FILE

OCC 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 Generation Assets.	)	Case No. 08-917-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan.	)	Case No. 08-918-EL-SSO

DIRECT TESTIMONY

of

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ON BEHALF OF
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I. INTRODUCTION

Q1. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A1. My name is Lee Smith, and I work for La Capra Associates, One Washington Mall, Boston, Massachusetts.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A2. I am testifying on behalf of the Office of the Ohio Consumers' Counsel ("OCC").

Q3. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A3. I am a Managing Consultant and Senior Economist at La Capra Associates. I have been with this energy planning and regulatory economics firm for 24 years. I have prepared testimony on regulatory issues, power costs, rates and cost allocation regarding more than 50 utilities in 18 states and before the Federal Energy Regulatory Commission. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level.

Q4. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A4. I have a bachelor's degree with honors in International Relations and Economics from Brown University. I have completed all requirements for a Ph.D. in economics except the dissertation from Tufts University.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A5. La Capra Associates has been retained by the OCC to review the Electric Security Plans ("ESPs") filed by Columbus Southern Power Company ("CSPCO") and Ohio Power Company ("OPCO"), together known as American Electric Power – Ohio ("AEP-Ohio", or "Companies"), and the comparison of the ESPs to the Market Rate Offers ("MROs") presented by the Companies. I will address the question of whether the proposed ESPs are "more favorable in the aggregate" than the MROs, and whether the proposed ESPs should be accepted by the Commission.

Q6. PLEASE DESCRIBE THE TOPICS COVERED IN YOUR TESTIMONY.

A6. First, I describe the ESPs and the MROs proposed by the Companies in detail. Second, I explain how the Companies have priced the generation service, included in both the ESPs and the MROs, that is not based on projected or estimated market prices during the ESP period. Third, I analyze, critique, and revise the estimate of market prices that is included in both ESPs and MROs. Fourth, I utilize the results of prior analyses to compare the proposed ESPs and MROs. Fifth, I discuss a number of other components of and issues in the proposed ESPs. Finally, I make recommendations to the Commission regarding the ESPs filed by the Companies.

Q7. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A7. I find that the Companies have not demonstrated that the proposed ESPs are more favorable to customers than the MROs. I recommend that the Commission only consider adopting ESPs after making the modifications made by OCC witnesses. I am making the following recommendations:

- A reduction to the initial generation price, reflecting updated and lower fuel costs and the market prices of power likely to prevail in the ESP period:
- A rejection of the POLR charges proposed by the Companies;
- A rejection of the deferral scheme[1] included in the proposal;
- A reduction of the proposed automatic increases to distribution rates; and
- Some revisions to the proposed fuel adjustment clause to better protect customers.

Q8. WHAT IS THE FRAMEWORK FOR FUTURE STANDARD SERVICE OFFER SERVICE TO OHIO ELECTRIC RETAIL RATEPAYERS, AS MANDATED BY THE MOST RECENT LEGISLATION?

A8. Amended Substitute Senate Bill No. 221 ("SB 221") required each electric utility to offer Standard Service Offer ("SSO") generation service to all retail customers beginning January 1, 2009. This service could be provided by an Electric Security Plan or a Market Rate Offer. The latter for AEP Ohio, however, was not

[1] Although if the Commission accepts my recommendations, rate increases may be held below the 15% that would have triggered deferrals.

solely based on market prices, but was a blended price that had to consist of a large amount of power at a price based on the most recent prior SSO price. The legislation states that the Companies should demonstrate that the proposed ESPs are more favorable to customers than the MROs.

It is important to note the legislation does not require the SSO rates set through an ESP to be cost-of-service-based, nor have the Companies proposed such a rate for SSO service. The legislation, however, did contain provisions for annual review of ESP rate adjustments to prevent excessive earnings to the utility.

II. OVERVIEW OF THE PROPOSED ESPS AND THE MROS

Q9. CAN THE ESP AND MRO PRICES BE EASILY COMPARED?

A9. No, for several reasons. First, a fundamental characteristic of the proposed ESPs but not the MROs is a deferral of certain costs the amount of which is unknown at this time. Second, the comparison presented by the Companies is not a complete cost comparison. Third, the prices presented in the filing do not reflect current conditions of the fuel, energy and financial markets. I believe that some cost elements in both the ESP and the MRO should be updated to provide a more meaningful comparison between them. For these reasons, I will describe and update some of the components of the ESPs and the MROs in detail before comparing the two.

Q10. HOW HAVE THE COMPANIES DESIGNED THEIR ESPS?

A10. The Companies have proposed an identical structure of an ESP for both CSPCO and OPCO. This construct consists of a (1) SSO generation service rate[2] that customers will pay in 2009 to 2011 which will be determined by the amount that will hold annual rate increases (except for the impact of transmission rate increases) to 15% per year[3] for the years 2009 to 2011, (2) a Provider of Last Resort ("POLR") charge (which will be discussed in Section VI), and (3) several new rate riders, which would recover projected increases in various costs such as, transmission costs and energy efficiency and demand reduction costs. The Companies project that price increases, reflecting all charges except transmission charges, would be considerably higher than the 15% cap proposed and so they seek to defer all costs above the 15% cap during the three-year ESP period. They propose to recover deferred costs, with carrying costs at their weighted average cost of capital, over seven years beginning in 2012, from all SSO customers either through a future ESP or the non-market portion of an MRO. (Assante p. 8-9) AEP-Ohio witness Mr. Assante estimates that total deferrals in 2009, including carrying costs for 2009, would be $118.2 million for CSPCO and $316.7 million for OPCO. Additional deferrals are projected for 2010 for OPCO. Over time, the Companies estimate that customers would be charged carrying costs of $99.4 million for CSPCO and $361.8 million for OPCO.

[2] Which will in some years be lower than what the Company has defined as its generation price; the difference between the price and the charge will result in cost deferrals.

[3] The fifteen percent target was based purely on the Companies' judgment. (Baker, p. 20)

Q11. WHAT IS THE BASIS FOR THE AMOUNT OF COSTS THAT WILL BE DEFERRED?

A11. Deferral amounts will depend on the difference between generation revenues that would result from rates which increase at approximately 15% per year and revenue targets that result from the Companies' offered SSO service. I use the term "revenue targets" because the dollars that the Companies plan to collect through the SSO service are not based on the cost of providing generation service. The Companies project total deferrals of $412 million in 2009.

The Companies construct an underlying pricing structure for the SSO generation service included in the ESP that is based upon two components. One component is market-priced power, purchased to meet 5% of the 2009 load, 10%, of 2010 and 15% of 2010 load. The other component, which will provide the remainder of the generation needed (95% in 2009), will be based on the Companies' calculation of its current SSO price, adjusted to 2009, 2010, and 2011 levels for various components of power costs, through a Fuel Adjustment Clause ("FAC") and an automatic increase to the non-FAC portion of the current SSO.

Q12. WHY DOES THE SSO INCLUDE AN AMOUNT OF POWER PROCURED AT MARKET PRICES[4]?

A12. The Companies have chosen to include some market-based power in their ESP, as part of the "continuing transition to market rates." (Baker p. 22) This is not a

[4] I will refer to power procured at market prices as "market-based power."

requirement of Senate Bill 221 for the filing of ESP. However, Senate Bill 221 does have a market-based power requirement for MRO generation service.

Q13. PLEASE PROVIDE AN OVERVIEW OF THE MRO DESCRIBED BY THE COMPANIES.

A13. As specified by R.C. 4928.142 (D), an initial 2009 MRO for CSPCO and OPCO should be priced using a blend of 10% market-based power, and the remaining 90% priced at the utility's most recent SSO price, adjusted for known and measureable changes to specified costs. In the Companies' proposed MROs (and also in the ESPs) the most recent SSO price is adjusted for projected changes in fuel and purchased power costs. In each year 2010 and 2011 the proportion of market-based power increases, again as specified by R.C. 4928.142 (D). The AEP-Ohio MRO also includes a POLR charge.

Q14. THE LEGISLATION DESCRIBES THE MARKET-BASED POWER THAT IS BLENDED INTO THE MRO AS RESULTING FROM A COMPETITIVE BID. SINCE AEP-OHIO HAS NOT YET GONE THROUGH THE COMPETITIVE BID PROCESS, HOW DO THE COMPANIES REPRESENT THE PRICE OF MARKET-BASED POWER?

A14. The Companies estimate the price of electric generation that would result from a competitive auction in 2009 for power for 2009 - 2011. They use this value for market-based power for the three years of the ESP.

Q15. WHAT IS THE BASIS FOR THESE VARIOUS PARTS OF THE ESTIMATED MARKET PRICE OF POWER (ELECTRICITY)?

A15. The average energy price is estimated based on forward market prices. This price is adjusted for load shape and for uncertainty. Estimates of PJM Ancillary services, PJM Capacity Obligations, Transaction Risk, and a retail administration charge are added to the energy price. I discuss this estimation process in detail in section IV of my testimony.

Q16. DOES THE ESP USE THE SAME ESTIMATED MARKET PRICE THAT IS USED IN THE MRO?

A16. Yes, apparently. While this is not stated explicitly in testimony, Mr. Baker describes the power purchases through the market in the ESP as a "slice of system." It, like the market-based power in the MRO, would consist of a purchase, resulting from a competitive solicitation, of a specified percentage of the Companies' load in every hour.[5]

Q17. IF BOTH THE ESP AND THE MRO CONSIST OF SOME POWER (OR ELECTRICITY) PRICED AT THE SAME MARKET-BASED PRICE, SOME POWER PRICED AT A STANDARD SERVICE OFFER PRICE, AND A POLR CHARGE, HOW ARE THEY DIFFERENT?

A17. There are four major differences. The first difference is that some generation costs are deferred under the ESP, which reduces the rate increases during 2009 to

[5] Deposition of J. Craig Baker, October 25, 2008 at 8-9

2011, but increases rates, and therefore customer costs, in 2012-2018. The second difference is that twice as much power is purchased from the market in the MRO as in the ESP. The third difference is that the ESP escalates the base or non-FAC portion of the existing SSO rate annually by 3% and 7% per year during the ESP period, while the base portion of the SSO rates does not escalate in the MRO. S.B. 221 does not allow escalation of the base SSO contained in an MRO. The fourth difference is that the ESP also contains a distribution rate increase which is supposed to pay for enhanced reliability.

Q18. WHY IS THE NON-FAC PORTION OF THE SSO PRICE INCREASED IN THE ESP BUT NOT IN THE MRO?

A18. Senate Bill 221 allowed the most recent SSO price to be increased in an MRO only for FAC cost elements. For the proposed ESP, the Companies have chosen to increase what they define as the FAC portion by the same adjustments allowed in the MRO (prudently incurred cost of fuel, purchase power costs, costs of meeting renewable and energy efficiency requirements, and costs to comply with environmental regulations), and to also increase the non-FAC portion by the 3% and 7% escalation factors. They state that this is to cover inflationary factors plus unanticipated generation-related cost increases. They have not presented any analysis to justify these percentage increases, and in fact state that these increases are not based on costs. The specific increases for each Company were chosen at least partly because "...these are consistent with the percentages that were used to adjust total rates in the RSP, so we believe customers are familiar with that."[6] This is hardly a good reason to increase rates especially in hard economic times such as these. While rate increases may not necessarily be required to be based on cost of service, they should nevertheless be reasonable and be tied to some measure of need on the part of the Companies that can be justified.

Q19. HAVE THE COMPANIES PROVIDED A COMPARISON OF THE COSTS THAT WOULD BE PAID BY CUSTOMERS UNDER THEIR ESP AND THEIR MRO?

A19. No, they have not. They have compared certain parts of both plans, but not the total costs to be paid by ratepayers. My testimony, after describing and analyzing the components of the two plans, will present such a comparison.

III. COMPUTATION OF THE PRICES OF THE SSO

Q20. YOU STATED THAT THE COMPANIES DEVELOP THE PRICE OF THE SSO PORTION, INCLUDING THE FAC ADJUSTMENTS, OF BOTH THE ESP AND THE MRO IN ALMOST THE SAME WAY. WOULD YOU PLEASE EXPLAIN HOW THEY DEVELOP THE SSO PRICES AND THE FAC ADJUSTMENT MECHANISM?

A20. The 2009 generation rates are developed for the ESPs and the MROs by adjusting the most recent SSO generation rates. Senate Bill 221 specifies that the Commission may allow for "known and measureable changes from the level of

[6] Deposition of J. Craig Baker, October 25, 2008 at 56.

any one or more of the following costs" (all specifically limited to prudently incurred costs): fuel, purchased power, costs of meeting renewable energy and energy efficiency requirements, and costs to comply with environmental laws and regulations.

The Company proposes to meet this legislative directive by including, in a new FAC, certain accounts that reflect fuel, purchased power, and environmental subaccounts, which S.B. 221 allows to be adjusted automatically. The current SSO rate, which is being increased, recovers both FAC costs and base generation costs. The FAC rates (the portion of the SSO rates that apply to FAC cost components) are the bases for the increases in the SSO in the Companies' computations. In order to adjust the most recent SSO prices only for changes in these FAC accounts, they must identify the equivalent to the FAC costs in the current SSO prices. The remainder of the current SSO price is the base generation rate.[7]

Q21. IF THE AMOUNT OF THE FAC COSTS IN THE CURRENT SSO IS NOT KNOWN, HOW DID THE COMPANY ESTIMATE THE ALLOWED INCREASE TO THE CURRENT SSO FOR INCREASES IN FAC COSTS?

A21. AEP-Ohio witness Mr. Nelson began this process by adding up 1999 amounts for the accounts that he has identified as belonging in the FAC. He then escalated

[7] As I discuss in Section VI, the Companies propose to increase the base generation component in their ESPs.

these amounts by the increases to 1999 generation rates that had been allowed in the Rate Stabilization Plan for 2006, 2007, and 2008. The allowed increases were 7% for OPCO and 3% for CSPCO. He also made further adjustments for the Power Acquisition Rider ("PAR") for CSPCO and for changes in the Regulatory Asset Charge ("RAC") for OPCO. This produced his estimate of FAC includable costs for 2009.

Q22. IS THIS A REASONABLE WAY TO DETERMINE THE COST OF FUEL, PURCHASED POWER, AND EMISSIONS ALLOWANCES FOR THE PURPOSE OF CALCULATING AUTOMATIC ADJUSTMENTS, AS ALLOWED IN R.C. 4928.143 (B) (2)?

A22. No, it is not. The cost of fuel, purchased power, and emissions allowances are actual numbers. The 7% and 3% escalation to rates that was adopted in Case No. 04-169-EL-UNC was based on opinion – the Companies' opinion about the increase in total generation revenues that they wanted. Over the RSP period, the fuel costs[8] experienced by the Companies, which are only a part of the total generation costs, may have increased more or less than these escalations to rates. If fuel costs actually increased more from 1999 to 2008 than the total of these escalations, then the Companies' calculated 2008 fuel "rate" will have understated 2008 fuel costs. One result is that it will appear that fuel costs are increasing more in 2009 than they actually are, and the FAC adjustment will be larger than if

[8] I will adopt Mr. Nelson's convention hereinafter of using "fuel clause" and "fuel costs" to refer to all costs which are allowed in the FAC

the 2008 actual fuel cost number had been used. Another result will be that the calculated base generation amount will be larger. Although the Companies have stated that in future years fuel cost collection will be trued up to actual fuel costs in the FAC, they would still have a higher base generation rate and higher total generation revenue.

Q23. WOULD A MISSTATEMENT OF THE 2008 STARTING POINT FOR FUEL COSTS BE SIGNIFICANT?

A23. Certainly. If the Company has understated the fuel costs in the 2008 SSO price, and this is used as the basis for the adjustment to the SSO price in the MRO, the portion of the MRO priced on SSO generation will be overpriced for 2009.

This may be made clearer with a simple example. Let us start with a most recent SSO rate of 4.5 cents/kwh. In this example the Companies methodology produces a FAC rate of 2.5 cents, leaving a base generation rate of 2 cents. Further assume that the estimate of FAC costs for 2009 is 3.5 cents, and this estimate is correct, so no true-up will be needed. Customers will pay 3.5 cents plus 2 cents in 2009, or 5.5 cents. If the actual FAC costs in 2008 had been 3 cents, the base generation rate would have been 1.5 cents. In 2009 customers would pay the correct 3.5 cent generation rate plus the base generation rate of 1.5 cents, for a total of 5 cents – one/half a cent less for every kWh.

Q24. HOW WILL THE PROPOSED FAC ADJUSTMENTS WORK IN 2009-2011?

A24. AEP-Ohio witness Mr. Roush testifies that the FAC will be trued up to costs in the future. Since the Companies apparently propose not to apply carrying charges to over-collections through the FAC, it is important to set the initial FAC as accurately as possible. An initial overstatement of FAC costs will cause customers to not receive full compensation for any overpayment by them during 2009. The apparent lack of symmetry in the Companies' proposal regarding carrying charges on the true-up is a problem that will be discussed later.

Q25. DO WE KNOW WHAT ACTUAL FUEL AND PURCHASED POWER COSTS WILL BE IN 2008?

A25. No. The Companies have presented no information about actual costs to date, or an estimate for the entire 2008 year. They should be required to make such an estimate.

IV. ANALYSIS OF PROJECTED MARKET PRICES OF POWER (OR ELECTRICITY)

Q26. PLEASE DESCRIBE THE COMPANIES' ESTIMATES OF MARKET-BASED POWER PRICES.

A26. The Companies produce price estimates for each general rate category, residential, commercial, and industrial, for both CSPCO and OPCO. These all use the same values for the basic energy costs, for "Retail Administration", and

Ancillary Services, and class-differentiated numbers for other components of the market cost.

There appears to be an error in the OPCO line loss values. For CSPCO, the cost of line losses was greatest for the residential class, and least for the industrial class. This is usually true, since the residential class is served at secondary line voltage and the other classes take some service at higher line voltages. However, in the table on p. 13 of Mr. Baker's testimony, for OPCO line losses are $1.28 for residential, $4.46 for commercial, and $2.49 for industrial. In my subsequent analysis and table, I believe the Companies numbers should have been $4.46 for residential, $2.49 for commercial, and $1.28 for industrial and I have made adjustments to these corrected numbers. I will adjust these line losses in Table 3.

Q27. DO THE COMPANIES' ESTIMATES OVERSTATE THE PROJECTED MARKET COST (OR PRICE) OF POWER FOR THE ESP PERIOD?

A27. Yes. The data used by the Companies to estimate the fundamental forward energy price, "ATC Swap" does not reflect current market conditions and current forward energy prices. In addition, the Companies' estimate appears to have overstated some of the "adders" to the ATC Swap price, resulting in an overstatement of the market price.

Q28. WHAT IS THE PROBLEM WITH THE DATA UTILIZED TO CALCULATE THE ATC SWAP?

A28. The Companies testify that they have utilized forward price data from the first week of the first three quarters of 2008. Mr. Baker claims that this "...would provide the most accurate representation of recent market conditions..." (Baker, p. 15) The Companies, however, have provided no evidence that this is "the most accurate representation", or even that it is "an accurate representation" of recent or more importantly of current market conditions. I agree with Mr. Baker that the price of energy changes on a daily basis, and that utilizing one day is not the best way to judge the current market. For the last three months, oil, natural gas, coal, and forward energy prices have fallen significantly. While this was not known to the Companies at the time of their filing, we now have more recent data, including data from the first week of the fourth quarter.

Q29. WHAT DOES MORE RECENT FORWARD PRICE DATA REVEAL?

A29. Forward prices have dropped dramatically in the 4th quarter. Since the Companies have used prices from the first week of each quarter, when I refer to price data it will continue to refer to the first week of a quarter. The Companies' estimate of the ATC Swap price was $57.84 for both CSPCO and OPCO. I have done an analysis of how forward market prices for 2009-2011 at the PJM West Hub have changed from the first week of the first three quarters of 2008 to the fourth quarter of 2008. This data is shown in Table 1 below. I used PJM West Hub data because La Capra Associates gets forward price data from the Intercontinental

Exchange ("ICE"), which does not report the Dayton Hub. This data shows that forward prices for 2009 alone have dropped by more than 17% from the three quarter average to the fourth quarter.

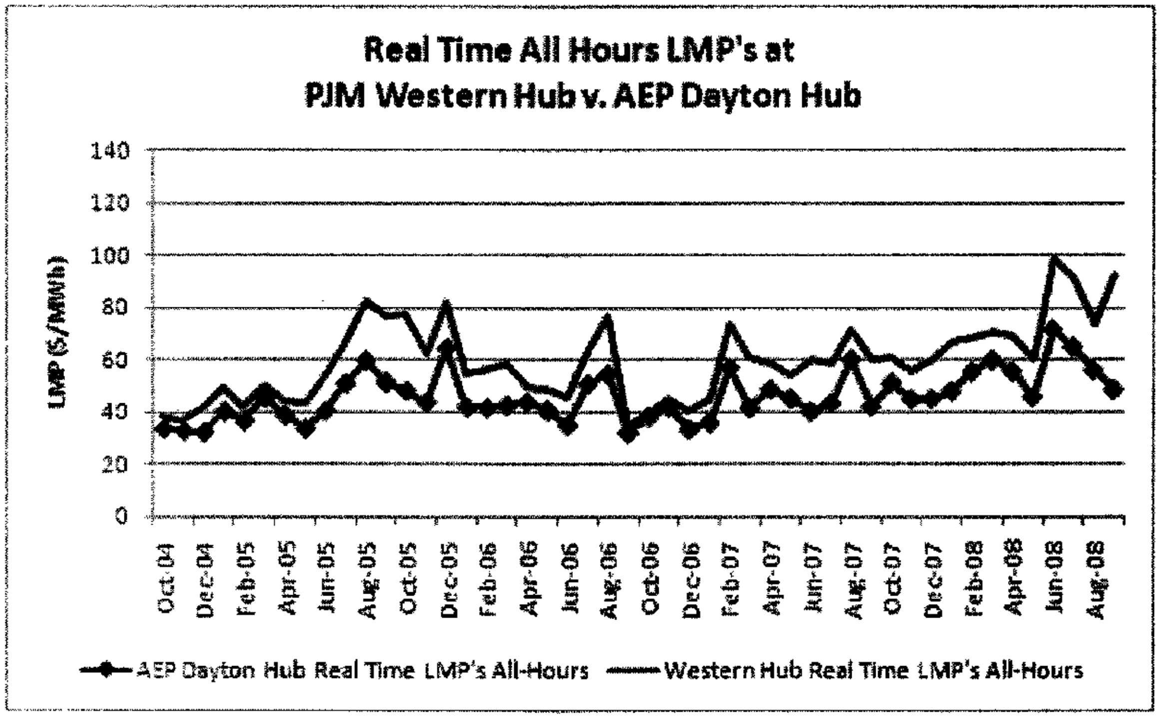
TABLE 1

2009 PJM Western Hub Real Time All Hours Forward Prices				
Quarter 1	Quarter 2	Quarter 3	3 Quarters Average	Quarter 4
$ 67.97	$ 74.32	$ 94.75	$ 79.01	$ 65.28

The basis difference between PJM West and AEP will be different from the difference between Dayton and AEP. Rather than doing an independent analysis of the basis difference between PJM West and the AEP zone, I used the PJM West data to adjust the Companies' data. I assumed that the Dayton Hub data changed from the three quarter average to the fourth quarter by the same percentage as the PJM West data for 2009 to 2011 that I reviewed.[9] Actual PJM data on real-time LMPs shows that Dayton Hub and PJM West prices generally move together. The graph below illustrates this with all hours data for 2008. My updated estimates of the same forward energy only price are $49.82.

[9] The decrease from the 3 quarter average to the 4th quarter was somewhat less when 2010 and 2011 are taken into account, and is the number we used to adjust the Companies' energy price.

GRAPH 1



Q30. IS IT REASONABLE TO UTILIZE DATA FROM THE FOURTH QUARTER OF 2008 TO ESTIMATE WHAT AUCTION PRICES FOR 2009 WILL BE?

A30. Yes, it is. It is unlikely that this decrease will be reversed in the near future. Forward market prices for 2009 -2011 have been dropping since a peak in the summer of 2008. Moreover, there have been even larger decreases in the price of oil and the forward price gas. Forward NYMEX natural gas prices for 2009 were $9.728 on July 27 and were $6.947 on October 27, as can be seen in the table below. Even coal prices have dropped recently. Ms. Medine testifies that since July 2008 prices have fallen by 20 percent for Appalachian coal and by less for other coal sources. (Medine testimony p. 11) All of this movement suggests that the decrease in electric market prices that we observe in the October data is more likely to continue than to reverse.

TABLE 2

NYMEX FUTURE GAS PRICES

Delivery Month	Price	Transaction Date
Jan '09	$10.2370	7/28/2008
Feb '09	$10.3740	7/28/2008
Mar '09	$10.0740	7/28/2008
Apr '09	$9.3660	7/28/2008
May '09	$9.2700	7/28/2008
Jun '09	$9.3530	7/28/2008
Jul '09	$9.4400	7/28/2008
Aug '09	$9.5100	7/28/2008
Sep '09	$9.4520	7/25/2008
Oct '09	$9.6200	7/28/2008
Nov '09	$9.8420	7/25/2008
Dec '09	$10.1970	7/25/2008
Average	**$9.7279**	

Delivery Month	Last	Transaction Date
Jan '09	$6.6600	10/27/2008
Feb '09	$6.7080	10/27/2008
Mar '09	$6.6650	10/27/2008
Apr '09	$6.6000	10/27/2008
May '09	$6.6750	10/27/2008
Jun '09	$6.8050	10/27/2008
Jul '09	$6.9350	10/27/2008
Aug '09	$7.0010	10/27/2008
Sep '09	$6.9800	10/27/2008
Oct '09	$7.1240	10/27/2008
Nov '09	$7.4220	10/27/2008
Dec '09	$7.7850	10/27/2008
Average	**$6.9467**	

Moreover, if the Companies do hold a competitive solicitation in the near future, bidders would rely on the most recent forward data, in order to determine their bids. Bidders normally plan to hedge such future sales, which means that current forward prices, not what prices were three or six or nine months ago, are most relevant to the prices that would be offered in response to a competitive solicitation.

Q31. WHAT OTHER ELEMENTS IN THE COMPANIES' MARKET PRICE ESTIMATES ARE ALSO OVERSTATED AND WHY?

A31. The estimate of the cost of power purchased through a competitive bid include elements in addition to the forward energy price, as noted earlier in my testimony. There are several elements included in the Companies' market price that are overstated because they are based upon the basic forward energy price, the ATC Swap value, that is now much lower than the number Mr. Baker was using a basis for the market price. The elements that depend upon the forward energy price include the "load shape and following" value[10], and losses. I have adjusted these elements by my adjustment to the energy price. In addition, I believe that what are described by the Companies as the retail administration charge and the transaction risk adder are overstated.

[10] I accepted the Companies' load following adjustments as the basis for my adjustments, but the Companies' loss following adjustment for the CSPCO residential class seems somewhat high.

Q32. WHAT ARE YOUR CONCERNS ABOUT THE RETAIL ADMINISTRATION CHARGE THAT IS INCLUDED IN THE COMPANIES ESTIMATE OF MARKET PRICE?

A32. According to Mr. Baker, a retail administration charge would be included in a bid price to provide full requirements service. It is expected that costs in this category cover marketing, personnel, overheads and profits related to selling power into MRO auction. The Company uses $5/MWH for this cost. This estimate of a retail margin is likely to overstate the costs that would apply to a wholesale transaction, as the supplier would not be selling to specific customers but to the Companies. It is unlikely that marketing and overhead costs would be more than $1.00/MWH. I base this conclusion on the calculation that a charge of $1.00/MWH would result in the supplier recovering more than $2 million for CSPCO alone in 2009. I think it is very unlikely that a supplier would need more than these amounts for the marketing and overhead function.

This $5.00 per MWH adder is also supposed to include the suppliers' profit margin. I have seen estimates of profit margins that run from $1 to $2/MWH. This suggests that the costs that are reflected in "retail administration", in total, may be from $2 to $3/MWH.[11]

[11] I will reflect the retail administration value as 0 and includes these dollars under transactions costs.

Q33. WHAT ABOUT MR. BAKER'S STATEMENT THAT THE STATE OF CONNECTICUT INCLUDES A RANGE OF $5/MWH TO $10/MWH FOR THIS CHARGE?

A33. The Connecticut charges that he cites do not reflect supplier costs. In Connecticut the utilities hold an actual market solicitation for the power for their Standard Service load. Connecticut has no reason to and does not make any estimates as to the cost components of bids in standard service offer auctions. What Mr. Baker may be referring to is a charge in Connecticut that is an adder to the wholesale power costs of the supplier by the utilities. The purpose was "...increased wholesale rates to reflect a proxy for the retail price." (Connecticut Docket no. 03-07-01) Such an increase reflects costs of retail suppliers to market service to customers. They are not properly a part of wholesale costs.

Q34. MR. BAKER ALSO INCLUDES IN THE MARKET PRICE A COMPONENT CALLED "TRANSACTION RISK" WHICH VARIES BY UTILITY AND BY CUSTOMER CLASS FROM $4.45 TO $5.47 PER MWH. WHAT IS THIS COST COMPONENT SUPPOSED TO REPRESENT AND IS THIS A REASONABLE ESTIMATE OF THOSE COSTS?

A34. This transaction risk component is supposed to reflect a number of risks, including commodity price risk, migration risk, and credit risks described by Mr. Baker (Baker, p. 11). While these appear in name to be legitimate risks, further scrutiny shows that such risks will not impose significant costs on bidders. Commodity price risk is always a concern in <u>retail</u> market transactions since the individual customer transactions are small. In a wholesale transaction for power offered through a competitive bid, however, the commodity price risk to the supplier can be minimized through the use of forward purchasing. The supplier will bear very little risk if it hedges its obligations. Migration risk appears to be almost non-existent, especially in the early years, as the blending of a below market price of SSO with the MRO market price results in a price below market. Lastly, the credit risk concern is again nearly non-existent with a regulated utility counterparty procuring power under a Commission approved process that is implementing legislative mandates.

Q35. WHAT WOULD YOU ESTIMATE TO BE THE ADJUSTMENT THAT WOULD BE ADEQUATE TO RECOVER THESE VARIOUS COSTS FOR RETAIL ADMINISTRATION AND TRANSACTION RISK?

A35. I believe that a liberal estimate of the total of these two adders together is from $4 to $5 per MWH. This is the value that I have included in my alternative market price, under the one label, Transaction risk adder, as the costs included in the two categories are not easily distinguishable. It results in reducing the market price estimates by about $6 per MWH.

Q36. WHAT IS THE FULL RESULT OF YOUR MODIFICATIONS TO THE MARKET PRICE THAT IS USED IN BOTH THE ESP AND THE MRO?

A36. My estimates of updated and corrected market prices are $73.94 for CSPCO and $71.07 for OPCO. These are lower than the Companies prices by about 16%. The components of this estimate are shown in Table 3 below.

TABLE 3

UPDATED, REVISED MARKET BASED POWER PRICES

CSP Estimated Competitive Electric Retail Service Price for			
Cost Components	CSP Residential	CSP Commercial	CSP Industrial
ATC Simple Swap	$49.82	$49.82	$49.82
Basis	$0.51	$0.51	$0.51
Load Shape and Following	$8.26	$4.59	$1.99
Retail Administration	$0.00	$0.00	$0.00
Ancillary Services	$1.19	$1.19	$1.19
Losses	$3.46	$2.18	$0.78
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	$81.76	$72.97	$65.20
Class Weight	34%	40%	26%
CSP Total	**$73.94**		

OP Estimated Competitive Electric Retail Service Price for the			
Cost Components	OP Residential	OP Commercial	OP Industrial
ATC Simple Swap	$49.82	$49.82	$49.82
Basis	$0.51	$0.51	$0.51
Load Shape and Following	$6.60	$5.22	$2.22
Retail Administration	$0.00	$0.00	$0.00
Ancillary Services	$1.19	$1.19	$1.19
Losses	$3.85	$2.15	$1.10
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	$78.08	$74.37	$66.17
Class Weight	26%	22%	52%
OP Total	**$71.07**		

Q37. IF FUEL AND PURCHASED POWER COSTS HAVE BOTH DECREASED SINCE THE COMPANIES' FILING, SHOULD FUEL AND PURCHASED POWER COSTS INCLUDED IN THE FAC ALSO HAVE DECREASED?

A37. Yes. Another OCC witness, Ms. Emily Medine, testifies regarding decreases in the Companies' costs. I believe the Companies should provide an updated estimate of their 2009 FAC costs in order to set the rate as accurately as possible.

V. COMPARISON OF ESP AND MRO

Q38. PLEASE DESCRIBE HOW THE ESP AND THE MRO SHOULD BE COMPARED.

A38. The full cost to customers of the two plans should be compared, producing total dollar and percentage differences in costs. Opinions about additional features of one plan versus the other should then be considered to determine if features justify the cost differences.

Q39. HOW DID MR. BAKER COMPARE THE ESP AND THE MRO?

A39. The deferral of costs under the ESP makes the initial three years of rates lower than the undeferred costs under the MRO. However, the Company claims that the ESP would be more favorable than the MRO even without the deferral. (Baker testimony[12], p. 16) As evidence that the ESP is more favorable than the MRO, Mr. Baker presents a table in Exhibit JCB-2 that does not include full generation

[12] Mr. Baker states than Exhibit JCB-2 demonstrates that the ESP is more favorable. This exhibit does not reflect the impact of deferrals.

costs. He includes the cost of market-based power, the POLR charge, and Incremental Environmental charges under both options, and additional non-FAC generation and distribution cost increases under the ESP. However, he does not include the cost of the non-market-based power under either option. Even though the price of non-market-based power is the same, the Companies include <u>more</u> non-market-based power in the ESP option (95% in 2009, 90% in 2010 and 85% in 2011) than they include in the MRO option (90% in 2009, 80% in 2010 and 70% in 2011).

Q40. DO YOU THINK THE COMPANIES HAVE PORTRAYED ALL ASPECTS OF GENERATION COSTS CORRECTLY?

A40. No. The computations of total customer costs and rate increases shown on Data Response Staff 10-1 show the Non FAC generation cost increasing each year. However, the ESP is supposed to have less SSO power each year. This results in the Companies paying themselves a price than has increased much more than the ostensible 3% increase for the non FAC portion of generation each year. This would not be allowed for the SSO power blended into the MRO. I have not corrected this in my portrayal of the full costs of the two options as proposed by the Companies, but I do address then when I modify the Companies proposals.

Q41. HAVE YOU PREPARED A FULL COMPARISON OF THE PROPOSED MRO AND THE ESP?

A41. Yes. First I simply added the cost of SSO power to the costs included in Exhibit JCB-2, based on the Companies' estimates of the both the market prices and the SSO prices. This complete version of Exhibit JCB-2 is found in my LS Exhibit 1. LS Exhibit 1 shows that without any deferrals, for the period 2009 through 2011 CSPCO customers would pay $185 million more and OPCO customers $220 million more for the total cost of the ESP as proposed by the Companies than for the total costs of the MRO. This is due primarily to the additional non-FAC increases and the additional distribution increases in the ESP.

Q42. HOW DID YOU CALCULATE THE COST OF SSO POWER?

A42. I started with the Companies' values for generation costs in 2009, found on Data Response Staff 10-1. This portrays generation charges to customers under the Companies' proposal. Generation charges are separated into Non FAC, the increase in Non FAC, FAC, and the increase to FAC. The cost of market based power is not shown separately but is included in the FAC costs. This table does not reflect what the Companies view as their full generation cost, because some generation costs are being deferred. Exhibit JCB-2 shows the Companies estimates of market based power costs. In order to determine the price for the SSO portion of generation costs, I first assumed that the Companies had calculated the base portion of the SSO correct. I addressed the amount of SSO costs in the FAC by subtracting the market based power costs, and then adding in the deferrals. This indicates what the Companies indicate they will pay themselves for SSO power for the 95% of their load that will be supplied by SSO power in 2009.

In the MRO, the Companies will be purchasing less SSO power and more market based power, and this will be reflected in the full cost of generation. Again, I used the Companies' values for the cost of market based power. For the SSO portion, I assumed that costs would be less because less SSO power was included in the blend. Essentially I used the estimate of the per MWH price of SSO power based on the Companies numbers, and applied this to the lower volumes which would be acquired at SSO prices.

VI. OTHER ISSUES REGARDING THE ESP

Q43. ASIDE FROM THE CALCULATION OF THE FAC AND THE FAC ADJUSTMENT, ARE THE COMPANIES' REQUESTS ALL CONSISTENT WITH REGULATORY POLICY?

A43. I do not think that they are. The starting point for the MRO and the ESP is clearly the most recent SSO price. To grant the Companies increases to these prices for specific investments implies that 1) either the Companies do not have enough earnings to pay for these investments or that 2) the Companies will not make these investments without additional revenues and they are investments which are in the public interest. With regard to the first, there has been no indication that the Companies' earnings are insufficient to make these investments. The carrying charges on the incremental environmental investments do not seem to pass these criteria, and I have removed them. I have also removed the increase to the non FAC generation costs as well as some of the proposed distribution increase for the same reason.

Q44. ARE THERE OTHER PROBLEMATIC ISSUES WITH REGARD TO THE PROPOSED ESPS?

A44. Yes, there are a number of additional issues.

- There are several problems with proposed generation charges.
- The carrying charges on 2001 – 2008 incremental capital investment are not justified, and the amount of deferrals resulting from the carrying costs on environmental investments may have been misstated.
- The proposed POLR charges are not justified.
- The entire deferral concept is a problem,
- The inclusion of an automatic increase to distribution rates under the ESP is a problem.
- The fact that the Companies propose to treat distribution customers differently if the Commission selects the ESP over the MRO is a problem.

Q45. WHAT ARE THE PROBLEMS WITH THE PROPOSED GENERATION CHARGES?

A45. I think that the proposed FAC escalation of the non-FAC generation charges is unreasonable. The estimate of the FAC is clearly too high, based, as was the market price estimate, on outdated fuel and purchased power costs. The lack of carrying charge for any possible over-recovery of costs in the proposed FAC adjustment mechanism is a problem, particularly since if the FAC is not reduced enough to reflect actual 2009 fuel and power costs, customers will most likely end up overpaying. The lack of a fully fleshed out FAC tariff with formulae and definitions is a problem, as we cannot determine the interaction between FAC collections and deferrals without knowing how the true-up and carrying charges will work.

There is no basis to increase the non-FAC portion of the generation charge in the ESP. Senate Bill 221 clearly does not allow such an increase in the case of an MRO. The only adjustments under an MRO that are allowed to the prior SSO price are those that can be included in an FAC, and these are all cost-based. The major difference between the proposed ESP and an MRO is that the ESP includes only half the amount of market-based power that is in the MRO. This does not seem to be justification for an additional increase to the SSO price, and even an additional annual increase. It is clear there is no cost basis for the charge and no cost basis for the different treatment of the non-FAC generation rate in the ESP and the MRO. Even part of the Companies' rationale for the non-FAC generation charge, "…customers are familiar with that"[13] is misleading. Customers will not be experiencing a continued increase of 3% (if they are lucky enough to reside in CSPCO's territory rather than in OPCO's territory), but a total increase of

[13] Deposition of J. Craig Baker, October 25, 2008 at 56.

approximately 15% per year. This increase is much higher than customers have been accustomed to. Another irrational aspect to this rate increase is that, without the deferral, it would result in higher rate increases in OPCO territory than in CSPCO territory. There is no basis to expect that costs will increase in one territory by 4% more than in the other.

Q46. WHY DO YOU BELIEVE THAT THE CARRYING CHARGES ON 2001-2008 INCREMENTAL ENVIRONMENTAL CAPITAL EXPENDITURES ARE NOT JUSTIFIED?

A46. This increase to rates does not meet the criteria for inclusion that I discussed on p. 29. The Companies have not demonstrated that they have not had enough earnings to make these investments or that they would not have made them without additional rate revenues, since they have already made these investments. Moreover stockholders will reap the benefits over the lives of these investments.

Q47. WHAT IS THE POSSIBLE MISSTATEMENT OF DEFERRALS ASSOCIATED WITH THE CARRYING COSTS ON ENVIRONMENTAL INVESTMENTS?

A47. The Companies have requested recovery of large amounts of carrying costs on environmental investments made from 2001 to 2008. Mr. Nelson reports jurisdictional revenue requirements of 2001 to 2008 of $ 84 million for OPCO and $26 million for CSPCO. Mr. Baker includes these costs as part of the cost of the ESPs for 2009, 2010, and 2011 in his Exhibit JCB-2. However, Mr. Roush, calculating revenue requirements, shows these values as non-FAC costs only in the year 2009. It is not clear from the exhibits of Mr. Roush or Mr. Assante how the 2010 and 2011 carrying costs on past environmental investments have been treated. If the Companies' presentation does not reflect these dollars that the Companies are requesting in their computation of deferral amounts, the actual deferrals could turn out to be higher than the Companies have indicated by hundreds of millions of dollars. This question must be addressed in discovery, depositions, and possibly supplemental testimony.

Q48. WHAT ARE YOUR OBJECTIONS TO THE PROPOSED POLR CHARGE?

A48. The Companies are requesting an additional $508 million from ratepayers for compensation for a cost that they are highly unlikely to incur. In fact, the major reason for the request is the Companies' claim that the legislature or regulators may change an existing element of S.B. 221, should a municipal aggregation return to SSO service when market prices are higher than the cost of SSO service. There are no current municipal aggregations in their territory; forward price information makes it questionable that there will be in the near future; and there would have to be major turnarounds in prices for market prices to climb above SSO prices. Even though I have projected lower market prices than the Companies, market prices remain below SSO prices.

The most unreasonable aspect of this request is that it is unnecessary. If the Companies had to purchase more power to serve returning customers, at any price, this cost would automatically be reflected in the FAC and be recovered from all non-shopping customers, including those that had returned to SSO service. The Companies are currently collecting only 1 mil per kWh in a POLR charge, and there has been no indication that they have needed even this amount to cover costs.

The Companies admit that they have estimated the cost that they might have to pay for options because of the POLR obligation, but that they might not pay this cost. Given the unlikelihood of any need for such charge, I suggest that such a cost would be deemed imprudent.

Q49. WHY DO YOU BELIEVE THE OFFERED PHASE-IN AND DEFERRAL IS A PROBLEM?

A49. The phase-in and deferral will result in customers paying a projected additional $461.2 million in carrying costs in the years 2012- 2018 (Assante Exhibit LVA-1). The increment of these costs to future ratepayers will mean that either they will pay more even if all customers are then paying market prices, or it will be another reason proffered in the future to not move to a competitive market for generation. In addition, it is unreasonable to charge these carrying costs to customers who are currently shopping and thus will not receive the "benefit" of these deferrals. Moreover setting the carrying costs at the cost of capital is not reasonable and results in excessive payments by customers. If deferrals are approved by the Commission, the carrying costs should be set at the long term cost of debt.

Q50. ALTHOUGH YOU OBJECT TO THE PHASE-IN, IF A PHASE IN WAS APPROPRIATE, WHY WOULD THE COMPANIES NOT PHASE-IN RATE INCREASES UNDER THE MRO OPTION?

A50. According to Mr. Baker, "such a phase-in would be incompatible with a market pricing regime." (Baker, p.16) Since the MROs are not yet "market priced", it is not clear that phasing in would be inappropriate. Offering it as a benefit only under the ESPs seems designed simply to make the ESPs look more favorable than the MROs since the price under an ESP would appear artificially lower as compared to the MRO.

Q51. HAS THE AUTOMATIC DISTRIBUTION RATE INCREASE BEEN JUSTIFIED?

A51. No. AEP proposes annual increases to its distribution rates over the three-year term of its ESP to support a gridSMART program and its Enhanced Service Reliability Plan ("ESRP")[14]. The Companies have demonstrated neither that the reliability plan will be appropriately monitored, nor that it will increase reliability, nor that it consists fully of new expenditures. The ESRP is not structured as an "incentive plan", as contemplated by R.C. 4928.143(B)(2)(h), because the requested distribution increase is not dependent upon the Company's reliability

[14] The gridSMART component is proposed only for CSP.

performance. In fact, there is no penalty for the Company's failure to meet any reliability targets as a result of the implementation of the ESRP. The plan is devoid of any goals or milestones, making it difficult to judge the reasonableness of the program. Moreover, it appears that AEP's proposed ESRP consists of routine distribution reliability matters, the costs of which are already being collected in rates. My comments reflect OCC's position, which is explained fully in the testimony of OCC Witness Cleaver. AEP has not born the burden of proving that significant investment, beyond what is currently being done, is necessary for distribution reliability enhancement. OCC does not support AEP's proposed annual distribution rate increase of approximately 4.06% for CSP that pertains to the Enhanced Service Reliability Program ("ESRP") nor does OCC support the proposed annual six and one-half percent distribution rate increase for OP that is dedicated solely to the ESRP.

Q52. PLEASE DISCUSS THE REMAINING COSTS THAT ARE INTENDED TO BE RECOVERED IN THE AUTOMATIC DISTRIBUTION INCREASE.

A52. The proposed distribution increase in the ESP is also intended to recover expenditures on an initiative to develop an intelligent distribution/transmission network, called gridSMART. OCC supports part of these initiative, providing there is a more detailed project plan and requirements document involving budget, resource allocations and operating cost projections for the full 7-10 year implementation period and beyond, along with a specific set of performance measures and metrics as recommended by OCC witness Finamore. The gridSMART distribution costs which the OCC supports result in an approximate 2.94% distribution increase to CSP, are acceptable as explained in the testimony of Witness Finamore. I have reflected these in LS Exhibit 3 and Exhibit 4.

Q53. PLEASE DISCUSS THIS INCREASE TO DISTRIBUTION RATES.

A53. Distribution rates would increase automatically each year of the ESP. Mr. Baker describes this as "single issue rate making for distribution service." (Baker, p. 17) It is not the same as typical single issue rate making, which would examine the costs of a single issue, and base an increment to rates on an increment to costs. This is simply an arbitrary 3% and 7% increase which is supposed to "enable the Companies to proceed now with their gridSMART and enhanced distribution reliability initiatives."

Q54. HOW ARE CUSTOMERS TREATED DIFFERENTLY UNDER THE ESP AND THE MRO OPTION?

A54. In addition to the deferral issue discussed above, there are a number of differences, which the Companies portray as advantages in the ESPs. These include stockholder support for low-income and economic development, only under the ESPs. Another difference is that the Companies include in the ESP an automatic increase to distribution rates.

Q55. DO YOU THINK THE COMPANIES HAVE PORTRAYED ALL ASPECTS OF GENERATION COSTS CORRECTLY IN THE MRO?

A55. No. The computations of total customer costs and rate increases shown on Data Response Staff 10-1 show the Non FAC generation cost increasing each year. However, the ESP is supposed to have less SSO power each year. This results in the Companies paying themselves a price than has increased much more than the ostensible 3% increase for the non FAC portion of generation each year. This would not be allowed for the SSO power blended into the MRO. If this is an error in the MRO computations, as it seems to be, it has slightly overstated the cost of the MRO.

Q56. CAN YOU SUMMARIZE THE RESULTS ON THE COMPARISON OF THE ESPS AND THE MROS OF THE CHANGES THAT YOU ARE RECOMMENDING?

A56. Yes. On LS Exhibit 2 I have summarized the impact on total costs based on:

- the lower market prices based on the updating and modifications that I have made to the Companies' market prices,
- the reduction of the base generation component as less SSO power is included,
- no escalation of the base generation component,
- a lower increase in the distribution rate for CSPCO, and none for OPCO: and
- no POLR charge.

- removal of the carrying costs on the incremental environmental capital expenditures

I conclude that on this basis, the ESPs as modified are slightly more favorable than the MRO for CSPCO and for OPCO.

I have also used these total costs to calculate the rate increases that will result from the ESPs. These results are shown in LS Exhibit 3. The average expected increase for CSPCO in 2009 will be 10.5%, 10.9% in 2010, and 11.1% in 2011. The average expected increase for OPCO in 2009 will be 19.5%, 15.4% in 2010, and 7.3% in 2011, with no deferrals. They could be lower if the FAC costs for 2009 have been overstated. Without the Companies' deferral provisions, these increases could also be higher if there are significant increases in fuel and purchased power costs. They could also be lower if the FAC costs for 2009 have been overstated. However, with the deferral provision, such increases would result in still more costs being shifted to future ratepayers and still more carrying charges being borne by ratepayers.

VII. RECOMMENDATIONS

Q57. WHAT ARE YOU RECOMMENDATIONS REGARDING THE ESP AND THE MRO OPTIONS?

A57. I recommend that the Commission only approve an ESP if at least the following changes are made to the Companies' proposal:

- There should be no deferral provision;
- The FAC should be reduced to reflect more current fuel and power costs;
- A detailed FAC should be approved which includes carrying charges on annual under or over recoveries at the same weighted average cost of long-term debt;
- The base generation rate should not increase;
- No POLR charges should be allowed in the ESP;
- Rates should not be increased by the carrying costs on the incremental environmental capital expenditures; and
- The distribution increase should be reduced for CSPCO and eliminated for OPSCO, under conditions recommended by OCC witness Finamore.

There are enough apparent errors and inconsistencies in the Companies filing that the ESP must be reviewed and tested during the proceeding very carefully.

Q58. DOES THIS CONCLUDE YOUR TESTIMONY?

A58. Yes. However, I reserve the right to incorporate new information that may subsequently become available. I also reserve the right to supplement my testimony in the event that AEP Ohio submits new or corrected financial or other data in connection with this proceeding.

LS Exhibit 1

COMPLETE COST COMPARISON OF MRO AND ESP

	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	$78	$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 Other Costs for 90%, 80%,70% load								
Base Non-FAC Costs	$445	$434	$413	$1,292	$512	$568	$562	$1,642
Base FAC Costs	$477	$490	$576	$1,544	$380	$308	$358	$1,046
FAC Increase	$246	$220	$225	$692	$348	$326	$196	$870
Estimated Total Cost of Companies's MRO	$1,490	$1,653	$1,909	$5,052	$1,610	$1,799	$1,938	$5,347
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 Other Costs for 95%,90%, 85% load								
Base Non-FAC Costs	$470	$488	$502	$1,460	$540	$639	$683	$1,862
Base FAC Costs	$504	$552	$700	$1,755	$401	$347	$435	$1,182
FAC Increase	$260	$248	$273	$781	$367	$367	$238	$972
Estimated Total Cost of Companies's ESP	$1,506	$1,701	$2,030	$5,237	$1,636	$1,868	$2,063	$5,567
Estimated Benefit of Companies' ESP	($16)	($48)	($121)	($185)	($26)	($69)	($125)	($220)

LS Exhibit 2

COMPARISON OF REVISED MROS AND ESPS INCLUDING UPDATED FUEL PRICES

	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)	$73.94	$73.94	$73.94		$71.07	$71.07	$71.07	
Estimated Purchase Cost of 10%/20%/30%	$168	$336	$504	$1,008	$200	$400	$600	$1,200
2001 - 2008 Incremental Environmental (90%/80%/70%)	$0	$0	$0	$0	$0	$0	$0	$0
POLR (90%/80%/70%)	$0	$0	$0	$0	$0	$0	$0	$0
Estimated Cost of 10%/20%/30% Market Rate Option	**$168**	**$336**	**$504**	**$1,008**	**$200**	**$400**	**$600**	**$1,200**
Estimated Other Costs for 90%, 80%,70% load								
Base Non-FAC Costs	$445	$409	$371	$1,226	$512	$470	$427	$1,408
Base FAC Costs	$477	$516	$461	$1,454	$380	$491	$494	$1,365
FAC Increase	$246	$220	$225	$692	$348	$326	$196	$870
Estimated Total Cost of Companies's MRO	$1,337	$1,482	$1,561	$4,379	$1,439	$1,687	$1,717	$4,844
Estimated Cost of Companies' ESP								
Estimated Purchase Cost of 5%/10%/15%	$84	$168	$252	$504	$100	$200	$300	$600
2001 - 2008 Incremental Environmental	$0	$0	$0	$0	$0	$0	$0	$0
POLR	$0	$0	$0	$0	$0	$0	$0	$0
Annual non-FAC Increase	$0	$0	$0	$0	$0	$0	$0	$0
Annual Distribution Increase	$10	$10	$11	$31	$0	$0	$0	$0
Estimated Cost of Companies' ESP	$94	$178	$263	$535	$100	$200	$300	$600
Estimated Other Costs for 95%,90%, 85% load								
Base Non-FAC Costs	$470	$460	$451	$1,381	$540	$529	$518	$1,587
Base FAC Costs	$504	$580	$559	$1,644	$401	$552	$600	$1,553
FAC Increase	$260	$248	$273	$781	$367	$367	$238	$972
Estimated Total Cost of Companies's ESP	$1,328	$1,467	$1,546	$4,341	$1,408	$1,648	$1,656	$4,712
Estimated Benefit of Companies' ESP	**$9**	**$14**	**$15**	**$38**	**$31**	**$39**	**$61**	**$131**

LS Exhibit 3

Columbus Southern Power Company

Summary of Requested Rate Increase

Description	Current Rates	2009 Non-FAC Increase	2009 FAC Increase	2009 Total Increase	2009 Total Bill % Increase	2010 Non-FAC Increase	2010 Maximum FAC Increase	2010 Total Increase	2010 Total Bill % Increase	2011 Non-FAC Increase	2011 Maximum FAC Increase	2011 Total Increase	2011 Total Bill % Increase
FAC Components	$604,035,556		$147,939,877	$147,939,877			$247,612,870	$247,612,870			$273,242,516	$273,242,516	
Adjustment to FAC Base				$0			($16,000,000)	($16,000,000)			($17,000,000)	($17,000,000)	
Deferred FAC			$111,709,281	$111,709,281			$0	$0			$0	$0	
Reduced Market Cost Est.			($16,000,000)	($16,000,000)			($32,000,000)	($32,000,000)			($48,000,000)	($48,000,000)	
Total FAC Components	$604,035,556	$0	$243,648,958	$243,648,958	13.70%	$0	$199,612,870	$199,612,870	12.60%	$0	$208,242,516	$208,242,516	9.55%
Non-FAC Components													
Adjustment to Non-FAC Base				$0	0.00%	($10,000,000)		($10,000,000)	-0.51%	($9,000,000)		($9,000,000)	-0.41%
2001 - 2008 Incremental Environmental Capital Investment		$0		$0	0.00%	$0		$0	0.00%	$0		$0	0.00%
Annual 3% Non-FAC Generation Increase		$0		$0	0.00%	$0		$0	0.00%	$0	$0	$0	0.00%
Subtotal Non-FAC	$447,647,871	$0	$0	$0	0.00%	($10,000,000)	$0	($10,000,000)	-0.51%	($9,000,000)	$0	($9,000,000)	-0.41%
POLR	$14,560,921	$0		$0	0.00%	$0		$0	0.00%	$0		$0	0.00%
Distribution	$340,137,828	$10,000,052		$10,000,052	0.56%	$10,294,054		$10,294,054	0.52%	$10,596,699		$10,596,699	0.49%
Energy Efficiency and Peak Demand Reduction		$13,554,675		$13,554,675	0.76%	$14,843,325		$14,843,325	0.76%	$9,576,500		$9,576,500	0.44%
Transmission Cost Recovery	$181,192,902			$0	0.00%			$0	0.00%			$0	0.00%
Other*	$191,037,658	($80,648,306)		($80,648,306)	-4.53%			$0	0.00%	$22,800,000		$22,800,000	1.05%
Total	$1,778,632,736	($57,093,581)	$243,648,958	$186,555,377	10.49%	$15,137,379	$199,612,870	$214,750,248	10.93%	$33,973,199	$208,242,516	$242,215,715	11.11%
AS FILED	$1,778,632,736	$90,549,167	$147,939,877	$238,488,844	13.41%	$54,955,368	$247,612,870	$302,568,237	15.00%	$74,710,957	$273,242,516	$347,953,473	15.00%

* Includes effects of expiring and new Regulatory Asset Charges, Expiring Line Extension Surcharges, Universal Service Fund, Advanced Energy Fund, kWh Tax, expiring special contracts and other miscellaneous items.

Ohio Power Company

Summary of Requested Rate Increase

		2009				2010				2011			
Description	Current Rates	Non-FAC Increase	FAC Increase	Total Increase	Total Bill % Increase	Non-FAC Increase	Maximum FAC Increase	Total Increase	Total Bill % Increase	Non-FAC Increase	Maximum FAC Increase	Total Increase	Total Bill % Increase
FAC	$520,987,721		$68,614,486	$68,614,486			$207,444,763	$207,444,763			$237,578,113	$237,578,113	
Adjustment to FAC Base				$0			($16,000,000)	($16,000,000)			($19,000,000)	($19,000,000)	
Deferred FAC			$300,082,035	$300,082,035			$159,251,758	$159,251,758				$0	
Reduced Market Cost Est.			($20,000,000)	($20,000,000)			($40,000,000)	($40,000,000)			($60,000,000)	($60,000,000)	
Total FAC Components	$520,987,721	$0	$346,696,521	$346,696,521	20.09%	$0	$310,696,521	$310,696,521	15.06%	$0	$158,578,113	$158,578,113	6.66%
Non-FAC Components													
Adjustment to Non-FAC Base				$0	0.00%	($11,000,000)		($11,000,000)	-0.53%	($11,000,000)		($11,000,000)	-0.48%
2001 - 2008 Incremental Environmental Capital Investment		$0		$0	0.00%	$0		$0	0.00%	$0		$0	0.00%
Annual 7% non-FAC Generation Increase		$0		$0	0.00%	$0		$0	0.00%	$0		$0	0.00%
Subtotal Non-FAC	$512,735,422	$0	$0	$0	0.00%	($11,000,000)	$0	($11,000,000)	-0.53%	($11,000,000)	$0	($11,000,000)	-0.46%
POLR	$39,700,305	$0		$0	0.00%	$0		$0	0.00%	$0		$0	0.00%
Distribution	$326,265,130	$0		$0	0.00%	$0		$0	0.00%	$0		$0	0.00%
Energy Efficiency and Peak Demand Reduction		$16,775,000		$16,775,000	0.97%	$17,847,250		$17,847,250	0.87%	$11,803,125		$11,803,125	0.50%
Transmission Cost Recovery	$190,538,964			$0	0.00%			$0	0.00%			$0	0.00%
Other*	$135,826,463	($27,105,030)		($27,105,030)	-1.57%			$0	0.00%	$15,200,000		$15,200,000	0.64%
Total	$1,726,034,005	($10,330,030)	$346,696,521	$336,366,491	19.49%	$6,847,250	$310,696,521	$317,543,771	15.40%	$16,003,125	$317,156,226	$174,581,238	7.34%
AS FILED	$1,726,034,005	$157,839,504	$66,614,486	$224,453,990	13.00%	$85,128,437	$207,444,763	$292,573,199	15.00%	$98,881,066	$237,578,113	$336,459,179	15.00%

* Includes effects of expiring and new Regulatory Asset Charges, Expiring Line Extension Surcharges, Universal Service Fund, Advanced Energy Fund, kWh Tax, expiring special contracts and other miscellaneous items

CERTIFICATE OF SERVICE

I hereby certify that a copy of the *Direct Testimony of Lee Smith on behalf of the Office of the Ohio Consumers' Counsel,* has been served upon the following parties via regular U.S. Mail service, postage prepaid (and a courtesy copy via electronic transmission) this 31st day of October, 2008.

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