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FILE

EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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PUCO

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
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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**		

OP Estimated Full Requirements Service Price for the Calendar Year 2009-2011 Term			
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.

<u>PROVIDER OF LAST RESORT CHARGE</u>

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.

<u>AMORTIZATION OF MISCELLANEOUS DEFERRED COSTS</u>

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.

ECONOMIC GROWTH ADJUSTMENTS TO BASELINES FOR ENERGY EFFICIENCY AND PEAK DEMAND REDUCTIONS

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.

<u>INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY</u>

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.

JMG/OPCO GAVIN SCRUBBER LEASE ACCOUNTING

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	$86	$134	$263
Annual 7%/6.5% Distribution Increase	$24	$50	$77	$150	$21	$44	$68	$133
Estimated Cost of Companies' ESP	$272	$413	$555	$1,240	$328	$515	$707	$1,551
Estimated Benefit of Companies' ESP	**$49**	**$95**	**$139**	**$283**	**$43**	**$81**	**$115**	**$238**