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BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

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

OHIO POWER COMPANY'S AND
COLUMBUS SOUTHERN POWER COMPANY'S
APPLICATION FOR REHEARING

On December 8, 2010, the Commission issued an Entry initiating this proceeding. In its Entry the Commission makes statements regarding and seeks information from interested parties concerning the application filed on November 24, 2010, on behalf of Ohio Power Company (OPCo) and Columbus Southern Power Company (CSP) (collectively referred to as "AEP Ohio" or "the Companies") with the Federal Energy Regulatory Commission (FERC) in FERC Docket No. ER11-2183-000.

The Companies' FERC application seeks approval from the FERC to make changes to the wholesale charges that they assess for supplying capacity associated with retail loads served by alternative load-serving entities (also referred to in Ohio as competitive retail electric service (CRES) providers). Under the Fixed Resource Requirement (FRR) provisions in the PJM Interconnection, L.L.C. (PJM) Reliability Assurance Agreement (RAA), the amounts that the Companies currently recover from CRES providers in connection with their sales to retail customers that switch away from the Companies are set by PJM's Reliability Pricing Model (RPM) capacity auction prices. Those prices are not based upon, and would not permit the Companies to fully recover, their capacity costs. Accordingly, consistent with express provisions in the RAA and their rights established by the Federal Power Act (FPA), the

Companies requested approval for an alternative mechanism that would more accurately calculate and recover their capacity costs.

In its December 8 Entry, at Finding 4, the Commission first asserts that in *In re Columbus Southern Power Company*, Case No. 08-917-EL-SSO, and *In re Ohio Power Company*, Case No. 08-918-EL-SSO (*ESP Cases*), it approved retail rates, "including recovery of capacity costs through provider-of-last-resort (POLR) charges to certain retail shopping customers, based upon the continuation of the current capacity charges established by the three-year capacity auction conducted by PJM, Inc., under the current fixed resource requirement (FRR) mechanism."

Next, also in Finding 4 of its December 8 Entry, the Commission concludes that, as a result of the Companies' application to the FERC, "the Commission will now expressly adopt as the state mechanism for the Companies the current capacity charges established by the three-year capacity auction conducted by PJM, Inc. during the pendency of this review."

The Commission further finds, at Finding 5 of its December 8 Entry, that a review is necessary in order to determine the impact of the proposed change to AEP Ohio's FERC-regulated wholesale capacity charges. As a result, the Commission's Entry seeks comment regarding "(1) what changes to the current state mechanism are appropriate to determine the Companies' FRR capacity charges to Ohio competitive retail electric service (CRES) providers; (2) the degree to which AEP-Ohio's capacity charges are currently being recovered through retail rates approved by the Commission or other capacity charges; and (3) the impact of AEP-Ohio's capacity charges upon CRES providers and retail competition in Ohio."

Pursuant to §4903.10, Ohio Rev. Code, and §4901-1-35(A), Ohio Admin. Code, the Companies respectfully apply for rehearing of the Commission's December 8, 2010, Entry. The Entry is unreasonable and unlawful in the following respects:

I. The Commission's Entry is unlawful and unreasonable in finding that the POLR charges approved in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO cover the Companies' costs of supplying capacity for retail loads served by CRES providers; the Commission also erred in finding that the approved POLR charges were based upon the continued use of RPM auction prices to set capacity charges for CRES providers.

    A. The Provider of Last Resort Obligation under Ohio law

    B. The approved POLR charge and the wholesale RAA capacity charge are related to separate services that are based on distinct costs.

    C. CSP's and OPC's POLR charges approved in the *ESP Cases* simply do not reflect the capacity costs recovered under the FRR charges.

    D. The Commission's decision in the *Ormet Case* and the *Eramet Case* also directly undercut the Entry's present finding that the approved POLR charges already reflect the capacity cost associated with shopping customers.

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

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

IV. Finding 4 of the Entry and subpart 1 of Finding 5 must be reversed and vacated because they are in direct conflict with, and preempted by, federal law.

A memorandum in support of this application for rehearing is attached.

Respectfully submitted,

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MEMORANDUM IN SUPPORT

In FERC Docket No. ER11-2183-000, CSP and OPCo have applied for authority to revise the amounts that they charge for supplying capacity associated with retail loads served by alternative load-serving entities (referred to in Ohio as competitive retail electric service (CRES) providers).[1] Under the Fixed Resource Requirement (FRR) provisions in the PJM Interconnection, L.L.C. (PJM) Reliability Assurance Agreement (RAA), the amounts that CSP and OPCo currently recover from the CRES providers in connection with CRES providers' sales to retail customers that switched away from CSP/OPCo are set by PJM's Reliability Pricing Model (RPM) capacity auction prices. Those prices will not permit the Companies to fully recover their costs. Consequently, consistent with the express provisions of the RAA and rights established by the Federal Power Act, the Companies submitted an alternative mechanism to more accurately calculate and recover their costs of supplying capacity for retail loads served by CRES providers.

Through their application to FERC, the Companies sought to revise the compensation they receive for meeting their FRR capacity obligations in accordance with Section D.8 of Schedule 8.1 of the RAA.[2] That provision expressly provides that the Companies may, "at any time, make a filing with FERC under Section 205 of the Federal Power Act proposing to change the basis for compensation to a method based on [their] cost or such other basis shown to be just and reasonable." While it is true that Section D.8 also references the option of a "state compensation mechanism" and suggests that a state mechanism may "prevail" in lieu of a

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[1] American Electric Service Corporation initially filed on November 1, 2010, an application with FERC in FERC Docket No. ER11-1995, on behalf of the Companies. Pursuant to a Deficiency Letter issued on November 19, 2010, the Companies' revised application was refiled with FERC in FERC Docket No. ER11-2183-000 on November 24, 2010.

[2] PJM Rate Schedule FERC No. 44 at 113, Section D.8 of Schedule 8.1 of the RAA ("Section D.8").

federally-approved alternative, that reference does not justify the Commission's action in this instance and is inapplicable here for several reasons.

First, Congress has mandated that the FERC exercise plenary authority over the regulation of wholesale electric transactions involving the sale of capacity as well as the sale of energy. Thus, the state compensation mechanism referenced in Section D.8 cannot be invoked to usurp the Companies' right under Section 205 of the FPA to petition FERC to change the basis for compensating them for capacity charges to CRES providers. Nor can it be used to justify a state proceeding that seeks to undermine and derail a pending FERC proceeding commenced under the last proviso in Section D.8. Yet that apparently is what the Commission is doing here, as evidenced by its comments in the pending FERC proceeding.[3]

Second, even if a state regulatory entity could exercise authority to establish the capacity charges to be paid to the FRR Entity by CRES providers, this Commission has no authority to do so under Ohio law.

Third, even if were permissible for it do so as a matter of both federal and state law (which it is not), this Commission has not adopted a state compensation mechanism within the purview of Section D.8 because it has never issued an order that requires CRES providers to compensate the Companies for their FRR capacity obligations. It certainly did not do so in the *ESP Cases* when it approved provider-of-last resort ("POLR") charges to certain retail customers and it did not do so in the December 8 Entry. The POLR charges relate to an entirely different service and are based on an entirely different set of costs than the capacity charges provided for in Sch. 8.1, Sec. D.8 of the RAA. During the entire period in which the current retail POLR charges have been in effect, the Companies have been collecting the PUCO-approved POLR

[3] The Commission's December 10, 2010 Comments in Docket No. ER11-2183-000 state that there is no need for the FERC proceeding to advance because the Commission has provided a state compensation mechanism. Comments at 2 and n.1 (attached hereto as Attachment A).

charge from certain retail customers <u>and</u> the separate FERC-approved FRR capacity charge from CRES Providers. Heretofore, no one – not the Commission, not the CRES Providers and not the retail customers nor their advocates – has suggested that the POLR charge or any other PUCO-approved retail charge compensates the Companies for their capacity obligations under the RAA and is, in whole or in part, the state compensation mechanism referenced in Sch. 8.1, Sec. D.8. While the Entry in this proceeding purports to adopt an interim "state compensation mechanism," it does not do so effectively because it does not require switching customers or CRES providers to pay any additional amounts to the Companies to compensate them for the FRR capacity obligations.

Fourth, even if the prior ESP Orders or the December 8, 2010 Entry could be read to have established a state compensation mechanism for capacity charges to be paid by switching retail customers or CRES providers, the Commission's action would be invalid because the Commission failed to provide the Companies any semblance of due process by summarily purporting to establish a rate to be paid by CRES providers without any record basis to do so or any opportunity for the Companies to be heard on this issue.

Each of these reasons, which singly and collectively establish the grounds for rehearing, is discussed more fully below. Any one of these reasons requires the Commission to vacate its findings in paragraph 4 of the Entry.

The Commission erroneously asserts in Finding 4 of its Entry that in the *ESP Cases*, it approved retail rates, "including recovery of capacity costs through provider-of-last-resort (POLR) charges to certain retail shopping customers, based upon the continuation of the current capacity charges established by the three-year capacity auction conducted by PJM, Inc., under the current fixed resource requirement (FRR) mechanism." Also in Finding 4 of its December 8

Entry, the Commission unlawfully states that, as a result of the Companies' application to the FERC, "the Commission will now expressly adopt as the state mechanism for the Companies the current capacity charges established by the three-year capacity auction conducted by PJM, Inc. during the pendency of this review."

Each of these reasons also requires the Commission to vacate its finding in subsection 1 of paragraph 5 of the Entry. In subsection 1 of Finding 5, the Commission seeks comment regarding "what changes to the current state mechanism are appropriate to determine the Companies' FRR capacity charges to Ohio [CRES providers]." This finding is erroneously premised on the existence of a "current state mechanism," although no such mechanism is in place. It also would be unlawful as a matter of both federal and state law for the Commission to now adopt any mechanism to determine the Companies' FRR capacity charges.

The Commission further finds, at Finding 5 of its December 8 Entry, that a review is necessary in order to determine the impact of the proposed change to AEP Ohio's FERC-regulated wholesale capacity charges. As a result, the Commission's Entry seeks comment regarding ". . . (2) the degree to which AEP-Ohio's capacity charges are currently being recovered through retail rates approved by the Commission or other capacity charges; and (3) the impact of AEP-Ohio's capacity charges upon CRES providers and retail competition in Ohio."

While these subparts of Finding 5 of the Entry also appear to be designed to support taking further action in this proceeding regarding the Companies' wholesale capacity charges that are beyond this Commission's jurisdiction, AEP Ohio recognizes that the Commission has broad authority to investigate matters involving Ohio utilities and that it may explore such matters even as an adjunct to its own participation in FERC proceedings such as FERC Docket ER11-2183-000. Therefore, while the Companies disagree that there is any need for an investigation or PUCO proceeding regarding this matter, AEP Ohio plans to participate in the investigation component of this proceeding and its current application for rehearing is focused on the interim rate that the Commission purported to establish in Finding 4 of the Entry and on subpart 1 of Finding 5 that appears to be aimed at further modifying the wholesale capacity charge.

I. The Commission's Entry is unlawful and unreasonable in finding that the POLR charges approved in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO cover the Companies' costs of supplying capacity for retail loads served by CRES providers; the Commission also erred in finding that the approved POLR charges were based upon the continued use of RPM auction prices to set capacity charges for CRES providers.

The Commission's claim in its December 8 Entry that the POLR charges it approved for the Companies in the *ESP Cases* were intended to recover their costs of supplying capacity for retail loads served by CRES providers is without basis. That notion reflects a misunderstanding of the basis for the retail POLR rates approved for CSP's and OPC's retail customers. The POLR charges relate to an entirely different service and are based on an entirely different set of costs than the capacity rates provided for under Section D.8 of Schedule 8.1 of the RAA. As the record in the *ESP Cases* confirms, the POLR rates are not the "state compensation mechanism" envisioned under the RAA and there is no overlap (and thus no double recovery) between the Ohio retail POLR charges and the FRR compensation provided for under the RAA. Simply put, the PUCO's approval of retail POLR charges do not compensate CSP and OPC for the wholesale capacity that they are required to make available as FRR Entities under the RAA.

A. The Provider of Last Resort Obligation under Ohio law

Am. Sub. S.B. No. 3, 1999 Ohio SB 3, effective October 5, 1999 (SB 3) which was subsequently modified by S.B. 221, restructured regulation of electric utilities by introducing retail customer choice for electric generation service and providing for future deregulation of generation service in Ohio. Of importance to this proceeding, SB 3 granted retail customers the right to not shop and avoid market-based rates by taking the standard service offer ("SSO") of their electric distribution utility (*i.e.*, CSP and OPC). *See* Ohio Rev. Code Ann. § 4928.141 (2010). A unique aspect of Ohio's restructuring laws is that retail customers that do shop for alternative generation service may return to the utility's SSO if they subsequently decide to return or if their CRES provider turns the customer back or defaults on its obligation to serve. Ohio Rev. Code Ann. § 4928.14 (2010).

A corollary to these customer rights is the electric distribution utility's obligation to be the provider of last resort, a requirement imposed on electric distribution utilities by multiple statutory provisions.[4] When coupled with the right to choose a retail generation supplier, availability of the SSO means that a retail customer may freely leave the electric distribution utility when the market price is lower than the stabilized SSO rate and may just as easily return when the market price rises above the SSO rate. Given the volatile nature of market prices for electricity, there exists an opportunity for "churn" or migration of customers on and off SSO service. Another POLR obligation provides that customers of a defaulting competitive provider may return to the electric distribution utility's SSO until the customers choose an alternative supplier.[5] Thus, Ohio electric distribution utilities must stand ready to provide full generation services as necessary to fulfill their statutory POLR obligation.

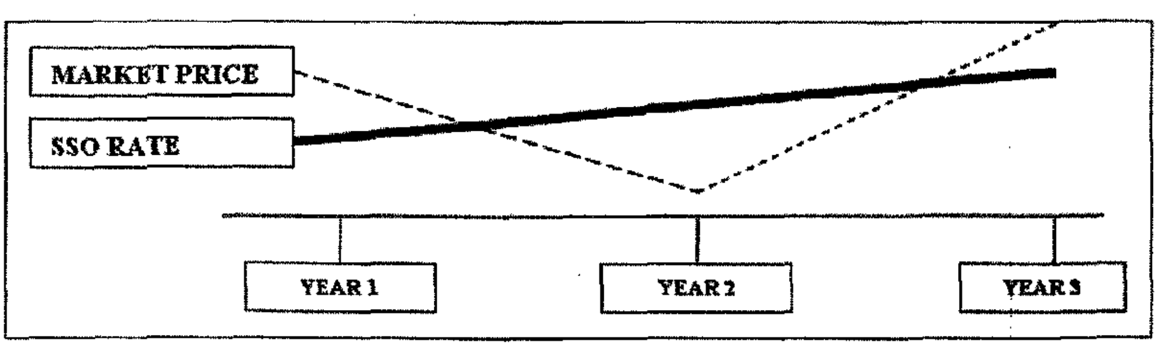
[4] R.C. § 4928.141(A) imposes on an electric distribution utility the requirement to provide consumers within its certified service territory "a standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service." Ohio Rev. Code Ann. § 4928.141(A) (2010). CSP and OPC recover their capacity charges from retail customers through the PUCO-approved SSO rates and, for shopping customers, through the wholesale FRR capacity charges to CRES Providers approved by this Commission.

[5] Ohio Rev. Code Ann. § 4928.14 (2010).

B. The approved POLR charge and the wholesale RAA capacity charge are related to separate services that are based on distinct costs.

As the prior discussion confirms, CSP's and OPC's POLR obligations address the right of retail customers to shop and subsequently return for generation service under the SSO rates. This section demonstrates that, contrary to Finding 4 of the Entry, the Companies' POLR charges were never intended to compensate CSP and OPC for meeting their wholesale FRR capacity obligations to CRES Providers that serve shopping customers.

The PUCO-approved retail POLR charges reflect the value of the customers' right, or *option*, to switch suppliers but retain the safety net of the SSO rate; *i.e.*, retail customers have the right to come back to the Companies, *if* electricity prices move in a way that makes switching back to CSP or OPC an economically attractive choice or if a CRES Provider turns back the customer or defaults on its obligations. The value of that option existed at the beginning of the 2009-2011 rate term covered by the last PUCO proceeding, independent of the actual outcomes that eventually materialize in the future. In other words, CSP and OPC were obligated at the outset of that term, based on then-current circumstances and uncertainties, to provide an SSO rate for the full three-year term and undertake the attendant POLR risk. The simple hypothetical example in the diagram below illustrates the customers' POLR optionality and CSP's and OPC's attendant POLR risks:



Under this example, customers may stay on (or return to) the SSO rate in years 1 and 3, while they would likely shop in the market during year 2. CSP's and OPC's obligations to support the SSO price during the period covered by the PUCO rate orders was firmly established on the first day that the rates became effective, even though neither company could predict with certainty market prices (the dotted line) over the three subsequent years. The migration risk, for which the PUCO authorized the POLR charges, is illustrated in year 2 when customers could leave the SSO to pursue more favorable market prices. The retail POLR charge reflects the cost of the customers' POLR optionality, and the amounts collected through the POLR charges allow CSP and OPC to "hedge" against market changes and ride out fluctuations in SSO load. As explained in the next section, the POLR charge does not reflect the cost of CSP's and OPC's installed capacity.

C. CSP's and OPC's POLR charges approved in the ESP Cases simply do not reflect the capacity costs recovered under the FRR charges.

During the entire period in which the current retail POLR charges have been in effect, CSP and OPC have charged CRES providers the FRR capacity charge as provided for under the RAA. And during that entire time, neither the PUCO nor any CRES providers or shopping customers have ever argued that the FRR charges were duplicative of the POLR charges. Now that CSP and OPC have sought to increase the FRR charges to recover their costs, commenters in the FERC proceeding have seized upon snippets of AEP testimony taken out of context to argue that FRR charges coupled with CSP's and OPC's POLR charges results in a double charge. This is apparently the premise of the PUCO's own comments before the FERC (Attachment A to this application for rehearing). Of course, eliminating the FRR capacity charge would result in CRES providers getting free use of CSP's and OPC's capacity resources, which would be highly inequitable and inconsistent with express provisions of the RAA. When the PUCO's decision to adopt the retail POLR charges and AEP's supporting POLR testimony are examined in detail, it becomes obvious that there was never any intention that the POLR charges would displace the FRR capacity charges or serve as the "state compensation mechanism" under the RAA. Indeed, neither the RAA nor the FRR were raised in the PUCO proceeding in connection with the deliberation of the appropriate POLR charges.

The cost of CSP's and OPC's POLR obligations result from trying to balance and quantify two of the goals of electric restructuring in Ohio, not from the cost of AEP's installed capacity. The first goal is to preserve the customers' right to take competitive generation service from their electric distribution company or from CRES Providers. The second goal is to provide customers rate stability and protection from the volatility of short-term market prices through the existence of a default standard service offer. In the proceedings before the PUCO, AEP's POLR charge witness was J. Craig Baker, who described the potential conflict between these two goals in his direct testimony as follows:

> Despite the many changes to Ohio's customer choice legislation enacted in 1999 (Am. Sub. S.B. No.3 - S.B.3) that were made by S.B. 221, the fundamental premise of S.B. 3 remains. That is, all ***customers are free to switch to receive generation service from Competitive Retail Electric Service (CRES) providers.*** Further, customers can become part of a government aggregation group as another form of switching.
>
> ***Conversely, customers also are free to continue to rely on their incumbent utility for generation service at a tariff rate.*** Even those customers who switch can choose to return to their incumbent utility. Further, if the CRES provider to whom customers switched or the supplier to the government aggregation group were to default in its service obligation, those customers can return to the incumbent utility.
>
> ***This flexibility*** leaves the Companies in the precarious position of being exposed to losing generation service load when the market price is low but needing to stand ready to begin serving that load again when the market price is high, and in the case of a CRES or other supplier default, doing so at a moment's notice. There is a definite and significant cost associated with providing ***this flexibility***.
>
> In addition to the challenges of providing capacity and energy on short notice, ***the Companies would provide service to returning customers at the SSO rate***

> ***(even though they are likely to be returning because market prices exceed the SSO).***

ESP Cases, Cos. Ex. 2A at 25-26 (emphasis added) (attached hereto as Attachment B).

Further, Mr. Baker testified:

> [C]ustomers have the right to leave the utility and take service from an alternative supplier as well as the right to return to AEP's ESP pricing if future market price fluctuations make it advantageous for them to do so. AEP is holding the other side of that arrangement; AEP is obligated to stand ready to handle whatever load fluctuations may result from such switching. The financial risk inherent in such arrangements is a result of the asymmetrical relationship that exists between the two parties - one party is holding the rights that will bring financial benefits to themselves and at the same time impose financial losses on the other party.

Id. at 30. Mr. Baker went on to describe "the keys to understanding AEP's cost of providing its POLR obligation":

> Wholesale price volatility and the asymmetrical impacts of retail choice - *i.e.*, the customer is the party who holds the ability to choose if and when they want to take service from a competitive retail provider or under the utility's ESP plan - are the keys to understanding AEP's cost of providing its POLR obligation. The customers' option to switch providers can be demanded opportunistically, at the economic convenience of customers. In fact, Ohio's desire to create structures and incentives to encourage customer switching is one of the stated policy goals of SB 221. When determining the cost of AEP's POLR obligation, it is important to realize that in financial terms, such one-sided rights that customers receive through retail choice are equivalent to a series of options on power. When it becomes apparent that there are economic benefits from switching between a competitive supplier and the ESP price, the rational customer will exercise his or her flexibility to change providers. AEP, however, will bear the difference between market and ESP prices as a loss. Thus, an option pricing model provides an effective way to calculate the cost of AEP's POLR obligation.

Id. at 30-31. Finally, during cross-examination, Mr. Baker provided a very succinct description of the risks that the companies were attempting to quantify in determining the cost of the POLR obligation:

> In my view the [proposed POLR charge] is the series of options that are provided to customers, the right to leave the customer's tariff and go back -- the SSO tariff price and go to the market when it's economically attractive and then come back

> to the SSO rate when that's economically attractive. That's my definition of POLR.

ESP Cases, Tr. Vol. XIV at 193:18-25 (attached hereto as Attachment C).

When read in context, it becomes readily apparent that the Entry's conflation of the two charges is arbitrary and capricious. The decision in the *ESP Cases* contains absolutely no discussion of the CRES Providers' FRR obligations or the RAA provisions under which CSP and OPC serve as "FRR Entities" to enable the CRES Providers to meet those obligations. Rather, after hearing the evidence and considering the proposal, the PUCO acknowledged that AEP's proposed POLR charge would cover two distinct risks: "the cost of allowing a customer to remain with the Companies, or to switch to a [competitive] provider and then return to the Companies' SSO after shopping" and noted that CSP and OPC "utilized the Black-Scholes Model to calculate their cost of fulfilling the POLR obligation, comparing customers' rights to 'a series of options on power.'" *ESP Cases* (Mar. 18, 2009) at 38-39 (internal citations omitted) (included as Attachment C to FirstEnergy's Protest). The PUCO also recognized its Staff's position that there are "two risks involved: one risk is the risk of customers returning to the SSO and the other risk is that the customers leave and take service from a [competitive] provider (migration risk)." *Id.* at 39. Regarding the migration risk (that customers could migrate, *i.e.*, leave when market prices drop below the SSO rate during the period of the ESP), the PUCO granted most of the requested POLR revenue requirement in order to compensate AEP Ohio for that risk. *Id.* at 40. Regarding the second risk (a customer shopping and then returning to the SSO rate when the market price goes back up), the PUCO permitted shopping customers to bypass the POLR charge only if they agree (at the time they begin shopping) to pay a market price if they end up returning to SSO service later. *Id.*

Finding 4 of the Entry does not cite even a single passage from the *ESP Cases* record wherein the RAA or the FRR obligations were ever mentioned in the context of the POLR charges, let alone any record-basis that the POLR charges were approved for those purposes. The silence speaks volumes. Of course, there is no record basis to conclude that the approved POLR charges reflect the cost of capacity to support a CRES provider's generation service to a shopping customer and, likewise, no basis to presume that the POLR charge somehow overlaps with the wholesale capacity charge or otherwise results in double recovery for AEP Ohio. Indeed, if the Commission had believed that the POLR charge already resulted in recovery of such capacity charges for AEP Ohio, there would have been no reason to further adopt the RPM-based wholesale capacity charge for AEP Ohio – as Finding 4 purports to do. Rather, Finding 4's conclusion that the POLR charge already reflects such capacity costs and simultaneous decision to adopt the RPM-based wholesale capacity charge fundamentally amounts to a *non sequitur* and serves to further compound the Commission's error.

Similarly, the Commission in the *ESP Cases* ordered that the Companies' approved POLR charge could be avoided by shopping customers who promise to pay a market rate if they return to the SSO. (*ESP Cases*, Opinion and Order at 40.) To the extent that the POLR charges reflect capacity costs associated with shopping customers, this would mean that such customers would receive free capacity during the entire period when they shop (which could be permanent). This makes no sense and further reveals that a charge that is bypassable by a customer cannot possibly be recovering capacity costs for serving that same customer. Thus, not only would this be unduly discriminatory and anti-competitive – to the unfair advantage of competing CRES providers serving those shopping customers – but it would also mean that customers receive free capacity at the expense of AEP Ohio. On rehearing, the Commission should recognize that the Entry misapprehends the POLR charge approved in the *ESP Cases* and reverse Finding 4.

D. The Commission's decision in the Ormet Case and the Eramet Case also directly undercut the Entry's present finding that the approved POLR charges already reflect the capacity cost associated with shopping customers.

Finally in this regard, the Entry's presumption that the POLR charges reflect capacity costs of serving shopping customers is flatly inconsistent with other decisions wherein the Commission had occasion to interpret and clarify the POLR charges after the decision in the *ESP Cases*. More specifically, in its July 15, 2009 Opinion and Order in Case No. 09-119-EL-AEC (*Ormet Case*), the Commission addressed the POLR charges as follows:

> The Commission finds that under the terms of the unique arrangement AEP-Ohio will be the exclusive supplier to Ormet (Tr. I at 37-38; Tr. IV at 484). Therefore, there is no risk that Ormet will shop for competitive generation and then return to AEP-Ohio's POLR service. If AEP-Ohio were to retain these charges, AEP-Ohio would be compensated for a service it would not be providing. * * * During the term of the unique arrangement, AEP-Ohio shall credit any POLR charges paid by Ormet to its economic development rider in order to reduce the impact of the unique arrangement on other ratepayers' bills.

Ormet Case, Opinion and Order at 13-14. This position was upheld by the Commission in its September 15, 2009 Entry on Rehearing in the *Ormet Case*.

Similarly, in its October 15, 2009 Opinion and Order in Case No. 09-516-EL-AEC (*Eramet Case*), the Commission found that the customer agreed not to shop during the term of the proposed reasonable arrangement. *Eramet Case*, Opinion and Order at 7 ("Based upon the evidence in the record, the Commission finds that that Eramet knowingly decided that it would not shop for electric service in exchange for securing a long-term power contract with CSP.") As with the *Ormet Case*, the Commission decided in the *Eramet Case* to eliminate the POLR charge for the affected customer:

> If there is no risk of Eramet shopping and returning to standard offer service during CSP's ESP, CSP will incur no costs for providing POLR service that can be recovered under Section 4905.31, Revised Code. Accordingly, the Commission finds that CSP should credit any POLR charges paid by Eramet to its economic development rider in order to reduce the amount of delta revenues recovered from other ratepayers.

Eramet Case, Opinion and Order at 8-9. This decision was upheld on the Commission's March 24, 2010 Entry on Rehearing in the *Eramet Case*.

Thus, both the decision in the *Ormet Case* and the decision in the *Eramet Case* clearly and unequivocally hold that the Companies POLR charges are based strictly on the migration risk associated with shopping and that risk is nonexistent (and the attendant cost being recovered through the POLR charges is not incurred) where a customer agrees not to shop.[6] There is no discussion of the POLR charges reflecting capacity costs of any kind. Indeed, the direct and explicit impact of the Commission's decisions in the *Ormet Case* and the *Eramet Case* is that the involved customers avoid the POLR charges even though AEP Ohio was deemed to be the exclusive supplier for those customers and would clearly incur capacity costs in serving them. Hence, those decisions confirm that the POLR charges do not reflect capacity costs.

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

The Commission's attempt in Finding 4 to "expressly adopt as its state compensation mechanism the AEP Ohio Companies' charges established by the reliability pricing model's three-year capacity auction conducted by PJM" is not sustainable. It appears that the Commission has determined that, in light of the rates proposed by the Companies' FERC filing, it

[6] AEP Ohio's reference to these decisions in no way endorses them. AEP Ohio has challenged the decisions before the Supreme Court of Ohio in Case Nos. 2009-2060, 2010-722 and 2010-723. But the decisions do represent the Commission's views on the approved POLR charges and that is the context of AEP Ohio referencing them here.

was necessary for the Commission to step in and establish its own mechanism for the Companies to recover FRR capacity costs from CRES providers. In particular, the Commission's Entry purports to establish, on an interim basis, the prices that the Companies may charge for providing capacity to support CRES providers' sales to retail customers. But the provision of generation capacity to CRES providers is a wholesale transaction that falls within the exclusive ratemaking jurisdiction of the FERC.[7] The FERC recently reiterated that its "authority under the FPA includes the exclusive jurisdiction to regulate the rates, terms and conditions of sales for resale of electric energy in interstate commerce," and that efforts by a state commission to set the rate for the wholesale sale of electric energy are preempted by FERC's exclusive jurisdiction.[8] Recognition of FERC's exclusive jurisdiction over the FRR capacity compensation received from "alternative retail LSEs" (*i.e.*, the CRES providers) is memorialized in Section D.8, which expressly reserves the right of each "FRR Entity" (*i.e.*, CSP and OPCo) to make filings under FPA Section 205, and the right of each retail LSE (*i.e.*, a CRES Provider) to "at any time exercise its rights under Section 206 of the FPA."

Alternatively, even assuming the Commission is not precluded by federal law from regulating wholesale transactions involving capacity (although it clearly is), the Commission cannot adopt as the state compensation mechanism for the Companies the current capacity charges the Companies charge CRES Providers under the PJM Tariff. That action is entirely at odds with Sec. D.8. That section sets out three possible alternatives for the recovery of FRR

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[7] *See* FPA Section 201(b), 16 U.S.C. § 824(b) (2006); *e.g., Mississippi Power & Light Co. v. Mississippi ex rel. Moore,* 487 U.S. 354, 374, (1988) ("Congress has drawn a bright line between state and federal authority in the setting of wholesale rates"); *FPC v. Southern Cal. Edison Co.,* 376 U.S. 205, 215-16 (1964) ("Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction, making unnecessary such case-by-case analysis. This was done in the Power Act by making FPC jurisdiction plenary and extending it to all wholesale sales in interstate commerce..."); *U.S. v. Public Utilities Comm;n of California,* 345 U.S. 295, 308 (1953) ("Congress interpreted [*Attleboro*] as prohibiting state control of wholesale rates in interstate commerce for resale, and so armed the Federal Power Commission with precisely that power").

[8] *Public Utilities Comm'n of California,* 132 FERC ¶ 61,047 at P 64 (2010).

capacity charges: 1) a state compensation mechanism; 2) the establishment of capacity charges through the capacity auction in accordance with Attachment DD to the PJM Tariff as the default option in the event there is no state compensation mechanism; or 3) a cost-based method or other "just and reasonable" method specific to the FRR Entity based upon a filing made "at any time" and approved by the FERC. Section D.8 does not allow the Commission to adopt the federal default option as a temporary or permanent state compensation mechanism; these are mutually exclusively options, as evidenced by the fact that the default option becomes available only if there is no state compensation mechanism. And, it clearly does not allow the Commission to preempt the FRR Entities' right under Section 205 of the Federal Power Act to propose a change in the basis for compensating it for its capacity obligations by locking in the current capacity charges established in accordance with Attachment DD to the PJM Tariff to the exclusion of any alternative basis the FRR Entity might otherwise be permitted to propose.

Moreover, the Commission is a creature of statute and has no statutory authority beyond that conferred by the General Assembly. *See Discount Cellular, Inc. v. Pub. Util. Comm.*, 112 Ohio St.3d 360, 373, 2007-Ohio-53, 859 N.E.2d 957 (2007) (*citing Reading v. Pub. Util. Comm.*, 109 Ohio St.3d 193, 2006-Ohio-2181, 846 N.E.2d 840, ¶ 13 (2006)). Ohio law does not confer upon the Commission – even assuming that doing so would be permitted under Federal law (which it is not) – the authority to regulate wholesale transactions. No provision of Title 49, Ohio Rev. Code, authorizes the Commission to establish wholesale prices for the Companies provision of capacity that CRES providers require in order to serve their retail electric generation service customers. Even though the Commission suggests that it is acting out of concern for "retail competition in Ohio" (December 8 Entry, at Finding 5), "[a] concern for the future of the competitive market does not empower the commission to create remedies beyond the parameters of the law." *Industrial Energy Users v. Pub. Util. Comm.*, 117 Ohio St.3d 486, 491, 2008-Ohio-990, 885 N.E.2d 195 (2008) (citation omitted).

When the General Assembly wants to empower the Commission to perform acts delegated to it under federal law, it must confer statutory jurisdiction to do so – as it has done in order to implement the 1996 Telecommunications Act through enactment of Section 4927.04, Revised Code. The General Assembly has not chosen to do so in this instance. Thus, even if FERC had delegated authority to establish wholesale capacity charges (which it has not), the Commission lacks subject matter jurisdiction under Ohio law to do so. Accordingly, Finding 4 of the Entry should be reversed and vacated on rehearing.

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

There is another, and more fundamental, flaw in the Commission's determination in Finding 4 of its Entry to adopt the current RPM auction prices as the state compensation mechanism for the Companies during the pendency of its review in this proceeding. Even assuming the Commission has subject matter jurisdiction to establish a wholesale capacity charge (which it does not), multiple provisions within Title 49 of the Revised Code require that the Commission provide a public utility due process prior to unilaterally establishing or changing a rate. Consequently, Finding 4 of the Entry violates Ohio law and should be reversed and vacated on rehearing.

The Commission "may temporarily alter [or] amend" an existing rate without a hearing only "[w]hen the . . . commission deems it necessary to prevent injury to the business or interests of the public or of any public utility of this state in case of any emergency[.]" §4909.16, Ohio

Rev. Code. The Companies' filing of a FERC application seeking to modify the basis on which it recovers its capacity costs, however, would not credibly qualify as an "emergency" for which unilateral, immediate action by the Commission would be necessary "to prevent injury to the business or interests of the public[.]" *Id.* Regardless, the Commission's December 8 Entry gives no indication that the Commission was acting pursuant to §4909.16.

Absent an emergency situation, the Ohio Revised Code requires the Commission to provide notice and a public hearing before setting a utility rate, even if the ratemaking is only temporary. *See, e.g., Lucas Cty. Commrs. v. Pub. Util. Comm.*, 80 Ohio St. 3d 344, 347, 686 N.E.2d 501 (1997) (holding that, "[p]ursuant to R.C. 4905.26 and 4909.15(D), the commission may conduct an investigation and hearing, and fix new rates to be substituted for existing rates, if it determines that the rates charged by a utility are unjust or unreasonable."). In *Ohio Bell Telephone Co. v. Public Utilities Commission of Ohio*, 64 Ohio St. 3d 145, 593 N.E.2d 286 (1992), the Court considered a Commission order prohibiting local exchange telephone companies ("LECs") from billing customer-owned, coin-operated telephone ("COCOT") providers for directory assistance calls placed by COCOT phone users. When the Commission issued that order, it explained that the prohibition was simply "'an interim policy position'" while the Commission investigated complaints that ratepayers were unfairly subsidizing the LECs' directory assistance service. *Id.* at 146. The Supreme Court of Ohio reversed and vacated the Commission's order. The Court held that "[r]egardless of how the action is characterized by the commission, it is still a rate change subject to the procedural requirements of R.C. 4905.26." *Id.* at 148. Accordingly, the Commission was required to provide notice and a public hearing under §4905.26, Ohio Rev. Code, which states in relevant part:

> upon the initiative or complaint of the public utilities commission, that any rate, fare, charge, toll, rental, schedule, classification, or service, . . . is in any respect

> unjust, unreasonable, unjustly discriminatory, unjustly preferential, or in violation of law, . . . if it appears that reasonable grounds for complaint are stated, the commission shall fix a time for hearing and shall notify complainants and the public utility thereof. . . . The parties to the complaint shall be entitled to be heard, represented by counsel, and to have process to enforce the attendance of witnesses.

Id. The Court explained that the statute required "a formal evidentiary hearing," rather than the "notice and comment format" that the Commission had attempted instead to use. *Id.* For the same reasons, the Commission may not impose a wholesale capacity charge on the Companies without notice and a full evidentiary hearing. The Commission's action in this proceeding purports to effect a rate change – it imposes a FRR capacity cost-recovery mechanism different from the mechanism that the Companies have sought FERC's approval to apply. Per the Supreme Court's finding in *Ohio Bell Telephone*, "before the commission may order a change in utility rates on policy grounds, the procedural requirements of R.C. 4905.26 for notice and a public hearing must first be satisfied." *Id.* The Commission here has not satisfied those statutory requirements. Regardless, the Commission provided no notice to the Companies of its intention to establish the rates that Finding 4 of its Entry purports to set. There is no rate-setting process contained in Ohio law that permits the Commission to establish rates for a public utility without first notifying the public utility of its intention to set rates. As a result, the Commission also failed to provide the Companies with any opportunity to be heard regarding the justness and reasonableness of the rates that the Commission established. The rates are not just and reasonable because they chronically under-recover the Companies' costs.

In addition, Section 4903.09, Ohio Rev. Code, requires that, in all contested cases, the Commission must make a complete record of its proceedings, including a transcript of all testimony and exhibits, and the Commission must file, with the record of the case, findings of fact and written opinions setting forth the reasons prompting its decisions, based upon those findings of fact. In this case, the results of which the Companies vigorously contest, the Commission created no record basis for the establishment of the rates that it set. Perhaps not surprisingly, as a result, its Entry provides virtually no explanation of the basis for and manner in which the Commission arrived at its decision to establish the rates that it set. Where the Commission's order fails to state specific findings of fact, supported by the record, and fails to state the reasons upon which the conclusions in the Commission's order were based, the order fails to comply with the requirements of §4903.09, Ohio Rev. Code, and is, therefore, unlawful. *Motor Service Co. v. Pub. Util. Comm.*, 39 Ohio St.2d 5, 313 N. E.2d 803 (1974). *See also Allnet Comms. Serv. v. Pub. Util. Comm.*, 70 Ohio St. 3d 202, 209, 638 N.E.2d 516 (1994) (holding that the Commission must at least "suppl[y] some factual basis and reasoning based thereon in reaching its conclusion."). For all of these reasons, Finding 4 of the Commission's December 8 Entry failed to provide AEP Ohio with the important due process protections provided by Title 49 of the Ohio Revised Code and must be reversed.

IV. Finding 4 of the Entry and subpart 1 of Finding 5 must be reversed and vacated because they are in direct conflict with, and preempted by, federal law.

The Commission lacked jurisdiction to issue Finding 4 and subpart 1 of Finding 5 of the Entry because they are in direct conflict with, and preempted by, federal law. The Commission acknowledges that this proceeding was initiated in direct response to the Companies' filing of an application with FERC, under Schedule 8.1, Section D.8 of the RAA to change the basis for compensating the Companies for their capacity obligations to a cost-based method. Entry at ¶3, citing FERC Docket No. ER11-1995. By this proceeding the Commission is seeking to delay or derail the FERC's own review and adjudication of the Companies' application to propose a change in the method for determining capacity charges.[9] As a result, the Commission's action – this proceeding – is an apparent attempt by the Commission to assert state jurisdiction in direct violation of federal law.

The central and common issue in this proceeding and in the pending FERC proceeding is the interpretation of Schedule 8.1, Sec. D.8 of the RAA. The RAA is a FERC-approved tariff and its interpretation and application falls within the exclusive jurisdiction of the FERC. *AEP Texas North Co. v. Texas Indus. Energy Consumers*, 473 F.3d 581, 585 (5th Cir. 2006) ("FERC, not the state, is the appropriate arbiter of any disputes involving a tariff's interpretation."). Thus, it is up to the FERC, not this Commission, to decide whether Ohio properly or effectively adopted a "state compensation mechanism" within the purview of Section D.8 in the Companies' *ESP Cases*. Similarly, it is up to FERC to decide if a state compensation mechanism can be properly or effectively initiated only after the FRR Entity has begun to collect capacity charges as determined in accordance with the PJM Tariff and in an effort to eliminate the FRR Entity's right to propose a change in method as expressly reserved in Schedule 8.1, Sec. D.8. Each of these issues falls within the exclusive jurisdiction of the FERC under the FPA. The Commission has already intervened in the pending FERC proceeding; it has and can continue to advance arguments that it has adopted, or yet may adopt, a state compensation mechanism in that proceeding.

That the Commission in this case is unlawfully intruding into an area reserved exclusively to the FERC is abundantly clear from settled precedent. The provision of service to CRES Providers is a wholesale transaction and as such it falls exclusively within the FERC's exclusive jurisdiction under FPA Section 201, 16 U.S.C. § 824(b), over "the sale of electric energy at wholesale in interstate commerce." *See generally, Mississippi Power & Light Co. v.*

[9] See note 3, *supra*.

Mississippi ex rel. Moore, 487 U.S. 354, 374 (1988) (recognizing the "bright line between state and federal authority in the . . . regulation of agreements that affect wholesale rates" and holding that states "may not consistent with the Supremacy Clause *conduct any proceedings* that challenge the reasonableness of FERC's [decisions]" (emphasis added)). FERC's exclusive jurisdiction unquestionably extends to the wholesale sale of capacity as well as the sale of energy. See e.g. *Conn. Dept. of Pub. Util. Control v. FERC*, 569 F.3d 477, 484 (D.C. Cir. 2009) ("[T]here is nothing special about capacity decisions that places them beyond the Commission's jurisdiction.")

The proceeding now pending before the FERC as Docket No. ER11-2183 is in effect a proceeding to amend the RAA by allowing the Companies to collect capacity charges on a cost-basis under Sch. 8.1, Sec. D.8 of the RAA. The FERC has the exclusive jurisdiction over that proposal to amend the tariff. To the extent that there is a question as to whether Ohio presently has a compensation mechanism in place in retail rates to compensate the Companies for their FRR capacity obligations that question may and should be resolved by the FERC. Consistent with the Supremacy Clause, this Commission may not usurp the FERC role in this regard. It may not do so by declaring *ipso facto* that a state mechanism was previously established. Nor can it do so by appropriating the current capacity charges determined under federal law and the federally-approved tariff as the state compensation mechanism.

Similarly, now that there is a proceeding pending before the FERC which specifically invokes the Companies' right under Section 205 of the FPA as reserved in a FERC-approved tariff, it is improper and unlawful for the Commission to initiate a proceeding to challenge the the Companies' capacity charges to CRES Providers. Under Section 205 of the FPA, 16 U.S.C. § 824d, FERC has the duty to ensure that all rates and charges for the transmission or sale of electric energy or capacity subject to its jurisdiction are "just and reasonable." This federal statute imposes a duty on the Commission and a concomitant right on the Companies. *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002). This right was memorialized in the RAA itself, but even if it had not been, the Companies' right to receive just and reasonable capacity charges could not have been undermined by the RAA. *Id.* (holding that a provision in an ISO operating agreement that required owners of transmission assets to give up their right to file changes in tariff rates, terms and conditions was unlawful as in conflict with Section 205 of the FPA). While Sch. 8.1, Sec. D.8 of the RAA recites that a state compensation mechanism may be established and may "prevail," it does not provide or suggest that the existence of a state mechanism, let alone the prospect of a someday-to-be state mechanism, abrogates FERC's plenary authority to review and determine whether charges within its jurisdiction are just and reasonable or waives the Companies' statutory right to petition the FERC to authorize changes in the methods by which the Companies are compensated for service subject to the FERC's jurisdiction.

Thus, separate and apart from the issues of whether this Commission might have established in the past a proper and enforceable state compensation mechanism consistent with Sec. D.8, federal law and its limited state authority, or whether it might yet do so at some time in the future -- issues which must be decided in the negative for the reasons already discussed – at the present time with a proceeding pending before the FERC to review the Companies' proposed changes for recovering capacity costs associated with retail loads associated with CRES providers, it is beyond cavil that the Commission's Entry, which was expressly intended to stop the pending FERC proceeding, is preempted by federal law. Consistent with the Supremacy Clause,

> Congress has drawn a bright line between state and federal authority in the setting of wholesale rates and in the regulation of agreements that affect wholesale rates. States may not regulate in areas where FERC has properly exercised its jurisdiction to determine just and reasonable wholesale rates or to ensure that agreements affecting wholesale rates are reasonable.

Mississippi Power & Light, 487 U.S. at 374. Schedule 8.1., Sec. D.8 of the RAA is a provision within a FERC-approved tariff. Its interpretation and application is a matter within the exclusive jurisdiction of the FERC. By opening this proceeding, and creating a parallel state review of the reasonableness of the Companies' capacity charges, the Commission acted in flagrant disregard and disrespect of the supremacy of federal law.

CONCLUSION

For the foregoing reasons, the Commission should grant rehearing to reverse and vacate the interim rate established in Finding 4 of the Entry and to narrowly tailor its review of the Companies' current capacity charges as proposed in Finding 5 to be consistent with its limited authority under both federal and state law.

Respectfully submitted,

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Counsel for Columbus Southern Power Company
and Ohio Power Company

CERTIFICATE OF SERVICE

I certify that Columbus Southern Power Company's and Ohio Power Company's foregoing Application for Rehearing was served by First-Class U.S. Mail upon counsel for all parties of record identified below this 7th[th] day of January, 2011.

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ATTACHMENT A

COMMENTS SUBMITTED BY THE PUBLIC UTILITIES COMMISSION OF OHIO (December 10, 2010), FERC DOCKET No. ER11-2183-000

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation	)	Docket No. ER11-2183-000
PJM Interconnection, L.L.C.	)	

COMMENTS
SUBMITTED ON BEHALF OF
THE PUBLIC UTILITIES COMMISSION OF OHIO

INTRODUCTION AND BACKGROUND

On November 24, 2010, American Electric Power Service Corporation ("AEPSC") on behalf of Columbus Southern Power Company ("CSPCo") and Ohio Power Company ("OPCo") (collectively, the AEP Ohio Companies) filed proposed formula rate templates under which each of the AEP Ohio Companies would calculate its respective capacity costs under Section D.8 of Schedule 8.1 of the Reliability Assurance Agreement (RAA). The Ohio-only filing reflects that the revised capacity charges will be billed to competitive retail electric service ("CRES") providers operating in the State of Ohio.

On November 26, 2010, the Federal Energy Regulatory Commission (FERC) issued its Combined Notice of Filings #1 inviting comments concerning

AEPSC's application by December 10, 2010. The Public Utilities Commission of Ohio (Ohio Commission) hereby submits its comments responding to AEPSC's application and FERC's invitation for public input in the above-captioned proceeding.

DISCUSSION

On December 8, 2010, the Ohio Commission issued an entry (attached) in Case No. 10-2929-EL-UNC inviting comments from interested persons concerning the AEP Ohio Companies' capacity charges to Ohio's CRES providers. The Ohio Commission's entry notes that currently the PUCO-approved rates for the AEP Ohio Companies include recovery of capacity costs through provider-of-last-resort charges to certain retail shopping customers.[1] These rates are based on the continuation of the current FRR mechanism and the continued use of PJM's reliability pricing model's three-year auction results. The AEP Ohio Companies' filing for formula rates could impact this current mechanism. Consequently, the Ohio

1 PUCO Case No. 08-917-EL-SSO, In the Matter of the Application of the Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets; and PUCO Case No. 08-918-EL-SSO, In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan. See also, In the Matter of the Columbus Southern Power Company and the Ohio Power Company, Case No. 05-1194-EL-UNC.

Commission's investigation invites comments from interested persons concerning the following issues: (1) what changes to the current Ohio Commission mechanism are appropriate to determine the AEP Ohio Companies' Fixed Resource Requirement (FRR) capacity charges to the State of Ohio's CRES providers; (2) the degree to which the AEP Ohio Companies' capacity charges are currently being recovered through retail rates approved by the Ohio Commission or other capacity charges; and (3) the impact the AEP Ohio Companies' capacity charges will have on CRES providers and retail competition in the State of Ohio. Although the state compensation mechanism has implicitly been in place since the inception of AEP-Ohio's current Standard Service Offer,[2] the Ohio Commission expressly adopted as its state compensation mechanism the AEP Ohio Companies' charges established by the reliability pricing model's three-year capacity auction conducted by PJM. Currently, the 2010/2011 clearing price is equal to $174.29 per MW-day.[3]

2 *Supra* n.1.

3. The 2010/2011 rate equals $208.20 per MW-day including adders for transmission losses (3.4126%), the scaling factor (1.06633), and the pool requirement (1.0833). The 2010/2011 rate is effective through May 31, 2011. The 2011/2012 rate, which becomes effective on June 1, 2011, is equal to $110.00 per MW-day (without the adders).

Consistent with Section D.8 of Schedule 8.1 of the RAA, which dictates that state imposed compensation mechanisms prevail in those instances where the state jurisdiction requires the load serving entity (LSE) (or switching customers) to compensate the FRR entity,[4] the Ohio Commission maintains that there is no current need for FERC to advance its proceeding regarding this matter because the Ohio Commission has a rate for capacity charges to CRES providers. Consequently, the Ohio Commission respectfully requests that FERC dismiss the application and close this investigation, or, in the alternative, suspend its final decision in this proceeding until the Ohio Commission has concluded its state proceeding. If FERC elects to hold the case in abeyance, the Ohio Commission will inform FERC, in the above-captioned proceeding, as to the outcome of its investigation.

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4 Schedule 8.1 reads as follows: "In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA."

CONCLUSION

The Ohio Commission thanks FERC for the opportunity to provide its Comments in this proceeding.

Respectfully submitted,

/s/ Thomas W. McNamee

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On behalf of
The Public Utilities Commission of Ohio

CERTIFICATE OF SERVICE

I hereby certify that the foregoing have been served in accordance with 18 C.F.R. Sec. 385.2010 upon each person designated on the official service list compiled by the Secretary in this proceeding.

/s/ Thomas W. McNamee

Thomas W. McNamee

Dated at Columbus, Ohio this December 10, 2010.

ATTACHMENT

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

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

ENTRY

The Commission finds:

(1) Ohio Power Company and Columbus Southern Power Company (AEP-Ohio or the Companies) are electric light companies as defined in Section 4905.03(A)(3), Revised Code, and public utilities as defined in Section 4905.02, Revised Code. As such, the Companies are subject to the jurisdiction of the Commission in accordance with Sections 4905.04 and 4905.05, Revised Code.

(2) Sections 4905.04, 4905.05, and 4905.06, Revised Code, grant the Commission authority to supervise and regulate all public utilities within its jurisdiction.

(3) On November 1, 2010, AEP Electric Power Service Corporation, on behalf of AEP-Ohio, filed an application with the Federal Energy Regulatory Commission (FERC) in FERC Docket No. ER11-1995. At the direction of FERC, AEP refiled its application in FERC Docket No. ER11-2183 on November 24, 2010. The application proposes to change the basis for compensation for capacity costs to a cost-based mechanism and includes proposed formula rate templates under which the Companies would calculate their respective capacity costs under Section D.8 of Schedule 8.1 of the Reliability Assurance Agreement.

(4) Prior to the filing of this application, the Commission approved retail rates for the Companies, including recovery of capacity costs through provider-of-last-

resort charges to certain retail shopping customers, based upon the continuation of the current capacity charges established by the three-year capacity auction conducted by PJM, Inc., under the current fixed resource requirement (FRR) mechanism. *In re Columbus Southern Power Company*, Case No. 08-917-EL-SSO; *In re Ohio Power Company*, Case No. 08-917-EL-SSO. See also, *In re Columbus Southern Power Company and Ohio Power Company*, Case Nos. 05-1194-EL-UNC et al. However, in light of the change proposed by the Companies, the Commission will now expressly adopt as the state compensation mechanism for the Companies the current capacity charges established by the three-year capacity auction conducted by PJM, Inc. during the pendency of this review.

(5) Further, the Commission finds that a review is necessary in order to determine the impact of the proposed change to AEP-Ohio's capacity charges. As an initial step, the Commission seeks public comment regarding the following issues: (1) what changes to the current state mechanism are appropriate to determine the Companies' FRR capacity charges to Ohio competitive retail electric service (CRES) providers; (2) the degree to which AEP-Ohio's capacity charges are currently being recovered through retail rates approved by the Commission or other capacity charges; and (3) the impact of AEP-Ohio's capacity charges upon CRES providers and retail competition in Ohio.

(6) All interested stakeholders are invited to submit written comments in this proceeding within 30 days of the issuance of this entry and to submit reply comments within 45 days of the issuance of this entry.

It is, therefore,

ORDERED, That written comments be filed within 30 days after the issuance of this order and that reply comments be filed within 45 days of the issuance of this entry. It is, further,

ATTACHMENT

ORDERED, That a copy of this entry be served on AEP-Ohio and all parties of record in the Companies' most recent standard service offer proceedings, Case Nos. 08-917-EL-SSO and 08-918-EL-SSO.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Valerie A. Lemmie

Steven D. Lesser

Cheryl L. Roberto

GAP/sc

Entered in the Journal
OCT 0 8 2010

Reneé J. Jenkins
Secretary

ATTACHMENT B

TESTIMONY OF J. CRAIG BAKER (July 31, 2008), Case Nos. 08-917-EL-SSO and 08-918-EL-SSO

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FILE

EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

DIRECT TESTIMONY
OF
J. CRAIG BAKER
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: July 31, 2008

INDEX TO DIRECT TESTIMONY OF
J. CRAIG BAKER
PUCO CASE NO. - 08-917-EL-UNC
PUCO CASE NO. - 08-918-EL-UNC

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
J. CRAIG BAKER
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY
PUCO CASE NO. - 08-917-EL-UNC
PUCO CASE NO. - 08-918-EL-UNC

PERSONAL DATA

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is J. Craig Baker and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by American Electric Power Service Corporation (AEPSC) AEPSC is a subsidiary of American Electric Power Company, Inc. (AEP). My title is Senior Vice President – Regulatory Services.

Q. WHAT ARE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT – REGULATORY SERVICES?

A. I am responsible for AEP's utilities' interactions with the regulatory bodies in the eleven states in which they provides retail electric service as well as with the Federal Energy Regulatory Commission. This responsibility involves day-to-day interaction as well as periodic rate filings to ensure recovery of their cost of service. In addition, I am responsible for developing and advocating public policy positions on emerging or changing issues affecting AEP's utilities. Columbus

Southern Power Company (CSP) and Ohio Power Company (OPCO) (collectively, the Companies or AEP Ohio) are subsidiaries of AEP.

Q. **WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I received a Bachelor's Degree in Business Administration from Walsh College in 1970 and a Masters Degree in Business Administration in Finance from Akron University in 1980. I joined the AEP System in 1968 and through 1979 held various positions in the Computer Applications Division. I transferred to the System Operation Division in 1979 and held positions of Administrative Assistant and Assistant Manager. In 1985, I took the position of Staff Analyst in the Controllers Department and, in 1987, I became Manager-Power Marketing in the System Power Markets Department. In 1991, I became Director, Interconnection Agreements and Marketing. I became Vice President-Power Marketing for AEPSC and Senior Vice President of Energy Marketing for AEP Energy Services, Inc. in November 1996 and August 1997, respectively. On July 1, 1998 I became Vice President of Transmission Policy for AEPSC. In January 2001, I became Senior Vice President – Regulatory Services.

In my positions of Manager of Power Markets, Vice President – Power Marketing and Senior Vice President of Energy Marketing I was involved day-to-day in analyzing market prices and developing sales offerings based on those market prices. As the senior person responsible for those activities during much of that period I was responsible for the results of the Company in this area. Since I left the day-to-day wholesale market activities I have been AEP's lead person involved in the development of ISO/RTO's and their associated markets (energy, capacity, ancillary services, etc.). With AEP's experience in three RTOs I am well-versed in the workings of their markets.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses a variety of policy and other issues which relate to the Standard Service Offer (SSO) being proposed as part of the Companies' Electric Security Plan (ESP). It is important to note, however, that the Companies' ESP addresses considerably more than the SSO. Am. Sub. S.B. No. 221 (S.B. 221) places great emphasis on changing the way we as a society think about the sources and uses of electricity. These changes will of necessity require changes in the ways the Companies operate and plan for the future. AEP Ohio's President, Joseph Hamrock, addresses the Companies' response to these aspects of S.B. 221 in his testimony. I also address a variety of other issues that relate to the Companies' ESP.

COMPARISON OF ESP TO EXPECTED RESULTS FROM MARKET RATE OFFER (MRO)

Q. ARE YOU FAMILIAR WITH THE CONTENT OF THE COMPANIES' ESP APPLICATIONS AND THE TESTIMONY OF MR. HAMROCK AND THE COMPANIES' OTHER WITNESSES?

A. Yes, I am.

Q. CONSIDERING EACH COMPANY'S ESP, HOW DO THEY COMPARE TO THE EXPECTED RESULTS THAT WOULD OTHERWISE APPLY UNDER AN MARKET-RATE OFFER (MRO)?

A. The concise answer is that each ESP is more favorable in the aggregate for customers when compared to the expected results under an MRO. Moreover, the Companies' ESPs, which address a broad range of issues, will have the effect of stabilizing and providing certainty regarding retail electric service. The more expansive answer begins with a comparison of the SSO under the ESP compared to the SSO resulting from an MRO. In that regard, the SSO under the ESP is more attractive for customers than the SSO resulting from a market-rate offer. The favorable comparison, however, does not end there. As Mr. Hamrock's testimony explains, the Companies' ESPs contemplate various programs that not only will complement the state's economic development efforts generally, but will support the General Assembly's desire, as evidenced by several provisions of S.B. 221 to make Ohio a center for education, research and innovation in the areas of energy efficiency, energy management and advanced energy resources.

Q. FOCUSING ON THE ESP VERSUS MRO SSO, HOW DO YOU PROPOSE TO MAKE THAT COMPARISON?

A. Since the Companies' ESP is for the three-year period 2009 – 2011, it is reasonable to begin the comparison with a projection of an MRO-based SSO during that same time. The first step in determining the MRO-based SSO is to determine the extent of market price that would be blended with the prior year's SSO. As passed by the General Assembly, S.B. 221 contemplates ten percent of market price in year one (2009) and no less than twenty percent in year two (2010) and no less than thirty percent in year three (2011).

Q. HAS THE GENERAL ASSEMBLY ACTED TO MODIFY THE MARKET PRICE PERCENTAGE BLENDS FROM THOSE ENACTED IN S.B. 221?

A. Yes. In Amended Substitute House Bill No. 562 (H.B. 562) the General Assembly modified the percentages. I have been advised by counsel that the ten percent in 2009 did not change. For 2010, however, the market price percentage blend will be amended to be no more than twenty percent. For 2011, the market price percentage blend will be amended to be thirty percent.

Q. FOR PURPOSES OF THE COMPARISON OF THE ESP VERSUS MRO, DO THE COMPANIES HAVE AN OPINION CONCERNING WHICH PERCENTAGES OF MARKET PRICE SHOULD BE ASSUMED FOR THE ESP/MRO COMPARISON?

A. Yes. The Companies' counsel has advised me that the proper comparison to make is to the market price percentage blends in effect at the time our ESP applications were filed. Consistent with that understanding, the Companies have assumed a MRO phase-in of 10 percent, 20 percent and 30 percent, which is permissible under either S.B. 221 or H.B. 562.

Q. AT YOUR DIRECTION WAS THE EXPECTED COMPETITIVE MARKET PRICE OF FULL-REQUIREMENTS SERVICE FOR THE TERM 2009-2011 CALCULATED?

A. Yes. The calculated price for full requirements service (or Competitive Benchmark) for the 2009-2011 term was $85.32 for OPCO and $88.15 for CSP.

The Competitive Benchmark prices were calculated as part of the Companies' obligation under S. B. 221 in order to provide the Commission with one of the components needed to evaluate the proposed ESP. These prices reflect a comprehensive, balanced calculation of the market cost of full requirements service for the 2009-2011 time period.

Q. ARE THERE EXAMPLES WHERE COMPETITIVELY PRICED FULL REQUIREMENTS SERVICE HAS BEEN PROCURED FOR RETAIL CUSTOMERS?

A. Yes. There have been a number of auctions in multiple states for full requirements service that was competitively bid in support of deregulation to fulfill customer load requirements.

Q. WHAT RANGE OF PRICES HAVE OTHER SIMILAR AUCTIONS PRODUCED FOR FULL REQUIREMENTS SERVICE?

A. The range of prices observed in other auctions have typically been either similar or higher than the Companies' Competitive Benchmark. For example, in New Jersey, results from competitive auctions for full requirements service over the last three years have ranged between $99/MWh and $120/MWh. This is a similar range to that observed for auction results for full requirements service in Delaware during the same time frame. As explained later in my testimony, energy and capacity comprise the majority of the total competitive price. New Jersey and Delaware would likely see higher prices due to both states having more transmission constraints than the AEP System.

Q. WHY WERE THE CALENDAR YEARS 2009-2011 SELECTED AS THE APPROPRIATE TIME FRAME TO PRICE FOR THIS PROCEEDING?

A. Calendar years 2009-2011 match the proposed time frame of the ESP and thus provide an 'apples to apples' comparison between the ESP and the Competitive Benchmark.

Q. HOW WERE THE PRICING COMPONENTS INCLUDED IN THE CALCULATION OF THE COMPETITIVE BENCHMARK DETERMINED?

A. S.B. 221 does not identify a comprehensive list of items that would be included by a supplier in providing retail electric service but it does provide some general guidance. Section 4928.20(J), Ohio Rev. Code, discusses the scenario in which customers that are part of a governmental aggregation and elect not to receive standby service, must pay the market price for competitive retail electric service upon returning to the Companies' generation service. The provision states that 'such market price shall include, but not be limited to'

- Capacity
- Energy Charges
- All RTO charges, including but not limited to
    - Transmission
    - Ancillary services
    - Congestion
    - Settlement and Administrative Charges

- All other costs incurred by the utility that are associated with the procurement, provision and administration of that power supply.

Q. WERE ANY OTHER SOURCES CONSIDERED IN DETERMINING WHAT PRICING COMPONENTS SHOULD BE INCLUDED?

A. Yes. Processes in place in states with deregulated electricity markets were considered to understand the pricing components they used to set competitive generation rates in their respective auctions. In general, what I have been referring to as full requirements service used to develop the Companies' Competitive Benchmark, is very similar from state to state. The way in which various pricing elements are grouped and the specific labels applied to them vary, as one would expect, but the essence of what components are necessary to provide competitive generation service are largely similar across the various deregulated states.

For example, since the initiation of competitive procurement of market-priced supply in 2004, Maryland's utilities have relied on full-requirements contracts with wholesale suppliers to serve residential standard service load. These full-requirements contracts require sellers to supply:

- Energy
- Capacity
- Ancillary services
- Losses

- Any other electrical services (other than transmission and distribution services) necessary to deliver power to the customer's meter to serve that customer's requirements at all times

The Delaware Public Service Commission has developed a pricing framework in order to evaluate the competitive procurement bids submitted by individual auction participants. The following cost items are included in that pricing framework:

PJM Western Hub On-Peak and Off-Peak Prices

Electric Distribution Company (EDC) Specific Unhedged Congestion Adder

EDC-Specific Marginal Loss Adder

EDC Rate Class-Specific Load Shape Adder

Capacity Price

Loss Adder

Ancillary Service Adder

Renewable Portfolio Standard

Transaction Cost and Risk Adder

Q. WHY DID THE COMPANIES CHOOSE THE STATES OF DELAWARE AND MARYLAND TO USE THE CALCULATION OF FULL REQUIREMENTS PRICING COMPONENTS?

A. Both Delaware and Maryland were among the first states to fully implement electric deregulation and have several years of auction results and methodology to examine. The experiences of Delaware and Maryland provide a reasonable and representative view of deregulated markets.

Q. WHAT PRICING COMPONENTS DID YOU INCLUDE IN YOUR CALCULATIONS OF 2009-11 PRICES?

A. Based on the components referred to in S.B. 221 and on what other competitive auctions have identified, the following components have been included:

- ATC Simple Swap (adjusted for basis) – This component is simply the price of the industry standard energy product traded through the broker market and on the electronic exchanges, such as the Intercontinental Exchange[1]. The 'basis adjustment' is the historical price relationship between different physical delivery points. For example, while the AEP-Dayton Hub is the liquid trading location where market quotes are available, AEP Ohio loads are settled by PJM at the AEP Zone. Since forward market quotes are not available for the AEP Zone, a pricing differential between the two points must be added to the AEP-Dayton Hub market prices to derive the market price for energy at the AEP Zone location.

- A Load following/shaping adjustment – This component adjusts the standard energy price (the ATC Simple Swap) to account for the fact that the Companies' customers do not use a constant volume of energy across all hours of each day. This component adjusts the price of the ATC Simple Swap to price the specific load shape of the Companies' customers. In addition, this component includes the pricing implications

[1] Intercontinental Exchange (ICE) is a leading electronic marketplace for energy trading and price discovery. ICE allows market participants direct access to energy futures and Over-the-Counter commodity products for oil and refined products, natural gas, power and emissions.

that arise from the inevitable uncertainty of exactly what the level of customer demand will be on any given day or hour over the 2009-2011 time frame. The calculations are based on CSP's and OPCO's historical load shape by hour, publicly available historical PJM market prices and volatility to model the cost of the load's shape and variability.

- PJM Ancillary Services – This component prices the cost of ancillary services required by the PJM RTO to serve load in the PJM footprint.
- Losses – This component represents the costs of distribution losses that must be supplied in the form of additional energy in order to fulfill the load demand at the customer's meter.
- PJM Capacity Obligations – This component reflects the cost of PJM's required capacity obligations for load serving entities and was derived from the PJM Reliability Pricing Model (PJM Capacity Auction) results for the relevant time period.
- Transaction Risk – This component reflects a variety of risks that will vary based on the unique profile and business objectives of each individual bidder. Examples of such supplier risks include commodity price risk, migration risk and credit risks.
- A retail administration charge – This component is included to capture the various costs that a supplier would need to add to their full-requirements offer in order to cover the costs of participating in an auction and fulfilling the contractual obligations. Marketing, personnel, overhead, taxes and profits are all examples of cost components that need to be included to

arrive at a full requirements service market price. For example, the state of Connecticut includes a range of \$5/MWh to \$10/MWh for this charge.

Q. **WERE THE PRICING ELEMENTS USED IN DETERMINING THE COMPANIES' COMPETITIVE BENCHMARK SIMILAR TO THE METHODOLOGY EMPLOYED TO ESTABLISH THE ESTIMATED MARKET PRICE FOR ORMET?**

A. Yes. The pricing elements used in determining the Companies' Competitive Benchmark are similar to the pricing elements and methodology approved by the Commission in estimating the market price for Ormet. The Competitive Benchmark methodology is more complex, by necessity, than was utilized to price Ormet's unique situation. For example, although certain elements, including PJM ancillary services, were not specifically identified in the Companies' Ormet filing, the costs associated with these elements were handled through other mechanisms.

Q. **WHAT PRICING ELEMENTS HAVE THE LARGEST RELATIVE IMPACT ON THE PRICE OF THE COMPETITIVE BENCHMARK?**

A. When reviewing all of the elements that go into pricing the Competitive Benchmark, it is easy to lose sight of the relative importance of the individual pieces. The tables below provide the specific costs included in the Competitive Benchmark for both CSP and OPCO and their respective impacts on the total cost.

CSP Estimated Full Requirements Service Price for Calendar Year 2009-2011 Term			
Cost Components	CSP Residential	CSP Commercial	CSP Industrial
ATC Simple Swap	$57.84	$57.84	$57.84
Basis	$0.51	$0.51	$0.51
Load Shape and Following	$9.59	$5.33	$2.31
Retail Administration	$5.00	$5.00	$5.00
Ancillary Services	$1.19	$1.19	$1.19
Losses	$4.01	$2.53	$0.91
PJM Capacity Requirements	$15.78	$11.80	$7.86
ARR Credit	($2.73)	($2.05)	($1.40)
Transaction Risk Adder	$5.47	$4.93	$4.45
Class Total	$96.66	$87.08	$78.67
CSP Total	**$88.15**		

[illegible]			
Cost Components	OP Residential	OP Commercial	OP Industrial
ATC Simple Swap	$57.84	$57.84	$57.84
Basis	$0.51	$0.51	$0.51
Load Shape and Following	$7.66	$6.06	$2.58
Retail Administration	$5.00	$5.00	$5.00
Ancillary Services	$1.19	$1.19	$1.19
Losses	$1.28	$4.46	$2.49
PJM Capacity Requirements	$13.47	$12.51	$8.15
ARR Credit	($2.42)	($2.16)	($1.41)
Transaction Risk Adder	$5.07	$5.13	$4.58
Class Total	$89.60	$90.54	$80.93
OP Total	**$85.32**		

As can be observed from the tables, the most significant contributors to the overall cost of full requirements service are the direct energy cost, the capacity obligation implemented by PJM, and the load shaping and following premium necessary to convert the standard quoted energy product to the specific load profiles of CSP and OPCO. Looking at the tables in more detail, the ATC Simple

Swap (the direct energy component) accounts for approximately 66% of the total price for CSP and approximately 68% of the total price for OPCO. The cost of the ATC Simple Swap, which can be readily observed, is the single largest determinant by a factor of four in the Competitive Benchmarks. The second largest factor is the PJM capacity component, which accounted for approximately 14% and 12%, for CSP and OPCO respectively, of the total price. Thus, roughly 80% of the total competitive benchmarks reflect the basic components of serving load, that being energy and capacity.

Q. PLEASE DESCRIBE HOW THE COMPETITIVE BENCHMARKS WERE CALCULATED.

A. The prices were calculated based on observable market inputs and commonly accepted pricing methodologies. For example, the market price of the ATC Simple Swap was obtained from a 3rd party, publicly available market source. The PJM Capacity Obligations were calculated using the published results of PJM capacity auctions. The volatility numbers necessary to model certain risk components were calculated directly from PJM historical pricing data and publicly available market quotes. All phases of calculating the Competitive Benchmarks relied on verifiable, public data; a comprehensive and intuitive set of pricing components; and a reliance on rigorous and commonly accepted computational methodologies. In areas that included qualitative decisions, such as the 'Retail Administration Charge', the experiences in other deregulated states was considered to reflect a balanced and reasonable approach in determining an appropriate charge.

Q. SINCE THE ATC SIMPLE SWAP HAS THE LARGEST NET IMPACT ON THE FULL REQUIREMENTS PRICES, HOW WERE THE MARKET PRICES USED IN YOUR CALCULATIONS SELECTED?

A. The ATC Simple Swap price is simply the standard quoted product that is actively traded on the electronic platforms such as ICE and through the broker market – but the price of that energy changes on a daily basis. Since the value of a full requirements service price is constantly changing, based on the daily moves in power prices, the challenge faced is selecting the appropriate time period to use in selecting energy pricing inputs. Changing the day or days used to gather the ATC Simple Swap pricing inputs will impact the ultimate price. This challenge was addressed by creating selection criteria that would provide the most accurate representation of the general market prices that have existed over the recent past. Instead of simply using the market prices from one day to gather the inputs for the ATC Simple Swap value, we chose a series of days. In addition, instead of selecting just one time frame from which to gather energy price inputs, we concluded that staggering the time frames across the first 7 months of 2008 would provide the most accurate representation of recent market conditions. For these reasons, an average of the market prices from the first week of each of the first three quarters of 2008 was used to calculate the ATC Swap price used in calculating the Competitive Benchmark.

Q. ARE THERE OTHER FACTORS TO CONSIDER IN MAKING THE ESP VERSUS MRO COMPARISON?

A. Yes, there are. The non-market portion of an MRO-based SSO can be adjusted for known and measurable changes in cost of fuel; purchased power costs; costs of complying with the supply and demand portfolio requirements, including renewable energy resource and energy efficiency requirements; and costs of environmental compliance requirements, including deratings of facilities associated with environmental compliance. For purposes of making the ESP versus MRO comparison, these costs will be recovered as part of the Companies' ESP-based SSO or as part of an MRO. While only a percentage of these costs will be reflected in an MRO-based SSO, since a decreasing percentage of the non-market portion of an MRO-based SSO will be reflected in that SSO, the SSO will reflect market price as the remaining component of the SSO.

Further, in an MRO context the FAC applicable to the non-market SSO component would not be phased-in since such a phase-in would be incompatible with a market pricing regime. In addition to the FAC impacts, the carrying costs associated with environmental investments which are part of the ESP's SSO, also would be included as part of the MRO's SSO.

Q. WHAT ARE THE RESULTS OF THE COMPANIES' ESP VERSUS MRO COMPARISON?

A. As shown on EXHIBIT JCB-2, the Companies' ESP is more favorable when compared to the MRO. The analysis reflected on the exhibit is conservative. For instance, the ESP evaluation includes the benefits arising from the gridSMART and enhanced reliability programs, and the evaluation charges the related costs against the ESP. Therefore, the evaluation shows the ESP value being even closer to the MRO than is likely.

Q. WOULD THE RESULT OF THE COMPARISON BE THE SAME IF THE MARKET PRICE PERCENTAGE BLEND REFLECTED THE AMENDMENT CONTAINED IN H.B. 562 TO THOSE PERCENTAGES?

A. Yes. While the spread between the ESP and MRO would be reduced, the ESP still would be more favorable.

Q. ARE THERE OTHER ASPECTS OF THE COMPANIES' ESP THAT SHOULD BE CONSIDERED IN COMPARING THE ESP TO AN MRO?

A. Yes. Besides the comparison shown in my exhibit of the resulting SSO, there are other features of the ESP that support it being more favorable in the aggregate. For instance, the ESP alternative provides for single issue rate making for distribution service. This feature enables the Companies to proceed now with their gridSMART and enhanced distribution reliability initiatives. The MRO alternative does not appear to contemplate single issue distribution service rate making.

Another feature that is part of the Companies' ESP package that would not necessarily be included in an MRO is the shareholder funded commitment focused on economic development and low-income customer assistance.

Moreover, there are other features in the ESP with rate-related impacts that still would be included in an MRO and therefore have the same impact on both sides of the comparison. Those features relate to the statutory mandates concerning alternative energy resources, energy efficiency and peak demand reduction, the provider of last result obligation, and the non-mandated, but obviously appropriate, economic development/job retention efforts.

PHASE-IN OF FAC EXPENSES

Q. ARE THE COMPANIES PROPOSING TO PHASE-IN THE EXPENSES THAT WOULD OTHERWISE FLOW THROUGH THE FAC DESCRIBED BY COMPANIES' WITNESS MR. NELSON?

A. Yes they are. The operation of the FAC proposed by Mr. Nelson accommodates a phase-in and Mr. Assante describes the accounting associated with the phase-in, including the accounting requirements for the Companies to be able to provide a phase-in plan.

Q. WHY ARE THE COMPANIES PROPOSING THE FAC, ALONG WITH THIS PHASE-IN?

A. The FAC is an appropriate way to reflect changes in the costs of the various components of the FAC. In addition to being consistent with provisions within S.B. 221 that authorize recovery of such costs through a fuel clause, the proposed FAC advances the policy outlined in Section 4928.02(G), Ohio Rev. Code, to recognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment, and it also advances the policy outlined in Section 4928.02(J), Ohio Rev. Code, to provide coherent, transparent means of giving appropriate incentives to technologies that can adapt successfully to potential environmental mandates. The basic reason for the phase-in relates to the history of the fuel and fuel-related cost components included in the FAC and the cost levels of those components in the Companies' current rates. The fuel clauses that were included in the Companies' unbundled rates in their Electric Transition Plan proceeding were the EFC rates in effect on October 5, 1999. The unbundled generation rates, including the October 5, 1999 EFC were frozen for five years, through the end of 2005.

In the Companies' RSP case, each of the Company's generation rates were increased in 2006, 2007 and 2008 by fixed percentages – three percent for CSP and seven percent for OPCO. Those percentage increases were intended to move the Companies' generation rates closer to market-based rates and to support the Companies' ability to finance projected capital investments associated with environmental compliance facilities. Those increases were not cost-of-service based and were not characterized as being applicable to any particular cost component such as the October 5, 1999 EFC rate.

In the context of implementing the FAC it is necessary to establish a baseline that represents the level of FAC costs that are reflected in current rates. The difference between that baseline and the projected 2009 FAC costs would be the basis for the initial FAC costs to be recovered in 2009.

It would not be unreasonable for the Companies to take the position that the percentage rate increase in the RSP case did not increase the Companies' recovery of the cost components that will be included in the FAC. However, in an effort to reflect a more moderate approach the Companies are proposing to establish a baseline which assumes that the annual RSP fixed increase percentages acted to increase the recovery of the components that will be in the FAC. That is, to treat it as if the FAC components were increased by three percent for CSP and seven percent for OPCO.

Even that more moderate approach, however, still leaves a substantial difference between the baseline and the projected 2009 FAC costs. In order to further moderate the impacts of implementation of the FAC the Companies have proposed a phase-in. The goal of the FAC phase-in is to hold annual total rate increases to approximately fifteen percent for each rate schedule in the Companies' tariffs.

Q HOW WAS THE DECISION MADE TO TARGET THE INCREASE TO APPROXIMATELY FIFTEEN PERCENT?

A. The fifteen percent target is judgmental. It must be recognized that the factors primarily driving the increases are related to rapidly increasing fuel expenses and environmental compliance investments that the Companies have made. In addition, the Companies believe the time is right to proceed with advanced distribution reliability programs and gridSMART. Finally, there are obvious rate impacts associated with several of the mandates found in S.B. 221.

The long and short of it is that addressing these myriad factors results in rate increases. The Companies' phase-in proposal seeks to levelize the impact on customers in a manner that makes the most sense. I should note, as Mr. Hamrock does in his testimony, that the target of approximately fifteen percent will not include impacts from the Transmission Cost Recovery Rider or from new government mandates.

Q. HOW DOES THE RATE IMPACT TARGET OF APPROXIMATELY FIFTEEN PERCENT COMPARE TO ELECTRIC UTILITY RATE INCREASES BEING AUTHORIZED IN OTHER STATES?

A. Looking at the other companies on the AEP system with recent rate activity the range of requested rate increase ranged from 20%-34%.

Q. DO YOU HAVE AN ESTIMATE OF THE FAC PHASE-IN PERCENTAGES THAT MIGHT OCCUR, GIVEN THE COMPANIES' RATE IMPACT TARGET OF APPROXIMATELY FIFTEEN PERCENT?

A. Yes. Under the proposed phase-in, the increase from the baseline to projected 2009 FAC costs would approximate the following schedule:

	CSP	OPCO
First Bill Cycle 2009	57%	18%
First Bill Cycle 2010	100%	62%
First Bill Cycle 2011	100%	100%

Q. IN THE PROJECTED 2009 FAC COSTS USED BY MR. NELSON, DID YOU DIRECT HIM TO REFLECT AN INCREMENT OF PURCHASED POWER ON A SLICE OF SYSTEM BASIS FOR EACH COMPANY EQUIVALENT TO FIVE PERCENT OF THAT COMPANY'S LOAD?

A. Yes, I did.

Q. WHY WOULD THE COMPANIES PURCHASE THIS POWER?

A. As part of the ESP, the Companies propose to purchase power on a slice-of-system basis in increasing increments during each year of the ESP. The increments are five percent in 2009, ten percent in 2010 and fifteen percent in 2011. These amounts represent half the market rate impact on customers' rates that likely would result from implementing the MRO alternate. Therefore, these purchases can be seen as a limited feature for the continuing transition to market rates, without starting the clock that would result in full market rates by no later than ten years after an MRO is initiated. The purchases also are consistent with state policy to recognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment.

Seen from a different perspective, these purchases will reflect the Companies' agreement to accept the Ormet and Monongahela Power Company loads into their service territories. The Companies believe that during the time that they will not be on the MRO track they should be able to rely to some extent on the market as a source to serve the equivalent of those new loads and can also be used as a source of supply for future economic development in the Companies' service territories. Reflecting those purchases in the FAC is consistent with the cost recovery mechanisms approved by the Commission for both the Mon Power and Ormet situations.

Q. HAVE YOU READ THE TESTIMONY OF MR. ASSANTE CONCERNING ACCOUNTING ASSOCIATED WITH THE PHASE-IN, INCLUDING THE INCLUSION OF CARRYING COSTS ON THE DEFERRED INCREMENTAL FAC COSTS?

A. Yes, I have.

Q. IS THERE AN ALTERNATIVE APPROACH TO THE TRADITIONAL PHASE-IN MR. ASSANTE DISCUSSES IN HIS TESTIMONY?

A. S.B. 221 refers to securitizing any phase-in, inclusive of carrying charges. It is my belief that securitization of the phase-in/carrying charges could reduce the customers' financing costs associated with a phase-in. It is my understanding that unfortunately, S.B. 221's passing reference to securitization is not adequate to actually implement securitization in the most economic way, i.e., for the debt to receive a AAA credit rating from the rating agencies. Securitization with a AAA credit rating, which has been used by other utilities, would enable the securitized debt to obtain a low interest rate for the benefit of ratepayers who would pay the interest as well as the principal. Without securitization, in order to cover financing costs , customers would have to reimburse the Companies at the Companies' weighted average cost of capital rate which is a higher rate than a AAA secured interest rate on the phase-in bonds.

Q. WHY DO YOU SAY THE REFERENCE IN S.B. 221 TO SECURITIZATION IS INADEQUATE?

A. It is my understanding that, in order to securitize the deferred unrecovered FAC costs that result from the phase-in, existing law would need to be amended to include sufficient language to provide legal assurance that the debt will be secured and, as such, qualify for a AAA credit rating. AAA rated debt is awarded the lowest interest rate available in the market. Presently S.B. 221 does not include sufficient language to support a AAA credit rating from the credit rating agencies for the securitized debt. The Companies intend to pursue the legislative changes needed to achieve securitization. If the present law is amended to make securitization feasible, the Companies will, with the Commission's approval, securitize the remaining balance of the deferred unrecovered phase-in FAC costs, including to-date carrying charges and cease recovery of a weighted average capital cost based carrying cost.

CARRYING COSTS ON ENVIRONMENTAL INVESTMENT

Q. ARE YOU AWARE THAT MR. NELSON TESTIFIES REGARDING THE RECOVERY OF CARRYING COSTS ASSOCIATED WITH ENVIRONMENTAL INVESTMENTS MADE DURING THE 2001-2008 PERIOD AND TO BE MADE DURING THE 2009-2011 ESP PERIOD?

A. Yes I am.

Q. WHY ARE THE COMPANIES REQUESTING RECOVERY OF THESE COSTS?

A. The environmental investments previously made and still to be made are critical to the Companies' ability to keep their fleet of generating facilities in operation. Alternative energy resources, including renewable energy resources, and energy efficiency and peak demand reduction programs have an important place in the Companies' resource portfolio. However, those resources and programs will not replace the need for the existing base load generation—at least not in the foreseeable future. Therefore, the environmental investments have been, and will continue to be critical to the Companies' ability to provide service to their customers and to support the energy requirements of Ohio's economy.

In addition to being consistent with provisions within S.B. 221 that authorize such recovery through automatic increases, this proposal helps advance the policy outlined in Section 4928.02(C) , Ohio Rev. Code, to promote diversity of electricity supplies and suppliers while also advancing the policy outlined in Section 4928.02(A), Ohio Rev. Code, to maintain reasonably priced retail electric service.

Q. HAVE THE COMPANIES REQUESTED RECOVERY OF CARRYING COSTS ON THE ENTIRETY OF THEIR ENVIRONMENTAL INVESTMENTS MADE FROM 2001-2008?

A. No. As explained by Mr. Nelson, the Companies are not proposing to recover carrying costs associated with a large portion of their 2001-2008 environmental investment. What is being requested is only what is not presently reflected in the Companies' existing SSO rates. This position represents another advantage of the Companies' ESP in comparison with an MRO.

PROVIDER OF LAST RESORT CHARGE

Q. WHAT IS THE SCOPE OF THE COMPANIES' OBLIGATION AS THE PROVIDER OF LAST RESORT?

A. Despite the many changes to Ohio's customer choice legislation enacted in 1999 (Am. Sub. S.B. No. 3 – S.B.3) that were made by S.B. 221, the fundamental premise of S.B. 3 remains. That is, all customers are free to switch to receive generation service from Competitive Retail Electric Service (CRES) providers. Further, customers can become part of a government aggregation group as another form of switching.

Conversely, customers also are free to continue to rely on their incumbent utility for generation service at a tariff rate. Even those customers who switch can choose to return to their incumbent utility. Further, if the CRES provider to whom customers switched or the supplier to the government aggregation group were to default in its service obligation, those customers can return to the incumbent utility.

This flexibility leaves the Companies in the precarious position of being exposed to losing generation service load when the market price is low but needing to stand ready to begin serving that load again when the market price is high, and in the case of a CRES or other supplier default, doing so at a moment's notice. There is a definite and significant cost associated with providing this flexibility. In addition to the challenges of providing capacity and energy on short notice, the Companies would provide service to returning customers at the SSO rate (even though they are likely to be returning because market prices exceed the SSO).

In addition to being consistent with provisions within S.B. 221 that authorize such charges, this proposal advances the policy outlined in Section 4928.02(A), Ohio Rev. Code, to promote diversity of electricity supplies while also advancing the policy to maintain reasonably priced retail electric service.

Q. **ARE THERE PROTECTIONS IN PLACE FOR THE COMPANIES TO LIMIT THEIR EXPOSURE TO THESE COSTS?**

A. There are some limited protections in the context of shopping rules discussed in the testimony of the Companies' witness Mr. Roush these are consistent with S.B.

221 which continue to support customers having a true market option. There are other protections, however, that would appear to shield the Companies from some costs associated with providing the flexibility but in practice might not.

Q. **DO YOU HAVE AN EXAMPLE OF SUCH A PROTECTION?**

A. Yes, I have been advised by counsel that a government aggregation may elect not to receive standby service from the incumbent utility operating under an ESP. If the utility is notified of that election, it is prohibited from charging customers of the government aggregation for standby service. However, customers of that government aggregation who return to the utility for generation service will be required to pay the market price of power incurred by the utility to serve the customers (plus any amount attributable to compliance with the alternative energy resource mandates in S.B. 221). This protection, however, is not unlimited since the Commission has the authority to relieve customers of this market price exposure after two years.

Q. **WHY DO YOU BELIEVE THIS PROTECTION FOR THE COMPANIES MIGHT NOT BE EFFECTIVE?**

A. The most likely time for a supplier to a governmental aggregation to default is when market prices are at their highest levels. While charging those market prices, which in today's market condition would be in a range of $85-90/MWh, or higher, is theoretically consistent with customer choice, I simply do not believe that the Commission and/or the General Assembly and Governor will sit back and fail to intervene while residential customers are forced into paying those rates.

Q. **DO YOU HAVE AN EXAMPLE OF GOVERNMENT ACTION WHICH LEADS YOU TO THIS BELIEF?**

A. Yes. S.B. 221 itself is a government action to protect customers from having to pay market prices for power beginning in 2009. The market price over a full year at on-peak and off-peak hours would be considerably lower than what the market price could be at the time of a supplier's default. The enactment of S.B. 221 convinces me that utilities likely would not be permitted to charge market rates to those customers who agreed to forego standby service.

Q. **DO YOU BELIEVE THAT CUSTOMERS WHO PAID NO STANDBY, OR POLR CHARGE STILL WOULD BE ENTITLED TO POLR SERVICE.**

A. Yes, while I certainly cannot predict the ultimate resolution of such a situation I am quite confident that those customers will not be required to pay peak spot market prices. To me this is no different than many non-residential customers who urged the passage of S.B 221 so they could pay rates regulated by the Commission.

Q. **DO YOU HAVE ANOTHER EXAMPLE OF HOW IT APPEARED THAT A UTILITY NO LONGER NEEDED TO PLAN TO SERVE POWER TO A CUSTOMER BUT ONCE AGAIN WOUND UP WITH THAT SERVICE OBLIGATION?**

A. Yes and this example is striking. Ormet used to be a customer of OPCO. When its service contract expired prior to the availability of customer choice, OPCO agreed to a modification of its service territory so that the Ormet facilities wound up in the service territory of another electric supplier. This agreement accommodated Ormet's desire to purchase power in the market and OPCO no longer had to plan on serving Ormet's load which had been in the range of 500 MW.

Several years later when market prices no longer were attractive to Ormet it filed a complaint with the Commission seeking to return to the comfort of OPCO's service territory. Recognizing the State's interest in enabling Ormet's continued existence in an economically weak portion of Ohio, OPCO, along with CSP and several of their industrial customers agreed to Ormet's return to service from OPCO and CSP, at a level of over 500 MW.

Q. DO YOU THINK THIS WAS AN IMPROPER OUTCOME?

A. Just focusing on the interests of CSP and OPCO and its shareholders, the outcome was far from ideal. Looking at this situation from a broader Ohio economy perspective I suppose it could be considered reasonable. My point, however, is that when viewed through the lens of the nature and extent of the Companies' POLR obligation, here we have load exceeding 500 MW that did not simply switch to another generation provider, it actually was removed from OPCO's certified service territory. Nonetheless, when push came to shove the customer and its massive load switched back to AEP Ohio. This is the ultimate nature and scope of AEP Ohio's significant POLR obligation. The obligation exists even when statutes and contracts tell you otherwise.

Q. WITH THIS BACKGROUND IN MIND, HOW DID THE COMPANIES DEVELOP THE POLR CHARGE THEY HAVE INCLUDED?

A. As I discussed previously, customers have the right to leave the utility and take service from an alternative supplier as well as the right to return to AEP's ESP pricing if future market price fluctuations make it advantageous for them to do so. AEP is holding the other side of that arrangement; AEP is obligated to stand ready to handle whatever load fluctuations may result from such switching. The financial risk inherent in such arrangements is a result of the asymmetrical relationship that exists between the two parties – one party is holding the rights that will bring financial benefits to themselves and at the same time impose financial losses on the other party.

Q. **WHY IS AN OPTION MODEL THE APPROPRIATE WAY TO VALUE A UTILITIES POLR OBLIGATION?**

A. The costs of AEP's POLR obligation can be best understood in light of potentially having to buy high and sell low. Wholesale price volatility and the asymetrical impacts of retail choice – i.e., the customer is the party who holds the ability to choose if and when they want to take service from a competitive retail provider or under the utility's ESP plan - are the keys to understanding AEP's cost of providing its POLR obligation. The customers' option to switch providers can be demanded opportunistically, at the economic convenience of customers. In fact, Ohio's desire to create structures and incentives to encourage customer switching is one of the stated policy goals of SB 221. When determining the cost of AEP's POLR obligation, it is important to realize that in financial terms, such one-sided rights that customers receive through retail choice are equivilant to a series of options on power. When it becomes apparent that there are economic benefits from switching between a competitive supplier and the ESP price, the rational customer will exercise his or her flexibility to change providers. AEP, however, will bear the difference between market and ESP prices as a loss. Thus, an option pricing model provides an effective way to calculate the cost of AEP's POLR obligation.

Q. WHAT METHOD WAS USED TO PRICE THE OPTION RISK INVOLVED IN ITS POLR OBLIGATION?

A. AEP used the Black-Scholes option pricing model to calculate the value of its POLR obligation. The Black-Scholes option pricing model is the widely used option model. Among its many applications, it is used extensively to provide basic benchmark pricing for equity and commodity options.

Q. WHAT ARE THE REQUIRED QUANTITATIVE INPUTS IN THE BLACK-SCHOLES MODEL?

A. The inputs necessary to calculate the price of an option using the Black-Scholes model are (1) the market price of the of the underlying asset, (2) the strike price, which is the price level at which the option holder has the right to buy or sell the asset, (3) the time frame that the option covers, (4) the risk free interest rate and (5) the volatility of the underlying asset.

The inputs used in calculating the cost of the Companies' POLR obligation and how they correspond to the defined elements of the Black-Scholes model are listed in the table below.

Black-Scholes Inputs	(1) Market Price	(2) Strike Price	(3) Time Frame	(4) Interest Rate	(5) Volatility
AEP Inputs into Black-Scholes	The competitive benchmark prices discussed in relation to the MRO	The proposed ESP price as contained in our filing	Calendar Years 2009-2011 (the same term as our proposed ESP and the same term used to calculate our competitive benchmarks	The interest rate of the 3 year Treasury note	The volatility of the futures contract for the term 2009-2011

Q. WHERE DOES THE RISK OF THE POLR OBLIGATION COME FROM SINCE THE PROPOSED ESP RATE IS LOWER THAN THE FORECASTED FULL REQUIREMENTS PRICE?

A. The ESP price and the full requirements market price are only two of the variables that need to be taken into consideration. The time frame of the option – in this case the 2009-2011 time period set out in our filing– as well as the interest rate also have an impact on the cost of the POLR obligation. Even more importantly, the volatility of electricity prices plays an important role. Simply because our proposed ESP rate is currently under the market price of competitive retail electric service does not mean that there will not be periods over the next three years where those pricing lines could cross. Electricity is an extremely volatile commodity traded. This volatility no doubt is responsible for customers urging the passage of S.B. 3 so they could get access to market prices and then urging the passage of S.B. 221 so that they would be protected from market prices. The option calculation takes into account the extreme volatility of electricity prices when calculating the cost of the POLR obligation. It is also important to remember that the Black-Scholes model also uses AEP's proposed ESP price and the estimation of competitive retail electric service prices as direct inputs. As a direct result of the difference between the Companies' proposed ESP rates and the much higher competitive retail electric service prices, the cost of fulfilling the Companies' POLR obligation is significantly lower than if the difference were not as large.

Q. IN THE PREVIOUS EIGHT YEARS, VIRTUALLY NO CUSTOMER SWITCHING HAS OCCURRED IN THE COMPANIES' SERVICE TERRITORY. WHY DO THE COMPANIES BELIEVE A POLR CHARGE IS JUSTIFIED UNDER THE PROPOSED ESP?

A. S.B. 221 makes clear that the promotion of retail competition, including large scale governmental aggregation, is one of the policy goals of the state. Moreover, given the volatility of electricity prices, market rates could fall below the SSO during the term of the ESP. The freedom for customers to switch suppliers while leaving the Companies obligated to provide POLR service imposes a quantifiable financial risk on the Companies. The POLR charge the Companies are requesting in this filing is a fair and reasonable approach to addressing the inherent risk associated with acting as the Provider of Last Resort.

Q. HOW HAS THE POLR OBLIGATION BEEN ADDRESSED IN OTHER DEREGULATED STATES?

A. The way in which POLR obligations are dealt with varies from state to state. Many states require customers returning to utility service to go on some type of market price – transferring the risk of switching from the utility to the customer.

If such an approach were used in Ohio, many have stated that the State's goal of relative price stability for customers would not be achieved.

Q. HOW DOES THIS APPROACH TO HANDLING THE COMPANIES' POLR OBLIGATION AND ITS PROPOSED RETAIL SWITCHING RULES ADDRESS THE CONCERNS OF ALL STAKEHOLDERS?

A. The Companies are proposing to leave in place the switching rules currently in effect. We believe the inclusion of the POLR charge in conjunction with the rules that allow for broad switching among all customers provides a fair and balanced approach. While Ohio continues to develop and encourage retail competition as outlined in S.B. 221, we believe this is the best way to provide customers the freedom to explore competitive alternatives while still providing a reasonable method of dealing with the obligation that imposes on the Companies.

Q. WHY SHOULD THE POLR CHARGE BE NON-BYPASSABLE?

A. All customers, even those who have switched generation suppliers, have the right to rely on the Companies for generation service. As a related matter, the fact that CRES providers do not assume the POLR obligation also helps to keep generation rates offered by CRES providers lower. Therefore, the charge must be non-bypassable.

Q. BASED ON THIS ANALYSIS WHAT IS EACH COMPANY'S POLR REQUIREMENT?

A. The POLR revenue requirements are $108.2 million for CSP and $60.9 million for OPCO per year. Companies' witness Mr. Roush uses these revenue requirements to develop the Companies' proposed POLR rates.

__TEST FOR SIGNIFICANTLY EXCESSIVE RETURN ON COMMON EQUITY__

Q. WHY ARE THE COMPANIES ADDRESSING IN THIS FILING VARIOUS ISSUES CONCERNING THE DETERMINATION THE COMMISSION WILL NEED TO MAKE CONCERNING THE COMPANIES RETURN ON EQUITY FOLLOWING THE END OF EACH ANNUAL PERIOD OF THE ESP?

A. I have been advised by counsel that the Commission must consider, following the end of each annual period of the ESP, if adjustments made in the ESP resulted in the return on common equity being significantly in excess of the return on common equity earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risks, with adjustments for capital structure as may be appropriate. The Commission must also consider the capital requirements of future committed investments in Ohio. The Company will have the burden of proving that significantly excessive earnings did not occur.

As I review the statutory language, I see two significant uncertainties in the statutory provision. In light of the fact that the burden of proof concerning this analysis rests with the Companies, it is important to have the Commission address these uncertainties.

Q. WHAT ARE THE TWO UNCERTAINTIES TO WHICH YOU REFER?

A. One uncertainty is centered on the notion of publicly traded companies that face comparable business and financial risks. The other uncertainty is centered on the meaning of "significantly excessive." This latter point really is a two-part uncertainty: how will "excessive" be defined and how will "significantly excessive" be defined?

Q. **BESIDES MEETING THE BURDEN OF PROOF ARE THERE OTHER REASONS THAT THE COMMISSION SHOULD PROVIDE SOME CLARITY CONCERNING THESE UNCERTAINTIES?**

A. Yes there are. The refund potential inherent in the earnings test creates financial uncertainty which in turn results in financing costs that would be higher than otherwise. The uncertainties I have identified add further risk to the overall financial uncertainty risk. Therefore, the interests of the Companies and their customers are best served by the Commission providing clarity on these matters.

Q. **HOW HAVE THE COMPANIES APPROACHED THESE ISSUES IN THIS PROCEEDING?**

A. The Companies are presenting the testimony of Companies' witness Dr. Makhija. His testimony proposed the determination of comparable publicly traded companies and the application of the term "significantly excessive."

I have reviewed the approach proposed and supported in Dr. Makhija's testimony and, while I recognize that the Commission needs to retain some degree of judgment in how those concepts are applied, I believe his methodology should be endorsed by the Commission as the starting point for its earnings analysis.

Q. **IN YOUR OWN ANALYSIS OF THE SIGNIFICANTLY EXCESSIVE EARNINGS TEST REQUIREMENT, WHAT CONCLUSIONS HAVE YOU REACHED CONCERNING THE BUSINESS RISK FACING THE COMPANIES?**

A. As I think about the business risk facing the Companies under S.B. 221 I categorize those risks in five categories. These are migration risk, asset risk, financial risk, transition to market risk and litigation risk. Attached to my testimony as EXHIBIT JCB-1 is a list of risks that I see as falling within each of these categories. Based on my forty years of experience in the utility industry and my general familiarity with many other industries, I am unaware of other industries that can be said to have comparable business and financial risks as the Companies do.

Q. ARE THERE OTHER ASPECTS OF THE SIGNIFICANTLY EXCESSIVE EARNINGS TEST THAT YOU BELIEVE THE COMMISSION SHOULD CLARIFY PRESENTLY AS OPPOSED TO WAITING UNTIL IT ACTUALLY APPLIES THE TEST?

A. Yes. I think it will be necessary to adjust the Companies' returns on equity for two factors. The first factor is mentioned in the testimony of Companies' witness Mr. Assante. As he points out, the phase-in deferrals would result in earnings as if there had been no phase-in.

While the return on equity may be the same under a phase-in or no phase-in scenario, the reality of the situation is that customers will not have paid rates that reflect the amounts of the deferrals. Therefore, it would be inappropriate to base a finding of a significantly excessive return on equity or revenues that the Companies had not received and worse-yet, to order the Companies to return these "revenues" to customers even though the customers had not even made those payments. My further concern with ordering a refund of recoveries which had not actually been paid is the concern raised by Mr. Assante regarding the inability to offer a phase-in because the deferral requirement of probability of recovery will be severely jeopardized. So that we and our auditors can determine whether a phase-in is achievable, the Commission needs to address this issue.

Similarly, although not related to the proposed phase-in, the Commission needs to address the treatment of the off-system sales on the Companies' return on equity.

Q. **WHAT IS MEANT BY OFF-SYSTEM SALES?**

A. Off-system sales are opportunity wholesale sales by the AEP system. The sales are made pursuant to rates approved by the Federal Energy Regulatory Commission under its exclusive jurisdiction. The margins from these sales are allocated to the AEP operating Companies, including CSP and OPCO. The AEP system does not plan its generating facilities based on anticipated off-system sales. Instead, generating facilities are planned to meet current and anticipated firm loads. To the extent capacity is available and a demand for that capacity exists on the wholesale market, the opportunity is pursued and hopefully an opportunity sale, or off-system sale, is made.

Q. **WHAT IS YOUR RECOMMENDATION REGARDING THE TREATMENT OF OFF-SYSTEM SALES IN THE CONTEXT OF THE EARNINGS TEST?**

A. With this background, I have been advised by counsel that it would be unlawful for the Commission to order a refund based on earnings influenced, in part, by recoveries received through FERC-jurisdictional rates. Even without this legal issue, I believe it would be inappropriate to order a refund based on a return on equity which results, in part, from these off-system sales. The entire focus of S.B. 221 is on retail sales. Indeed, to the extent that earnings result from sources other than adjustments in the ESP, I believe that it would be inappropriate to consider such earnings as excessive. The return on equity test must be reviewed in this context, and the Commission should make clear in this ESP order that it will exclude the impact of off-system sales from any application of the test.

Q. ARE THERE OTHER ADJUSTMENTS THAT MIGHT NEED TO BE MADE BY THE COMMISSION AS PART OF THE EARNINGS TEST?

A. Yes, at least one other adjustment might need to be made in the context of OPCO's eventual resolution of the JMG lease issue. Depending on how that matter is resolved there may need to be an adjustment. OPCO would, as part of any JMG lease filing, address the treatment of any such adjustment.

Q. DO YOU HAVE ANY OTHER MATTERS RELATED TO THE EARNINGS TEST THAT THE COMMISSION SHOULD RESOLVE AT THIS TIME?

A. Yes. I recommend that the earnings test be performed on the two Companies on a combined basis. These two Companies are operated as a single entity, with a single management structure. Their participation in economic development efforts is based on a combined basis instead of as two companies competing against one another. Reviewing earnings on a separate company basis puts form over substance and would result in a penalizing one company or not penalizing the other company for decisions made based on the overall perspective of AEP Ohio.

<u>MODIFICATION OF CORPORATE SEPARATION PLAN AND AUTHORITY TO SELL OR TRANSFER CERTAIN GENERATING ASSETS</u>

Q. WHAT IS THE STATUS OF THE COMPANIES' CORPORATE SEPARATION PLAN?

A. In their electric transition plan proceedings each Company was authorized to legally separate its distribution, transmission and generation functions. In their RSP proceeding, however, the Commission modified the previously approved corporate separation plans. In particular, the Commission authorized the Companies to operate on a functional separation basis. (RSP Opinion and Order, p. 35).

Q. WHAT ARE THE COMPANIES PROPOSING IN THIS PROCEEDING REGARDING CORPORATE SEPARATION?

A. The Companies are proposing that the Commission authorize the Companies to remain functionally separated and authorize a plan to retain the distribution and, for now, the transmission assets and to eventually move their generating assets to a to-be-formed affiliate company. The Commission's authorization of such a request would be the first of several steps that would need to be taken before actual transfer could be completed. Of course, one important step in that process would be to obtain Commission authority to actually sell or transfer the generating assets.

Q. WHY DO THE COMPANIES REQUEST THIS AUTHORITY?

A. I have been advised by counsel that functional separation can only be permitted for an interim period. Counsel also has advised me that the underlying requirement remains for corporate separation of the provision of competitive retail electric service from the provision of noncompetitive retail electric service. While the length of the "interim period" for which functional separation is permitted is not defined, it is not contemplated as a permanent solution. Therefore, ultimately, and in my opinion probably sooner rather than later, legal separation must be achieved. We believe the three-year ESP accommodates a reasonable extension period of functional separation. However, eventually legal separation will be required and all parties should understand how the Companies would implement their corporate separation

Q. WHEN THE COMPANIES EVENTUALLY ARE AUTHORIZED TO LEGALLY SEPARATE THEIR DISTRIBUTION, TRANSMISSION AND GENERATION ASSETS WOULD THEY BE ABLE TO AVOID THE STATUTORY PHASE-IN REQUIREMENT IN THE CONTEXT OF A FUTURE MRO?

A. No. As of the effective date of S.B. 221 both Companies directly own operating electric generating facilities that had been used and useful in Ohio. Counsel has advised me that therefore, §4928.142 (D) Ohio Rev. Code, will require that when in the future, the Companies seek authority to establish the Standard Service Offer under an MRO only a portion of the SSO for the first five years of the MRO can be competitively bid. Therefore, as I understand it, when the Companies apply for an MRO to determine their SSO, even if the Companies' modification to their corporate separation plan had been previously granted their rates would not be based on one hundred percent market at that time.

Q. **DOES CSP OWN ANY GENERATING ASSETS WHICH HAVE NOT BEEN DECLARED USED AND USEFUL IN OHIO?**

A. Yes, it owns two such facilities. On September 28, 2005, CSP purchased the Waterford Energy Center located in southeastern Ohio. The Waterford generating facility is a natural gas combined cycle power plant. It has a nominal generating capacity of 821 MW. On April 25, 2007, CSP completed the purchase of the Darby Electric Generating Station. The Darby plant, located near Mount Sterling, Ohio, is a natural gas simple cycle generating facility with a nominal generating capacity of 480 MW and a summer capacity of approximately 450 MW.

Q. **IRRESPECTIVE OF CSP'S CORPORATE SEPARATION PLAN YOU HAVE DISCUSSED, WHAT IS CSP'S REQUEST CONCERNING THESE TWO FACILITIES?**

A. CSP requests authority to sell or transfer these two plants. However, CSP has no present plan to exercise that authority. Neither of these units have ever been in CSP's rate base and customers' generation rates have not reflected CSP's investment in the plants or the expenses of operating and maintaining the plants.

The amendment to §4928.17 (E), Ohio Rev. Code, concerning the sale or transfer of generating assets could not have been more of a reversal of state law. Up to July 30, 2008, a utility could divest generating assets without Commission approval. As of July 31, 2008, prior Commission approval of such a sale or transfer is required. Many argued during the legislative debates over S.B. 221 that this represents an appropriate change in public policy with respect to generating assets that had been the basis for rates that customers have been paying, i.e., used and useful for rate base purposes. While I do not agree with these arguments that same argument cannot be made regarding the Darby and Waterford facilities. Therefore, I believe it is appropriate for the Commission to grant CSP, as part of the ESP, the authority to sell or transfer those generating assets.

Q. IF PRIOR TO JULY 31, 2008, CSP COULD HAVE SOLD THOSE PLANTS WITHOUT HAVING TO OBTAIN COMMISSION AUTHORITY WHY DID IT NOT DO SO?

A. There are two parts to the answer to that question – a practical part and a philosophical part. As a practical matter transactions of this nature do not happen over night. It is not clear to me that the transaction could be completed in time. More important, however, is the philosophical part. The implementation of S.B. 221 should occur in a fair and responsible manner. Since rushing to sell these plants might be perceived by some as trying to avoid the General Assembly's intent in this regard, we chose to bring this issue before the Commission.

Q. DO CSP AND/OR OPCO HAVE GENERATION ENTITLEMENTS RESULTING FROM ARRANGEMENTS OTHER THAN THE WHOLE OR PARTIAL OWNERSHIP OF GENERATING ASSETS?

A. Yes they do. On May 16, 2007 AEP Generating Company, an affiliate of CSP purchased the Lawrenceburg Generation Station located in Lawrenceburg, Indiana. The Lawrenceburg plant is a combined-cycle natural gas power plant with a generating capacity of 1,096 MW. CSP has a contract for the output of the Lawrenceburg plant.

In addition, CSP and OPCO each have a contractual entitlement to a portion of the output from the generating facilities of the Ohio Valley Electric Corporation (OVEC). Those facilities are the Kyger Creek plant owned by OVEC and Clifty Creek plants owned by OVEC's subsidiary, Indiana-Kentucky Electric Corporation. These entitlements have not been reflected in rate base for either Company.

Q. PLEASE DESCRIBE CSP'S AND OPCO'S RELATIONSHIP WITH OVEC.

A. OVEC was formed in 1952 by several regional utilities to provide power to a uranium enrichment plant near Portsmouth, Ohio. AEP is one of the owners and CSP, which was not part of the AEP system in 1952, is another of the owners. OVEC and the Atomic Energy Commission (AEC) executed a power agreement which ultimately was terminated on April 30, 2003.

The OVEC "Sponsoring Companies", which include CSP, a part owner of OVEC, and OPCO, through AEP's part ownership of OVEC, signed an Inter-Company Power Agreement (ICPA) which provides for excess energy sales to the Sponsoring Companies of power not utilized by the AEC (subsequently the Department of Energy, DOE). Only after the 2003 termination of the OVEC-AEC/DOE agreement, OVEC's entire generating capacity has been available to the Sponsoring Companies. The term of the ICPA has been extended to March

13, 2026. The combined capacity of the Kyger Creek and Clifty Creek plant is 2,390 MW. CSP's and OPCo's shares as Sponsoring Companies are 4.44 percent and 15.49 percent, respectively.

Q. DO CSP AND OPCO BELIEVE THAT THEY NEED COMMISSION AUTHORIZATION TO SELL OR TRANSFER THE OVEC AND CSP LAWRENCEBURG, ENTITLEMENTS?

A. I have been advised by counsel that since these entitlements are contractual in nature and do not arise from generating assets that either Company wholly or partly owns, Commission approval for such transactions is not required.

Q. WHY ARE YOU TESTIFYING ABOUT THE LAWRENCEBURG AND OVEC TRANSACTIONS?

A. The focus of S.B. 221 on generation-related transactions indicates an interest in the sale or transfer of generating assets wholly or partly owned by an electric distribution utility. Though Commission approval of the intended transactions I have just described is not required, and I am not aware of any requirements to inform the Commission of these transactions, I believe it would be inappropriate to discuss matters that are jurisdictional, i.e. the Darby and Waterford plants, and not give a complete picture regarding plants that have not previously been deemed used and useful by the Commission.

AMORTIZATION OF MISCELLANEOUS DEFERRED COSTS

Q. ARE THE COMPANIES PROPOSING TO BEGIN THE AMORTIZATION OF MISCELLANEOUS DEFERRED COSTS

A. Yes. The proposal is to begin that amortization in 2011 and complete the amortization approximately eight years later.

Q. WHAT IS THE RATIONALE FOR THE TIME PERIODS?

A. As Mr. Assante notes in his testimony, a significant portion of these deferrals have been on the Companies' books since the Market Development Period. With the passage of S.B. 221, and the filing of an ESP which makes adjustments to distribution rates, it is appropriate to address at this time the amortization of these deferrals. The Companies believe that with other ESP rate increases it would be in the interest of customers to put off the commencement of the amortization.. To further moderate the rate impact on customers, the Companies propose to amortize the deferrals over approximately eight years, starting in 2011. Mr. Roush testifies in support of a rider that will recover these deferrals along with carrying charges on the unrecovered balance of the deferrals.

<u>ECONOMIC GROWTH ADJUSTMENTS TO BASELINES FOR ENERGY EFFICIENCY AND PEAK DEMAND REDUCTIONS</u>

Q. WHY ARE THE COMPANIES ADDRESSING IN THIS FILING THE BASELINES FOR THE ENERGY EFFICIENCY AND PEAK DEMAND REDUCTIONS MANDATED BY S.B.221?

A. Since the Companies' obligations regarding energy efficiency and peak demand reduction begin in 2009 it is important for us to know how the baselines will be determined. While the precise level of the baselines cannot be determined until the Companies' total kilowatt hours sold in 2008 are known, we can establish for

2009 and thereafter the "rules of the road" for making adjustments to the preceding three year's average kilowatt hours sold.

Q. WHAT ADJUSTMENTS TO THE BASELINES ARE THE COMPANIES PROPOSING?

A. I have been advised by counsel that the Commission has the authority to reduce these baselines to adjust for new economic growth in the utility's certified territory. The term "economic growth" if broadly interpreted could include all new load added during the three-year baseline period.

Q. WHAT ECONOMIC GROWTH ADJUSTMENTS ARE THE COMPANIES PROPOSING FOR THE BASELINE YEARS 2006-2008?

A. There are four categories of economic growth that the Companies are proposing. The first category relates to the Commission's January 26, 2005 Opinion and Order in the Companies RSP proceeding. One of the results of that order was that the Commission concluded that "$14 million should be allotted by [the Companies] for the benefit of [their] low-income customers, as well as for economic development during the RSP period." (p 34). As directed by the Commission, the Companies worked with the Commission's Staff to develop the use of that money. The Staff in turn, was directed to work with the Department of Development in relation to the use of the money. It is the Companies' position that to the extent the $14 million was used for economic development purposes which resulted in increased load, that load should be removed from the average three-year baselines.

Q. WHAT IS THE SECOND CATEGORY OF ECONOMIC GROWTH-RELATED LOAD THAT SHOULD BE REMOVED FROM THE CALCULATION OF THE BASELINES?

A. The second category relates to the load acquired by CSP when it absorbed the service territory formerly served by Monongahela Power Company (Mon Power). The record in that proceeding (Case No. 05-765-EL-UNC) reflects the Commission's concerns for Mon Power's customers if they were not served under an RSP. The Commission stated that "Mon Power's retail customers may be facing potential rate shock and rate instability.... The Commission remains resolute that the RSP option is the best option for Ohio's electric customers...." (June 14, 2005 Entry, p.1).

The Staff also testified that CSP's assumption of the responsibility of providing a Standard Service Offer to the former Mon Power customers.... is "not normal load growth within the CSP service territory .... and was "in response to a request by the Commission as a matter of public policy...."

The Staff's witness Mr. Cahaan also testified:

> There are important economic development issues. Certainly, a major reason for promoting a rate stabilization plan in the former Mon Power service territory was related to concerns of economic dislocation. It is also clear that neighboring locations in Ohio have strong economic ties and are strongly linked. In general prosperity in one area spills over into other areas, boosting their economic health. Conversely, dislocation and economic decline in an area spill over to neighboring areas. The benefits of providing a rate stabilization plan to the southeastern corner of the State will provide benefits to the rest of the CSP service territory as well. (*Id.* at 4)

In its post-hearing brief the Staff argued that if CSP did not absorb Mon Power's service territory, prices would leap to a level that "almost certainly will drive out major employers from a region which already has very few. This is a crushing blow to a region which has weathered many, too many, in recent years." (Brief, pp 1,2).

Finally, in its November 9, 2005 Opinion and Order in that proceeding the Commission held that with the service territory transfer "economic benefits will insure to all citizens and businesses in both regions by helping to sustain economic development in southeastern Ohio." (Opinion and Order, p.11)

Given this record it is clear that CSP's acquisition of the former Mon Power service territory served the interest of economic development in Ohio and resulted in new economic growth in CSP's certified service territory.

Q. WHAT IS THE THIRD CATEGORY OF ECONOMIC GROWTH-RELATED LOAD THAT SHOULD BE REMOVED FROM THE CALCULATION OF THE BASELINE?

A. The third category relates to the Ormet load being served by CSP and OPCO. As discussed elsewhere, as a result of a complaint filled by Ormet against it's then-current electric supplier and OPCO (Case No. 05-1057-EL-CSS), as of January 1, 2007 Ormet became a customer of a new CSP/OPCO combined service territory.

In the Commission's November 8, 2006 Supplemental Opinion and Order the Commission reviewed the extensive economic benefits resulting from the transfer of service responsibility to CSP and OPCO. These benefits included the employment of about 1,000 people with annual wages of $40,000,000 and healthcare benefits costing over $10,000,000 per year. Further, Ormet pays about $1,000,000 annually in taxes to Monroe County, Ohio and its school district.

"These extensive economic benefits can only be obtained through the resumption of operations at [Ormet's] Hannibal Facilities, and the Stipulation will facilitate the resumption of those operations." (p.7).

Based on the record in that case it is clear that CSP's and OPCO's service to Ormet resulted in economic growth in their certified territory.

Q. **IS THERE ANY ADDITIONAL GROWTH-RELATED LOAD THE COMPANIES ARE SERVING THROUGH THEIR JOINT SERVICE TERRITORY?**

A. Yes. In its November 7, 2007, Finding and Order in Case No. 07-860-EL-AEC the Commission approved a service contract between the Companies and Hannibal Real Estate LLC. (Hannibal). Hannibal is a steel plate storage and distribution company which, prior to obtaining Ormet's former rolling mill facility, which had been idle since 2005, had been located in White Plains, New York. Hannibal estimated its reopening the rolling mill facility will result in 20-30 jobs with very competitive wages.

This special contract has brought additional economic growth benefits to Monroe County and the load of Hannibal should be removed from the three-year baseline calculation.

Q. **LOOKING BEYOND THE BASELINE FOR 2009, DO THE COMPANIES ANTICIPATE ANY OTHER ECONOMIC GROWTH-RELATED LOAD ADJUSTMENTS TO THE APPLICABLE BASELINES?**

A. Yes. Besides the continuation of adjustments for the loads I have discussed, the Companies are mindful of the likelihood of future load growth due to economic growth tied to the economic development efforts of the Companies, and state and local agencies with responsibility for economic development. These economic development efforts are important to the state as a whole and to the communities we serve. Failing to adjust the baselines for such load will result in a disincentive to promote economic growth. This is because the larger the baselines the greater the amount of energy efficiency and peak demand reduction which must be achieved in order to avoid the imposition of non- compliance forfeitures. Therefore, we ask the Commission to declare that load resulting from the Companies' and/or state and local agencies with responsibility for economic development will be excluded from the baseline calculations.

POSSIBLE EARLY PLANT CLOSURE

Q. WHY ARE THE COMPANIES ADDRESSING IN THIS FILING THE ACCOUNTING FOR POSSIBLE EARLY PLANT CLOSURE?

A. Some of the Companies' units could experience failures or safety issues that would require significant investment to keep them operating. As long as it is economical and safe to do so, the Companies intend to keep their units running as long as possible. However, considering the number of units the Companies' own it is possible that one or more of their units may experience a failure or safety issue requiring a significant investment that would not be cost effective to make. It is possible, therefore, that the date at which one of these units is no longer able to cost-effectively operate could be a date earlier than assumed for depreciation accrual purposes. Mr. Assante discusses in his testimony how the Companies propose to account for and recover the cost for such an event.

INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY

Q. PLEASE DESCRIBE THE BACKGROUND OF THE COMPANIES' EFFORTS TO CONSTRUCT AN INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) GENERATING FACILITY IN MEIGS COUNTY, OHIO.

A. In its January 26, 2005, Opinion Order in Case No. 04-169-EL-UNC, the Companies' Rate Stabilization Plan (RSP) proceeding, the Commission urged the Companies:

> "to move forward with a plan to construct an [IGCC] facility in Ohio." [The Companies] should engage the Ohio Power Siting Board in pursuit of such a plant. We are encouraged by emerging information that suggests that the IGCC technology will be economically attractive. It is worth noting that the Commission is exploring regulatory mechanisms by which utilities, given their POLR responsibilities, might recover the costs of these new facilities." (pp. 37-38).

The Commission explained its interest in IGCC technology in the context of the Companies' statutory POLR responsibilities, the Commission's responsibility to enhance the business climate in Ohio, Ohio's express statutory policy that consumers are entitled to a future secure in the knowledge that electricity will be available at competitive prices, and the Commission's opinion that electric generators of the future should be both environmentally friendly and capable of taking advantage of Ohio's vast fuel resources.

Q. **DID THE COMPANIES SHARE THE COMMISSION'S INTEREST IN IGCC TECHNOLOGY?**

A. Absolutely, and we continue to be interested in building and operating an IGCC facility in Meigs County, Ohio.

Q. **HOW DID THE COMPANIES PROCEED IN RESPONSE TO THAT PORTION OF THE RSP ORDER?**

A. On March 18, 2005 the Companies filed an application for authority to recover costs associated with the construction and operation of an IGCC facility. That application was docketed as Case No. 05-376-EL-UNC. In that application the Companies requested authority to implement a three-phase mechanism for recovering their IGCC costs. As the Companies' then - President testified at that *time*, however, *the Companies would not continue on the IGCC construction path* if cost recovery were subject to uncertainty. In addition, the Companies obtained a certificate from the Ohio Power Siting Board to construct the proposed IGCC plant. (OPSB Case No. 06-30-EL-BGN).

Q. **HOW DID THE COMMISSION RULE IN THE IGCC CASE?**

A. In its April 10, 2006 Opinion and Order the Commission approved Phase I recovery of approximately $24 million of pre-construction costs. In the Commission's June 28, 2006 Entry on Rehearing, the Commission, based on its belief "that there may be elements of the design and engineering that may be transferable to other projects" (p. 16), ordered that if the Companies have not

> "commenced a continuous course of construction of the proposed facility within five years of the date of issuance of this entry on rehearing, all Phase I charges collected for expenditures associated with items that may be utilized at other sites, must be refunded to Ohio ratepayers with interest." (p.17).

Q. WERE THE COMMISSION'S IGCC ORDERS APPEALED?

A. Yes, they were.

Q. WHAT WAS THE OUTCOME OF THE APPEAL?

A. I will not attempt to explain the Ohio Supreme Court's rationale. I note, however, that the Court reversed in part and affirmed in part the Commission's orders and remanded the proceeding back to the Commission. The Court's opinion, of course, was based on the law as it existed prior to the enactment of S.B. 221.

Q. DOES THE ENACTMENT OF S.B. 221 PROVIDE LEGAL AUTHORITY FOR THE COMMISSION TO APPROVE THE COMPANIES' THREE-PHASE COST RECOVERY PROPOSAL FOR IGCC COST RECOVERY?

A. That is a question the Commission, and then perhaps the Ohio Supreme Court would need to answer. I can say, however, that from the Companies' perspective there are several provisions in S.B. 221 which appear to create barriers to the construction of the IGCC facility in Meigs County.

Q. CAN YOU IDENTIFY ANY EXAMPLES OF THOSE PROVISIONS?

A. Yes. While S.B. 221 does address construction work in progress (CWIP) and surcharges for the life of an electric generating facility owned by the electric distribution utility, those are mentioned only in the context of an ESP. An IGCC facility will be a long-lived asset. The structure of S.B.221 may require the electric distribution utility to remain in an ESP for decades to assure an opportunity for IGCC cost recovery. Foregoing the MRO alternative on such a long-term basis is a very steep price to pay for what we believe is a sensible component of meeting our POLR obligation and meeting what appear to be ever-increasing environmental restrictions.

Another example of a barrier is the CWIP provision itself. Ohio's CWIP provision has several restrictions that tend to minimize the benefits of CWIP. S.B. 221 does not appear to overcome these restrictions. These include the seventy-five percent complete requirement, the limit on CWIP as a percentage of total rate base and the effect of so-called "mirror CWIP." The limit on CWIP as a percentage of total rate base causes particular uncertainties since the concept of a generation rate base has no applicability under S.B. 221.

Q. **DO THE COMPANIES INTEND TO ABANDON THEIR INTEREST IN CONSTRUCTING AND OPERATING AN IGCC FACILITY IN MEIGS COUNTY?**

A. Definitely not. The Companies, our customers, Ohio's coal industry and the State of Ohio cannot afford to give up on this project. The examples I just mentioned are not unique to IGCC technology. They are real barriers to the construction of any base load generation in Ohio. We are encouraged that while the General Assembly addressed renewables and energy efficiency in S.B.221, it also recognized the need for advanced energy resources, including clean coal technology, such as IGCC, with design capability to control or prevent the emission of carbon dioxide. It is our hope that we can work with the Governor's administration, the General Assembly and any other party that has a genuine interest in securing Ohio's energy future in a responsible and realistic manner to enact legislation that will make an IGCC facility in Meigs County, Ohio a reality. I must note, however, that since we originally proposed our IGCC construction plans, CSP has acquired additional generating capacity. This additional capacity will impact the timing for an IGCC plant addition.

<u>JMG/OPCO GAVIN SCRUBBER LEASE ACCOUNTING</u>

Q. PLEASE DESCRIBE THE BACKGROUND CONCERNING OPCO'S LEASE WITH JMG FUNDING, LP (JMG) PERTAINING TO SOLID WASTE DISPOSAL FACILITIES (SCRUBBERS) AT THE GAVIN PLANT.

A. In Case No. 93-793-EL-AIS, the Commission authorized OPCO to enter into a lease with a third party, JMG Funding. The lease provides for the purchase of the Gavin scrubbers at the end of its initial fifteen-year lease term at the higher of the scrubbers' net book value or its market value to be based on a mutually agreeable appraisal. The lease also has an option to renew the term for an additional nineteen years from 2010 to 2029.

Q. PLEASE DESCRIBE THE NATURE OF THE APPLICATION FILED BY OPCO IN CASE NO. 08-498-EL-AIS.

A. In that application OPCO sought authority to assume obligations of JMG under loan agreements, to refinance certain obligations related to those loan agreements, to enter into loan agreements in connection with the refinancing, to enter into guarantees and to enter into interest rate management agreements.

Q. HAS THE COMMISSION COMPLETED ITS CONSIDERATION OF THE APPLICATION?

A. Yes it has. In its June 4, 2008 Finding and Order in that docket the Commission approved the application, subject to two conditions.

Q. WHAT ARE THOSE CONDITIONS?

A. First, OPCO was ordered to seek Commission approval prior to exercising the option to purchase the leased facilities and/or terminate the lease in 2010 or renew the lease. Second, Ohio Power Company was ordered to provide details of how it intends to incorporate the lease in its ESP.

Q. HAS OPCO DETERMINED WHETHER IT WOULD RENEW THE LEASE FOR THE NINETEEN-YEAR PERIOD OR BUY THE SCRUBBERS AT THE HIGHER OF THEIR REMAINING NET BOOK VALUE OR MARKET?

A. No, it has not since it does not know the scrubbers' market value at this time. An analysis to determine the least cost option cannot be completed without an appraisal being performed and discussions with the lessor completed to agree on the scrubbers' market value. Since the initial fifteen-year lease term does not end until 2010, OPCO has not yet completed the necessary discussions with the lessor to engage an appraiser and agree on a market value after receiving the appraisers report. Until the market value of the scrubbers at the termination date can be determined and agreed to it is not possible to determine which option is the least cost option. Therefore, OPCO reserves the right to seek an appropriate modification to its ESP rates, in 2010 or whenever the determination is made, to recover any increased costs, as appropriate.

Q. **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

Migration Risk

- Customers have come and go rights (rules to be determined) -- Company retains provider of last resort status at tariff rates
- Distributed generation is encouraged
- Governmental aggregation is promoted – including by-passability of charges
- Governmental agencies to pursue energy price risk management
- Competition from other EDUs that own generation

Asset Risk

- No future stranded cost recovery for historical "g" assets
- Performance standards and targets for service quality to customers
- Requirement to have T&D available for customer generation and distributed generation
- Risk that Commission requires separation from RTO participation (infrastructure investment associated with membership)
- Mandated compliance for advanced energy portfolio forces utilities to pursue/investment in technologies that may not perform as expected in introducing technical risk
- By-passability of advanced energy costs through shopping

Financial Risk

- A symmetrical earnings test – set rates and claw back on one side – no true up on the other
- Prudency review of generation-related costs
- Penalties for under compliance with advanced energy/DSM/EE (potentially in excess of $200 million/year)
- Commission can require phase-in of rates to ensure rate and price stability
- Lack of definition around earnings test-present and future

Transition to Market Risk

- Commission can stall the Market Rate Option (MRO) at 10% phase in after the first year – no ability to return to ESP
- Approved ESP can later be rejected before end of term if MRO provided better economics for customers

Litigation Risk

- Political uncertainty of implementation of new law presently and in the future as new deal structures and technologies emerge – or changing it in the future
- It may well be years before all of the provisions of the bill are resolved through court activity

EXHIBIT JCB-2

	Columbus Southern Power Company				Ohio Power Company			
	2009	2010	2011	Total	2009	2010	2011	Total
Estimated Cost of Market Rate Option								
MWH Load to be Purchased under 10%/20%/30% MRO	2,271,512	4,543,023	6,814,535		2,815,095	5,630,189	8,445,284	
Estimated Market Price ($/MWH)	$88.15	$88.15	$88.15		$85.32	$85.32	$85.32	
Estimated Purchase Cost of 10%/20%/30%	$200	$400	$601	$1,201	$240	$480	$721	$1,441
2001 - 2008 Incremental Environmental (90%/80%/70%)	$23	$21	$18	$62	$76	$67	$59	$202
POLR (90%/80%/70%)	$97	$87	$76	$260	$55	$49	$43	$146
Estimated Cost of 10%/20%/30% Market Rate Option	$321	$508	$695	$1,523	$371	$596	$822	$1,789
Estimated Cost of Companies' ESP								
Estimated Purchase Cost of 5%/10%/15%	$100	$200	$300	$601	$120	$240	$360	$721
2001 - 2008 Incremental Environmental	$26	$26	$26	$78	$84	$84	$84	$252
POLR	$108	$108	$108	$325	$61	$61	$61	$183
Annual 3%/7% non-FAC Increase	$14	$29	$44	$87	$42	$88	$134	$263
Annual 7%/6.5% Distribution Increase	$24	$50	$77	$150	$21	$44	$68	$133
Estimated Cost of Companies' ESP	$272	$413	$655	$1,240	$328	$515	$707	$1,551
Estimated Benefit of Companies' ESP	$49	$95	$139	$283	$43	$81	$115	$238

ATTACHMENT C

HEARING TRANSCRIPT TESTIMONY OF J. CRAIG BAKER (December 10, 2008), Case Nos. 08-917-EL-SSO and 08-918-EL-SSO

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

- - -

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

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PROCEEDINGS

before Ms. Kimberly W. Bojko and Ms. Greta See, Hearing Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-C, Columbus, Ohio, called at 9:00 a.m. on Wednesday, December 10, 2008.

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and we would like to mark that as 2F so that there will be a readable copy of that in the record.

EXAMINER BOJKO: It will be so marked as Companies' Exhibit 2F.

(EXHIBIT MARKED FOR IDENTIFICATION.)

MR. RESNIK: Thank you very much.

\- - -

J. CRAIG BAKER

being previously sworn, as prescribed by law, was examined and testified as follows:

DIRECT EXAMINATION

By Mr. Resnik:

Q. Please state your name.

A. My name is J. Craig Baker.

Q. Mr. Baker, do you have before you a copy of what has been marked as Companies' Exhibit 2E?

A. Yes, I do.

Q. Could you identify that document, that exhibit for us, please?

A. That is additional rebuttal testimony in this case.

Q. And do you have before you a copy of what's been marked as Companies' Exhibit 2F?

A. Yes, I do.

Q. And could you identify that exhibit,

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please?

A. Yes. This is a chart that shows the relative positioning of the three-year LIBOR with three-year Treasury rate for the period of July of '07 through July of '08.

Q. And is that the same chart that appears on page 17 of your rebuttal testimony?

A. Yes, it is.

Q. Only it's in color and readable.

A. That's correct.

Q. Thank you. Going back to Companies' Exhibit 2E, your rebuttal testimony, do you have any corrections that need to be made?

A. I do. I have a few that missed the last-minute edit checking so what I'd like to do is run through them. First is on page 2, line 17. I'd like to replace the word "legislature" with "General Assembly."

The next is on page 6, line 4, there's an extra word, and I would like to scratch the word "to" between "the" and "selling" on line 4, page 6.

Page 7, line 8, fourth word in should be "this" instead of "his."

MR. RANDAZZO: Could I have that one back, Mr. Baker, please?

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THE WITNESS: Certainly, Mr. Randazzo. Page 7, line 8, fourth word in, which is "his," should be "this."

MR. RANDAZZO: Okay. Thank you.

A. Page 20, line 12, the last two words should be hyphenated, "cost-based."

And the last one is on page 21, line 7, there was a missing word between "70" and annually, and the missing word is "million."

Q. Mr. Baker, any other changes that need to be made?

A. No, that's it.

Q. Okay. And if I were to ask you the questions that appear in what's been marked as Companies' Exhibit 2E, and let's incorporate into that the color chart that's marked as Companies' Exhibit 2F, would your answers be the same as are contained in your rebuttal testimony?

A. Yes, they would.

MR. RESNIK: Thank you, your Honor. I have no further questions for Mr. Baker, and he's available for cross-examination.

EXAMINER BOJKO: Thank you.

Do we have any volunteers to begin?

MR. WHITE: Your Honor, before we start

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cross, I'd like to make a motion to strike.

EXAMINER BOJKO: Okay. Please proceed, Mr. White.

MR. WHITE: The question on page 2, "Are these examples consistent with the legislative discussion leading up to the passage of Senate Bill 221 and the language of the bill," I'd like to strike that question and answer. It's hearsay and without substantiating -- without anything else substantiating what the discussions were, it shouldn't be on the record.

EXAMINER BOJKO: Do you have a response, Mr. Resnik?

MR. RESNIK: Yes. Mr. Baker has the specific qualification to testify about what was going on at the legislature given the fact that, as he said, he was the lead representative for the AEP-Ohio companies in that entire process. And so he is, as many people have given their view of what the legislature means or doesn't mean -- legislation means or doesn't mean, I think this gives color, if you will, from Mr. Baker's perspective about whether or not cost-of-service concepts are somehow implicitly in the bill.

MR. WHITE: Your Honor, if I may. Giving

interpretation to what a statute means is different than actually testifying to discussions that occurred.

MR. RESNIK: Your Honor, it's not hearsay. He heard this. This was his personal knowledge that he is reflecting here.

EXAMINER BOJKO: Okay. Do you have any other ones?

MR. WHITE: No, that's the only motion to strike I have.

EXAMINER BOJKO: Are there any other motions to strike?

MR. RANDAZZO: I could probably come up with something, your Honor.

EXAMINER BOJKO: Let's go off the record.

(Discussion off the record.)

EXAMINER BOJKO: Let's go back on the record.

Given that this was Mr. Baker's personal experience and his participation in the matter and given -- or, to be consistent with all of our other discussions that we've had on Senate Bill 221 throughout this hearing process, we're going to deny the motion to strike and we'll allow it and allow parties to question or cross-examine Mr. Baker on his

experience during the SB 221 process.

Okay. Now do we have any volunteers?

MR. RANDAZZO: I'll go.

EXAMINER BOJKO: Okay. Thank you, Mr. Randazzo.

CROSS-EXAMINATION

By Mr. Randazzo:

Q. Mr. Baker, let's pick up where the motion to strike left off, and do you regard your experience during the legislative process as something that qualifies you as an expert on legislation?

A. I would not consider myself an expert, in general, on legislation; however, I learned a lot and experienced a lot and probably know more about this process than, if I had my way, I'd know, want to know.

Q. Fair statement.

Now, I'd like to ask you something that is in the portion of your testimony that's on the bottom of page 2 and carrying over to the top of page 3, and let me begin, you make reference there to a "Just and Reasonable Standard." And then you say the standard was connected to the evaluation of costs incurred by the companies in setting rates.

Did the Commission during the legislative process propose to establish a just and reasonable standard?

THE WITNESS: I'm sorry, could I have the question read back?

EXAMINER BOJKO: You may.

(Record read.)

A. I do not remember the Commission taking that position.

Q. Well, you are aware, are you not, Mr. Baker, that the just and reasonable standard is one that's included in the Federal Power Act, right?

A. Yes.

Q. And presently under the Federal Power Act AEP is selling electricity in the wholesale market based upon a market-based pricing mechanism, correct?

A. Yes, they are. But I would point you -- I'd link -- in my view the testimony was intended to link the two, cost of service and just and reasonable. Where I do agree with you the, FERC has found market-based rates to be just and reasonable.

Q. Okay. But, at least academically, there's no necessary connection between the just and reasonable standard and a particular methodology for establishing prices, is there?

A. There doesn't have to be.

Q. And in your experience dealing with laws that are associated with regulation of public utilities, the use of the just and reasonable standard does not imply a particular ratemaking methodology, does it?

A. I don't think it has to, Mr. Randazzo, but in states which have been traditional regulation of generation at state level, those two, cost of service and just and reasonable, have generally been linked.

Q. Okay. Now, what is your understanding of the objective behind the just and reasonable standard? And let me ask the question more specifically.

Is it your understanding of the standard itself to be one which requires a balancing of interests between the utility and customers for purposes of establishing rates?

A. Yes, I would agree with that.

Q. All right. Is the company's responsibility to be the provider of last resort a competitive or noncompetitive function?

A. I was asked this question in my second round of testimony, and I believe I said that it is a

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responsibility of the distribution company and I didn't know how it could be passed off to a competitive supplier.

Q. Okay. I'm asking you if you are aware in my next question. Are you aware of any requirements in Senate Bill 3 as modified by Senate Bill 221 that deals with how pricing for noncompetitive services is to occur and, more specifically, what ratemaking methodology is to be used by the Commission for noncompetitive services?

A. I haven't reviewed that in preparation so I wouldn't venture an answer at this point.

Q. If the General Assembly has specified a ratemaking methodology for noncompetitive services, that, of course, would control, correct? I'll withdraw the question.

A. I'm sorry?

Q. I'll withdraw the question.

Are ancillary services competitive or noncompetitive services?

A. I would believe that -- the way I would answer that, Mr. Randazzo, is I think you're asking me for definitions under the bill, and as I did with POLR, what I'd like to say is that I believe that if a customer shops, they could get -- they could

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provide ancillary services from their supplier.

Q. Are you aware of anything in Senate Bill 3 as modified by Senate Bill 221, and I'm asking if you are aware, that deals with the question of whether ancillary services are a competitive or noncompetitive services?

A. Again, I have not gone back and researched that for purposes of this testimony.

Q. As part of this application, the electric security plan application, have the companies asked the Commission to declare ancillary services to be competitive or asked the Commission to declare that the provider of last resort function be declared -- be a competitive service?

A. I don't know.

Q. Now, on page 3 as well there's a question I want to ask you about words used in the question, assuming that you had something to do with the question as well as the answer. In the question it refers to true regulation. Can you tell me what you mean by "true regulation" there?

MR. RESNIK: Can I have the question read back, please?

EXAMINER BOJKO: It says "true reregulation."

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MR. RANDAZZO: Oh, true reregulation, excuse me. That's what I meant to ask. Thank you. I'm sorry, your Honor.

Thank you, Mr. Resnik.

A. What I mean by that in this context is states which have had a plan for deregulation, passed deregulation legislation and have gone back to regulation of generation, as I believe I lay out in this answer which deals with the standard that you virtually eliminate customer choice, that you set rates on a cost of service and things of that ilk.

Q. Okay. And you say on the next page that -- in the sentence that begins on line 1, that "Ohio did none of these things," and from that you're, I think, trying to make the point, are you not, that we no longer have true reregulation in Ohio or we don't have true reregulation in Ohio. Is that the point you're trying to make?

A. I would say that we do not have true reregulation as I defined it in this answer.

Q. Okay. Now, one of the things that is identified on page 3, line 21 in discussing the Virginia legislation is your indication that they have virtually eliminated customer choice. Is it your understanding of Senate Bill 221 that it

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provides an opportunity for the companies to suggest limitations on shopping as part of an electricity security plan? Is that your understanding?

A. My recollection is there is that kind of provision, but I don't think it's consistent -- if we were to do that, wouldn't be consistent with other parts of the bill so I don't know how you rationalize those two things.

Q. Okay. Now, on the bottom of page 4 and top of page 5 you're there discussing your views on circumstances that might cause the Commission to modify an ESP and what would happen in the event the Commission did, as I read it. When you were on the stand previously, I discussed with you briefly a document that was marked and admitted as IEU Exhibit No. 5. It's the presentation from the EEI conference, the nicely colored document that I would be happy to furnish you a copy.

A. I remember a discussion about that document, yes.

Q. Okay. And --

MR. RANDAZZO: May I approach the witness?

EXAMINER BOJKO: You may.

Q. Mr. Baker, I'd like to ask you to turn to

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page 9 of that document. And am I correct that that page is a page that focuses on the earnings guidance provided by AEP at the Edison Electric Institute Conference?

THE WITNESS: Could I ask that that question be reread because I'm not sure I understood the lead-in to them. So if I could have it reread, I'd know how to answer the full question.

Q. The lead-in was we talked about this before.

A. No, I think there was a sentence or two before that.

(Record read.)

A. I'm sorry, is that the total -- okay. Then I read more into what you were asking me.

Q. I think so.

A. Yes, this is a document that was provided at the fall EEI conference that deals with our guidance as far as 2008 and 2009 earnings.

Q. Okay. At the bottom of that page 5 there's a statement that says: "The 2009 guidance provides a range for reasonable Ohio outcome." Do you see that?

A. Yes, I do.

Q. As you understand it, the outcome that is

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being referenced there would be the outcome of this proceeding, right?

A. Yes. We are talking about this filing of an ESP, but that is a broad term that deals with one of the many issues that goes into the creating of the guidance.

Q. Okay. What was the reasonable Ohio outcome that was embedded in the earnings guidance?

A. I don't have that answer.

Q. Well, let me ask it this way, if there was a reasonable Ohio outcome and it was identified to the Commission and it happened to be different than the proposal as filed by the companies, it would be okay with AEP if the Commission approved that reasonable outcome, right?

A. That one I will need to have reread.

Q. Let me reask it.

A. Thank you.

Q. Is the only outcome that is reasonable to AEP for purposes of an electric security plan the outcome that's been proposed in the application?

A. The Commission under the legislation, as I understand it, has the right to modify our plan. When and if they do, I would certainly hope they would approve it, but if and when they modify it, we

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would have to evaluate what the outcome was and decide whether that was acceptable to the company.

Q. And based upon page 5 of IEU Exhibit No. 6, there's been some effort on the part of AEP to identify a reasonable Ohio outcome for purposes of providing earnings guidance to the investment community, right?

MR. RESNIK: Can we have that back? I'm not sure you had the reference right.

EXAMINER BOJKO: I think Mr. Randazzo said this chart was in both documents. We've been in IEU Exhibit 5 on page 9.

MR. RANDAZZO: Yes, I'm sorry. And it's the same chart on page 5 of IEU Exhibit No. 6. Sorry for the confusion.

A. Mr. Randazzo, in developing guidance, as I understand the way our financial group does this, they look at potential series of outcomes across the range of our total business and get a high and a low outcome. So I don't know the individual pieces that go into this, and there wasn't a single-point estimate that said this is reasonable or this is not reasonable. The company hasn't made that determination.

Q. Okay. Fair enough.

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If we could turn to page 5, bottom of the page where you focus on the Purchase Power Proposal.

A. This is in my testimony, not the exhibit?

Q. Yes, it is, I'm sorry. Yeah, good question.

Turning to page 5 of your rebuttal testimony where you begin the discussion of the Purchase Power Proposal, the title Purchase Power Proposal is the same as the slice-of-system proposal?

A. Yes, it is.

Q. Now, if the Commission were to approve this aspect of the application, and regardless of the percentage that is selected for the portion that is sourced from the market, which source of supply, the market purchases or existing generating assets owned by the companies would flow first through the meter?

A. The way I would describe that, Mr. Randazzo, is that these purchases would be dedicated to the Ohio Power and Columbus & Southern companies and, therefore, would be part of the FAC charge.

Q. Okay. What I'm really asking here is let's assume that -- as I understand it, you're going to be purchasing based upon a forecast of requirements, correct?

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A. Correct.
Q. Okay. And let's assume that in 2009 you forecast normal weather and sales associated with normal weather and you purchase, for purposes of this discussion, 5 percent of your total SSO requirements from the marketplace based upon that forecast.
A. All right.
Q. Are you with me?
A. I'm with you.
Q. As weather actually turns out, it deviates from normal and that deviation results in actual sales that are less than the forecast. Does the cost of the 10 percent purchase get reflected in the FAC with the residual cost being determined by the generating assets owned by the companies, or is there some blend of those actual purchases with the existing generation to determine how much flows through the FAC?
A. We haven't developed the RFP for this, Mr. Randazzo, but let me try to answer your question in how I think it would be done.
We would be going out for the slice of system based on -- to give people an idea of what their expected supply requirement would be, but if there were weather or loss of load, then that would

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reduce the amount of power we would purchase under the 5 percent.
Q. Okay. So you would end up with the percentage being dictated by the ratio between actual sales and actual purchases, correct?
A. What I'm saying is that you would be forecasting and telling the suppliers to supply 5 percent of the load and you would change it over time as conditions change. That's where I think we would go, but as I say, we haven't finalized that.
Q. Well, if you did anything other than that, then the actual percentage of purchases at market prices would be something higher or above the 10 percent number that I used in my hypothetical, right?
A. Well, if we did it based on a pure forecast, it could be higher or lower.
Q. Right. But, as you say, you haven't developed exactly how that's going to work yet?
A. No. But as we've thought of slice of system, the way I described it is generally the way we've done it.
Q. Okay. Now, on page 6 and also on page 7 you discuss the expectation that the companies had relative to the Monongahela Power and Ormet

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transactions. As a general proposition do you think that the expectations in these areas should manifest themselves in the results produced by regulatory actions?
THE WITNESS: I'm going to need that question read back.
(Record read.)
A. I'm not sure I understand the question, but let me try to answer it as best I can. As we looked at it, our expectation was that we would be going to market and we recognize that the Commission only needed to deal with the period up till we went to market.
It was our expectation that if we had something other than market, we could come to this Commission, as we did -- as we have done in this case, and ask for treatment, and it would have been our expectation that we would have gotten the same kind of treatment we've asked for here.
Q. Well, let's talk about -- you picked a certain time frame here on expectations. When Senate Bill 3 was enacted, was it the expectation that market prices would be lower than cost-based ratemaking prices that existed at the time?
A. I would say that probably different

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people had different opinions on that.
Q. Well, AEP --
A. I'm sorry.
Q. Let's talk about AEP. Didn't you -- didn't the companies request stranded cost recovery as part of the transition to --
A. Yeah. I may have misunderstood your question so let me try to clarify it.
Q. Sure.
A. I thought what you were saying was an expectation of what it would be in 2006 when we went to market.
Q. Right.
A. And I believe that we did feel that our forecast said there would be stranded costs for AEP. I know there were people who said to the contrary and said the prices in the case of AEP companies, it would have been -- the price would have been higher. That led to the debate about whether or not AEP had stranded costs.
Q. Right. And the Commission awarded stranded cost recovery for AEP, correct?
A. No, I don't believe they did.
Q. Okay. If the Commission did order stranded cost recovery in the form of transition cost

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payments made by customers, would you agree that the expectation at the time was that market prices would be less than legacy prices?

MR. RESNIK: Are you done?

MR. RANDAZZO: Yeah.

MR. RESNIK: I'm sorry. I would object. The regulatory transition charges were not stranded costs associated with changing value of the generation plants relative to the market price that was anticipated. So I think the question is assuming that the regulatory transition charges were stranded costs in the sense that the prior question was asking about it.

EXAMINER BOJKO: I think Mr. Baker can answer the question if he understands the question and he is more than capable of clarifying his response if he needs to.

THE WITNESS: Could I have the question read back, please?

(Record read.)

A. My recollection, it could be flawed, Mr. Randazzo, was the Commission approved a settlement, and the settlement was a -- with a number of parties, and we waived our rights to the stranded cost in order to get regulatory assets.

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Q. So your understanding is that the provisions dealing with the recovery of regulatory assets was something other than recovery that was associated with transition costs or stranded costs?

A. It had nothing to do, in my mind, with the difference between market and the cost of our assets. It had to do with there were regulatory assets that we had on the books for stuff that happened prior to 1999 that we didn't want to write off.

Q. All right. Let's go back to expectations. Was it the expectation at the time of Senate Bill 3 that market prices would be less than the prices that had been previously produced by traditional regulation?

THE WITNESS: Can I have that read back, please?

(Record read.)

A. I believe I answered that question. I'm not sure I'm catching the nuance, if there is one, but I believe there were some people who thought that market prices -- and I'm talking purely in the case of AEP-Ohio. Some thought the prices would be -- market prices would be higher and some thought it would be lower.

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Q. Okay. If customers of AEP believed that -- somehow, believed that market prices would be lower, do you think it would be appropriate to respect that expectation by producing a regulatory outcome that satisfied that expectation?

A. I think regulatory outcomes are determined by what the General Assembly tells the Commission to do and they have to interpret it.

Q. All right. Let's move on to another subject. On page 7 you talk here again about what I'll call the slice-of-system proposal, and here you're saying that the proposal "will help the Companies encourage further economic development in their service territories." I'm referring to page 7, line 16 and 17. Do you see that?

A. Yes, I do.

Q. As a general proposition the slice-of-system proposal results in a standard service offer price that is higher than it would otherwise be without the slice-of-system component, right?

A. I would say that's the expectation today, not knowing where the cost of generation --

Q. Sure.

A. -- will be over this whole period, I

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can't guarantee that, but for purposes of this filing, yes, I'd agree with that.

Q. Okay. So how is it that the slice-of-system proposal which produces somewhat higher prices in the aggregate helps economic development?

A. Again, let's clarify. You said would result in higher prices.

Q. Right.

A. And I put a caveat in the last answer --

Q. Well, if I may, Mr. Baker. Mr. Nelson who testified previously indicated that one of the reasons why we ought to consider providing carrying charges on environmental costs is that it will continue to make the lower-cost coal-fired generation available to customers at a price that's significantly below market.

But that aside, I understood your caveat before, and I'm happy for you to make it again, but the context of my question was understanding the caveat that you made previously.

A. Certainly. What I meant by that term was that we would have started to lock in supplies and we would have a good idea of what the cost would be. Now, we wouldn't have it all locked in because we

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talk about doing this in tranches over periods, and there would -- I believe that the rate will still be very economically attractive, and we will know we would have supplies in order to meet that rather than having to go out in the market in realtime when it happens and be debating as to whether it's economically advantageous to pursue economic development relative to the then cost of power in the market.

Q. Well, I thought on page 6 that you made it clear finally that the slice-of-system proposal has nothing to do with the companies' need for generation supply to serve Ormet or Monongahela Power customers. That's on page 6, line 10 and 11. Right?

A. Those are what the words say, but what we are saying is we are not putting the proposal forward based on a need for power, it's about the issue around Mon Power and Ormet and our expectations going forward.

Q. Well, I understand the expectation part. We talked about that. I'm just trying to connect the dots here in terms of how a proposal that in general has the tendency to increase prices relative to an ESP without the slice-of-system proposal would encourage economic development.

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A. Because we would have more supply available to us at known prices that we could then help the State go after economic development with prices that I believe will still be attractive relative to the competition around us.

Q. Well, you would also know the cost of your own generation, right, the company's generation?

A. We would have a good estimate.

Q. Would it -- strike that.

Now, turning to the off-system sales discussion on page 8 and 9 of your testimony, are you aware of how off-system sales were treated for purposes of developing Columbus & Southern and, more specifically, Ohio Power's rates and charges historically under traditional regulation?

A. If we're talking about the period of let's just use an example the rate cases that were done in the '90s which set the rates that are the base of our current rates, those off-system sales were treated as credits to rate base.

Q. And so the -- translating that, if we can, Mr. Baker, would it be fair to say that in those rate cases rather than making adjustments to rate base to exclude a portion of the asset value that might be associated with making off-system sales, the

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full amount of generating asset plant cost was used for purposes of developing retail rates under traditional regulation?

A. I'm not sure I can -- I won't buy the proposition that starts out with "as opposed to doing this, therefore, that." I will agree that they were treated as a credit to rate base.

Q. If those off-system sales costs were treated as a credit to rate base, then is it your understanding that the full amount of the generating plants associated with providing off-system sales was included in rate base?

MR. RESNIK: I'm sorry, can I have that question read back, please?

EXAMINER BOJKO: Yes.

(Record read.)

A. The full amount of the -- or the fixed costs associated with the full capacity for those two companies was included in rate base because those plants were built to serve the internal load of those two companies.

Q. Right. And historically, particularly in the case of Ohio Power, it was quite common in those traditional rate cases for stakeholders to make claims that Ohio Power had excess capacity because of

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the large reserve margin, was it not?

A. I would not be surprised. I notice it appears -- has appeared that way in various states.

Q. And would you accept that, subject to check, in the case of Ohio Power?

A. I would accept it, subject to check, that some intervenors took that position.

Q. And would you accept, subject to check, that the Commission rejected excess capacity arguments because of the ability to make off-system sales to reduce and -- thereby reduce the cost ultimately that was borne by customers?

A. I will accept that, subject to check.

Q. Okay. And, based upon that history, would you also accept then that the generation rates, and particularly the non-FAC rates, include costs associated with generating assets, some of which for some portion of time have been used to support off-system sales?

A. To support off-system sales, we make off-system sales with surplus energy that we have on the system, and it comes about because it's not needed at that time to serve the native load, even though they were built to serve native load.

Q. And now the answer to my question.

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A. That was the answer to your question.
Q. Well, let me ask it this way. If those plants were built to serve native load customers, why is it that it's appropriate to take those assets to market?
A. Because it's better than letting surplus energy sit idle.
Q. All right. And if native load customers are paying for those generating assets, do you think it's appropriate they receive some portion of the benefit that's derived from utilizing those assets when they would otherwise be idle?
A. I don't think the customers are paying for those generation assets. They're paying for service that they received as rates were set, Mr. Randazzo, back in the mid-'90s. We've had many changes. We've gotten away from cost of service and we just continue to make off-system sales, and we said what we think the right treatment is.
Q. Okay. Mr. Baker, at page 20 -- and this is the last area of my questions. Page 20 you begin a discussion in your rebuttal testimony of sale or transfer of certain generating assets. I thought from your prior testimony that there was no current plan to transfer or sell any of these generating

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assets. Is there a current plan to sell or transfer any of these generating assets?
A. No.
Q. So do you think it's unreasonable to withhold authority that may be required from this Commission on the transfer or sale of generating assets until such time as the companies actually have a plan to sell or transfer the generating assets?
A. I think it's appropriate for that authority to be given as part of our ESP, which is part of our total plan.
Q. Well, didn't you previously receive authority from the Commission to transfer generating assets?
MR. RESNIK: I'll object, your Honor. It's been asked and answered from Mr. Baker's prior stint on the stand.
MR. RANDAZZO: That's fine.
Q. Mr. Baker, I'd like you to assume that AEP previously asked and received -- asked for and received authority to transfer generating assets and elected to not transfer generating assets. With that history, why is it that it is so important for you to receive authority to transfer these generating assets at a time when you have no plan to transfer the

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generating assets?
A. Let's talk about the time, Mr. Randazzo. The plants we're talking about were not part of that previous request for EWG status that was put in front of this Commission. These plants -- these plants are ones that were bought after Senate Bill 3 passed in anticipation of going to the market, and the shareholders of the company took the risk on these plants and, therefore, I think it's appropriate for us to have the authority to, if we choose, to transfer or sell these assets at our discretion.
Q. Okay. That's as straightforward as anybody could put it, Mr. Baker.
MR. RANDAZZO: Thank you very much. That's all I have.
EXAMINER BOJKO: Mr. Petricoff?
MR. PETRICOFF: Thank you, your Honor.
\- - -
CROSS-EXAMINATION
By Mr. Petricoff:
Q. Good afternoon, Mr. Baker.
A. Good afternoon, Mr. Petricoff.
Q. This is the third and probably final time that we'll engage in this dialogue, at least hopefully, in this case.

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A. Well, I'll miss it.
Q. As will I.
If you would, turn to page 4 of your testimony, and I want to refer you to the sentence that starts on line 6, and I'll read it to you, it says: "Section 4928.143(B)(2), Revised Code, makes it clear that a company may provide any provision in an ESP for approval by the Commission as long as the ESP in the aggregate is more favorable to customers when compared with the expected results from an MRO option."
I want to explore that statement with you. What if the ESP application had a provision in it that violated a state statute but the ESP in the aggregate was more favorable than the expected outcome of the MRO, would the Commission have to accept the ESP or could it require the offending provision to be amended?
A. I assume that the Commission cannot do something that breaks the law.
Q. What if the ESP had a provision that violated a Commission rule but the ESP in the aggregate was more favorable than the expected outcome of an MRO, would the Commission have to accept the ESP or could the Commission require the

offending provision be amended?
A. I don't know the answer to that because, unlike the law, I assume the Commission could change the rule.
Q. So you're uncertain on that one?
A. My answer is my answer.
Q. Well, my question is that you're uncertain whether the Commission would have the authority to amend an ESP because it violated a Commission rule?
THE WITNESS: Can the question be read back?
(Record read.)
A. I'd say I was uncertain.
Q. One last question in this series. What if the ESP had a provision that violated an established regulatory principle but the ESP in the aggregate was more favorable than the expected outcome of the MRO, would the Commission have to accept the ESP or could it require the offending provision to be amended?
A. I don't know what you mean by "regulatory principle."
Q. Okay. Let's assume that a regulatory principle would be the outcome that the Commission

has taken when faced with similar issues in similar cases over a long period of time.
MR. RESNIK: And, your Honor, I'm going to object. There by definition cannot have been similar cases to an ESP under Senate Bill 221. I think that's what's taken us all so long to get through this. So when we talk about established regulatory principles, those principles were established in a different regulatory environment so I would object to the question.
EXAMINER BOJKO: I guess I didn't think Mr. Petricoff's question had to be necessarily in the here and now.
I think you're just speaking generally if there was a regulatory principle in place; is that right?
MR. PETRICOFF: That's correct.
Q. And maybe I'll give you an example of a regulatory principle and then see if that can assist you. For example, over the years the Commission has decided that there -- that customers in like position should be treated in like manner by the utility. That's an example of an established utility principle.
A. I think the Commission's going to

redefine regulatory principle based on Senate Bill 221. I don't know how they're going to do that, but this is a bill that is unlike anything I've ever seen before, and it's going to create tremendous challenges so I'm not sure there is a historic regulatory principle that won't have to be tested.
Q. So it's your opinion that past decisions and past practices of the Commission will have to be reexamined in toto when approaching this case?
A. I think that the Commission will have to consider what Senate Bill 221 tells them to do when they have questions come before them.
Q. Let's move on here. On line 8 you recite that -- and this is we're measuring now between the ESP and the MRO -- that in the aggregate it is more favorable, and I want you to focus on the word "favorable."
In your opinion when the Commission evaluates whether an ESP is more favorable in the aggregate than the expected outcome of an MRO, is it strictly an economic or cost per kWh test?
A. No.
Q. So it's possible then, that the ESP could be lower per kWh but because it has an offending provision in it, the Commission could deem it to be

less favorable than the MRO?
A. Offending? Offending is kind of an interesting word. Do you mean something that is not permitted under law, going back to your earlier question?
Q. No. By "offending" I was thinking that it had a -- well, let me try it again, then.
Assuming that the ESP was lower by a penny a kilowatt-hour than the MRO but it had a provision in it which was not illegal but in the consideration of the Commission pernicious or offensive but not illegal, could the Commission, based on that, decide that it was not favorable, the ESP was not as favorable to the MRO, even though it was cheaper?
A. The Commission has the authority to reject our plan or to reject an ESP. I think the criteria should be looking at whether the ESP as it's defined here in the aggregate is more favorable. They're going to have to make that determination, and they are going to tell us whether they accept, modify, or reject our plan and we will react to that activity. I don't tend to tell the Commission what they can and cannot do.
Q. Let's move from reject and approach the

same issue and ask what about amend. Can the Commission amend the ESP without rejecting it because it considers an aspect of the ESP to be not as favorable as the MRO?

A. I think I just answered that I don't tell the Commission what they can and cannot do. They will do what they do, and we will have to determine whether the plan is still acceptable to us.

Q. Fair enough.

Let's turn to page 13 of your testimony. If you would. I'd like you to turn to line 18, and here's the sentence I want to have a dialogue with you about. Your testimony says: "No. First, I have been advised by counsel that customers who return to the Companies' SSO upon the default of their competitive supplier are statutorily entitled to service at the SSO rate."

I want you to focus in on the word "default." What did you mean there when you said "default"?

A. Well, it was the advice of my counsel, so I assumed that what we were talking about was for whatever reason the competitive supplier failed to continue to supply a customer under a contract.

Q. Okay. And if a customer -- well, let me

ask you this, does a CRES, a competitive retail electric supplier now if they are going to qualify to do business in AEP or on the AEP systems, do they have to supply a bond or provide other financial security?

A. I would expect they would.

Q. And the company generally can rely upon that security in the case that the CRES does not meet its obligations to supply power?

A. Again, I would assume so, but I'm not sure that it necessarily would cover whatever the impacts were.

Q. Well, now I'm just focusing in on the word "default." You would agree with me that in a situation like that where the CRES didn't supply and the company supplied and then, you know, confiscated the bond or took other actions, that that would be a default that would fit in the language that -- your testimony here on lines 18 to 20.

A. I didn't get into -- in thinking this through, Mr. Petricoff, I wasn't thinking about what the -- what bonds were out there or what the company could do with those bonds. It was purely that if there was a default, as I understand it, that the customers could come back at the SSO rate.

Q. Let me give you another situation. Let's say that there wasn't a default but the CRES supplier stopped supplying because the contract came to an end. It was a year contract. We're now in the 366th day, assuming this wasn't a leap year, and the CRES stops supplying. In that situation does the customer have a right to come back to the SSO rate?

A. I believe they do.

Q. Let's say that the customer now is -- actually, before we do that, your advice from counsel seemed to be specific as to upon default. Your understanding then, is that it's broader than on default. It's just anytime the customer wants power they can return to the SSO rate?

A. With the exception of the governmental aggregation that I talk about later, it is my understanding that if a customer comes back for whatever reason, that they can come back at the SSO rate.

Q. Well, let's talk about the government aggregation now. If you have a government aggregation and the government aggregator has given the notice under section 4928.20(J) that it does not care to pay the POLRs or have its members pay the POLRs and that they will return at market. In that

case if there's a default, do the customers come back at market rates rather than the SSO rate?

THE WITNESS: Could I have that read back, please?

(Record read.)

A. We had a lot of dialogue about this in my second round of testimony, and the Bench was asking a number of questions about the standby and the POLR, and I indicated that I wasn't sure how the Commission would deal with POLR and standby, whether they were one and the same or not. And then we got into a dialogue about what standby service was, and there were current tariffs that had standby service. So at that point I indicated I really didn't know exactly how the Commission would treat the governmental aggregation in relation to our request for POLR but they would do what they did, and we would look at it.

I also in my direct testimony talked about the potential that although, as you described it as I think what the law provides, that there may be a situation where if, in fact, the market rates were so high and that's the reason the governmental aggregator got out of business -- went out of business, there is a chance that we would not be allowed to charge market-based rates. That's

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captured in my direct testimony.

Q. Well, I want to see if we can funnel down to something. What is your understanding today as to the ability of a governmental aggregation to waive the POLR charges as you have -- you being AEP -- have applied for them in this case and come back if the customers come back at market?

A. We indicated that we thought the POLR charge was nonbypassable regardless of aggregation, and it was brought to my attention that the POLR might be a standby and, therefore, we might be precluded from doing it, and I said in that case that's what the Commission will tell us, but our proposal was that POLR is there regardless.

Q. Okay. And you've not received similar advice from counsel as you have on line 18 and 19 as to what happens with the governmental aggregation as you discuss on page 14 in lines 1 to 3.

A. Nothing more than what's in my direct testimony.

Q. In that case I'd like to -- I want to ask you a series of questions about the fuel adjustment clause now.

A. Can you point me to a section in my testimony that we're talking about?

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Q. Yes, I can. Actually, these questions are going to center around your testimony on page 14, lines 7 to 9, where you indicate that your understanding that this current Commission cannot bind some future commissions that would have to decide whether the companies could flow through their fuel adjustment clause, the market prices of serving the loads returning to customers. I want to explore that concept with you.

Let's start with an easy example. If the fuel adjustment clause requested by AEP is approved by the Commission in 2009 and in 2010 500 new customers move into the AEP territory, could the Commission in 2010 deny recovery by AEP of the fuel and purchased power costs associated with that incremental load of 500 new customers because the fuel adjustment clause was authorized by a past Commission?

THE WITNESS: Could I have the question read back, please?

(Record read.)

A. The issue we're trying to address here is the idea that you just go out and buy at market to serve the load, not whether or not you can use your own generation or the purchase. The implication of

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what everyone was -- what I read other people's testimony to say was you don't have a risk because just go out and buy at market and you got it covered.

When we were in -- when I was sitting in listening to Miss Medine testify, she took this position and then followed it up with, but if your own generation is cheaper, then you wouldn't go out to the market and buy it, you would use your own generation.

So we've got a bit of dichotomy between where what people are saying on one hand and then what they say a couple minutes later about economic dispatch and how you do resources.

If you're asking do they have a prudency, can they look at prudency, of course they'll look at prudency as far as the purchase decision or the dispatch decision. Yes, they'll look at this --

MR. PETRICOFF: Your Honor, I move to strike. It's nonresponsive. The question asked about Commission authority.

MR. RESNIK: Your Honor, could I have the question and answer read back, please?

EXAMINER BOJKO: Yes.

(Record read.)

MR. RESNIK: I think --

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EXAMINER BOJKO: Actually, well, he didn't answer it. I mean, the question wasn't prudency that Mr. Petricoff was asking, so the answer will be stricken.

And, Mr. Baker, maybe you could try to answer the question. I was looking for some response in that long answer somewhere and I just couldn't find it.

THE WITNESS: Okay. I was trying, but if I didn't do it, I'll try again.

EXAMINER BOJKO: Does the Commission have authority under his hypothetical to modify the previous decision?

THE WITNESS: I don't believe that they -- if the question was around if a fuel adjustment clause is put in place, could they deny passing through -- costs through a fuel adjustment clause, I think the answer is no. That, I think, is set up as far as this bill.

What we're talking about here is a specific action the company takes. This is the action of going out and purchasing power to serve returning customers and flow it through the FAC. I think a future Commission could decide that they didn't like that activity if there were cheaper

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generation available in the fleet, and that's the risk that I think we have.

Q. (By Mr. Petricoff) But it is your testimony and your belief that the Commission in 2010 could not go back and redo the fuel adjustment clause in terms of passing through fuel and power prices that took place in 2009 if it was done in accordance with a fuel adjustment clause that was approved.

MR. RESNIK: Your Honor, I'm going to object because Mr. Petricoff is switching from the narrow point that Mr. Baker just identified in his answer that we're talking about a means of dealing with the POLR issue and buying market power to do that, which is being suggested by some parties, and then we should pass it through the fuel clause which, of course, is not our proposal. And he's -- his question is talking on a much broader scale, well, if the Commission approves a fuel clause, can they deny costs.

EXAMINER BOJKO: I think that was the point of Mr. Petricoff's question. I was trying to figure out exactly what Mr. Baker said because his response was twofold, and I think he was seeking that clarification, so let's let Mr. Baker clarify if he can.

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THE WITNESS: Can I have it read back, please?

(Record read.)

A. I tried to answer that as to the first part so I'll try to do it again and hopefully be a little more clear. I think if the Commission approved a fuel adjustment clause as provided for in this bill, that they could not say we couldn't have a fuel adjustment clause going forward. Decisions on how that fuel adjustment clause is done I think could be changed in the future.

Q. But I want to narrow in just one more level, one more gradation level down, and that is on lines 7 and 8 of your testimony you say that the Commission cannot bind some future Commission, but isn't it true from your past answer that the Commission in 2009 can, in fact, bind future commissions as to what can go through the fuel adjustment clause, at least retroactively, to any future action of the Commission?

I'll withdraw the question. I've got to fix it up a bit.

Let's go back and look at this language that says the Commission cannot bind some future Commission. I'm asking you now that if this

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Commission issued a fuel adjustment clause and said for the period of time that's covered by this fuel adjustment clause, all purchased power and fuel costs will be passed through, wouldn't you agree that that would, in fact, bind future commissions until the time that those -- that the future commissions change that order prospectively?

A. Okay. Let's -- if you would allow me, I'd like to just use what I was talking about in this section, not to just have the broad generic, and I hope that that answers your question. I'm really trying to --

Q. I want a specific answer to my theoretical question. Going to come down to the POLR in a minute. That's my next question.

MR. RESNIK: Can I have the question read back, please?

EXAMINER BOJKO: Yes.

(Record read.)

MR. RESNIK: Well, your Honor, I guess I'm going to object because I'm not sure where this is going. I think that's exactly consistent with Mr. Baker's testimony that this Commission cannot bind a future Commission, the future as it's conditioned, until the Commission in some future

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point changes what this Commission is doing --

EXAMINER BOJKO: I think we're focusing on semantics, and I think that maybe Mr. Baker gets the difference from what he said previously.

Do you understand the question?

THE WITNESS: Let me try. First of all, I don't think the Commission would ever put out an order that says all purchased power and all fuel would be allowed to be flown through a fuel clause. So I have trouble with the question because of the premise it sets on.

And then if you start to say, okay, we're not going to flow through all purchases and all fuel regardless of what the company does, I think you'd have to get down to the specifics, which is what I was trying to do with my answer.

EXAMINER BOJKO: I think, Mr. Baker, the confusion is that you were saying that you believe that if a mechanism to recover such fuel costs was approved by the Commission, that that would be binding, but the exact costs that flow through that mechanism may or may not be approved by future Commissions, is that --

THE WITNESS: That's what I was trying to say.

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EXAMINER BOJKO: Is that a good summary?
THE WITNESS: Thank you.
Q. (By Mr. Petricoff) Mr. Baker, if the Commission could authorize a fuel adjustment clause that couldn't be amended, save for prospectively that would cover new customers moving into the area, I think 500 -- we'll stick with the analogy of 500 new customers. Could the Commission likewise have the authority to pass a fuel adjustment clause that says 500 returning customers from CRES suppliers, any excess costs -- or, the costs of serving those customers would be flowed through the fuel adjustment clause? Would they have the authority to do that?
A. I believe they have the authority to do it. The question is not around flowing through the cost of serving customers; it's flowing through the cost of purchased power specifically at market for those returning customers. That's a different hypothesis.
Q. Well, let's funnel down to the final question, then. If the Commission -- do you believe that the Commission has the authority to approve a fuel adjustment clause that said any customers returning because of a default from a CRES provider will be provided standard service at the standard

service rates and the cost of the purchased power fuel for serving those customers will be flowed through the fuel adjustment clause?
MR. RESNIK: And just to clarify, is he asking him to disregard the advice of counsel that he received?
MR. PETRICOFF: That's a much more complex question that is irrelevant.
MR. RESNIK: Well, I'd like to think not.
EXAMINER BOJKO: That's overruled.
Let Mr. Baker answer that question if he can because now we're trying to get even narrower from where we were discussing a few minutes ago.
MR. PETRICOFF: This is the final question in the series.
THE WITNESS: Can I have the question reread?
EXAMINER BOJKO: Just so I'm clear, Mr. Petricoff, this isn't what's binding, you're saying do they have the authority.
MR. PETRICOFF: Do they have the authority to do it. I'm still focusing on this question about that this -- what this Commission can bind, you know, for a future period of time.
(Record read.)

A. I believe that the Commission could authorize the company to go out and purchase power for returning customers regardless of what their portfolio was and flow that through the fuel clause, I don't necessarily think that that -- or, I do think that that could be changed by a future Commission.
MR. PETRICOFF: Your Honor, I have no further questions. Thank you.
Thank you, Mr. Baker.
EXAMINER BOJKO: Mr. Maskovyak?
MR. MASKOVYAK: Thank you, your Honor.

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CROSS-EXAMINATION

By Mr. Maskovyak:
Q. Good afternoon, Mr. Baker.
A. Good afternoon.
Q. I would like you to turn to page 3 and look at lines 3 through 5, basically the last sentence of that part of the testimony beginning with "There is no mention of the word prudently." Or there's only one mention.
EXAMINER BOJKO: I'm sorry, I cannot hear a word that you're saying, Mr. Maskovyak.
MR. MASKOVYAK: I'm sorry, I'll speak up.
Q. You say there is no mention of the cost

of service and only one mention of the word "prudently." Do you see where I am?
A. Yes, I do.
EXAMINER BOJKO: Which page? I'm sorry.
MR. MASKOVYAK: Page 3.
A. Yes, I do. I see it.
Q. So by virtue of the fact that you state that the word "prudently" is only used once, does this mean that any cost or expense for which the companies seek reimbursement where it is not subject to 143(B)(2)(a) means it does not need to be prudent?
THE WITNESS: Could I have the question read back, please?
(Record read.)
A. What I believe is that the Commission as part of what has been proposed by Senate Bill 3 should approve the plan, or reject the plan, or modify the plan, and once you've done that, those are the rates that are in place for -- going forward for supply to customers. I don't think it falls under a prudency discussion at that point because it's approval of the plan.
Q. So does that mean the companies would be otherwise free to seek costs that may well prove to be imprudent?

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A. It's part -- again, I go back to the plan, and we put something in front -- it's compared to the MRO. If the General Assembly had wanted prudent to be the conditions of the plan, approving the plan, I think they would have put that language in.

Q. Can I take it from your answer that your answer is yes?

MR. RESNIK: Your Honor, I'll object. He gave his answer.

MR. MASKOVYAK: I'm not sure though whether it falls as a yes or no, your Honor. Truthfully, I don't know.

EXAMINER BOJKO: Mr. Baker, can you answer it any further?

THE WITNESS: No, I can't.

Q. (By Mr. Maskovyak) If a cost was found to be imprudent or thought to be imprudent that was not part of 143(B)(2)(a), is it the company's position that this would not be a bar to recovery?

THE WITNESS: Could I have that read back?

(Record read.)

A. I haven't thought through all of that because I've thought -- I've tried to think of this

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in the context of what we have put in front of the Commission as far as our plan is concerned, and the section you pointed to is the section that forms the general basis of our FAC which is clearly that's subject to the word "prudent." It's there.

The others are requests. I think the Commission has to look -- it's not asking for continued trueup of costs or anything. There are dollars we're asking for either in values that are defined in the plan, values that are automatic increases, purchased power. I think the Commission needs to look at that as part of the plan, not whether any single decision is prudent in their judgment.

Q. Thank you.

Staying with page 3 with the question and answer beginning on line 6 regarding the reasonably priced goals, are you with me?

A. Yes.

Q. In your answer would it be fair to say that you essentially define "reasonably priced" to mean that any amount that makes the ESP in the aggregate less than the MRO meets the definition of reasonably priced?

A. Yes, I think it would be.

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Q. Is the question of how much profit the company may make irrelevant to the question of reasonably priced?

A. Yes. Of course, subject to the significant excessive earnings test.

Q. Okay. Thank you. Let's turn to page 4. I'm going to look at the question and answer beginning on line 17 where you talk about the circumstances that would warrant the Commission modifying an ESP. Do you see where I am?

A. Yes.

Q. In your answer you discuss three possibilities, which you label as A, B, and C.

A. Yes.

Q. Is it my understanding that these are the only ways you believe by which the Commission may modify the ESP?

A. These were three that I thought of when I was writing the testimony. I didn't go any further than that.

Q. So is it possible there could be more ways or other ways than the three you enumerate?

A. I don't know.

Q. If the Commission did modify the ESP in the ways that you suggest, would it still be

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considered a modification by the companies such that you could decide to withdraw the application?

A. The question asks about modifying the ESP. That to me is by definition, therefore, modifying the ESP, which we then have the right to determine whether we want to accept it.

Q. Okay. Thank you.

I'd like now to turn to the Purchase Power Proposal section on page 5 with the question and answer beginning on line 11. I'd like you to look at the part of your answer beginning on line 15 starting with the word: "Although the Companies propose to administer its slice-of-system purchases within the FAC mechanism the proposal was not made under that section and the Commission is not limited to that section in approving it." And I assume by "that section" you're referring back to the previous sentence in reference to 4928.143(B)(2)(a).

A. Yes.

Q. I know you were not in the room when Mr. Nelson was here testifying, but I believe in response to questions from OCC that Mr. Nelson testified that the company was, in fact, seeking recovery pursuant to 143(B)(2)(a).

MR. RESNIK: I'll object, your Honor. I

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think that Mr. Nelson's testimony just referred to (B)(2), he did not use the letter (a).

EXAMINER BOJKO: Let's ask the witness if he knows.

Can you respond to this question?

THE WITNESS: Certainly. That is, I think that's defined by my answer on line 18 carrying through line 22 that I consider it a two-step process, that the approval of AEP going forward and purchasing the 5, 10, and 15 from the market is just part of the overall plan. The flowing the results of that purchase then through the fuel clause are consistent with the 4928.143(B)(2)(a).

Q. All right. We may not need Mr. Nelson. Do you have a copy of the company's application?

A. Yes, I do.

Q. Can I get you to turn to page 4 and look at Roman numeral II.A, the Fuel Adjustment Clause? Perhaps you can clarify for me.

A. Yes, I see it.

Q. The first sentence starts: "As permitted by 4928.143(B)(2)(a), Ohio Revised Code, the Companies propose implementing an adjustment mechanism" and so forth. And if you continue on in that section and slide over to page 5, in the second

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bullet point it talks about the purchased power costs that are part of this mechanism, as I understand it.

A. All I can do is point you back to my testimony because it talks about two proposals. That is the area where we recover the cost. That's not the approval of whether we can make the 5, 10, and 15 percent purchase as part of the plan.

Q. So the bullet point at the top of page 5 is not connected to the beginning of that particular part that says that this is pursuant to 143(B)(2)(a).

A. Recovery of. It's two steps in this process. I don't know how I can be more clear about that.

Q. All right. Can you then tell me what section you are relying on?

A. I'm terrible with these numbers in this legislation, but it's the whole ESP section.

Q. I'm not sure what you're referring to, sorry. When you say "the whole ESP section" --

A. That's fine. I'll go through the legislation.

EXAMINER BOJKO: Section 143, is that what you're talking about?

THE WITNESS: Let me look it up.

Q. Is there a statutory section to which you

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are specifically citing for the proposition that it's not (B)(2)(a) but something else?

A. I'm looking. It's 4928.143(B)(2).

Q. But none of the underlying subsections apply.

A. There are words that say the plan may provide for or include without limitation any of the following.

Q. I understand. And your proposal, can it be found in any of the following subsections?

A. It was really intended to fall under the "without limitation" provision.

Q. Is the recovery for which you are seeking on this fuel cost a cost that could be sought under (B)(2)(a)?

MR. RESNIK: Your Honor, could I have the question read back, please?

EXAMINER BOJKO: Yes.

(Record read.)

MR. RESNIK: Well, I guess I'm going to object because I think now we're switching from the purchased power to fuel. Sort of leaves me in the dust, but . . .

MR. MASKOVYAK: I'm happy to go with purchased power.

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A. I look at (a) to be the recovery mechanism for the costs the company incurs in these specific areas in supplying the SSO. If we were to say it's covered under that section, then everyone who is saying you have to make these -- purchased powers has to be a least-cost plan could use that as a reason to deny the 5, 10, 15 purchase because they may not believe it's the least-cost plan, and we've taken the position that it is under the "without limitation" that we're asking for the approval, and we show that in the aggregate it's better than the MRO.

Q. I understand that. My question still is, though, could you seek recovery for those same costs pursuant to (B)(2)(a)?

A. No, and accomplish what we were trying to accomplish as part of this plan.

Q. And what is it you are trying to accomplish?

A. A plan in place that is better in the aggregate than the MRO and provides what I believe to be a good arrangement for customers and the company.

EXAMINER BOJKO: So could the purchases be at any cost?

THE WITNESS: No. I'm asking the

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Commission to approve the authority to buy 5, 10, and 15 and put it in the portfolio. Then when we actually execute on it, I would expect as part of the fuel clause that there would be a prudency and there would be a check, did, in fact, we go out and acquire it in the best fashion and the lowest cost to make those purchases, not in comparison to what the energy supply of our own system is.

EXAMINER BOJKO: So the prudency check would still be on the cost that you purchased it at, not maybe necessarily the execution of the purchases, which is what your line 21 says.

THE WITNESS: Well, I think it's the execution of, your Honor, not the cost, because if we're allowed to do it and we go out and -- we're given the authority to go out and make the 5, 10, 15 percent purchases, just because it comes in with a specific number is going to be relevant to whether we -- what the market set the price at. We have to show that we, in fact, did a good job of acquiring it in the market and got it in the most efficient manner from the market.

EXAMINER BOJKO: But the cost would be a factor in that consideration of whether the total execution was prudent or not.

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THE WITNESS: I think cost compared to what an alternative cost could be for a purchase, yes, so if we didn't do the execution right.

EXAMINER BOJKO: Thank you.

Q. (By Mr. Maskovyak) Following up on the Bench's question, but whether, in fact, the purchase itself is prudent is not a relevant question.

A. I believe that if it's accepted as part of the plan, it is prudent to go ahead and make the 5, 10, 15 purchase.

Q. Let's factor out -- I know you said that you could not have included the cost in (B)(2)(a) and accomplish the purpose of your plan, which was to make the ESP better in the aggregate. Factoring out the part about not accomplishing the purchase, just a question of whether it's possible legally within the confines of the statute, could the companies have requested for recovery pursuant to (B)(2)(a)?

A. I don't know.

Q. Let's look at other components of (B)(2)(a). Let's drop down to the last part of it where it talks about the cost of federally mandated carbon or energy taxes. If the company were to seek recovery for those, could you seek recovery and do so without using (B)(2)(a)?

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A. I'm sorry, I'm trying to find where you are in the --

Q. I'm in the same place.

A. You're still in (B)(2)(a). I'm sorry.

Q. Correct.

A. Okay.

Q. I just dropped down to the very last clause of (B)(2)(a) where it talks about various components that could be included as part of the recovery pursuant to (B)(2)(a), and the last one is the cost of federally mandated carbon or energy taxes.

My question was, could the company seek recovery of those costs but do so without using (B)(2)(a) as its way to do so?

A. I guess we could under the "without limitation," but I don't know why we would.

Q. Well, wouldn't you, in fact, avoid any prudency review if you decided to avoid using (B)(2)(a) and use the "without limitation" exception that you cite?

A. I think I've mentioned any number of times now that I'm not avoiding the prudency review by the -- I am subject to a prudency review on the 5, 10, 15, as far as the execution of the purchase. I'm

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asking for approval of the part of the plan which says the company is allowed to go out and buy 5, 10, 15 percent and add it to its portfolio.

I don't see a parallel to the cost of federally mandated carbon or energy taxes. That is going to be something that the government imposes, and we're going to ask for recovery very different than a part of the pieces of the plan that we put in to make up our ESP.

Q. I understand. I'm merely asking that if you decided to seek recovery for those costs, could you use the "without limitation" language to seek recovery by not using (B)(2)(a)?

A. I don't know, and we wouldn't. I don't think we plan on doing it that way.

Q. Okay. Thanks. Let's look at page 5. I want to turn your attention to page -- or, lines 18 through 22, and you talk about the purchases -- back to your two-step process that you have already previously discussed.

A. Yes.

Q. Do I understand you to say that the ESP contains the company's percentages, the 5, 10, and 15, and that is, if the ESP is more favorable than the MRO, then the PUCO must allow the 5, 10, 15

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percentages?
A. I'm saying that they should approve it if in the aggregate it is better than the MRO, the Commission will look at our ESP and decide to approve, modify, or reject.
Q. And so since you're not using (B)(2)(a), the Commission has no authority to examine prudency regarding whether there should be a purchase or what percentage that purchase should be.
A. I believe that they have the ability, just as I described, to review our plan and make the three potential decisions, and then it will be up to the company to decide how they react to either a modification or a rejection.
Q. I understand. But I'm asking specifically about this clause. Since you're not using (B)(2)(a), am I to understand that because of that it's the company's position that the Commission has no authority to examine prudency regarding whether there should be a purchase or what percentage that purchase should be?
A. You know, I've said it a couple of times and I'll use it again, I don't tell the Commission what they can and cannot do. I'm suggesting that they -- the company's position is they should approve

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it if, in fact, it's better in the aggregate than the MRO.
Q. Thank you, Mr. Baker.
Can we turn to page 9? I was looking at, and I would have you look at lines 5 and 6 where you state: "By contrast, it is no longer certain that the regulatory compact exists in Ohio given the passage of Senate Bill 221." Are you saying that the compact is dead?
A. I'm saying that in the case of generation the company has no assurances that when they make an investment in generation-related items, that there would be recovery over the life of the items which I consider to be part of the regulatory compact.
Q. If there is no regulatory compact now, can you tell me what there is?
A. There's Senate Bill 221.
Q. And what does that mean in terms of a regulatory compact --
A. I think --
Q. -- or replacement?
A. Sure. I think what it says is we're no longer certain, and we'll know what it is when we start to get some Commission orders.
Q. Would you say that Senate Bill 221, then,

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really replaces or says that we no longer, or that you, the companies, no longer have a duty to serve?
MR. RESNIK: Is this limited to generation?
MR. MASKOVYAK: Yes.
A. No. I think this says, just as we've laid out in the testimony, that we have an obligation to supply customers generation at an SSO rate.
Q. Okay. Thank you.
I'd like to turn to page 10, and I want to take a look at your chart at the bottom of the page. I was noticing in reviewing the chart that the time periods that you cite throughout are not equivalent time periods. The months range dramatically at times. The first block is five months I believe in '01. The second block is there months. The third is ten months. The fourth is nine months. The fifth is seven months. And the sixth is three months. Can you explain to me why such a radically divergent range of months was decided to be put in the chart?
A. Certainly. All we were trying to deal with was the statement that the OCC witness made, which is that the changing price over that two months was an unusual event and, therefore, that's the

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reason why you ought to use market quotes, and we just wanted to show that, in fact, it is not an unusual event for prices to move dramatically, simple as that.
Q. Wouldn't it be better to compare standard time periods as opposed to having a wide range of time periods?
A. No.
Q. Why not?
A. Because it's intended for one purpose, and the purpose is to show that there is volatility in prices and that period was not unique.
Q. Can you explain to me, for example, then, in the first period it goes through July 2001 but the second period yet starts in July 2001 and includes the same period of time; that same example is replicated in periods five and six. So is July '01 included both in the change downward as well as included in the change upward?
A. Yes.
Q. How does that help us understand?
A. It just shows that for one period, March through July, it went down 47 percent, and then looking at what it went down to in July, it turned around between July and September and went back up to

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33 percent. Those are significant changes in price, as I see it, and I think that is consistent with what OCC's witness was saying about that, there is volatility in this market.

Q. I would like to turn to page 13. On the previous page, 12, you start talking about the POLR risk and Mr. Cahaan's testimony, and then at the top of page 13 in lines 1 through 4 you start talking about the migration risk.

A. Yes.

Q. So for the company's POLR, the provider of last resort, is more -- is a charge that reflects more than just what that term reflects, which is a provider of last resort.

MR. RESNIK: Can I have that question read back, please?

(Record read.)

A. In my view the POLR -- the provider of last resort is the series of options that are provided to customers, the right to leave the customer's tariff and go back -- the SSO tariff price and go to the market when it's economically attractive and then come back to the SSO rate when that's economically attractive. That's my definition of POLR.

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Q. So it covers -- as you state in your testimony, it covers the migration risk out.

A. Now we're getting complicated because we're talking about migration risk and whose definition of migration risk. I told you what my definition of POLR was so if we could stay within that definition, it might make life easier for me.

Q. Well, I'm trying to understand since most people define the POLR risk or the provider of last resort risk the risk that you may have to serve additional customers for which you're not prepared to serve. You're saying it includes that plus much more.

A. I'm saying it includes the rights of customers -- my definition and what was intended as part of our ESP, that is a charge associated with the option that's provided to customers for both the right to leave and the right to come back.

Q. So it also covers the competitive risk.

A. Well, isn't that all a competitive risk?

Q. Possibly. You're not providing anything, though, to the customer who leaves.

A. The customer has the right to come back.

Q. I understand that.

Is the migration risk today any different

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than it has been since Senate Bill 3 was enacted?

A. Help me, please, here. Are we talking about the migration risk, my definition of the right for a customer to leave?

Q. Yes.

A. I would say that the migration risk -- I'm sorry, I'm not going to use that term. You took me down to almost using that.

Q. I'm using that term because you use it in your testimony.

A. But I use it in context of what we did, and that's ebb and flow, that's not a customer who's leaving because it's economically advantageous.

When I talk about people leaving because it's economically advantageous, today I would say the risk of customers leaving is probably a little less than it was at the time of Senate Bill 3, but I don't know that that would be the case tomorrow.

Q. Okay. Thank you.

Let's look at page 14. You talk about the aggregator and the problems associated with aggregation. Actually, if I may, why don't I turn you back to page 13 because you really start addressing this issue in the last sentence at the bottom on line 23 beginning with "While governmental

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aggregations could notify," and it continues on through line 5 on page 14. Am I to understand from your testimony there that the companies believe that aggregators are not likely to give notice of the risk to customers?

MR. RESNIK: Can I have that read back.

EXAMINER BOJKO: Yes.

(Record read.)

MR. RESNIK: I guess I would object, your Honor. The notice the statute contemplates is notice to the company, not notice to customers.

EXAMINER BOJKO: I think he might be asking that very question.

THE WITNESS: Could we have it read back?

(Record read.)

A. I don't think they give notice -- I don't know whether they'll give notice of the risk to customers. I'm not going to assume what a government aggregator will do.

Q. But it is your belief that if customers understood the financial exposure, they would not go with aggregators.

A. No, I don't think that's what this says. If I were a customer and some aggregator came to me and said, "You've got a choice of going with me, because it's economically advantageous, and paying a POLR charge so if the market goes crazy and I have to stop serving you, you can go back to the company at an SSO rate," I'd say don't give them the notice that I want to avoid the POLR charge. I think most people would think that was a cheap option.

Q. So you're suggesting that the aggregators will deceive.

A. I think I said that I didn't know what the aggregator -- I'm saying that if they do the following things, this is how I think customers would react.

Q. You also state that you're not sure that customers would understand the risk or the financial exposure, I think is the term you use.

THE WITNESS: Can I have that read back?

(Record read.)

MR. RESNIK: Is that a question?

EXAMINER BOJKO: He was asking about his statement on 3 and 4.

I think you were just asking if that's what he said; is that right?

MR. MASKOVYAK: (Nods head.)

A. That's not what it says.

Q. So you believe they will understand the

risk if properly presented.

A. If customers are provided the information, yes, I believe they'd understand the risk.

Q. All right. I want to stay with this page and slide down to the next question that begins at line 14 where we're talking about -- and then if you look at that question and your answer beginning on line 18 talking about: "The value of the customer's right to switch under Senate Bill 221 comes from the option customers are given." Does the option include the value if there are no realistic options to pursue in the market?

A. Well, I can't accept your premise that there are no realistic options.

Q. How about if there are few realistic options?

A. I think that if it becomes economically advantageous, there will be options for customers.

Q. I understand. Did I not hear you say a little while ago that you believe, if anything, there's less of a market today than there was in the years since Senate Bill 3 was enacted?

A. No, I didn't say any such thing.

Q. Can you tell me what you did say?

A. What I said was -- you asked me whether the risk was greater, and I said I thought the risk was slightly less. It had no implications of whether there's a market or not a market.

Q. And why would the risk be slightly less?

A. Because the delta between market price and the SSO is different.

Q. So you believe that there are ample providers available whom customers can switch to.

A. I believe there are current opportunities for customers in the PJM arena, and then for customers who can't access PJM, if it was economically advantageous, I believe there would be aggregators who would come in and attempt to serve those customers.

Q. Would you care to opine about the likelihood of those options?

A. It will all depend on the relative price in the market to the relative SSO price, and the closer they become, the more likely it is to happen, and that's why we're looking at it and dealing with it before the fact rather than dealing with it when it actually happens.

Q. When you valued this option of the right to switch, which I assume takes into account the fact

that you have lost sales as part of that equation, does the value of the option also include the fact that the companies will have excess power to sell even if the market price of that power at that point in time is less than the SSO?

A. This is the value to customers of being able to access the market as opposed to the SSO when it's economically advantageous. It doesn't look at what happens to the freed-up generation for AEP, but the freed-up generation would then be available to sell in the market at the same kind of rates the customers would be paying.

Q. And so I take it that the value of the option also does not necessarily include whether AEP chooses to buy any kind of insurance, for lack of a better term, to hedge their risk of the customers leaving.

A. We're setting this up based on the Black-Scholes model determining what the value of the options are and the risks that the company has. The company will decide over the period of the ESP whether to execute on options in order to hedge its risk or not. That's the company's decision.

Q. Do I understand that it's still true today that the company has not made a decision about

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whether they will purchase any hedges to this risk?
A. That's correct, we haven't made any decision.
Q. So it is possible that the companies will assume the full risk.
A. That is a decision the company makes, and if they do, that's their risk that they absorb.
Q. But this is not the same kind of risk that you would be willing to offer the customer.
A. I don't think there are customers out there who are willing to say to us we will not buy SSO service, so I don't see how you'd do it.
EXAMINER BOJKO: I'm sorry, you said you don't think there are customers?
THE WITNESS: No, I don't. I think that we haven't had people leave, and I don't think people are going to say just to avoid the POLR, I'll guarantee you that I will not buy power from you for the full ESP period.
Q. Can we turn to page 15? I'm looking at your testimony on lines 14 through 17 beginning with the word "finally."
A. Yes.
Q. I assume you're not conceding that the risk of switching is low here.

A. I just saying it's not -- I don't think it's a good idea to ignore risk.
Q. So are you saying that we must set the POLR rates high in order to guard against an unlikely risk because, although it's unlikely, the risk may still be very great?
A. I make no representation the POLR risk is being set high.
Q. Are you saying that the POLR risks or rates are set where they are according to the company because they have to guard against this unlikely risk even though it's unlikely because the risk may well be great?
A. Look, I'm not suggesting that the risk is great or not. I'm talking about assertions that others are making.
Q. Aren't you saying beginning at line 16 that the lesson is that the losses can be great by not hedging against unlikely risk? Isn't that your assertion?
A. I'm saying that I don't think it's a good idea, as others have suggested, to just not look at risk because right now they think the likelihood is small.
Q. So you are saying that we must guard

against risks, even if they're small, because the ramifications could be great.
THE WITNESS: Can I have that question read back?
EXAMINER BOJKO: Yes.
(Record read.)
A. What I'm saying is that I can't agree with other people's positions, as I see it, to ignore the risks. We have chosen not to ignore the risks or the value of the option by including the POLR as part of our ESP proposal.
Q. If you choose not to buy POLR insurance, would that be ignoring the risk?
A. That would be managing the risk.
Q. Why would it be managed?
A. Because the company has under that proposed -- under our proposal the ability to decide whether to hedge or not hedge, and that is a business call for the company.
Q. And is that because they will have the revenues generated by POLR on which to make a decision about whether they should just hold on to those versus -- and assume the risk by holding on to those versus taking that money and purchasing a hedge?

A. The rates will be the rates, and they will be what is approved under the -- an ESP that we effectively decide to accept. That's the premise my question is -- my answer is going to be working on. And in that case then we determine how to manage our costs under the rates that we have.
Q. I'd like to turn to page 16. I'm looking at your answer that begins at line 3. If you'd like to review the question that begins on the prior page down at line 21, feel free to do so, starting with "Certain intervenors." I want to concentrate on that part of your answer that begins on line 6 that talks about the put position.
A. Yes.
Q. You say you can't use the FAC because it ignores the put position. What is the value of that part of the position?
MR. RESNIK: Your Honor, if I may, I just note the testimony says the put "portion."
MR. MASKOVYAK: I'm sorry, put portion.
THE WITNESS: Can I have the question read back?
(Record read.)
A. I'm not sure I understand the question. Are you looking for what the dollar value of the

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total POLR --
Q. Or what percentage of the POLR risk is assigned to the put portion.
A. It's in the neighborhood of 90 percent.
Q. 90 percent. So I guess it would be fair to say from the company's position that the risk is much greater of customers leaving than returning?
A. No. That's not true.
Q. Okay. Then help me understand how the 90 percent rate -- what the 90 percent ratio reflects.
A. It's the result of running a Black-Scholes model comes out with those kind of ratios. A simple way to think about it is that the -- you only exercise the call, the second part, if you've exercised the put. So you have to achieve the put before you can achieve the call, and so you have to have the price go down below the SSO and then go up again above the SSO. And when you run that through the model, it puts the majority of the value of the risk in the put.
Q. I think that answers my question. Thank you.
All right. Let's turn to page 19, and I don't have a specific section, although I'm largely

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looking at the last part of that page, lines 13 through 19. If you'd like to review that first.
A. Okay, I've read it.
Q. Would it be fair to say that it's the company's belief that the Black-Scholes approach was the most accurate way to determine POLR?
A. It was the best way to -- yes, to determine the value of the combination of options that we have been talking about.
Q. And I think we agreed previously in your direct testimony that you knew of no one, and no one else did, of any utility using the Black-Scholes model to apply a POLR; is that correct?
A. When we talked about this in my direct, I said there wasn't another utility outside of Ohio that had the same kind of POLR risk.
Q. And, consequently, no other utility is using the Black-Scholes model?
A. Well, I don't know why you would do it if you don't have the risk.
Q. Have you found any literature, any academics that discuss using the Black-Scholes to calculate a POLR charge?
MR. RESNIK: Your Honor, I'm going to object. Mr. Baker's rebuttal testimony touches on

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two distinct features of the Black-Scholes model. One is the use of the LIBOR rate, which he discusses from page 16 through 18 at line 19, and then he picks up the second question that had to do with a reference, and actually I think it was in Miss Medine's testimony, about having run the model an indeterminate number of times.
This is not a whole rehashing of Black-Scholes. We've limited it to two points that came up, and I think that the cross-examination should be limited in that sense.
EXAMINER BOJKO: I hope it's not a whole rehashing. I hope you're just trying to lay a tiny bit of foundation.
MR. MASKOVYAK: I'm almost done with this.
EXAMINER BOJKO: Thank you. Please proceed.
MR. MASKOVYAK: Could we reread the question?
(Record read.)
A. I don't know how there would be any. If I just finished stating that no one has the POLR risk, the EDUs don't have the POLR risk anywhere else and it just appeared in Senate Bill 221, the chance

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of somebody writing an article on that use is pretty slim. I would expect that they'll probably write some articles, assuming the Commission approves it.
Q. Fair enough. Thank you, Mr. Baker.
Can we turn to page 20, and yes, I'm almost finished. I'm looking at the question and answer that begins at line 1 but I want to concentrate where it begins at line 9 where you say: "Therefore, I think it is appropriate to include a provision in an ESP that provides an opportunity for recovery during the ESP period of generation costs that at this time are unforeseen and consequently unquantifiable." So you're saying in there that we don't know what these costs will be for generation.
A. I'm suggesting that is an alternative to setting up some kind of a tracker which is not part of our proposal. We are asking for automatic increases that I believe are provided for in the bill.
Q. And this is because you can't know what the amount of those costs are.
A. It's because we're permitted to have automatic increases.
Q. Well, don't you justify it here by saying that we can't know what those costs are?

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A. I don't think I need to justify it. I think we're allowed to put automatic increases in, and I'm just explaining the thought process of there are reasons to put automatic increases in. It is not cost based.
Q. So the question of whether those costs will even materialize is not relevant.
A. No.
Q. No, it is not relevant?
A. It's not relevant because the costs could be greater. So whether they're lesser or greater, this is not a cost-based rate, it is a proposal for an automatic increase.
Q. Consequently, it would not necessarily be appropriate to have any mechanism to provide for any unforeseen decrease in costs.
A. As I say, it's not cost based. It's a single value.
Q. Can you explain the difference to me for giving cost recovery that's not known or unforeseen and unquantifiable and essentially what I would call a blank check?
A. I'm not asking for cost recovery. I'm asking for an automatic increase that's provided for in Senate Bill 221.

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MR. MASKOVYAK: Thank you. I have no more questions, your Honor.
EXAMINER BOJKO: Let's go off the record.
(Recess taken.)
EXAMINER BOJKO: Let's go back on the record.
Mr. Sites, do you have any cross-examination?
MR. SITES: I am pleased to report, your Honor, I have no questions. Thank you.
EXAMINER BOJKO: I guess we are to Mr. White.
MR. WHITE: Yes, just a few questions, your Honor.

CROSS-EXAMINATION

By Mr. White:
Q. Mr. Baker, I'm Matt White, and I represent the Kroger Company.
A. Yes, Mr. White.
Q. Just a few questions.
A. Certainly.
Q. Let me refer you to page 8 of your testimony.
A. Yes.

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Q. On page 8, the second question, you say: "Witness Higgins and Kollen recommend the OSS margins be credited to the retail FAC." And you also cite 4928.143(B)(2)(a), and you essentially say that OSS margins are not referenced in this provision and, therefore, they shouldn't be -- the credits shouldn't be included in the plan; is that correct?
A. I think you're shortening my answer significantly. I list quite a few reasons on pages 8 and 9, that's just one of the reasons I list.
Q. I understand that, but you're saying that is one of the reasons you list, correct?
A. Yes.
Q. Okay. Do you have a copy of Senate Bill 221 with you?
A. Yes, I do.
Q. Okay. I think you referenced this earlier in cross-examination, but can you read what 4928.143(B)(2) says?
A. Are you talking about the sentence that says: "The plan may provide for, or include, without limitation any of the following"?
Q. Yeah.
A. Okay.
Q. That's what I'm talking about.

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A. I think I just read it.
Q. Okay. That's good.
And again, you referenced this earlier, the term "without limitation," what does that mean according to you?
A. That means, according to me, that the company may propose as part of its ESP any of the following, but we could put other things in the plan.
Q. Okay. Does that include crediting off-system sales to customers, off-system sales margins?
A. Are you saying would we be precluded from doing that?
Q. Yes.
A. The answer is no, we would not be precluded. That would not be an appropriate thing to do.
Q. I'm just addressing how you had said in your testimony that off-system sales weren't included in 4928.143(B)(2)(a). That's all. I wasn't asking whether or not they were included.
Okay, I'd like to move to page 14 of your testimony.
A. Yes.
Q. On page 14 you state: "It is my

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understanding that this current Commission can not bind some future Commission which would have to decide whether the Companies could flow through their FAC the market price costs of serving the loads of returning customers." Is that correct?

A. I believe that's what that says, yes.

Q. Are you aware whether the companies proposed to defer generation charges that exceed 15 percent per year, whether or not the companies have proposed that?

THE WITNESS: Could I have the question read back?

(Record read.)

A. What the companies proposed was to defer FAC costs if the -- in order to limit increases to customers not on G, but on total bill to approximately 15 percent by customer class.

Q. And is it your understanding that those deferrals will be collected after the ESP period, the proposed three-year ESP period is over, by the company?

A. AEP's proposal would be to defer the FAC charges, as I described, and to collect it in a number of years after the ESP is completed.

Q. Okay. You also state that -- and this

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is, just so we're clear for the record, this is in regards to the proposal that would charge -- would allow AEP to recover costs after the ESP period is over for customers that are switching. Is that your understanding of that testimony?

A. No, it really isn't. What this is is dealing with a proposal that others have made that if a customer were to shop and then wanted to come back, that the company could go out and purchase power. That's what I'm talking about, that the Commission could in the future decide not to use that as the mechanism to deal with customers who were returning.

Q. But when you're referencing, "It is my understanding the current Commission can not bind some future Commission which would have to decide whether the Companies could flow through their FAC the market price costs of serving the loads of returning customers," that flow-through is meaning the Commission can't bind -- or the Commission can't bind a future commission from requiring that the company recover the money that they pay for purchasing power for customers that have shopped; is that correct?

A. You're missing the point that I'm trying to make.

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Q. Okay.

A. You're reading words in there that aren't there. The intent, and it may not be clear, but the intent was to deal with the fact that people have made the premise that we don't have a POLR risk because we could go out and purchase power in order to serve any customer that returns, regardless of what our portfolio is. And that's what I'm suggesting I don't think this Commission would bind a future commission on, not about running it through the fuel clause, but that decision. Then once they change that, then you have impacts in the FAC.

Q. Okay. After that line we were referring to earlier you state: "This concern is particularly acute since Mr." -- I don't know how to pronounce his name.

A. Mr. Cahaan.

Q. -- "Mr. Cahaan's suggestion would result in non-shopping customers subsidizing customers who did shop and then returned to the Companies' SSO." Would you say the companies' POLR proposal -- under the companies' POLR proposal, would nonshopping customers be subsidizing shopping customers?

A. No.

Q. Okay. If that's not the case, then would

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you say that under the company's POLR proposal that -- let me clarify before I ask this question. I forgot to clarify. First, this line of questioning I'll be talking about is the put option, and the put option is to cover the risk of customers leaving. So would you say that customers will only shop or exercise their put option when the electric market, the cost of electricity, is below the ESP price, or in the money, as they would say, in finance terms?

A. The assumption built into our modeling is that the customers would exercise it when it was economically advantageous. By that I mean that the price in the market was lower than the SSO price.

Q. Okay. So you're saying that the proposal, the POLR risk proposal, would not subsidize -- the company's POLR risk proposal would not cause nonshopping customers to subsidize shopping customers; is that correct?

A. That's correct.

Q. Okay. Also, along those lines, would you say that the company's POLR risk proposal would cause shopping customers to subsidize the company?

MR. RESNIK: Can I have the question read back, please?

(Record read.)

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A. No.
Q. Okay. Now, I'm going to get into a hypothetical here, and if you don't follow me, then I'll clarify. But if I'm a writer of a put option, and I sell that put option to you and the holder of that -- in the security underlying that put option and the value of that security goes down and the holder of that put option after the value of that security goes down chooses not to exercise that put option when it's in the money, quote/unquote, would you say that's in the economic best interest of the holder of the put option?
A. I need -- it would help me if we could work in a little bit more concrete terms, and let's try to do it around -- let's just create a hypothetical example. So let's assume that the tariff price is $50. I would assume --
Q. Well, this hypothetical is not energy prices. We're talking about stock prices which traditionally options are written under. We're talking about a stock option.
A. But -- okay.
Q. Okay.
A. All right.
Q. So if I write a put option for $50 or a

stock price at $50, the stock price goes down to $40, the stock option would be in the money, meaning that when the person who holds the option exercises the option, they'll have a right to sell to the writer of the option the price at $50, correct?
A. Correct.
Q. So if the person who does not exercise the put option when it's in the money --
A. Which person?
Q. The holder of the option.
A. So the person who could put it to the -- the product to the writer at 50.
Q. Yeah.
A. Okay.
Q. Would that be in the economic best interest of that person not to exercise that option when the stock price is at 40?
A. No; I would think it would be in their economic interest to do that.
Q. Similarly, when the market price goes below the ESP price, it's in the economic best interest of customers, correct --
A. Yes.
Q. -- to switch?
A. Yes.

Q. Okay. So would you say that if the holder -- and this is back to the stock option example, the holder of the put option does not exercise that option when it's in the money, it's a windfall for the writer of the put option.
A. No.
Q. Why is that?
A. There was a transaction that the parties agreed to, and the fact that the other party decided not to exercise it, it's not a windfall. He agreed to sell the option.
Q. Okay.
A. Just part of the transaction.
Q. Yeah, but part of the assumption under your option pricing model is that all holders of options will act in their economic best interests and would at all times.
A. Okay.
Q. Would it not be in the holder of the put option's best interest to exercise the put option when it's in the money?
A. Yes.
Q. Okay. So then I'm not understanding the why is it not a windfall if the actor has to act -- or has to act in his economic best interest, the

model price of the option in a way that the actor is acting in the economic -- will act in the economic -- in his economic best interest and then he doesn't act in his economic interest, why is it not a windfall to the company, or to the writer of the put option?
A. I'm just having trouble understanding what -- what you mean by the term "windfall." Would they have -- would they, in fact, have had a result that was more attractive to them than they would have if they exercised the option? Yes, I would agree with that.
Q. Windfall meaning that that scenario was not priced into the option price. The option price was not -- did not take into account the fact that the holder of the option would not -- the holder of the option would not exercise the option when it's in his economic best interest to do so.
A. The price was set based on the fact that the person had that option. That's why I won't call it a windfall. It was the transaction. Would the person who had written the put be more economically advantageous than he would if the party who had the put exercised it? Yes.
Q. Okay. Let me explain it to you slightly differently, then. It's understandable that when

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someone writes a put option they're taking the risk that the stock will go down and the option will be in the money, therefore, they'll have to pay out. Part of the benefit is that the stock goes up and they don't have to pay out and they get to keep the cost of the option that's paid to them.

So the benefit that they receive is included in the option-pricing model. However, what's not included in the option-pricing model is when the stock price goes down and the option is in the money, and the holder of the option doesn't exercise the option, even though it's in his economic best interest to do so.

MR. RESNIK: Your Honor, I'm going to object. I don't think it was a question. It sounded like testimony.

MR. WHITE: I'm trying to clarify my position.

EXAMINER BOJKO: Do you have a question?

MR. WHITE: Yeah.

Q. Is that true?

THE WITNESS: I didn't hear a question in there, but we could try it again.

EXAMINER BOJKO: I think the question was, is that true? Do you need to hear the "is that true" statement part?

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THE WITNESS: I have to.

EXAMINER BOJKO: Can you review that, please, Maria?

A. Let me try to answer it without trying to shortcut this. I will agree with you that the option modeling, as you describe it, doesn't value a person who does not do what is economically advantageous.

Q. Okay. So when the person doesn't do what's economically advantageous, it's a windfall to the writer of the option.

A. Okay. We're going to -- how many times are we going to talk about whether it's a windfall or not? I've answered that question three or four times, and I told you I'm not willing to term that a windfall. If you want to ask me five more times, we can do that.

Q. Okay.

EXAMINER BOJKO: But then you might get a nasty answer.

MR. WHITE: So I shouldn't ask that question again, is that what you're trying to say?

EXAMINER BOJKO: I don't think the answer's going to change. How about we move on.

Q. Okay. One more question, or maybe a

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couple more questions. When the exercise -- this may have been answered already, but just to clarify again, when the company created the Black-Scholes model, or whatever, they were under the assumption that customers will switch when it becomes in their economic best interest, i.e., meaning that customers will switch when the market price goes below the strike price or the ESP price; is that correct?

MR. RESNIK: Your Honor, a couple of objections. Regrettably, the company didn't create the Black-Scholes model, but beyond that, as I indicated earlier in an objection, the testimony on rebuttal that Mr. Baker has on the Black-Scholes model is very limited to two points, and, again, it sounds to me that we're getting back into a rehashing of the Black-Scholes model.

EXAMINER BOJKO: Well, again, I think that -- I hope that I'll give the same courtesy as I have extended to everybody else today and allow Mr. White a little bit of leeway to give some foundation.

But I don't think you meant to imply that the company or Mr. Baker here created the Black-Scholes model because he obviously didn't win the Nobel Peace Prize.

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MR. CONWAY: It's not a peace prize.

MR. WHITE: I would withdraw that.

EXAMINER BOJKO: I think what you were trying to say is that when the company decided to use the model, these are the assumptions that they made.

MR. WHITE: Yeah.

EXAMINER BOJKO: Is that what -- can you answer it, or do you need him to rephrase the entire question?

A. I'll try again. The use of the Black-Scholes model, as I said, doesn't build in a customer who does not take the economic option, but I would say that that doesn't discount the use of the model, number one, or necessarily say the number is wrong because in doing it, as we've told you, we took a lot of conservative approaches on the other side which kept the POLR down.

So there are balancings, for example, the fact that we used a single ESP price rather than increasing it for the price of the ESP for each of the three years, which would have driven it up significantly higher, or the change in market prices that some people have suggested. So there are things on both sides of the model, so I think it's a valid number.

Q. Okay. Also, in your testimony you talk about customers subsidizing customers that shop versus customers that don't shop, but according to your model how could there be customers that do shop if all customers act in their economic best interest and -- how could there be customers that do shop and customers that don't shop? If all customers act in their economic best interest, if it's in their economic best interest to exercise their option, i.e., switch when the market price goes down in the ESP, wouldn't all customers shop, if they're acting in their economic best interest, or not shop?

A. I was responding to somebody else's proposal that assumed only some people would shop. I think that's where I was coming from, and therefore saying you would have this unfair proposal. If everybody shops and acts in their economic interests, there would not be any subsidy.

MR. WHITE: No further questions, your Honor.

EXAMINER BOJKO: Thank you.

Mr. Kurtz?

MR. KURTZ: Thank you, your Honor.

CROSS-EXAMINATION

By Mr. Kurtz:

Q. Good evening, Mr. Baker.

A. Good evening, Mr. Kurtz.

Q. We're talking about the beginning of your testimony, the cost-of-service portion. I don't want to be repetitive because there have been a lot of questions on that already, but do I understand that basically one of the things you're saying is that anybody who thinks Senate Bill 221 reregulated generation is incorrect?

A. I believe it did not create a cost-of-service type approach to ratemaking for generation, is what I'm saying.

Q. Okay. Do you agree that Senate Bill 221 did reregulate utility earnings?

A. Are we talking, Mr. Kurtz, about generation, or are we talking about wires, or what?

Q. Total earnings, generation, distribution, transmission, any earnings that hits the utility's income statement or any revenue that hits the utility's income statement.

A. There is definitely a significantly excessive earnings test, so the bill provides for that.

Q. Okay. And to determine Ohio Power or CSP's earnings, we start with the income statement; is that correct?

A. Yes.

Q. And the income statement will include, as I just mentioned, does it not, all of the generation-related revenues that the utilities collect?

A. It would include -- it would include the revenues and some of those would be generation related.

Q. And it would also include expenses on the income statement that would then -- revenues minus expenses equals the net income?

A. Yes.

Q. Okay. And those expenses would include generation-related expenses.

A. Yes.

Q. Such as fuel -- fuel.

A. Yes.

Q. Depreciation on existing generating units?

A. All of those are things that are on the income statement.

Q. Let me read a list, and I think you'll

agree: Variable O&M associated with generation, fixed O&M associated with generation, property taxes on the power plants, insurance on the power plants, emission allowances. Are all those included on the income statement as expenses and, therefore, factored into the earnings equation?

A. They can be.

Q. Is it your position that any -- that the definition of reasonable under the statute is a set of ESP rates that are more favorable in the aggregate than what the MRO would have been?

A. Yes.

Q. Does it make any difference what constitutes the ESP set of rates as long as it's more favorable in the aggregate than an MRO? Can anything be in the ESP as long as it's better than the MRO?

A. You're taking me to a place that I'm not -- I don't know how to answer that question. Anything? You know, in an ESP that's pretty broad.

Q. Well, can you make up -- well, it is broad. It is broad. Do the elements of the ESP have to be legitimate expenses of the utility?

A. No.

Q. I'm sorry?

A. No.

Q. So that as long as -- that was my anything.

You can include in the ESP elements that are not legitimate expenses so long as the ESP is less -- is more favorable than what the MRO would have been; that's your definition of reasonable under the statute?

THE WITNESS: Could I have that read back?

(Record read.)

A. I believe the statute provides for noncost-based inclusions, for example, the automatic increases. And the test is whether or not it is more favorable in the aggregate than an MRO.

Q. Okay. Change subjects. The 5, 10, 15 percent purchases.

A. Yes.

Q. The first year purchase for one of the utilities is estimated to be how much? Is it a hundred million for CSP, 120 million for Ohio Power? Just give me a number to work with.

A. The numbers that are in my Exhibit JCB-2 in my original testimony were 100 million for Columbus & Southern, 120 million for Ohio Power. Mr. Hess has modified those numbers, and I don't know

whether your witness did as well, to reflect a different set of market prices.

Q. And let's just use Ohio Power, 120 million year 1. Then your Exhibit 2 shows it doubles year 2, 5 percent to 10 percent of 240 million, and ultimately a purchased power expense of 360 million in year 3. I know that's a forecast but that's what your exhibit shows.

A. Yes.

Q. Now, year 1, $120 million expense, assume that's the correct expense, the utility incurs an expense that then passes it through to consumers so it buys something for $120 million and it collects $120 million. There's no effect on earnings, just a straight pass-through with no markup; is that right?

A. The question is around deferrals and whether those get treated as earnings. If you assumed, and I don't believe you can do this, just look at a single element and say is it in one place, then it's in the other. It's in rates, but if I go with your hypothesis that I have a hundred million dollars of cost and I get a hundred million dollars of recovery, under that hypothesis there would be no impact on earnings, assuming no deferrals.

Q. Okay. Since there's no impact on

earnings, the hundred million dollar expense is matched by a hundred million dollars in revenue. Why does AEP want to impose this hundred million dollar expense on consumers?

A. It is part of our plan to reflect the fact that we have taken megawatts out of our portfolio in order to serve Ormet, and we would be doing the same thing for Mon Power under the bill that -- or, the ESP as we've got filed.

Q. Is the real motivation that when you buy a hundred million dollars worth of power, 5 percent of the energy needs of Columbus & Southern in this example, it frees up an equivalent amount of power of self-generation to be sold off system?

A. No, I don't think that's a good characterization. What I said was we had lost generation from our -- we would be losing generation from our portfolio to serve these customers and we're trying to replace it.

Q. Strike the motivation part of the question. Would the physical effect of buying that amount of megawatt-hours be to displace other generation that would be available for sale off-system?

A. If you hold everything else equal, yes.

Q. Now, the profits from off-system sales are allocated among the AEP East operating companies according to the interconnection agreement; is that correct?

A. Yes.

Q. Okay. And basically each of the operating companies, Ohio Power, Columbus & Southern, Kentucky Power, Indiana and Michigan, and Appalachian Power, get their member load ratio share of off-system sales profits no matter whose power plant generated the electricity for the sale.

THE WITNESS: Could I have the question read back just to make sure I am clear on all the words?

(Record read.)

A. I would just -- I would call it off-system sales margins, but they get their MLR share regardless of who supplies the power, yes.

Q. So under this hypothesis where you're buying 5 percent, 10 percent, 15 percent of power and then freeing up electricity for sale off system, the AEP shareholders do not get all of that additional margins from off-system sales; is that correct?

A. Again, you're going back to a premise that, as I said, it's to replace power that we have

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to now provide to Ormet and Mon Power, and if whatever comes out of any off-system sales, just as a general proposition, we share that in some jurisdictions with customers.

Q. And in other jurisdiction it's a straight flow-through to the ratepayers of that jurisdiction. Is that correct?

A. In some cases it is a direct flow-through; in other cases there's sharing.

Q. So the consumers in West Virginia, because there is an automatic flow-through of profits from off-system sales through their ENEC clause, their version of the fuel adjustment, those customers, if your 5 percent, 10 percent, 15 percent proposal in Ohio is adopted, the increase in off-system sales margins will actually benefit West Virginia ratepayers in the sense that they'll get their share, their member load ratio share of the additional off-system sales margins; is that correct?

A. I think you have to keep in mind that without this they would be disadvantaged with where they would have been had the company not had Ormet and Mon Power. It takes them back to where they would have been if Ormet and Mon Power hadn't been done.

Q. Is the answer yes, that the West Virginia consumers will benefit?

A. Their customers will be put back in the position they were if we hadn't entered into those.

Q. Really, any native load growth on any of the operating companies' systems reduces the amount of power that can then be sold off-system just as a matter of physical reality or mathematics; isn't that right?

MR. RESNIK: Your Honor, I'm going to object. I tried to adhere to your prior rulings about seeing if the foundation was being laid for something that was relevant to Mr. Baker's rebuttal testimony, and --

MR. KURTZ: I'll withdraw the question.

Q. One last. You opposed the proposal of OEG and Kroger that off-system sales margins or profits be used as a credit in the fuel adjustment clause?

A. Yes.

Q. How much profit from off-system sales did Ohio Power earn in a representative year, 2007 for example?

A. I don't have that number.

Q. Did you read Mr. Kollen's testimony where he has quantified the off-system sales profits in 2007 for Ohio Power Company at 146.7 million and for Columbus & Southern 124.7 million?

A. I read Mr. Kollen's testimony. I don't remember those numbers, and I didn't verify those numbers.

Q. Okay. There's nothing in your rebuttal testimony or anybody's rebuttal testimony that takes issue with those amounts?

A. No. I don't think there's any need to because we're not proposing to flow it back.

Q. I guess my only -- this is a large dollar item we're talking about, the margins from off-system sales.

A. Relative to what?

Q. Relative to the cost increases that AEP is proposing.

A. It is a significant number relative to the rate increases that the company is proposing.

MR. KURTZ: Thank you, your Honor.

EXAMINER BOJKO: OCC?

MS. ROBERTS: Thank you.

CROSS-EXAMINATION

By Ms. Roberts:

Q. Mr. Baker, let's start on page 4 of your testimony. On line 9 you indicate that there is no restriction on the company of including the items you've listed, POLR and FAC, et cetera, in their ESP plan; is that correct? Page 4, line 9.

A. Yes, that's what the sentence starts with. "An ESP is in no way restricted from having the provisions" and then lists the provisions.

Q. By the same token the Commission is not restricted in deciding that the company shouldn't be allowed to recover any of those items, is it?

THE WITNESS: Could I have that one read back?

(Record read.)

A. The Commission has the ability to approve, modify, or disapprove our plan, and so those are what they can do. It is -- what we have suggested is that they should do that based on whether or not the ESP in the aggregate is more beneficial to customers than the MRO.

Q. And on line 17 of that page in response to the question you have identified three items that you believe warrant the Commission modifying the ESP;

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is that correct?
MR. RESNIK: Your Honor, I'll object.
EXAMINER BOJKO: Grounds?
MR. RESNIK: It mischaracterizes the testimony, particularly the use of the word "warrant."
MS. ROBERTS: I just asked him if that's what he did.
EXAMINER BOJKO: Yeah, I think that's what it says, doesn't it?
MS. GRADY: Unless you want to strike that?
MR. RESNIK: No. No. Thank you. Appreciate the offer, though.
EXAMINER BOJKO: Can you answer the question?
THE WITNESS: Could I have it read back?
(Record read.)
A. I don't disagree that the word "warrant" shows up in the question. What I did in the answer, though, was to say ways that I could see a Commission modifying the ESP, and it lists three possible ways or three possible reasons.
Q. And I just want to ask this question, are there any other circumstances that you can identify

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that you think would warrant the Commission modifying the ESP?
A. I have not done an exhaustive research. What I did was I came up with three when I was writing the testimony.
Q. All right. If you turn to page 9 of your testimony --
A. Certainly.
Q. -- on line 13 you make a statement about off-system sales that if the General Assembly in Ohio intended to require a more significant item like OSS margins to be credited against the fuel, they surely had the opportunity to incorporate that mechanism in SB 221. Do you see that?
A. Yes, I see that sentence.
Q. In fact, the General Assembly made no indication of whether they thought it was or was not appropriate to have a crediting of off-system sales in an ESP, did they?
A. I believe that we say in the beginning of that paragraph that in the entirety of Senate Bill 221, OSS margins are not mentioned. But I would note that it isn't a secret about what AEP does in the wholesale market, and to -- in the response that I did to Mr. Kurtz, it's a significant number.

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In Virginia where they were going through a similar "what do we do after the current bill takes place," they knew about it, they decided to put in a sharing arrangement.
I think if the General Assembly had wanted to do that, they would have.
Q. But the statute speaks for itself; wouldn't you agree?
A. I stand by in the entirety, it's not mentioned.
Q. Thank you.
On page 10 of your testimony you had testified on direct that when -- and correct me if I mischaracterize this. I'm sure you or Mr. Resnik will do that -- that when the ESP application was prepared, that the company used the most recent data in an effort to get the most representative data; is that correct?
THE WITNESS: I'm sorry, can I have that read back?
(Record read.)
A. No, I wouldn't characterize it that way. I don't believe that's what I said.
Q. You didn't use the most current fuel prices to provide the most representative fuel prices

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in the ESP filing?
A. We're talking here about the competitive benchmark?
Q. No, I'm laying some foundational questions regarding your direct testimony to ask about page 10.
A. Okay. Can we start over then?
Q. Sure.
A. I thought -- you pointed me to page 9 so I assumed we were talking about the competitive benchmarks.
Q. I apologize, Mr. Baker.
A. Okay.
Q. In your direct testimony you testified, didn't you, that in preparing the ESP application the company attempted to use the most current prices, for example fuel prices, or in the example of Black-Scholes, the most current LIBOR interest rates, in an effort to present the Commission with the most representative filing of what the rate would be during the ESP period.
A. I think you'd have to point me to a spot in my testimony or my -- or the transcript. I don't remember using those words. I may have, but I'd like to see it in the context of where I said it.

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Q. All right. Here on page 10 you seem to make an argument that I would summarize as that if we update -- if we update, for example, energy prices, as OCC has suggested, then you can never update them enough because they would be out of date by the time the Commission issued an order. Is that a fair summary of your statement here on lines 5 through 9?

A. No. That's not a fair summary. What I'm saying is to pick a specific instant or a specific small period of time for the purposes of setting the competitive benchmark, this is all-around setting the competitive benchmark, that's not a valid way to approach it.

You need to look over a longer period of time as we did where we looked over effectively almost a nine-month period, and if -- once you do that, you get some stability to the pricing which should be more reflective of the future pricing than picking out a 1 day period or one 5-day period or one 15-day period, whatever choice it is, for one small spot. I just don't think that's a good approach.

Q. All right. Regarding the question on this page beginning on line 10, the last sentence, you say: "Do you agree with the assertion that the recent price decline marks the beginning of a trend?"

Mr. Baker, have you done any studies to determine whether the recent decline in prices is or is not a trend?

A. Have I done a study? We don't -- I've said before I don't have a forecast -- I don't forecast what the future price is. I don't think any of us know it. This is around the point that was made that it was an unusual event and that, therefore, you should use it because it creates -- it's a trend. And I'm saying that this is not an unusual event because it's happened before and you shouldn't -- this is support for the idea that you don't pick a single point in time.

Q. Are you also saying that the decline in prices is not a trend?

A. How long's a trend?

Q. That's your word, a trend. You're saying it's not a trend.

A. I would say I look at trends and I say long periods of time. For example, in this case the three years, that's what you're looking at, the period of the ESP, and I would say that it does not -- it marks the beginning of a trend but the trend may be up.

Q. But you don't know.

A. I've said that I don't know.

Q. Yeah. All right.

On page 12 of your testimony in the question on line 4 it says, "If the Companies' competitive benchmark were adjusted lower, as Staff Witness Johnson and OCC Witness Medine have proposed," and then it goes on. Can you identify for me where or when OCC Witness Medine proposed that the benchmark be reduced?

A. Ms. Medine said that we were kind of fast and loose, is my recollection, I'm kind of paraphrasing, with our choices for the inputs to our Black-Scholes model. And one of them I think she talked about was the market price, and so I just took the fact that another witness had said that the market prices were lower today and said what would it be if we used the prices as done by Miss Smith.

Q. Can you tell me if you agree that if the ESP price is updated, whether the MRO price should also be updated?

THE WITNESS: I'm sorry, can I have that read back?

EXAMINER SEE: Yes.

(Record read.)

A. I don't think we're proposing to update

the ESP price.

Q. No, but if they were updated, hypothetically speaking, if the ESP prices were updated in the Black-Scholes model, do you also agree that the MRO prices should be updated?

A. I need you to help me out here. Are you saying if we updated the ESP prices to have three years of ESP prices as forecasted? Is that what we're talking about here?

Q. If they were updated by the Commission in any way, would the MRO price also need to be updated to establish the appropriate inputs to the model?

MR. RESNIK: Can I have just the last part of that question, inputs what?

THE REPORTER: To the model.

Q. I'm sorry. I'm sorry. For the benchmark it should be. Let me say that again.

If the ESP price were updated, benchmark price were updated, would it also be appropriate to update the MRO price so that they would be presented on a similar basis?

MR. RESNIK: Your Honor, I'm going to object. The witness has indicated the company is not proposing to update the ESP. There's nothing in his testimony -- in his rebuttal testimony that says that we want to change the ESP from what we had filed so I think the question is irrelevant; if not irrelevant, at least outside the scope of rebuttal.

MS. ROBERTS: I think he opened the door, your Honor.

EXAMINER SEE: And I'm going to allow Mr. Baker to answer the question to the extent that he can.

THE WITNESS: Okay. I'm going to need it reread.

EXAMINER SEE: That's fine.

(Record read.)

A. We are not proposing, except in the case of the POLR, that the competitive benchmark be used in the ESP. We have used it for comparative purposes only to look at one versus -- look at the ESP and the fact that we have proposed a 5, 10, 15 percent purchase and priced that to make them -- to create an apples-to-apples situation.

Q. But you used similar time periods over which you expected these rates to be in effect; isn't that correct?

A. We used similar time frames to compare the ESP/MRO, yes.

Q. Yes. And you also had the rates in terms

of making an apples-to-apples comparison as consistent as possible regarding their inputs and how they were calculated?

A. We attempted to use the same numbers in the analysis that I provided in JCB-2.

Q. And that's what you believe to be the appropriate way to develop a comparison between the two.

A. Yes.

Q. If you turn to page 16 of your testimony --

MR. RESNIK: I'm sorry, which page?

MS. ROBERTS: Sixteen.

Q. -- you begin to talk about the Black-Scholes model. In your first answer you refer to the risk-free interest rate. Would you agree that the term "risk-free interest rate" is a term of art in the financial service industry?

A. Yeah, I think that's probably fair.

Q. Okay. And you address the intervenors' challenges to your calculation of Black-Scholes in your rebuttal; is that correct?

THE WITNESS: Could I have the question read back?

(Record read.)

A. I think the only place I do it, and if I'm wrong you can help me out, is the discussion of the LIBOR rate.

Q. And it's your premise in offering the Black-Scholes model to the Commission, isn't it, that it accurately reflects the risks to the company of the POLR obligation?

A. I think I've said it values the option that's provided to customers.

Q. Is there any basis upon which you have assumed that the value to the risk of the company is the same as the option value to the customers?

A. The POLR was calculated based on the value to customers.

Q. Have you -- has the company included -- AEP-Ohio -- in its 2009 budgeting, has it accounted for any shopping customers in 2009?

MR. RESNIK: Your Honor, are we still on the Black-Scholes, if I may inquire?

MS. ROBERTS: Yes.

MR. RESNIK: Well, I would object again. The testimony on rebuttal is limited to two discrete points. The degree of shopping assumed or not assumed is not one of those points addressed in Mr. Baker's rebuttal testimony. I can't see it

becoming a foundation for anything that's relevant.

EXAMINER BOJKO: Well, we'll give Ms. Roberts the same courtesy.

I don't know if you're just asking for my response, but let's see where it's gone.

THE WITNESS: Could I have the question read back?

(Record read.)

A. I believe what it would represent is the amount of shopping customers that we're experiencing today.

Q. What is included in the 2009 budget would be reflective of the shopping customers today; is that what you mean by your answer?

A. That's what we would have put for budgeting purposes. That doesn't mean that's what's going to actually happen and that's not necessarily -- well, I'll leave it at that's not what's actually going to happen. It's a budget.

Q. All right. On page 17 of your testimony, on line 4 your answer begins "U.S. Treasury rates and the LIBOR, the two most commonly used proxies for the risk-free interest rate." What authority do you use to support that statement?

A. Discussions with people who are in the

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industry who use U.S. Treasury rates and LIBOR.
Q. And who would that be?
A. I've talked to our finance people, I've talked to our commercial operations people, all of who use LIBOR as part of their day-to-day business.
Q. And in supporting the Black-Scholes model in your testimony, did you make the selection of what interest rates were used in that calculation?
A. People in commercial operations and I got together and talked about the various inputs, and one of the things we were trying to do was get a proxy for the risk-free rate, and the people who use the model on a day-to-day basis chose LIBOR.
Q. And on page 18 of your testimony, the answer beginning on line 5, you have a lot of data here over how the Treasury has compared to LIBOR over the last eight years. Where was this data sourced from?
A. I believe it was Bloomberg.
Q. And specifically on line 6 of that page you talk about the spread between LIBOR and the Treasury rates has ranged from a high of 107 basis points to a low of 26 basis points; is that correct?
A. Yes.
Q. And that looks like what is actually

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reflected on your Exhibit 2F, the chart of the LIBOR versus the Treasury rates. Is that correct?
A. That was the source of that, yes.
Q. Okay. The data that you used to evaluate that was -- what was the most recent source of the data you used to make that determination? Let me say that a different way. What was the most recent data you used in making that determination?
A. Well, since it's historical data on this chart, it would be the date that the data -- it would be those points in time.
Q. Okay. But the most recent data point would be 7/25/08; is that correct?
A. Yes, that's the most recent point.
Q. Do you know whether the spread between LIBOR and the U.S. Treasuries has changed since July of '08?
A. Yeah, I believe there was a short period of time, and I'm not sure exactly how many months or weeks, but during -- there was a period after Lehman fell that there become a spread because of the fact that the LIBOR was frozen for a period of time while the rate was dropping. I understand that they have now come back into the kind of tracking that we see here.

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MS. ROBERTS: Your Honor, may I approach the witness?
EXAMINER BOJKO: You may.
Q. It was your testimony, wasn't it, Mr. Baker, that the higher the interest rate used in the POLR calculation, the lower the POLR charge, resulting POLR charge?
A. Yes, that's what I said. And what I said, was it had a -- on lines 10 through 12, that it is not a big driver for the POLR charge.
Q. You used there an interest rate differential of a hundred basis points, isn't that correct, to make that determination?
A. Yes.
Q. All right. I've handed you a document from the Financial Trade Industry dated September 16th, and I would direct your attention to -- and I highlighted it on your copy but I didn't keep it on mine -- the second full paragraph. Is this your recollection, that it was in September that the LIBOR rate rose precipitously?
A. Precipitously is a "beauty in the eyes of the beholder" kind of word. So I -- what I would say is this was the period that I understood that there was a spread that developed that I indicated has come

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back to more normal historical values.
Q. But if you look at your chart, Mr. Baker, for July, what is the LIBOR rate shown there, for July 25th, 2008? Looks like it's about 4 percent, doesn't it?
A. It's slightly above 4, yeah.
Q. And in September the LIBOR rate rose, it says, 3.3 percent to 6.44 percent. Would you consider that a significant increase in the LIBOR rate?
A. Yes, that's an increase in the LIBOR rate. Yes.
Q. And do you know whether the spread between the LIBOR and the U.S. Treasuries has remained through the current period of this week?
A. In talking to people who deal with this, they told me that the spreads have come back to more normal values.
Q. Between 26 basis points and 107 basis points, is that what you consider to be the normal spread?
A. They felt that it was still -- that it was back within the range, that it hadn't gotten out of kilter like it did in the September time frame.
Q. I'm trying to understand what you

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consider the normal range to be. Do you consider it the range to be shown on your chart on page 17, which is a range between, you testify, 26 basis points to 107 basis points?

A. It was a normal range as defined by people in our company who borrow money based on the LIBOR.

Q. All right. Well, did the people in your company consider your testimony, your answer on line -- page 18, line 5, to be considered a spread in the normal LIBOR range?

A. I didn't ask them.

Q. So you don't know whether the current LIBOR spread is correlated in any way to your testimony on page 18?

A. The purpose of this was to refute a position that I heard during this hearing that there -- that LIBOR is highly volatile and it was in reference to the Treasury. And the purpose of this chart was purely to show that they tracked pretty closely, and so if you consider one to be volatile, then the other is to be volatile. I believe that's what the testimony says.

Q. I understand. But your testimony on page 18, the answer beginning at line 5, you discuss the

spread between LIBOR and the Treasury rate over the last eight years. And what I'm asking you is whether you can establish that there's any correlation between this spread and what the people you talked to consider to be a normal spread.

A. I did not show them this spread and say, "Do you see a correlation?" But if I look back at a chart like this, I would say -- and I'm looking at, you know, a seven-year time frame. If I'm in that kind of business and I look and I say, gee, look at what the spreads were for the last period, I think they would consider that in their decision, but I didn't talk to them about it.

Q. Okay. Regarding the run of the Black-Scholes model an indeterminate number of times, Mr. Baker, in running the model you used the same Black-Scholes model but what you changed were the inputs in that indeterminate number of runs; is that correct?

A. Yeah. Boy, I sure wish I hadn't used the word "indeterminate," but we did run it more than once, and what we did was we changed some of the inputs. For example, we would not have changed the term because it was three years from the start, it was three years at the end.

We would have changed it for the, for example, for the ESP. As that developed and it changed over time, we would rerun it. And we would rerun it for changes in market price at various times.

Q. And interest rates?

A. I don't remember whether we reran it specifically for a change in interest rates, but I would think --

Q. Do you know whether it was --

MR. RESNIK: Can he finish his answer, please?

MS. ROBERTS: Oh, I'm sorry.

EXAMINER BOJKO: Yes.

A. I would assume that the last time we ran it we updated to have the most current interest rates.

MS. ROBERTS: Thank you, Mr. Baker. I have no other questions.

EXAMINER BOJKO: Let's go off the record.

(Discussion off the record.)

EXAMINER BOJKO: Let's go back on the record. Mr. Bell.

MR. BELL: Thank you.

CROSS-EXAMINATION

By Mr. Bell:

Q. Mr. Baker, do you remember the line of examination of Mr. Randazzo relative to the inclusion of all of the generating -- Ohio generating plant in rate base in past rate proceedings?

A. I remember the discussion we had on the inclusion of all the generating assets that were owned by the company at that time.

Q. Is it not the company's position that the Commission in evaluating the company's ESP in this case should not consider the past recovery of capital or the return on capital in evaluating the current ESP? For instance, is it your position effectively that if the company, in fact, had recovered its total capital investments in generating assets, that that would be immaterial in reviewing the appropriateness of the company's ESP plan?

A. I don't think this is a cost-of-service bill, and the premise of the bill, as I understand it, is you take your current rates and you make adjustments to that.

Q. I think your answer is yes, you're saying then that the cost -- this is not cost of service, it could be entirely possible for AEP to have recovered

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its total capital investment in generating assets to the point that it now has a zero capital investment through past depreciation, et cetera, et cetera, and earned a reasonable return on the investment that existed in the past, that that is totally irrelevant from the company's perspective in the Commission's review of its current ESP, correct?

THE WITNESS: Could I have the question read back?

(Record read.)

A. To answer the question that she just read back --

Q. Yes.

A. -- I don't think it's possible that the company could have recovered all of its cost of capital and a fair rate of return.

To finish the answer, I do not believe that that, since it is a cost of service, that where we are in recovery of investment is an appropriate determinant.

Q. Thank you. That's fair. You have given me what I want, Mr. Baker. We're working together.

A. We'll try.

Q. Following up on a line of examination by Mr. Petricoff, you've been involved in the regulatory

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arena for several decades, have you not, Mr. Baker?

A. I have had some experience in the regulatory arena for several decades. I've only had responsibility for regulatory over the last seven years.

Q. Does the term, quote, public interest have any meaning to you?

A. Yes.

Q. Would you agree that within the context of the regulatory arena that, quote, public interest, end quote, transcends the parochial economic interest of either the company's shareholders or its ratepayers?

A. I don't -- can you help me with where that definition came from?

Q. I just made it up.

A. Well then that's --

Q. It's a concept.

A. Well, then I probably won't agree with you.

Q. Are you being facetious, Mr. Baker?

A. No, I'm not being facetious. I'd like to know where the quote came from, and if you can tell me that -- is it in the Federal Power Act? Is it in Senate Bill 221? Is it in the predecessor, Senate

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Bill 3? I need to know where it came from.

Q. Do you then -- would you agree, Mr. --

A. Baker.

Q. -- Baker, that to the extent that Senate Bill 221 does not define for the Commission the parameters by which the Commission is to ascertain whether the ESP is better than the MRO, that the Commission may, in use of its enlightened judgment, make that determination based upon its finding of what is in the, quote, public interest, end quote?

A. I believe what the Commission needs to do is make an evaluation of our ESP and compare it to the MRO and determine whether to accept, modify, or reject our plan.

Q. Didn't you in response to a question by Mr. Petricoff, say, and I quote, "The Commission can and will do what it needs to do"? And I think I got that word for word.

A. You may have. I'm surprised I threw "needs" in, but if that was my statement, I may have said it.

Q. And in determining what is, quote, more favorable, it is up to the Commission to consider -- to determine what factors it will consider, what time frame it will consider those factors influencing, as

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well as the circumstances under which those factors evidence themselves?

MR. RESNIK: Your Honor, I'm going to object. We've had more foundations built this afternoon than would be built at a mason's convention. I think that it is beyond the scope of the rebuttal testimony. The other foundations didn't seem to go anywhere. I don't think this one's going to either.

EXAMINER BOJKO: Well, I hate to deny Mr. Bell the same courtesy that I have offered to all the other masonry workers today.

MR. BELL: I'll wrap this up very shortly.

EXAMINER BOJKO: That's what I was going to ask.

MR. BELL: Yes.

EXAMINER BOJKO: If there's any way we could shortcut this, that would be great.

Q. (By Mr. Bell) Picking up on the line of Mr. Petricoff, do you believe the Commission should approve a proposed ESP plan that has been demonstrated not to be in the, quote, public interest, even though such a plan in the aggregate is found to be more beneficial than the MRO over the

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period of the plan?
A. I would say that since there are two options customers will be served under, either an MRO or an ESP, that if the ESP is more favorable than the MRO, it's in the public interest.
Q. Would you agree, Mr. Baker, that an appropriate measure of the benefits of the ESP would be the likely end result produced by the ESP over the period of the ESP, that is, testing the benefits by the results produced by the ESP?
A. I believe the Commission should be looking at the qualitative and the quantitative impacts of the MRO and the ESP in evaluating whether to approve it.
Q. That's fair. So that on page 5 where you state: "The plan to make purchases" -- and this is in respect to Purchase Power Proposal, that element of the plan you said "should be approved if the total ESP, including the purchases, is in the aggregate more attractive than an MRO."
By the use of the term "attractive," you do not there mean to imply a cosmetic attractiveness.
A. No, I didn't mean cosmetic.
Q. What you meant there, I trust then, is that it has to be substantively demonstrated to be

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more attractive or more beneficial.
A. It has to be a better option for customers than the MRO.
Q. And in your testimony going to the Commission doing what it's going to do, what the Commission is going to do, would you agree that the Commission in so doing can effectively alter the period of the company's proposed plan or any of its facets?
A. The Commission will put out an order, and if they modify the plan, they modify it, and then we will review it and determine whether that modification is acceptable.
Q. Does 221 in any way, shape, or form limit, for instance, the Commission in reducing the period of the plan, say, from three years to one year, if the Commission were to find that given the economics, the economy of the state of Ohio, it's in the public interest to abbreviate the period of the plan from three years to one?
A. I don't believe that the bill limits how the Commission can modify.
Q. And that is true with respect to the various components of the plan as well; is it not?
A. Yeah. I was going to finish the

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sentence.
Q. I'm sorry, I thought you finished.
A. They can modify -- I read the bill to say they can modify the plan. I don't see any limit as to what they can change. The impact, though, is that then becomes a modification to the plan and it then goes back to the company to decide what action to take.
Q. I'm not questioning the company's ability to accept or reject. I'm -- the question was solely directed toward the ability of the Commission to completely refigure, reconfigure, if you will, the company's proposed ESP leaving the Commission's reconfigured ESP then for either acceptance or rejection by the company.
A. I don't see anything that limits the Commission in the modification other than -- I read it that they're supposed to look at it consistent and approve it consistent with if it's more favorable than the MRO.
Q. So that such a modification can have -- such a modification can be motivated and predicated upon public interest factors as may be identified by the Commission.
A. And I go back to my statement I made

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earlier, that I think if it's better than the MRO, it would be in the public interest.
Q. The Commission's modification of the company's proposed plan can be directed towards making it even more beneficial than the benefits bestowed in the company's proposed ESP, may it not?
MR. RESNIK: Your Honor, I'm going to object. I know we've had questioning of nonattorneys on this, but the statute specifically says that the Commission shall approve the plan that's more favorable. It does not give the Commission latitude to make it even more favorable.
MR. BELL: I'll withdraw the last question. I think Mr. Baker sufficiently responded for purposes of my inquiry, and I did hold to my representation that my cross would be limited.
EXAMINER SEE: To 15 minutes?
MR. RINEBOLT: Of fame.
EXAMINER SEE: Mr. Rinebolt.
MR. RINEBOLT: Thank you, your Honor.

CROSS-EXAMINATION

By Mr. Rinebolt:
Q. Good evening, Mr. Baker.
A. Good evening, Mr. Rinebolt.

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Q. I know we've sat at the same witness table in the past involving this issue and we had different views then. I'm sure that that continues to this day, so I just want to clarify a couple of your points.
In your mind is cost-based regulation inherently the same as cost-of-service regulation?
A. I think -- I was thinking of cost of service in the broad sense, Mr. Rinebolt. When you were looking at how you determine rates, you look at all the costs of the company, determine a revenue requirement. When I'm using the term "cost based," I was tending to use that in reference to certain items of our ESP.
Q. So there are certain items that are cost based from your perspective.
A. Yeah. I would say the FAC is cost based.
Q. Based on your familiarity with the statute, do you believe that an MRO, a market rate option standard service offer rate is a cost-based rate?
A. Not in its entirety.
Q. Well, let me -- if I understand an MRO correctly, a bidding scheme is developed, the right to supply or that is -- the need for that supply is

bid out in the market in some form or fashion, and the lowest price wins. Is that your understanding of an MRO?
A. For whatever percentage a company is allowed to blend in that piece of it, yes.
Q. Okay. And the excess earnings test, there's obviously a revenue analysis involved in that, so that would also be a cost-based measure that's included in the statute. Is that a reasonable assessment?
A. I don't consider an earnings test that's a stand-alone to be a cost-based approach. It's a piece of the statute that deals with significantly excessive earnings. I wouldn't characterize anything more than that.
Q. Okay. At the top of page 3 you say that many parties have -- or, many parties for the legislative debate proposed a just and reasonable standard for evaluating costs. Does the statute in section 4928 still call for a reasonable rate for customers?
A. I'm sorry, would you point me to --
Q. 4928.02(A).
MR. RINEBOLT: Withdrawn. It's in the statute. No need to ask this.

On page 4 at the very, very top you -- and it actually begins on page 3, but you basically take the position that since the Ohio legislation doesn't look anything like the Virginia legislation, that there's no cost basis -- there's no reason to use cost in establishing rates. Is that basically your point, that Virginia -- Ohio's legislation isn't Virginia's?
A. No. My statement's about the cost of service is what's covered in the two Q and As above that.
Q. Okay.
A. This was just an example of another state that had a choice to do market, some kind of -- I guess they could have done a hybrid, I don't remember there ever being any discussion, or going back to a more traditional cost of service, and they chose to go back to a more traditional cost of service.
Q. On page 15 at line 9 you indicate that: "The cost of the POLR obligation for the Companies arises from the fact that the Companies must manage their portfolio." What kind of a portfolio are you discussing, Mr. Baker, are you referring to?
A. The generation portfolio.
Q. Generation. So AEP as a company has the

ability to manage a generation portfolio, I take it.
A. Yeah. We do it on a day-in/day-out basis.
Q. Okay.
A. It doesn't mean there aren't risks imposed by certain actions that may lead you to manage it differently.
MR. RINEBOLT: Your Honor, that's all I have.
Mr. Baker, thank you very much.
THE WITNESS: You're welcome.
EXAMINER SEE: Thank you.
Mr. Jones or Mr. Margard?
MR. JONES: No questions, your Honor.
EXAMINER SEE: Any redirect for Mr. Baker?
MR. RESNIK: No, we have no redirect, your Honor.
EXAMINER SEE: Okay.
MR. RESNIK: I wasn't sure if there were questions from the Bench.
EXAMINER SEE: No, there are no questions from the Bench.
MR. RESNIK: In that case, your Honor, I'd move for the admission of Companies' Exhibit 2E

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and 2F.
EXAMINER SEE: Are there any objections to the admission of 2E and 2F?
Hearing none, Companies' Exhibits 2E and 2F are admitted into the record.
MR. RESNIK: Thank you.
(EXHIBITS ADMITTED INTO EVIDENCE.)
EXAMINER SEE: And since we have already determined the briefing schedule, it's December 30th for initial briefs and reply briefs are due January 14th.
If there's nothing else to be addressed in this case --
MR. RESNIK: There's one other thing.
MS. GRADY: Your Honor.
EXAMINER SEE: I'm sorry?
MS. GRADY: I thought it was the 31st.
EXAMINER SEE: 30th.
MS. GRADY: The 30th.
EXAMINER SEE: It is the 30th.
MS. GRADY: Thank you.
EXAMINER SEE: Yes, Mr. Resnik.
MR. RESNIK: I would just like to indicate our, and my guess is probably other people's, appreciation for a lot of patience that was

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shown from the Bench, both you and Hearing Examiner Bojko. It's been a tough several weeks. Sometimes we may enjoy ourselves down here more than you're enjoying yourself up there, but I just wanted to note that for the record.
EXAMINER SEE: Thank you. We also appreciate you allowing, all of you allowing us to tag team because it allowed us to address other tasks that we're faced with.
Thank you very much.
MR. BELL: I think the same can be said for the reporter. She's put up with a lot.
MR. MASKOVYAK: Hear, hear.
EXAMINER SEE: Thank you all. That's all.
(The hearing concluded at 6:31 p.m.)
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CERTIFICATE

I do hereby certify that the foregoing is a true and correct transcript of the proceedings taken by me in this matter on Wednesday, December 10, 2008, and carefully compared with my original stenographic notes.

Maria DiPaolo Jones, Registered Diplomate Reporter, CRR and Notary Public in and for the State of Ohio.

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