revenues or rates to be collected through the NERC Compliance Rider in 2012, 2013, or 2014?

RESPONSE

No such estimates have been prepared at this time

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO FIRST SET

INTERROGATORY

INT-023. Does CSP or OP have any workpapers or documents to support its calculation of the annual revenues or rates to be collected through the NERC Compliance Rider in 2012, 2013, or 2014? If yes, please identify the documents or workpapers in AEP's possession and the individuals that were responsible for the calculations in those documents or workpapers.

RESPONSE

See IEU INT-022

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

INTERROGATORY

INT-034. Besides the riders listed in Interrogatories Nos. 13-33, are there any riders in the ESP filing that CSP or OP has not provided the annual revenues or rates to be recovered in 2012, 2013, or 2014? If the answer is yes, please identify those riders

RESPONSE

Yes, the Carbon Capture and Sequestration Rider.

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO SECOND SET

INTERROGATORY

INT-073. With regard to AEP's ESP proposal regarding recovery of environmental compliance costs, please identify the total dollar amount of such environmental compliance costs that AEP expects to recover from Ohio retail consumers within its certified service area during the proposed term of the ESP if its ESP is approved by the Commission as proposed.

RESPONSE

The Company has not calculated the total dollar amount of such environmental compliance costs for the 29 month ESP period.

Prepared by: Nelson

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO SECOND SET

INTERROGATORY

INT-082. Regarding the CCS facility being developed at Appalachian Power Company's Mountaineer plant site, identify any costs that CSP or OP will directly incur to implement this project.

RESPONSE

Once an agreement is entered into between Appalachian Power Company and other operating companies of AEP, AEP Ohio will be billed its share of Capital and O&M costs associated with the facility.

Prepared by: Nelson

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO SECOND SET

INTERROGATORY

INT-090. On page 8 of Laura Thomas' testimony, she states that she has included a component in the Competitive Benchmark price called a transaction risk adder. What are the components for determining that amount?

RESPONSE

The amount of the Transaction Risk Adder identified on page 8 of Company witness Thomas' testimony was based on a review of the experiences of various deregulated states and reflects a reasonable and balanced approach to determining a Competitive Benchmark price. See IEU INT-091 Attachments 2 and 3 for the analysis used to support the amount of the Transaction Risk Adder. See page 8 of Company witness Thomas' testimony for a listing of the types of items covered by the Transaction Risk Adder.

Prepared by: Thomas

COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
SECOND SET

<u>INTERROGATORY</u>

INT-091. Identify any supporting workpapers for interrogatories 89 and 90.

<u>RESPONSE</u>

See IEU INT-091 Attachment 1 for analysis regarding the Retail Administration Charge.
See IEU INT-091 Attachment 2 for analysis regarding the Transaction Risk Adder.
See IEU INT-091 Attachment 3 for analysis regarding a review of the Full Requirements Service components in various deregulated states.

Prepared by: Thomas

IEU INT-91 Attachment 3.pdf

IEU INT-91 Attachment 1.pdf

IEU INT-91 Attachment 2.pdf

TRANSACTION RISK ADDER - SUPPORTING ANALYSES

STATE	ENTITY / FORUM	AMOUNT / DESCRIPTION	DATE	RATIONALE
Ohio	FE ESP Filing	FE forecasted a Risk-Adder/Margin value of $10.75 to $21.73, or 13% to 22%.	2008	The estimated value of the Risk-Adder/Margin component of competitive FRS was based on a review of various auction results.
Ohio	Duke Ohio ESP Filing	Duke Ohio's forecasted FRS price included an Ask Adder and a Margin/Operating Risk Adjustment totaling $16.56, or roughly 18%.	2008	The Margin/Operating Risk Adjustment, which accounted for $13.93, was based on Value Line estimates of operating margin for all industries and which equaled 15%. This pricing component does not include sales, general and administrative costs.
Ohio	Duke Ohio MRO Filing	DE Ohio's forecasted FRS price included an Ask Adder and a Margin/Operating Risk Adjustment totaling $9.90, or roughly 17%.	2010	The Margin/Operating Risk Adjustment, which accounts for $9.10, is based on *Value Line estimates of operating margin for 2002-2007 for all industries and* which equaled 18.6%. This does pricing component does not include sales, general and administrative costs.
Maryland	Maryland Order No. 78710 - Price Anomaly Threshold	For competitive purposes the amount of the eight component of the PAT, the Transaction Cost and Risk Adder, is not publicly disclosed. However, the docket in which it *was approved suggests it is more than just* an immaterial percent or two.	2002 through the present	The PAT is actually a number, or price point, determined by the Commission Staff, the utilities and the Commission's SOS consultant. The objective in the PAT determination is to define the highest reasonable wholesale market prices for full service SOS according to current market conditions. The mechanism is *intended to work as a gross target designed to prevent irregular or out of market* bids from being included in a utility's SOS supply portfolio.
Maryland	Resource Insight, Inc. - Risk Analysis of Procurement Strategies for Residential Standard Offer Service	Risk and Transaction-Cost Adder; first year of contract - 5%; second year of contract - 10%	2008	Estimates of Risk and Transaction-Cost Adder were based on a user-defined percentage adder (Maryland Office of People's Counsel)
Research Report: "The Ethics of Dynamic Pricing"	*Ahmad Faruqui*, Ph.D., Principal The Brattle Group	Estimated Risk Premium for FRS at 15%	2010	The estimated risk premium was based on an analysis of recent auctions in the North East for FRS default service.
Pennsylvania	The NorthBridge Group, on behalf of PECO Energy Company.	Residual Compensation for recent 1 year auctions estimated at 4.5%. Residual Compensation for recent 3 year auctions estimated at roughly 7.3%.	2008	Mr. Fisher's analysis included auctions conducted in New Jersey, Delaware, Illinois, and Pennsylvania.
New Jersey, Maryland, Delaware, and Illinois	The Brattle Group - Trends in POLR Procurement	Auction bids were typically $2-$15/MWh higher, or 5-20% above estimates of the "no-risk" cost. (Premiums as high as 40+% for large customers.)	2008	Auctions have benefits but fixed-price FRS prices appear to contain a significant risk premium.
Rhode Island	Analysis of Standard Offer Service Approaches for Mass Market Customers by The NorthBridge Group	Residual Compensation for recent 1 year auctions estimated at 4.5%, or $4/MWh	2010	Standard Offer Service involves many costs and risks including: mismatch between revenues and supply costs, customer migration, unexpected congestion, uncertain load and price levels, uncertain load and price shapes, adverse selection, collateral requirements.

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO SECOND SET

INTERROGATORY

INT-092. In workpapers to Laura Thomas' testimony, she provides a capacity cost per MWH. Identify workpapers used to calculate the conversions to support this calculation.

RESPONSE

The requested calculation is provided in the attached, IEU INT-092 Attachment 1. The calculation converts the Company's 2012 Residential capacity cost ($/mw-day) to the capacity rate ($/MWh) as included in Company witness Thomas' testimony. This same methodology applies to each class for the 2012 and Jan 2013 - May 2014 time periods.

Prepared by: Thomas

IEU INT-092
Attachment 1

		Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
AEP Ohio FRR *including reserve margin	$/mw-day	347.97	347.97	347.97	347.97	347.97	347.97	347.97	347.97	347.97	347.97	347.97	347.97
Capacity Obligation	mw	3,744	3,744	3,744	3,744	3,744	3,658	3,658	3,658	3,658	3,658	3,658	3,658
Capacity Diversity		88%	88%	88%	88%	88%	88%	88%	88%	88%	88%	88%	88%
Days in Month		31.00	29.00	31.00	30.00	31.00	30.00	31.00	31.00	30.00	31.00	30.00	31.00
Discount Factor		0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Capacity Cost		$35,396,864	$33,089,881	$35,350,580	$34,182,675	$35,297,175	$33,348,188	$34,431,965	$34,400,657	$33,260,660	$34,338,040	$33,196,897	$34,268,467

Total Capacity Cost	*$410,561,847.95*
Forecasted Energy	14,407,872
Capacity Rate ($/MWh)	$28.50

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO SECOND SET

INTERROGATORY

INT-100. In Laura Thomas' testimony at page 26, she provides support for "NERC Generation Compliance Costs".

a. What expenses or capital costs categories does AEP anticipate would be covered by this rider?

b. Does AEP have any expenses or capital costs booked but deferred for this rider?

c. What is the amount of expenses, if any, currently booked but deferred?

d. Over what period of time were expenses or capital costs, if any, booked but deferred? Identify amounts by year.

RESPONSE

a. The Company is unable to determine the exact nature of such costs at this time.

b. No.

c. See IEU INT-100 b.

d. See IEU INT-100 b.

Prepared by: Thomas

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

INTERROGATORY

INT-113. In Laura Thomas's testimony and supporting exhibits, she provides a fuel cost that is constant Has the company attempted a calculation of the electric security plan ("ESP") and market rate offer ("MRO") alternative based on expected changes in the FAC for 2012, 2013, and 2014?

RESPONSE

No, the Company has prepared no such calculation

Prepared by: Laura J Thomas

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

INTERROGATORY

INT-129. What is the estimated level of weighted average cost of capital to be used for the Facility Closure Cost Recovery Rider?

RESPONSE

The Facility Closure Recovery Rider will use a pre-tax WACC, estimated to be 11 77% as described in Company witness Hawkins' testimony.

Prepared By: Andrea E Moore

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

INTERROGATORY

INT-129. What is the estimated level of weighted average cost of capital to be used for the Facility Closure Cost Recovery Rider?

RESPONSE

The Facility Closure Recovery Rider will use a pre-tax WACC, estimated to be 11 77% as described in Company witness Hawkins' testimony.

Prepared By: Andrea E Moore

Responses to Interrogatories
From Ohio Consumers' Council (OCC)

OCC 3-074
OCC 4-139
OCC 4-140

RPD 1-24 (& attachment)

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO
THIRD SET**

INTERROGATORY

INT-074. Please identify the earliest date that the AEP Pool can be terminated.

RESPONSE

The earliest date the pool can be terminated is January 1, 2014, unless the members all agree to terminate the AEP Pool earlier. It is more likely that the members will not terminate earlier than June 1, 2014, so that the termination coincides with the PJM planning year.

Prepared By: Philip J. Nelson

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FOURTH SET**

INTERROGATORY

INT-139. What was the actual total margin (profit) from all off-system sales each year, for the years 2000 through present for CSP and for OPCo?

RESPONSE

OPCo & CSP 's OSS margins ($000)

	OPCo	CSP
2010	81,304	73,533
2009	61,879	51,268
2008	181,498	146,560
2007	171,392	142,730
2006	199,737	133,501
2005	145,062	89,921
2004	96,988	64,849
2003	73,629	53,373
2002	77,282	57,333
2001	106,151	75,036
2000	136,352	89,001

Prepared By: Philip J. Nelson

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO THE OFFICE OF THE OHIO CONSUMERS' COUNSEL DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO FOURTH SET

INTERROGATORY

INT-140. What is the most recent estimate of the total margin (profits) from all off-system sales each year, for each year of the ESP term proposed for CSP and for OPCo?

RESPONSE

OSS Pre Tax Margins

	$000		
Period	**CSP**	**OPC**	**Total**
2012	130,254	83,791	214,045
2013	147,378	107,615	254,993
Jan - May 2014	70,767	55,992	126,759

Prepared By: Philip J. Nelson

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FIRST SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-024 Please provide a copy of all source documents from which the information OCC requested in INT-26 would be derived.

RESPONSE

See OCC RPD 1-24 Confidential Attachment 1 for the requested information.

Prepared by: Laura J. Thomas

See COMPETITIVELY SENSITIVE CONFIDENTIAL attachment, RPD 1-24 Attachment 1

Responses to Interrogatories From Ohio Energy Group (OEG)

OEG 3-003 (& attachment)

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

INTERROGATORY

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

RESPONSE

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

CALCULATION OF MEMBER PRIMARY CAPACITY
SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,348,000	0.33372	8,873,000	(2,525,000)
KPCO	1,470,000	0.06979	1,855,600	(385,600)
I&M	5,430,000	0.19041	5,062,600	367,400
OPCO	8,483,000	0.21728	5,777,000	2,706,000
CSP	4,857,000	0.18880	5,019,800	(162,800)
TOTAL	26,588,000	1.00000	26,588,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(2,525,000)	*****	+	*****	(33,877,150)
KPCO	(385,600)	*****	+	*****	(5,173,477)
I&M	367,400	9.92	+	5.24	5,569,784
OPCO	2,706,000	10.6	+	2.58	35,665,080
CSP	(162,800)	*****	+	*****	(2,184,238)

EQUALIZATION CAPACITY RATE: 13.4167
(This is the average $/kW rate paid by deficit members.)

NOTES:
* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,348,000	0.33392	8,878,400	(2,530,400)
KPCO	1,470,000	0.06925	1,841,200	(371,200)
I&M	5,430,000	0.19052	5,065,500	364,500
OPCO	8,483,000	0.21740	5,780,200	2,702,800
CSP	4,857,000	0.18891	5,022,700	(165,700)
TOTAL	26,588,000	1.00000	26,588,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,530,400)	*****	+	*****	(33,288,377)
KPCO	(371,200)	*****	+	*****	(4,883,278)
I&M	364,500	9.92	+	4.61	5,296,185
OPCO	2,702,800	10.6	+	2.37	35,055,316
CSP	(165,700)	*****	+	*****	(2,179,847)

EQUALIZATION CAPACITY RATE: 13.1554
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY
SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,348,000	0.33392	8,878,300	(2,530,300)
KPCO	1,470,000	0.06925	1,841,200	(371,200)
I&M	5,430,000	0.19052	5,065,600	364,400
OPCO	8,483,000	0.21740	5,780,200	2,702,800
CSP	4,857,000	0.18891	5,022,700	(165,700)
TOTAL	26,588,000	1.00000	26,588,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(2,530,300)	*****	+	*****	(33,690,044)
KPCO	(371,200)	*****	+	*****	(4,942,396)
I&M	364,400	9.92	+	4.69	5,323,884
OPCO	2,702,800	10.6	+	2.54	35,514,792
CSP	(165,700)	*****	+	*****	(2,206,237)

EQUALIZATION CAPACITY RATE: 13.3146
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY
SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,348,000	0.33392	8,878,300	(2,530,300)
KPCO	1,470,000	0.06925	1,841,200	(371,200)
I&M	5,430,000	0.19052	5,065,600	364,400
OPCO	8,483,000	0.21740	5,780,200	2,702,800
CSP	4,857,000	0.18891	5,022,700	(165,700)
TOTAL	26,588,000	1.00000	26,588,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,530,300)	*****	+	*****	(40,285,349)
KPCO	(371,200)	*****	+	*****	(5,909,940)
I&M	364,400	9.92	+	7.79	6,453,524
OPCO	2,702,800	10.6	+	5.08	42,379,904
CSP	(165,700)	*****	+	*****	(2,638,139)

EQUALIZATION CAPACITY RATE: 15.9212
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,355,000	0.33722	8,968,400	(2,613,400)
KPCO	1,470,000	0.06994	1,860,000	(390,000)
I&M	5,430,000	0.18474	4,913,200	516,800
OPCO	8,483,000	0.21955	5,838,900	2,644,100
CSP	4,857,000	0.18855	5,014,500	(157,500)
TOTAL	26,595,000	1.00000	26,595,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,613,400)	*****	+	*****	(35,815,700)
KPCO	(390,000)	*****	+	*****	(5,344,809)
I&M	516,800	9.92	+	6.52	8,496,192
OPCO	2,644,100	10.6	+	2.57	34,822,797
CSP	(157,500)	*****	+	*****	(2,158,480)

EQUALIZATION CAPACITY RATE: 13.7046

(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,377,100	0.32375	8,617,300	(2,240,200)
KPCO	1,470,000	0.06714	1,787,100	(317,100)
I&M	5,430,000	0.19468	5,181,800	248,200
OPCO	8,483,000	0.22780	6,063,400	2,419,600
CSP	4,857,000	0.18663	4,967,500	(110,500)
TOTAL	26,617,100	1.00000	26,617,100	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,240,200)	*****	+	*****	(29,669,203)
KPCO	(317,100)	*****	+	*****	(4,199,672)
I&M	248,200	9.92	+	6.58	4,095,300
OPCO	2,419,600	10.6	+	2.31	31,237,036
CSP	(110,500)	*****	+	*****	(1,463,462)

EQUALIZATION CAPACITY RATE: 13.2440

(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,379,000	0.32375	8,617,900	(2,238,900)
KPCO	1,470,000	0.06714	1,787,200	(317,200)
I&M	5,430,000	0.19468	5,182,200	247,800
OPCO	8,483,000	0.22780	6,063,800	2,419,200
CSP	4,857,000	0.18663	4,967,900	(110,900)
TOTAL	26,619,000	1.00000	26,619,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,238,900)	*****	+	*****	(29,761,680)
KPCO	(317,200)	*****	+	*****	(4,216,537)
I&M	247,800	9.92	+	5.55	3,833,466
OPCO	2,419,200	10.6	+	2.47	31,618,944
CSP	(110,900)	*****	+	*****	(1,474,193)

EQUALIZATION CAPACITY RATE: 13.2930

(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,379,000	0.32375	8,617,900	(2,238,900)
KPCO	1,470,000	0.06714	1,787,200	(317,200)
I&M	5,430,000	0.19468	5,182,200	247,800
OPCO	8,483,000	0.22780	6,063,800	2,419,200
CSP	4,857,000	0.18663	4,967,900	(110,900)
TOTAL	26,619,000	1.00000	26,619,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(2,238,900)	*****	+	*****	(29,413,963)
KPCO	(317,200)	*****	+	*****	(4,167,274)
I&M	247,800	9.92	+	5.05	3,709,566
OPCO	2,419,200	10.6	+	2.35	31,328,640
CSP	(110,900)	*****	+	*****	(1,456,969)

EQUALIZATION CAPACITY RATE: 13.1377

(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,379,000	0.32375	8,617,900	(2,238,900)
KPCO	1,470,000	0.06714	1,787,200	(317,200)
I&M	5,430,000	0.19468	5,182,200	247,800
OPCO	8,483,000	0.22780	6,063,800	2,419,200
CSP	4,857,000	0.18663	4,967,900	(110,900)
TOTAL	26,619,000	1.00000	26,619,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,238,900)	*****	+	*****	(29,663,803)
KPCO	(317,200)	*****	+	*****	(4,202,670)
I&M	247,800	9.92	+	5.47	3,813,642
OPCO	2,419,200	10.6	+	2.43	31,522,176
CSP	(110,900)	*****	+	*****	(1,469,345)

EQUALIZATION CAPACITY RATE: 13.2493
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,379,000	0.32375	8,617,900	(2,238,900)
KPCO	1,470,000	0.06714	1,787,200	(317,200)
I&M	5,430,000	0.19468	5,182,200	247,800
OPCO	8,483,000	0.22780	6,063,800	2,419,200
CSP	4,857,000	0.18663	4,967,900	(110,900)
TOTAL	26,619,000	1.00000	26,619,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,238,900)	*****	+	*****	(31,815,897)
KPCO	(317,200)	*****	+	*****	(4,507,572)
I&M	247,800	9.92	+	7.81	4,393,494
OPCO	2,419,200	10.6	+	3.25	33,505,920
CSP	(110,900)	*****	+	*****	(1,575,945)

EQUALIZATION CAPACITY RATE: 14.2105
(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY
SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,377,000	0.32728	8,705,000	(2,328,000)
KPCO	1,471,000	0.06852	1,822,500	(351,500)
I&M	5,428,000	0.19208	5,108,900	319,100
OPCO	8,465,000	0.22476	5,978,200	2,486,800
CSP	4,857,000	0.18736	4,983,400	(126,400)
TOTAL	26,598,000	1.00000	26,598,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,328,000)	*****	+	*****	(31,695,670)
KPCO	(351,500)	*****	+	*****	(4,785,665)
I&M	319,100	10.22	+	5.46	5,003,488
OPCO	2,486,800	10.8	+	2.55	33,198,780
CSP	(126,400)	*****	+	*****	(1,720,933)

EQUALIZATION CAPACITY RATE: 13.6150
(This is the average $/kW rate paid by deficit members.)

NOTES:
* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,377,000	0.32728	8,705,000	(2,328,000)
KPCO	1,471,000	0.06852	1,822,500	(351,500)
I&M	5,428,000	0.19208	5,108,900	319,100
OPCO	8,465,000	0.22476	5,978,200	2,486,800
CSP	4,857,000	0.18736	4,983,400	(126,400)
TOTAL	26,598,000	1.00000	26,598,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)	(2)			(3)
APCO	(2,328,000)	*****	+	*****	(31,236,003)
KPCO	(351,500)	*****	+	*****	(4,716,261)
I&M	319,100	10.22	+	5.75	5,096,027
OPCO	2,486,800	10.8	+	2.29	32,552,212
CSP	(126,400)	*****	+	*****	(1,695,975)

EQUALIZATION CAPACITY RATE: 13.4175
(This is the average $/kW rate paid by deficit members.)

NOTES:
* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

Responses to Interrogatories From PUCO

PUCO 18-001 (& attachment)
PUCO 28-001
PUCO 44-001

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO PUBLIC UTILITIES COMMISSION OF OHIO'S DATA REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO EIGHTEENTH SET

INTERROGATORY

INT-01. The following questions pertain to the Company's discussion of Ohio's allocation of the CCS FEED study, as addressed in the testimony of Mr. Nelson (p. 20). Indicate if you deem any of the information if your responses to be confidential.

(Excerpt from Phil's Testimony)
How was the Ohio Allocation for this study calculated?

The allocation to AEP Ohio is based on the ratio of AEP Ohio's megawatts of coal-fired capacity to the total coal-fired capacity of the AEP system for the coal units that are able to be retrofit with this technology and are fully controlled, or are scheduled to be fully controlled with SCR and FGD technology

What is the total expected cost of the commercial scale CCS Project and what is AEP Ohio's share?

The total cost for the CCS project is not known at this time and the FEED study will provide a detailed estimate However, preliminary estimates for the total capital project cost would be about $610 million with an estimated in-service date of 2015. There is an estimated annual O&M requirement of approximately $58 million beginning with the in-service date. Applying the same ratios as applied to the FEED Study cost produces an AEP Ohio revenue requirement of approximately $46 million. The Company is requesting that the CCSR be nonbypassable. The table below shows the calculations just described

QUESTIONS - REQUIRING RESPONSES

A) Provide criteria used to determine if an AEP coal-fired unit is able to be retrofit with this capture technology.

B) Provide a list of all AEP coal-fired units and all AEP Ohio coal-fired units that are able to be retrofit with this capture technology and are fully controlled, or are scheduled to be fully controlled with SCR and FGD technology.

INT-01 (CONTINUED)

C) What is the area requirement for the this capture technology?

D) How many years of operation would justify the use of this capture technology?

RESPONSE

The Ohio Companies' allocation factor of 46 5% in the table on page 21 of witness Nelson's testimony inadvertantly excluded the capacity of AEP Generating Co. (with ownership and entitlement shared by Indiana Michigan Power and Kentucky Power Companies) that would be considered capable of receiving a CCS retrofit. Including this capacity lowers the Ohio Companies' allocation factor to 43 4%. This revised factor should be replaced in the workpaper in Volume 5 of the proposed ESP filing and in the table on page 21 of witness Nelson's testimony.

A) The criteria used to determine if an AEP coal-fired unit is capable of having carbon capture technology retrofit is whether flue gas desulfurization (FGD) and selective catalytic reduction (SCR) technologies have been installed or are planned to be installed. Units controlled for SO_2 and NOx (primarily NO_2) are better candidates for CCS technology because of competing reactions that take place between these compounds and the specific chemical reagent (ammonia, advanced amines, etc), limiting the reagent's ability to react with CO_2 Depending on the technology selected (chilled ammonia or advanced amines), higher SO_2 and NOx concentrations in the incoming flue gas can have considerable impacts on the process, leading to higher reagent consumption, increased CCS equipment sizing, and increased waste/by-product generation by the capture system

Thus, on an uncontrolled unit, the resulting increased reagent consumption and associated impacts could shift the economics of the system to the point that CCS on that unit may no longer be feasible. There really are no minimum emissions criteria for CCS, but as described above the concentrations of SO_2 and NOx in the flue gas have a significant impact on the system design and economics. FGD systems for SO_2 control are advantageous for both chilled ammonia and advanced amine technologies, while the advanced amine technologies also perform better with an upstream SCR for NOx control. Finally, both chilled ammonia and advanced amine technologies require low inlet flue gas temperatures for optimum CO_2 capture Upstream SO_2 controls (FGD) remove the constituents that inhibit the capture process, and lower the incoming flue gas temperature to the capture system Thus, units that have FGD systems in place are favorable retrofit candidates.

B) A list of all AEP coal-fired units and all AEP Ohio coal-fired units that are able to be retrofit with this capture technology and are fully controlled, or are scheduled to be fully controlled with SCR and FGD technology is provided in Staff 18-1 Attachment 1

C) The area requirement for carbon capture technology is dependent upon the amount of flue gas treated and the individual design of each retrofit. Using Alstom's chilled ammonia technology as a basis, the product validation facility (PVF) at AEP's Mountaineer Plant (capture portion only), and the front end engineering and design completed so far for the Mountaineer commercial-scale facility (capture portion only) are approximately 3,000 - 3,500 sq ft. per MW. This includes the

INT-01 (CONTINUED)

major process islands and auxiliary equipment (refrigeration systems, cooling tower, electrical bldg , etc).

D) The economic justification of using capture technology is specific to each retrofit and the assumptions used within each individual analysis. At this time any economic analysis will be less robust that when the cost of not retrofitting CCS can be quantified (i.e. value of CO2 emission credits)

AEP Coal-Fired Generation - Units With Potential of Being Retrofit with Carbon Capture and Storage (CCS) Technology on 1/1/2015

Operating Company	Plant/Unit	MW Ownership Capacity	Total By Company	% By Company	Current FGD&SCR Controls
APCo	Mountaineer Unit 1	1,300			FGD&SCR
APCo	Amos Units 1-3	2,033	3,333	17.4%	FGD&SCR
OPCo	Amos Unit 3	867			FGD&SCR
OPCo	Mitchell Units 1&2	1,600			FGD&SCR
OPCo	Gavin Units 1&2	2,600			FGD&SCR
OPCo	Cardinal Unit 1	600			FGD&SCR
OPCo	Muskingum River Unit 5 (1)	585	6,252	32.6%	SCR
I&M	Rockport Units 1&2 (2)	2,210	2,210	11.5%	None
KPCo	Big Sandy Unit 2	800			SCR
KPCo	Rockport Units 1&2 (3)	390	1,190	6.2%	None
CSP	Conesville Unit 4 (4)	339			FGD&SCR
CSP	Conesville Unit 5	400			FGD
CSP	Conesville Unit 6	400			FGD
CSP	Zimmer Unit 1 (5)	330			FGD&SCR
CSP	Stuart Units 1-4 (6)	604	2,073	10.8%	FGD&SCR
PSO	Northeastern Units 3&4	910			None
PSO	Oklaunion Unit 1 (7)	102	1,012	5.3%	FGD
SWEPCO	Pirkey Unit 1 (8)	580			FGD
SWEPCO	Dolet Hills Unit 1 (9)	262			FGD
SWEPCO	*Flint Creek Unit 1 (10)*	264			None
SWEPCO	Turk Unit 1 (11)	440			Under Constr.
SWEPCO	Welsh Units 1-3 (1)	1,584	3,130	16.3%	None
Total Ohio			**8,325**	**43.4%**	
TOTAL		19,200	19,200	100.0%	

Operating Companies:
APCo - Appalachian Power Company
OPCo - Ohio Power Company
I&M - Indiana Michigan Power Company
KPCo - Kentucky Power Company
CSP - Columbus Southern Power Company
SWEPCO - Southwest Electricity and Power Company

Assumptions:
- Units would be fully controlled (SCR and FGD operational) prior to CCS retrofit
- Potential for sequestration of CO2 at each facility is dependent upon underlying geology

Notes:
(1) Muskingum River Unit 4 & Welsh Unit 2 could be retired prior to 2019 and not retrofitted with CCS
(2) Represents I&M's 85% ownership and entitlement share of Rockport Units 1&2
(3) Represents KPCo's 15% entitlement share of Rockport Units 1&2
(4) Represents CSP's 43.5% ownership in Conesville Unit 4
(5) Represents CSP's 25.4% ownership in Zimmer Unit 1
(6) Represents CSP's 26.0% ownership in Stuart Units 1-4
(7) Represents PSO's 15.6% ownership in Oklaunion Unit 1
(8) Represents SWEPCO's 85.9% ownership in Pirkey Unit 1
(9) Represents SWEPCO's 40.23% ownership in Dolet Hills Unit 1
(10) Represents SWEPCO's 50.0% ownership in Flint Creek Unit 1
(11) Represents SWEPCO's 75.0% ownership in Turk Unit 1

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO THE PUBLIC UTILITIES COMMISSION OF OHIO'S DATA REQUESTS IN PUCO CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO TWENTY-EIGHTH SET

INTERROGATORY

INT-28-001. Witness Laura J Thomas states in her pre-filed testimony @ p 4, lines 1 -2, "The Competitive Benchmark price is based on market data and includes the items that would be included by a supplier providing retail electric service to AEP customers " [emphasis added] Is the MRO benchmark price quantified by Ms. Thomas the same as a price that would be offered by a CRES provider? Is it the price that customers would see as a result of a competitive auction or procurement that would be sponsored by AEP Ohio? Or, referring to the "and" in Ms. Thomas' statement, is it a combination of these two alternatives? Please explain why and how it is one or the other, or a combination of the two

RESPONSE

As stated on page 4 of the testimony of Company witness Thomas, the Competitive Benchmark price is based on market data and includes the items that would be included by a supplier providing retail electric service to AEP Ohio customers. Such service can be accomplished through either service from CRES provider or through competitive bidding process under an MRO. The same price and components would apply in either situation with the following exceptions: a CRES provider's price would likely include additional customer acquisition costs and a supplier under an MRO would include POLR costs Neither of these additional costs were included in the Company's Competitive Benchmark price.

Prepared by: Laura J. Thomas

COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S
RESPONSE TO
THE PUBLIC UTILITIES COMMISSION OF OHIO'S
DATA REQUEST
PUCO CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO
FORTY-FOURTH SET

INTERROGATORY

INT-44-001 On page 8, lines 21 – 22 of her pre-filed testimony AEP witness Thomas describes her methodology for calculating the SS component of the MRO price a using "an average of the forward prices from the first week of each of the three quarters of 2010..."

Please clarify which daily forward price quotes comprise the average used to develop the SS component.

RESPONSE

The testimony of Company witness Thomas, page 8, lines 21-22 should be corrected to read "an average of the forward prices from the first week of each of quarter of 2010... "

The specific days for which forward prices were used are January 4-8; April 1 and 5-8; July 1-2 and 6-8; and October 1 and 4-7. These are identified in the Company's response to OCC RPD-036, Attachment 3.zip, file titled 'AD Prices 2012-2014 102910 xls', Column I

Prepared by: Laura J Thomas

Exhibit MMS-4

COMPETITIVELY SENSITIVE CONFIDENTIAL

EXC RPD 3-012 Attachment 1, Selected Pages: 6, APP-12

EXC RPD 3-014 Attachment 4, Selected Pages: 25

OCC RPD 1-24 Attachment 1

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Direct Testimony of Michael M. Schnitzer on Behalf of FirstEnergy Solutions Corp.* was served this 25th day of July, 2011, via e-mail upon the parties below.

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