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December 30, 2008

Public Utilities Commission of Ohio
PUCO Docketing
180 E. Broad Street, 10th Floor
Columbus, Ohio 43215

**In re: <u>Case No. 08-917-EL-SSO and 08-918-EL-SSO</u>**

Dear Sir/Madam:

Please find enclosed an original and twenty (20) copies of the BRIEF OF OHIO ENERGY GROUP ON LONG TERM ESP fax-filed today in the above-referenced matter.

Copies have been served on all parties on the attached certificate of service. Please place this document of file.

Respectfully yours,

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I hereby certify that true copy of the foregoing was served by electronic mail and ordinary mail, unless otherwise noted, this 30th day of December, 2008 to the individuals listed on the attached certificate of service:

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**BEFORE THE**
**PUBLIC UTILITY COMMISSION OF OHIO**

| | | |
|---|---|---|
| **IN RE: IN THE MATTER OF THE APPLICATION OF COLUMBUS SOUTHERN POWER COMPANY FOR APPROVAL OF ITS ELECTRIC SECURITY PLAN; AN AMENDMENT TO ITS CORPORATE SEPARATION PLAN; AND THE SALE OR TRANSFER OF CERTAIN GENERATING ASSETS** | ) | **Case No. 08-917-EL-SSO** |
| **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** |

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**BRIEF OF OHIO ENERGY GROUP**
**ON LONG TERM ESP**

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The members of the Ohio Energy Group ("OEG") who take service from Ohio Power or Columbus Southern Power are: AK Steel Corporation, Aleris International, Inc., ArcelorMittal USA, BP-Husky Refining, Brush Wellman, E.I., DuPont de Nemours & Company, Ford Motor Company, GE Aviation, Griffin Wheel, PPG Industries Inc., The Procter & Gamble Co., Republic Engineered Products, Inc., Severstal Wheeling (formerly Wheeling Pittsburgh Steel), and Worthington Industries.

These large industrial companies employ tens of thousands of people in Ohio. These are high wage, high benefit, family supporting jobs. The OEG member companies served by AEP consume approximately 2.7 billion kWh per year. While the cost of electricity is not the only factor that will determine if these companies can continue to operate in Ohio, it is a major factor. OEG submits this brief on the long term ESP.

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## I. INTRODUCTION AND STANDARD OF REVIEW

On July 31, 2008 Columbus Southern Power Company and Ohio Power Company (collectively "AEP" or "Companies") filed their Application requesting approval of their proposed Electric Security Plan ("ESP") pursuant to RC §4928.143. RC §4928.143 was enacted as a part of Senate Bill 221 and provides that an electric distribution utility may file an ESP requesting the recovery of certain generation costs, *"provided that such costs are prudently incurred."* (RC §4928.143(B)(2)(a)). SB 221 also contains a provision that following each annual period of the ESP the Commission will review the utilities' earnings and refund any *"excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned"* by comparable utility and non-utility companies. (RC §4928.143(F)). The significantly excessive earnings test is an extension of the traditional comparable earnings standard articulated by the United States Supreme Court in *Bluefield Water Works v. West Virginia*, 262 U.S. 679 (1923) and *FPC v. Hope Natural Gas Co.*, 320 U. S. 591 (1944). Under the *Hope* and *Bluefield* standard, the Commission sets rates in order to provide the utility with a rate of return on its prudently invested capital that is comparable with other business enterprises with corresponding risks. Likewise, SB 221 directs the Commission to set ESP rates based on the prudently invested capital of the utility, subject to an annual review to ensure that the ESP did not cause the utility's earnings to be significantly in excess of the returns earned by comparable utility and non-utility companies.

ESP filings are also subject to the §4928.02 policy requirements. Per these requirements, the Commission must "[e]*nsure the availability to consumers*" of "*reasonably priced retail electric service,*" and "[f]*acilitate the state's effectiveness in the global economy.*" In case No. 08-935-EL-SSO the Commission determined that the policy mandates cited above must be met in order for the Commission to approve any ESP rate plan filed under Chapter 4928. On page 8 and 12 of its December 19, 2008 Order the Commission states:

> *"A. Applicable Law*
>
> *Chapter 4928 of the Revised Code provides an integrated system of regulation in which specific provisions were designed to advance state policies of ensuring access to adequate, reliable, and reasonably priced electric service in the context of significant economic and environmental*

*challenges. In reviewing FirstEnergy's application, the Commission is cognizant of the challenges facing Ohioans and the electric power industry and will be guided by the policies of the state as established by the General Assembly in Section 4928.02, Revised Code, as amended by SB 221.*

* * *

*The Commission believes that the state policy codified by the General Assembly in Chapter 4928, Revised Code, sets forth important objectives which the Commission must keep in mind when considering all cases filed pursuant to that chapter of the code. Therefore, in determining whether the ESP meets the requirements of Section 4928.143, Revised Code, the Commission takes into consideration the policy provisions of Section 4928.02, Revised Code, and we use these policies as a guide in our implementation of Section 4928.143, Revised Code. The Commission has reviewed the ESP proposal presented by FirstEnergy, as well as the issues raised by the various intervenors, and we believe that, with the modifications set forth herein, we have appropriately reached a conclusion advancing the public's interest."*

Finally, the Commission should interpret RC §4928.143 to give effect to all of its parts and consider, in context, all of the words used giving effect to the overall statutory scheme. *D.A.B.E., Inc. v. Toledo-Lucas County Board of Health*, 96 Ohio St.3d 250 (2002). *See also*, *State v. Arnold*, 61 Ohio St.3d 175, 178 (1991) (a statute shall be construed, if practicable, as to give effect to every part of it). This means that to gain Commission approval the Companies have the burden of proving that its ESP plan is 1) more favorable in the aggregate than the forecasted results of an MRO (RC §4928.143(C)(1)); 2) contains only costs that are "*prudently incurred.*" (RC §4928.143(B)(2)(a)); and 3) conforms to the policy requirements, including that it provides "*reasonably priced retail electric service*," and "[f]*acilitates the state's effectiveness in the global economy.*" (RC §4928.02(A) and (N)).

Because Ohio Power and Columbus Southern maintain ownership of generating assets, we believe that regulating AEP in an ESP is a straightforward process. The Commission simply needs to examine each component of the proposed plan and approve or modify it as appropriate. The end result will be the ESP revenue requirement, which is then subject to claw-back in the retrospective earnings review cases. The Commission should not be fearful of the threat that the Companies will abandon the safety and high guaranteed returns under an ESP for the untested waters of an MRO. S.B. 221 purposefully made the MRO choice less attractive for utilities that own generation than the ESP, and the severe restrictions placed upon the MRO option by the Commission's November 24, 2008 FirstEnergy MRO Order makes that even more so.

## II. ARGUMENT

AEP's view of the ESP process is contrary to the legal framework established by the Commission in its December 19, 2008 ESP Order in Case No. 08-935-EL-SSO. AEP believes that no component of its ESP needs to be justified as prudent, reasonable or cost based. According to AEP, anything can be included in the ESP provided that it is more favorable in the aggregate than the forecasted result of an MRO. This erroneous belief guided AEP throughout its ESP and has rendered large portions of its ESP unreasonable or unlawful.

### A. <u>Component by Component Breakdown Of AEP's Proposed $3.058 Billion ESP.</u>

If approved, AEP's ESP will cost Ohio consumers **$5.823 billion** over the first three years, assuming that the fuel adjustment clause is increased at the maximum amounts each year and that there are no deferrals of fuel adjustment clause recoveries. The annual effect of the Company's proposed ESP increases will be **$2.816 billion** in 2011. This represents an increase of 73% for CSP consumers and 88% for OPC consumers compared to current rates. This represents a near doubling of the current rates of Ohio Power and Columbus Southern. The following table summarizes the cumulative effects of the AEP ESP rate increases for each Company, assuming the fuel adjustment clause at the maximum amounts each year and that there are no deferrals of fuel adjustment clause recoveries.

**AEP Companies' Proposed ESP Rate Increases**
**($ Million)**

| | Columbus and Southern Power Company | | | | Ohio Power Company | | | |
|---|---|---|---|---|---|---|---|---|
| | 2009 | 2010 | 2011 | Total ESP | 2009 | 2010 | 2011 | Total ESP |
| **AEP Companies' Proposed ESP** | | | | | | | | |
| Fuel Adjustment Clause (No Phase-in at Max Amounts)[1] | 280 | 507 | 760 | 1,547 | 367 | 574 | 812 | 1,753 |
| Purchases at Market Included in Basic Generation Rates[2] | 100 | 200 | 300 | 600 | 120 | 240 | 360 | 720 |
| Environmental Carrying Costs 2001-2008[2] | 26 | 26 | 26 | 78 | 84 | 84 | 84 | 252 |
| POLR[3] | 94 | 94 | 94 | 282 | 21 | 21 | 21 | 63 |
| Annual 3%/7% Non-FAC Increases in Basic Generation Rates[2] | 14 | 29 | 44 | 87 | 42 | 86 | 134 | 262 |
| Energy Efficiency and Peak Demand Reduction[1] | 14 | 29 | 39 | 82 | 17 | 35 | 47 | 99 |
| Other[1] | -81 | -81 | -58 | -220 | -27 | -27 | -12 | -66 |
| Annual 7%/6.5% Distribution Increases[2] | 24 | 50 | 77 | 151 | 21 | 44 | 68 | 133 |
| **Total Estimated Cost of AEP Companies' ESP** | 451 | 854 | 1,302 | 2,607 | 645 | 1,057 | 1,514 | 3,216 |
| **2008 Total Revenues Before ESP Rate Increases** | 1,779 | 1,779 | 1,779 | | 1,726 | 1,726 | 1,726 | |
| ***Cumulative ESP Percentage Rate Increases*** | 25.4% | 48.0% | 73.2% | | 37.4% | 61.2% | 87.7% | |

Notes: [1] Source: Roush Exhibit DMR-1 (annual increases were accumulated for each subsequent year)
[2] Source: Baker Exhibit JCB-2
[3] Source: Baker Exhibit JCB-2 adjusted to remove POLR recoveries under existing rates using amounts from Roush Exhibit DMR-1

In 2007, CSP and OPC earned after-tax returns on common equity of 22.1% and 11.7%, respectively.[1] During the first nine months of 2008 the after-tax returns on common equity for the Companies were: CSP 23.48% and OPC 13.5%.[2] Therefore, the earnings of the Companies were extremely healthy last year, and are growing even healthier this year.

With such healthy, arguably excessive earnings, how can the Companies justify raising rates 73% and 88% over three years? There is no justification. AEP's ESP is grossly inflated and full of imprudent and unreasonable costs which it attempts to justify on the single legal theory that: individual components of an ESP need not be reasonable, prudent or cost-based so long as the ESP is more favorable in the aggregate than an MRO. The Commission rejected this legal theory on December 19 in the FirstEnergy ESP case and should do so again here.[3]

[1] Direct Testimony of Lane Kollen, Ex. LK-2.
[2] Rebuttal Testimony of Stephen Baron at p. 2.
[3] Case No. 08-935-EL-SSO; Order of December 19, 2008, pp. 8-10.

The major components of AEP's ESP include:

1) A fuel adjustment clause (FAC) which incorporates the automatic recovery of the costs of coal, fuel oil, natural gas, purchased power from non-affiliated companies, purchased power pursuant to the AEP Interconnection Agreement (Pool Energy), $SO_2$ and $NO_X$ emission allowances, gains and losses on the sale of emission allowances, ash handling, fuel procurement unloading and handling, ash sales proceeds, gypsum handling and disposal costs, depreciation and capacity costs of long-term purchase power agreements, capacity equalization payments made under the AEP Interconnection Agreement (Pool Capacity), PJM Emergency Energy purchases, Renewable Energy Credits, and Emission Control Chemicals.[4] The total projected FAC rate increases over three years at the maximum are: **CSP – $1.547 billion** and **OPC – $1.753 billion.**[5]

2) Non-FAC base generation adjustment. This is made up of two components: 1) the recovery of carrying costs on 2001-2008 environmental capital investments; and 2) an annual 7% and 3% generation rate increase for OPC and CSP, respectively. The total non-FAC base generation increases over three years are: **CSP – $165 million and OPC – $514 million.**[6]

3) Provider of Last Resort (POLR) charge. The POLR charge each year of the three year ESP is requested to be: **CSP – $94 million** and **OPC – $21** million, for a total over three years of $282 million for CSP and $63 million for OPC.[7]

4) A distribution rate increase each year of 7% for CSP and 6.5% for OPC over the three-year period this amounts to: **CSP – $151 million and OPC – $133 million.**[8]

5) An energy efficiency and demand reduction rider. Over the three-year period these total: CSP – **$82 million and OPC – $99 million.**

6) Other (expiring RTC charges, expiring line extension surcharge, universal service fund, advanced energy fund, kWh tax, expiring special contracts) over the three years of: CSP – **negative $220 million** and OPC – **negative $66 million.**

7) An economic development rider. No cost recovery under this rider is currently being proposed.

8) After the three year ESP is over, recovery of previously authorized regulatory assets and other deferrals. The FAC deferrals plus carrying costs requested total: CSP – **$211,400,000** and OPC – **$800,800,000.**[9] Additional deferrals and amortizations total: CSP – **$182,400,000** and OPC – **$121,600,000.**[10]

[4] Exhibit PJN-1 and PJN-2.
[5] Exhibit DMR-1 and Exhibit LVA-1.
[6] Exhibit JCB-2.
[7] Exhibit DMR-1; Exhibit JCB-2.
[8] Exhibit JCB-2.
[9] Exhibit DMR-1.
[10] Exhibit LVA-2 and MJM-1.

**B. <u>The Commission Should Modify The Proposed ESP To Include Revenues Not Accounted For And To Exclude Expenses That Are Not Prudent Or Reasonable.</u>**

The Commission should adjust the Companies' Application so all revenues are properly accounted for and that only prudently incurred and reasonable costs are approved as recoverable.

Ohio Power and CSP are both Members of the AEP Interconnection Agreement. The Interconnection Agreement controls many aspects of the Companies' operations and an understanding of the Agreement is essential to addressing the issues raised here. Any state commission that tries to regulate an AEP utility without understanding the Interconnection Agreement is flying *blind*.

The Interconnection Agreement was originally entered into on July 6, 1951. It is an agreement among the AEP-East Operating Companies, under which the individual generation resources of the participating companies ("Members") are dispatched on a single-system basis, and the costs and benefits of generation resources are shared on a system-wide basis. The Members are Ohio Power, CSP, Kentucky Power Company, Indiana & Michigan Power Company, and Appalachian Power Company (Virginia and West Virginia). The Interconnection Agreement is a FERC-approved rate schedule.[11]

The Interconnection Agreement provides for meeting total AEP system energy requirements on a least-cost basis from among available resources. AEP Service Corporation, acting as agent for the Members, dispatches energy on an economic basis, assigning the highest incremental cost to off-system sales. Each Member meets its requirement initially out of its own generation to the extent dispatched, and thereafter through primary purchases from affiliates. The Interconnection Agreement prices such primary purchases at the delivering Member's *average cost of generation* for the month.[12]

Revenues from off-system sales are initially allocated to the Member providing the generation dispatched for each sale up to the amount of its generation costs for the sale. Above that point, the Members share net revenues (profits or margins) from such sales on the basis of their Member Load Ratio ("MLR") the ratio of each Member's Non-Coincident Peak ("NCP") load over the latest twelve-month period to the sum of NCP loads for

[11] Direct Testimony of Lane Kollen p. 7.
[12] Direct Testimony of Lane Kollen pp. 7-8.

all Members over the same period. Likewise, AEP Service Corporation makes energy purchases on a system basis and apportions the cost by MLR to Members.[13]

The Interconnection Agreement also contains a capacity equalization mechanism to levelize capacity investment imbalances among the AEP-East Members as they rotate the construction of new generation. Each participating Member bears its proportionate share of the system's total capacity and reserves based on its MLR. The "*deficit*" Members make capacity payments to the "*surplus*" Members based on the surplus Member's weighted average embedded costs of investment in its non-hydroelectric generating plant expressed on a per kilowatt per month basis plus associated fixed operating costs.[14]

**1. The Proposed Fuel Adjustment Clauses Should Be Modified To: a) Exclude The 5%, 10% And 15% Market Purchases; b) Include Profits From Off-System Sales; and c) Include Capacity Equalization Revenues.**

**a. <u>The 5%, 10% and 15% Market Purchases Are Projected To Cost $1.322 Billion, Are Imprudent, Unreasonable, And Proposed Solely To Increase AEP's Profits.</u>**

The Companies propose to include the costs of purchased power acquired at market prices for 5% of their native loads in 2009, 10% in 2010 and 15% in 2011. Companies' witness Mr. Baker describes this aspect of their proposed ESPs as "*a limited feature for the continuing transition to market rates.*" (Baker Direct at 22). The Companies have included the estimated effects of these purchases in their projected FAC rates for 2009-2011 using their projections of market prices.[15]

The Companies estimate that CSP will be able to purchase generation for $88.15 per mWh and OPC for $85.32 per mWh in 2009, 2010 and 2011, although the actual purchase prices will be reflected in the Companies' FAC riders, not these estimated prices. The Companies estimate that these purchases will cost CSP $100 million in 2009, $200 million in 2010 and $300 million in 2011, for a total of **$601 million** over the initial term of the ESP. The Companies estimate that these purchases will cost OPC $120 million in 2009, $240 million in 2010,

[13] Direct Testimony of Lane Kollen p. 8.
[14] Direct Testimony of Lane Kollen p. 8.
[15] Direct Testimony of Lane Kollen pp. 8-9.

and $360 million in 2011, for a total of **$721 million** over the initial term of the ESP.[16] The total projected cost for both Companies is **$1.322 billion**. The 5%, 10% and 15% market purchases make up 77% of CSP's total FAC costs and 76% of Ohio Power's total FAC costs.

The Companies do not need these purchases to serve their native loads. The Companies presented no evidence that the 5%, 10% and 15% purchases are needed for reliability purposes. In 2007, OPC and CSP had non-requirements sales for resale (to the other AEP Companies and to the AEP System pool for sale off-system) of 29,874,000 mWh and 10,697,000 mWh, respectively. In 2009, the Companies project that OPC and CSP will have non-requirements sales for resale of 27,027,000 mWh and 5,698,000 mWh, respectively, based on Companies' witness Mr. Nelson's Exhibits PJN-6 and PJN-3. In 2009, these sales for resale represent 46% of OPC's available energy sources and 19% of CSP's.[17]

These off-system sales figures demonstrate that both Companies already have significant amounts of surplus energy. To put this in perspective consider that in 2009, OPC's forecasted off-system sales of 27,027,000 mWh are almost equal to its 2009 forecasted native load sales of 28,151,000 mWh. For CSP, its 2009 forecasted off-system sales are more than 25% of its 2009 forecasted native load of 22,715,000 mWh.[18]

These 5%, 10% and 15% purchases at market prices are not cost-effective for ratepayers and should be disallowed. Even if the Companies did not already have huge blocks of surplus power that is being sold off system, the cost of these purchases is far greater than the Companies would have to pay to purchase from the AEP Pool pursuant to the AEP Interconnection Agreement. As described above, the Companies are legally entitled under the Interconnection Agreement, a FERC-regulated rate, to power that is available from their sister companies at a significantly lower cost. During 2007, CSP purchased 13,346,090 mWh from its Member affiliates for $298,226,000, or $22.35/mWh. For the first six months of 2008, CSP purchased 14,102,821 mWh from its Member affiliates for $308,595,000, or $21.88/mWh. For OPC, in 2007 it purchased 4,350,705 mWh from its affiliates for $111,411,000, or $25.61/mWh. For CSP for the first six months of 2007 the purchases

[16] Direct Testimony of Lane Kollen p. 9; Exhibit JCB-2.
[17] Direct Testimony of Lane Kollen pp. 9-10.
[18] Direct Testimony of Lane Kollen p. 10.

totaled 4,835,549 mWh for $131,563,000, or $27.21/mWh.[19] This information demonstrates that the costs of such affiliate purchases were a mere fraction of the cost of the 5%, 10% and 15% purchases at market prices that are proposed by the Companies.[20]

In essence, the Companies propose to purchase large blocks of power at market prices estimated at $85.32/mWh to $88.15/mWh when they can purchase from the AEP Pool at prices of $21.88/mWh to $27.21/mWh.

Why would AEP want its Ohio utilities to buy 5%, 10% and 15% of their native load needs at market prices that are 400% higher than the price of power that is available through the AEP Pool? The 5%, 10% and 15% purchases will not increase the earnings of CSP or OPC because the increased expense is simply matched by increased FAC revenue. The answer is this. Forcing the Ohio utilities to buy 5%, 10% and 15% of their native load needs at market frees up AEP's low cost utility-owned generation to make off-system sales. Profits from off-system sales are allocated among the AEP Members pursuant to the FERC-approved Interconnection Agreement on the basis of each AEP Company's Member Load Ratio. AEP shareholders also retain part of the profit from off-system sales.[21] Consequently, under the Companies' 5%, 10% and 15% proposal, the additional costs of the purchases at market will be assigned directly to the Ohio retail ratepayers, while the benefits of lower cost generation will be exported to the other AEP Members and other retail jurisdictions, such as West Virginia, Virginia, Kentucky, Indiana, and Michigan. Unfortunately, under AEP's 5%, 10% and 15% scheme, Ohio consumers and the Ohio economy will foot the bill.

The 5%, 10% and 15% market purchases are projected to cost $1.322 Billion. The 5%, 10% and 15% market purchase proposal should be rejected.

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[19] Direct Testimony of Lane Kollen at p. 10-11.
[20] Direct Testimony of Lane Kollen p. 10.
[21] Direct Testimony of Lane Kollen p. 13.

b. Ratepayers Should Receive The Benefits Of Off-System Sales Margins As A Credit To The Fuel Adjustment Clause Because They Pay For The Costs Of The Power Plants Used To Make Those Sales.

In 2007, the profit from AEP's off-system sales received by OPC was **$146.7 million** and for CSP was **$124.1 million.**[22] In each of the jurisdictions that AEP operates profits from off-system sales are used by the state commissions to lower rates. For example, in West Virginia profits from off-system sales are flowed through to ratepayers automatically through their fuel adjustment clause.[23] In Kentucky, profits from off-system sales are reflected in base rates and the fuel adjustment clause.[24] While the FERC-approved Interconnection Agreement requires that profits from off-system sales be treated as income to the utilities, each state commission determines its own retail ratemaking treatment. AEP's proposal to insulate off-system sales profits from Ohio ratemaking jurisdiction would be unreasonable and discriminatory. It would place Ohio at a further economic disadvantage compared to West Virginia, Virginia, Kentucky, Indiana and Michigan.[25] In the third quarter of 2008, the gross margin earned by the AEP utilities on retail sales in Indiana, Michigan, Kentucky, Virginia and West Virginia was $28.6/mWh.[26] For the same period, the gross margin earned by CSP and OPC on its Ohio retail sales was 64% greater at $46.8/mWh.[27]

The logic behind the ratemaking decision to use profits from off-system sales as a revenue requirement off-set is simple. Because the costs of the power plants that are physically making the sales are in rates, all revenue from the power plants should be a rate credit.

If the Commission is seeking a way to keep AEP's rates stable, then using profits from off-system sales as an FAC off-set should be ordered as an ESP modification. Based upon 2007 results, this would lower rates by **$146.7 million** for OPC and **$124.1 million** for CSP.

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[22] Direct Testimony of Lane Kollen p. 14.
[23] Id.
[24] Id.
[25] Direct Testimony of Lane Kollen pp. 14-15.
[26] IEU Hearing Exhibit 2.
[27] Id.

### c. <u>Ratepayers Should Receive The Benefits Of AEP Pool Capacity Revenues As A Credit To The Fuel Adjustment Clause Because They Pay The Cost Of That Capacity.</u>

The AEP Interconnection Agreement requires Members that are capacity "*deficit*" to pay the other Members that are capacity "*surplus*" a monthly capacity equalization charge. OPC is considered a "*surplus*" Member, so all "*deficit*" Members must pay OPC a charge to equalize their capacity costs. CSP is a "*deficit*" Member, so it must pay all surplus Members a fee to equalize their capacity costs. The Companies' filing does not appropriately account for these relationships within the AEP system in the FAC.[28]

The Companies propose that the AEP Pool capacity payments made by CSP be included in its FAC. However, the Companies do not propose to include any AEP pool capacity receipts as an offset to the costs recovered by OPC in its FAC.[29] Consequently, the additional AEP pool capacity receipts will be retained by OPC and will not be flowed through to the ratepayers who pay for the generation that allows OPC to receive the receipts. This asymmetry is unreasonable. If the capacity equalization payments made by CSP are charged to ratepayers in the FAC, then the capacity equalization revenues received by OPC should be credited in the FAC.[30] OPC each year receives approximately $249,000,000 – $331,800,000 in capacity equalization revenues.[31]

Again, if the Commission is looking for a way to keep rates stable, then utilizing AEP Pool capacity receipts as an FAC off-set should be ordered as an ESP modification.

### 2. AEP Has Provided No Justification For The Proposal To Arbitrarily Increase Non-FAC Generation Rates Annually By 3% For CSP And 7% For OPC.

The Companies' propose to increase their non-FAC basic generation charges by annual percentages during the initial term of their ESPs. None of the Companies' witnesses described this aspect of the Companies'

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[28] Direct Testimony of Lane Kollen pp. 16.

[29] Exhibit PJN-5 line 38 shows the amount in account 555 purchased power included for AEP pool capacity of $0 and includes a footnote that this applies only to CSP. In other words, it only is included in the Companies' proposed FAC if the amount is positive, i.e. a payment, which is the case for CSP.

[30] Direct Testimony of Lane Kollen p. 16.

[31] Since January 2007 through June 2008 OPC received between $8.30 and $11.06 per kW/month for its capacity surplus. Kollen Direct Testimony p. 26. OPC's monthly capacity surplus averages approximately 2,500,000 kW. AEP response to OEG Interrogatory 2-1.

ESPs other than to address the computation of these amounts.[32] However, the Companies' ESPs include increases in the basic generation rate (non-FAC rate) of 3% annually for CSP and 7% annually for OPC.[33]

This results in total rate increases over the three year ESP of: CSP – $87 million and OPC – $262 million.[34]

The Companies have not provided any cost basis in support of these 3% and 7% increases in the non-FAC basic generation rates. SB 221 requires that rate increases pursuant to an ESP be based on *"prudently"* incurred costs and result in reasonable rates. It does not allow for arbitrary rate increases. The Commission should not approve these generation rate increases.

**3. AEP Has Provided No Justification For The Automatic Distribution Rate Increase Of 7% For CSP And 6.5% For OPC.**

The Companies have proposed automatic distribution rate increases of 7% for CSP and 6.5% for OPC. The total rate increases under this proposal during the three year ESP are: OPC - $150 million; CSP - $133 million.[35]

The Companies have made no showing that these distribution rate increases are cost-based, reasonable or prudent. They are simply manufactured numbers which, if approved, the Companies claim would still result in an ESP that is more favorable in the aggregate than an MRO. But this is not the sole standard. As the Commission stated in the FirstEnergy ESP case. *"[T]he Commission does not believe that a distribution rider should be approved, unless it is based on a reasonable, forward-looking modernization program and prudently incurred costs."* Case No. 08-935-EL-SSO at p. 41.

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[32] See Exhibit JCB-2 and Exhibit DMR-1
[33] Direct Testimony of Lane Kollen p. 18.
[34] Exhibit JCB-2.
[35] Exhibit JCB-2.

**4. The Companies' Proposal For Environmental Carrying Costs Includes A Retroactive Portion (2001-2008) Which Is Illegal Under S.B. 221.**

The Companies propose to include "*environmental carrying charges*" in their generation rate. The proposed charges consist of a grossed-up rate of return on environmental investment plus depreciation plus property taxes and administrative and general expenses.[36] The proposed charges include these carrying charges on environmental investment incurred during 2001 through 2008 (retroactive portion) and annual increases due to environmental capital additions starting in 2009 (prospective portion).[37]

The Companies' proposed recovery of carrying costs on environmental capital additions starting in 2009 (prospective portion) is reasonable in concept as long as the recovery is in accordance with the requirements of Section 4928.143(B)(2)(b), which allows utilities to recover the costs of "*an environmental expenditure for any electric generating facility of the electric distribution utility, <u>provided the cost is incurred or the expenditure occurs on or after January 1, 2009</u>.*" (emphasis added)[38]

The Companies' proposal to recover environmental carrying costs on environmental capital additions during 2001 through 2008 obviously does not meet this statutory requirement. The statute provides for incremental recovery of prospective environmental costs on or after January 1, 2009, but does not provide for retroactive recovery of environmental costs incurred prior to that date.

Additionally, the Companies' existing RSP rates provide recovery of generation costs, including environmental, through December 31, 2008. The Companies propose that these rate levels be continued effective January 1, 2009 in their basic generation rates. Most recently, the Commission granted RSP increases in the rates charged for generation service in Case No. 07-63-EL-UNC to provide the Companies recovery of their increased environmental costs.[39]

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[36] See Exhibits PJN-8, PJN-9 and PJN-10.
[37] *Direct Testimony of Lane Kollen p. 20.*
[38] Direct Testimony of Lane Kollen p. 20.
[39] Direct Testimony of Lane Kollen p. 21.

The Companies' claim that existing rates do not provide full recovery of their environmental carrying costs also ignores their non-environmental investment and the effects of accumulated depreciation since 2000. In other words, the Companies' limited analyses fail to demonstrate that there is any net under-recovery of generation costs *in the aggregate*. To the contrary, the evidence indicates that the Companies are not under-recovering based on 2007 earnings. In 2007, CSP actually earned 22.1% on common equity and OPC earned 11.7%.[40] The returns on common equity earned by the Companies for the first nine months of 2008 are 23.48% for Columbus Southern and 13.5% for Ohio Power.[41]

The effects of the Companies' proposal to recover the retroactive portion of environmental carrying costs on their basic generation rates is to increase the CSP basic generation rate by $26 million and the OPC basic generation rate by $84 million starting on January 1, 2009.[42] OEG recommends that the Commission reject the Companies' proposal. This proposal is inconsistent with the statute and fails to properly consider all costs that already are recovered through present rates.

**5. AEP Must Properly Account For The IRS Section 199 Deduction When Calculating Its Prospective Environmental Cost Recovery.**

In addition to disallowing the recovery of the retroactive portion of the environmental carrying charge, the Commission should also properly account for the Section 199 deduction when calculating the prospective environmental revenue requirement. This issue has already been addressed and decided in Case No. 07-63-EL-UNC. In that case, the Commission required that the Section 199 deduction be used to reduce the income tax gross-up on the equity return in the computation of the revenue requirement, specifically for environmental costs. In its December 19, 2008 decision on the FirstEnergy ESP the Commission confirmed its position on the §199 deduction. Case No. 08-935-EL-SSO Order at p. 19. Consistent with these prior decisions, the Commission should direct the Companies to reflect the Section 199 deduction in the computation of the federal income tax component of the carrying charge rate.

[40] Direct Testimony of Lane Kollen p. 21.
[41] Rebuttal Testimony of Stephen Baron p. 2.
[42] Exhibit DMR-1; Exhibit PJN-8.

## 6. The Companies Have Not Provided Any Justification For Their Proposal For Authority To Sell Or Transfer Generating Assets And Purchased Power Contracts.

CSP requests authority to sell or transfer the Waterford Energy Center ("Waterford"), a combined cycle plant rated at 821 mW, and the Darby Electric Generating Station ("Darby"), a simple cycle plant rated at 480 mW in the winter and 450 mW in the summer. Nevertheless, CSP asserts that it has no plans to sell or transfer the Waterford or Darby plants at this time.[43]

The Companies argue that they are not obligated to seek authority from the Commission to sell or transfer various "*generation entitlements*," but that they may do so without further notification to or authorization from the Commission. Other terms for these "*generation entitlements*" would be "*purchased power contracts*" or "*purchased power entitlements*." The costs incurred pursuant to these purchased power contracts or entitlements are recognized by the Companies as purchased power expense recoverable in their proposed FACs. The Companies identify the following contracts or entitlements:

1. CSP's contract with AEP Generating Company for the output of the Lawrenceburg combined cycle plant with a rating of 1,096 mW.
2. CSP and OPC's contractual entitlements to a portion of the output of the OVEC generating facilities, Kyger Creek and Clifty Creek, with CSP's entitlement of 95.6 mW and OPC's entitlement of 370.2 mW.[44]

The only reason offered by CSP in support of its proposal that the Commission authorize the sale or transfer of the Waterford and Darby plants is that these plants have not previously been included in rate base. They were acquired in 2005 and 2007. This is not sufficient basis for the Commission to authorize the sale or transfer of these two plants.

First, the Companies cannot "*sell or transfer any generating asset it wholly or partly owns at any time without obtaining Commission approval.*" (R.C. 4928.17(E)). There are no conditions set forth in the statute limiting its application only to assets that were in rate base. Thus, the Commission should not make its decision

[43] Direct Testimony of Lane Kollen p. 24.
[44] Direct Testimony of Craig Baker pp. 43-45.

whether or not to authorize a transfer based on this distinction, but rather on whether the sale or transfer is prudent and whether the effect on the Companies' fuel and purchased power expense is prudent.

Second, the sale or transfer of these assets does not need to be addressed in this proceeding and certainly not through an open-ended pre-authorization as requested by the Companies. If at some future date, CSP has a specific proposal that the Commission can assess, then CSP can file an Application for the Commission to consider the sale or transfer at that time. Until then, this issue is not ripe for adjudication.

Third, the Companies only may recover fuel and purchased power costs that are *"prudently incurred"* (4928.143(B)(2)(a)) through their FAC riders. If the sale or transfer of these plants or purchase power contracts causes the Companies' costs recovered through their FAC riders to increase, then the increased costs would not be prudent because they could have been avoided. The sale or transfer of these assets will cause a huge increase in CSP's capacity equalization payments pursuant to the AEP Interconnection Agreement. Since January 2007 through June 2008, CSP has paid between $8.55 and $11.45 per kW/month for its capacity deficit. If CSP sells or transfers its generation entitlements, it will increase its capacity deficit by 2,462.6 mW, which will increase its capacity equalization payments by $252.7 million to $338.4 million annually.[45] Similarly, if OPC sells or transfers its generation entitlements, this will reduce OPC's capacity equalization receipts. Since January 2007 through June 2008, OPC has received between $8.30 and $11.06 per kW/month for its capacity surplus.[46]

Fourth, the Companies have the burden of proof regarding these issues. Yet, the Companies have done no studies and have no analyses or other documents that "*discuss the financial or operational effects of such a sale or transfer,*" according to the Companies' response to OEG-2-2.[47]

OEG recommends that the Commission reject the Companies' request. It is unsupported and will imprudently increase the Companies' fuel and purchased power expense. The Commission should also address the Companies' claim that they do not need to seek authorization to sell or transfer their generation entitlements. The Commission should make it clear in this proceeding that if the Companies sell or transfer these purchase

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[45] Direct Testimony of Lane Kollen p. 26.
[46] Direct Testimony of Lane Kollen p. 26.
[47] Direct Testimony of Lane Kollen, Exhibit___(LK-3).

power contracts, that it will consider as imprudent all incremental costs of fuel and purchased power resulting from such transactions and that these incremental costs will not be recoverable through the Companies' FAC riders.

7. **The Proposed Provider Of Last Resort Charge Should Be Bypassable For Customers Who Either Agree To Forego Their Right To Shop During The Term Of The ESP Or Agree To Not Take Service Under The ESP During Its Term Since These Customers Present No Risk To The Companies.**

As described by Companies' witness Craig Baker, the POLR charge is designed to compensate the Companies for the costs associated with "*standing by*" to serve returning shopping customers at the ESP rates and the cost to the Companies from ESP customers opportunistically leaving SSO service for lower priced market rates provided by Competitive Retail Electric Service ("CRES") providers. Mr. Baker characterizes this economically driven opportunistic behavior as causing the Companies to "*buy high and sell low*."[48] The basis for the proposed POLR charge, which is non-bypassable, is that SSO customers are free to shop whenever the market price from CRES suppliers is lower and return to SSO service whenever the ESP rates are lower than market. This creates a cost to the Companies that the POLR charge is designed to offset.[49]

The Companies have calculated a POLR charge that is designed to reflect the value of a financial option that would permit the owner to purchase SSO service at the proposed AEP ESP rates. Using the Black-Scholes model, the Companies have computed separate option prices for CSP and OPC, based on a series of inputs including the expected market price, the strike price (represented by the proposed ESP rates) and the three year time-frame covered by the ESP.[50]

While this proposal may be reasonable in concept, OEG has not verified the proposed level of the charge itself. However, one aspect of the proposal is clearly inappropriate. A POLR charge should not be imposed on all customers, whether or not they want to "*purchase*" the option. In the event that a customer elects to waive their option rights, such a customer should not be required to purchase the AEP "*POLR Option*." During the three year

[48] Direct Testimony of Craig Baker p. 30.
[49] Direct Testimony of Stephen Baron p. 10.
[50] Direct Testimony of Stephen Baron pp. 10-11.

term of the ESP, the Companies are proposing that each customer be required to purchase an option that will give such a customer the right (in economic terms) to either leave SSO service for a lower market price or return from the market to a lower SSO price (the ESP tariff). In either case, the Companies are required to 1) absorb the loss if the market becomes less expensive than the ESP price or 2) stand-by to serve potential return CRES customers in the event that the market becomes more expensive. There is a cost to providing customers this "*option*." However, if customers elect to waive their rights to shop during the three year ESP term, then there is no risk to the Companies from customer switching and no basis for the Companies to impose the POLR option charge. Simply put, if a customer decides to not buy the "*option*," then there should be no charge.[51]

The Companies' POLR charge should be waived for ESP *customers* who either:

> a) Agree to forego their right to shop during the three year term of the ESP
>
> <u>OR</u>
>
> b) Agree to <u>not</u> take service under the ESP and, in the event of a return to POLR service, agree to waive their right to take service under the ESP and accept market based rates.

Under either of these two elections, the Companies would not incur any of the risks which are the basis for the option based POLR charge. Customer's electing this "*waiver*" should not be charge the POLR charge.[52]

**8. The Companies' Should Be Required To Allow Customers To Participate In PJM Demand Response Programs Since These Programs Benefit The System And Customers Individually By Reducing Demand At Critical Times.**

PJM has had demand response programs in effect for a number of years. One of the early programs was the Active Load Management ("ALM") program, which is essentially a traditional interruptible load arrangement that retail customers could participate in via their Load Serving Entities (LSEs). The ALM program has been revised to accommodate the market driven capacity obligation mechanism of the PJM Reliability Planning Model ("RPM"). Demand resources can be directly bid into the RPM process (Demand Resource) or participate as Interruptible Load for Reliability ("ILR"). ILR load is certified that it can be interrupted and paid a price (interruptible credit) tied to the

[51] Direct Testimony of Stephen Baron pp. 11-12.
[52] Direct Testimony of Stephen Baron p. 12.

zonal capacity charge. PJM also offers other capacity related demand response programs associated with the PJM Synchronized Reserve Market and the PJM Regulation Market. Finally, PJM also offers economic demand response programs tied to locational marginal cost ("LMP").[53] These economic programs permit customers to participate in the savings associated with the difference between LMP costs and their generation rates. All of these programs are at the wholesale level, which means that a retail customer must participate through a competitive supplier (such as a curtailment service provider) or a Load Serving Entity such as AEP.[54]

The Companies propose to prohibit SSO customer participation in PJM Demand Response programs via a third party competitive supplier or directly as a PJM member. The Companies' position appears to be that SSO customers should not be permitted to participate in a wholesale PJM program, while purchasing provider of last resort supply. If this prohibition is adopted, the Companies should be required to offer PJM Demand Response programs to customers on an optional basis via an ESP tariff rider. The Companies' proposals for demand response programs should include specific participation by its retail customers in the PJM programs.

The Companies should offer, either directly, or through designated third party suppliers with whom the Companies enter agreements, participation in the PJM demand response programs. To the extent that there are real benefits to the Companies and their retail customers from participation, there is no reason to simply foreclose the opportunity to participate. While OEG recognizes that there must be coordination between the Companies and customer participation in PJM Demand Response programs under the ESP, this does not mean that potential savings to participating customers and perhaps, all of the Companies' customers, should be foregone.[55]

The Companies current Industrial Interruptible rates through the IRP rate schedules would not be affected by OEG's recommendation. These rate schedules should continue to be offered, as proposed by the Companies. The Commission should expand the Demand Response programs through the use of the PJM Demand Response options.

[53] Direct Testimony of Stephen Baron pp. 14-15.
[54] Direct Testimony of Stephen Baron pp. 14-15.
[55] Direct Testimony of Stephen Baron p. 15.

**9. The Companies' Proposed Energy Efficiency Rider Is Reasonable And The Underlying Allocation Of Costs On A Direct Assignment Basis Is Appropriate.**

As described by Companies' witness Roush and presented in his exhibits, this rider is designed to recover the costs associated with energy efficiency programs from customer classes on the basis in which these costs are incurred. Effectively, the program costs are being assigned to rate classes on the basis of customer use of the programs. This is a reasonable approach to cost recovery and OEG supports the proposal.

**10. The Commission Should Determine The Methodology For The Excessive Earnings Test In This Proceeding.**

We understand that in its December 19, 2008 Order in the First Energy ESP case that the Commission determined that a workshop should be used to develop a recommendation for the significantly excessive earnings test. However, on December 22, 2008 FirstEnergy withdrew its ESP. To the extent that the Commission will rule on this issue now we submit the following.

The Commission is required to review the ESP after one year and determine if the adjustments resulted in "*excessive earnings*" as measured by whether "*the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate.*" (RC §4928.143(F)) If the Commission finds that the ESP adjustments did result in significantly excessive earnings, "*it shall require the electric distribution utility to return to consumers the amount of the excess by prospective adjustments.*" (Id.)

**a. <u>Constitutional Origins of The Significantly Excessive Earnings Test.</u>**

The "*significantly excessive earnings*" test is grounded in well established U.S. Supreme Court constitutional law. The "*significantly excessive earnings*" standard is very similar, but more generous to the utilities, than "*comparable earnings*" standard which is traditionally required.

In *Bluefield Water Works v. West Virginia*, 262 U.S. 679,692 (1923) the United States Supreme Court set out the "*comparable earnings*" standard:

> *"A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally."*

Building on the *Bluefield* Case, the U.S. Supreme Court later confirmed the "*comparable earnings*" test as the proper standard for setting utility rates: *"the return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks."* F.P.C. v. Hope Natural Gas, 320 U.S. 591,603 (1944).

The "*significantly excessive earnings*" test is more generous to Ohio's electric utilities than the U.S. Supreme Court "*comparable earnings*" standard. The "*significantly excessive earnings*" test allows utilities to earn a profit that is not just comparable with similar companies, but even more. This means that Ohio's electric utilities are allowed to be more profitable than comparable businesses in the private sector, but not significantly more profitable.

The Commission needs to address the methodology for this test in this proceeding, or at least sometime in 2009. It cannot wait until 2010. Under Generally Accepted Accounting Principles ("GAAP"), the utilities are required to recognize a regulatory liability for any refunds that arise each year and that will be refunded to ratepayers prospectively in the following year.

First, the Commission must determine the methodology it will use to compute the rate of return on common equity threshold over which the Companies will be deemed to have significantly excessive earnings.

Second, the Commission must determine the methodology it will use to compute the utility's actual earned return on common equity for each review year.

Third, if the Company's actual earnings are in excess of the threshold, then the difference, grossed-up for taxes on a revenue requirement basis, should be refunded to ratepayers in accordance with the requirements of the statute.

### b. Determination Of The Significantly Excessive Earnings Threshold

The testimony of OEG witness Charles King sets forth a method for determining the significantly excessive earnings threshold.[56] Mr. King 1) identified a peer group of comparable utilities and non-utility businesses; 2) adjusted the earned returns of each group to match the risks faced by the two AEP companies operating in Ohio; 3) averaged the utility and non-utility returns to derive a base line earned level of return; and 4) applied an adder that describes the margin over this base line equity return that should be allowed before the earnings are considered significantly excessive. These steps are discussed in greater detail below.

First, Mr. King identified utilities and non-utilities that are comparable to the AEP companies. Value Line's Datafile contains the names of all 64 U.S. publicly traded companies that Value Line classifies as electric utilities.[57] The average of the earned returns on equity for these electric utilities in 2007 was 10.68 percent.[58]

The group of non-utility companies was compiled from a list of 5,688 companies found in the Value Line Datafile. This list was narrowed down by eliminating electric, gas and water utilities, companies that have a ratio of gross plant to revenue that are not similar to the AEP companies, small companies which would have higher return requirements than utilities, all companies with gross plant less than $1 billion, and any companies for which Value Line had not calculated a beta. The final list came to 219 companies.[59]

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[56] See Direct Testimony of Charles King pp. 4-10.
[57] See Direct Testimony of Charles King, Exhibit No.__(CWK-1)
[58] Direct Testimony of Charles King, p. 5.
[59] Direct Testimony of Charles King Schedule 4 of Exhibit No.__(CWK-1).

The average return on year-end 2007 equity of the non-utility companies was 14.14 percent.[60] However, these returns on equity cannot be considered comparable to the two AEP Companies because these non-utility companies are far riskier. The second step in Mr. King's methodology is to adjust the earned returns of each group to match the risks faced by the two AEP Companies.

For this purpose, Mr. King used the "*beta*" measure as generated by Value Line. Beta is a measure of the co-variance of each stock with that of the overall stock market. The overall stock market's beta is 1.00. To the extent that beta is greater than 1.00, the stock displays greater volatility and higher risk than the market. Betas less than 1.00 indicate less volatility and lower risk. The beta reflects all forms of risk, so it is the one comprehensive measure of risk that is available for most traded stocks.[61]

The average beta for the comparable non-utility companies is 1.08, reflecting the fact that these companies are, on average, more risky than the average for the market.[62] In contrast the average beta of the electric utility comparison group is 0.89, indicating a lower level of risk than the non-utility group.[63] The average return for the 219 non-utility companies needs to be adjusted in order to reflect the much lower risk associated with utility service. While there are many measures of the risk premium, there seems to be a consensus that measured over very long periods of time the risk premium has averaged about seven percent. Mr. King applied the difference between the 1.08 beta of the non-utility group and the 0.89 beta of the utility group, which is 0.19, to the seven percentage point risk premium to derive an adjustment of 132 basis points, or 1.32 percent. A reduction of 1.32 percent to the average non-utility earned return of 14.14 percent yields a risk-adjusted return of 12.82 percent.[64]

The third step of Mr. King's methodology is to average the utility and non-utility returns in order to derive a base line earned level of return. This step is necessary in order to account for the financial risk differences among the two AEP Companies. Columbus Southern has a ratio of equity to total capital of 47.3

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[60] Direct Testimony of Charles King, Schedule 2.
[61] Direct Testimony of Charles King p. 7.
[62] Direct Testimony of Charles King, Schedule 4 of Exhibit No.__(CWK-1).
[63] Direct Testimony of Charles King, Column E of Schedule 3 of Exhibit No.__(CWK-1)
[64] Direct Testimony of Charles King, pp. 7.

percent, and Ohio Power has a ratio of 47.7 percent. The utility comparison group has a slightly less risky ratio of 49.2 percent, and the non-utility group's ratio is even less risky at 51.7 percent.[65]

Mr. King adjusted both the utility and non-utility equity returns to recognize these differences in financial risk resulting from different capital structures.[66] They are:

- Columbus Southern 12.20%
- Ohio Power 12.22%

The final step in Mr. King's methodology is to apply an adder that describes the margin over this base line equity return that should be allowed before the earnings are considered significantly excessive. Here, it is necessary for the Commission to exercise its own judgment because there is no objective, generally accepted measure of a "*significantly excessive return*." OEG recommends the use of the adders that the FERC awards to encourage investment by utilities in major innovative transmission lines. FERC provides a 50 basis point adder for participation in Regional Transmission Organizations and another adder of up to 150 basis points as an incentive for investment. FERC apparently believes that that this 200 basis point adder provides such a high return that it is sufficient to encourage risky investments in transmission lines that must traverse difficult terrain and encounter siting resistance. Anything more than this healthy 200 basis point adder would be significantly excessive.[67]

If we add 200 basis points to the base line returns on year-end equity, the thresholds of significantly excessive earnings are:[68]

- Columbus Southern 14.20%
- Ohio Power 14.22%

[65] Direct Testimony of Charles King, p. 7.

[66] Direct Testimony of Charles King Schedule 6 of Exhibit No.__(CWK-1).

[67] OEG has not adopted the statistical confidence levels that the utilities' witnesses have recommended because the use of statistical confidence ranges would limit any finding of excessive earnings to so few observations that the test would become a cipher. A 95 percent confidence interval would mean that only 2.5 percent of all observations in the sample company groups would be deemed to have excessive earnings. A 90 percent confidence interval would increase that proportion to five percent. These intervals virtually ensure that no Ohio utility would ever be found to have experienced significantly excessive earnings.

[68] Direct Testimony of Charles King, p. 9.

These threshold numbers are merely illustrative of the results that are derived from the methodology that OEG recommends. The first application of the significantly excessive earnings test will be in 2010 and based on earned returns in 2009. It is almost certain that 2009 earnings for AEP's peer group of comparable companies will be *negatively affected by the current recession, which will lower the significantly excessive earnings* threshold.

### c. Calculation of the Utility's Actual Earnings.

The Commission should compute the actual earned return on common equity for each annual period using the per books actual accounting earnings on common equity and the utility's year-end actual common equity balance, with limited ratemaking adjustments. The authorized ratemaking adjustments should be specified by the Commission in this proceeding and should be modified only prospectively upon consideration of a request from the utility or other party to add or remove such adjustments.[69]

The list can be as extensive or limited as the Commission believes is necessary to ensure that rates are reasonable. At a minimum, the ratemaking adjustments should be consistent with the requirements and limitations on cost-based recoveries specified in §4928.143(B)(2). For example, only prudent fuel and purchased power expenses should be included. Also, at a minimum, the ratemaking adjustments that are reflected should be consistent with other Commission orders wherein there were specific disallowances of or directions relating to rate base, expense or rate of return amounts or components.[70]

Contrary to the Companies' argument, the Commission also should include all profits from off-system sales in the computation of earnings, just as it should include all prudent purchased power expenses. The Companies' witness Mr. Baker proposed that the Commission reduce actual earnings for the review year to exclude the profits from off-system sales.[71] This is not reasonable. First, SB 221 contemplates no such ad hoc exclusions to the utility's earnings. Removal of these off-system sales profits would result in a distorted picture

[69] Direct Testimony of Lane Kollen p. 25.
[70] Direct Testimony of Lane Kollen p. 25.
[71] Direct Testimony of Craig Baker p. 38-39.

of the utilities' financial condition. Second, the Companies offer no proposal for the removal of all the costs associated with making the off-system sales for purposes of the significantly excessive earnings test. Such off-system sales are available to the Companies and the AEP system only because the costs of the underlying generating assets and purchased power contracts are recovered from ratepayers. These costs include both fixed and variable costs. These costs also include the common equity investment in the Companies' generating facilities.[72] Thus, the Companies' proposal is biased against Ohio ratepayers due to a fundamental mismatch between the off-system sales revenues they propose be removed from the test and the limited, if any, costs that they propose be removed.

Mr. Baker argues that the off-system sales revenues are "*FERC-jurisdictional*" and should be excluded from retail rates on that basis.[73] This position is completely contrary to the requirements of the Interconnection Agreement and the federal preemption resulting from this FERC-regulated rate. While the Interconnection Agreement is a FERC-regulated rate, federal preemption does not require that the rate be ignored, but rather requires that the costs or revenues incurred pursuant to that rate be imposed on the states for retail ratemaking purposes. Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953 (1986); Mississippi Power & Light Co. v. Mississippi ex. rel. Moore, 497 U.S. 354 (1988). All AEP Companies share in the AEP system off-system sales margins based on their member load ratio shares no matter which utility's power plants actually generated to make the sales. The FERC-regulated Interconnection Agreement rate requires that AEP allocate these margins to each of the AEP Members. In 2007, this amounted to $146.7 million for OPC and $124.1 million for CSP.[74] In all the AEP regulated jurisdictions, these off-system sales margins are flowed through by the AEP Members to their retail ratepayers. Mr. Baker's position would discriminate against Ohio by applying the FERC approved Interconnection Agreement differently and worse for this state compared to West Virginia, Virginia, Kentucky, Indiana and Michigan.[75]

[72] Direct Testimony of Lane Kollen p. 33-34.
[73] Direct Testimony of Craig Baker p. 38-39.
[74] Direct Testimony of Lane Kollen p. 14.
[75] Direct Testimony of Lane Kollen pp. 33-35.

Mr. Baker proposes that the significantly excessive earnings test be performed "*on the two Companies on a combined basis.*" (Baker Direct at 39). This proposal is prohibited by the express language of the statute. The statute specifically refers to the earnings of "*the electric distribution utility,*" in the singular, not the plural. The statute states: "*. . . the commission shall consider, following the end of each annual period of the plan, if any such adjustments resulted in excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity . . .*" In addition, the statute prohibits including directly or indirectly the revenue, expenses or earnings of any affiliate, such as sister utilities in the same holding company. R.C. 4928.143(F) states: "*In making its determination of significantly excessive earnings under this division, the commission shall not consider, directly or indirectly, the revenue, expense, or earnings of any affiliate or parent company.*"

Companies' witness Dr. Makhua proposes that the Commission average the Companies' earnings over a three year period, presumably coincident with the initial term of the proposed ESP. (Makhua Direct at 11). This proposal also is prohibited by the express language of the statute. The statute specifically requires an annual application of the significantly excessive earnings test. It does not allow averaging over a multi-year period. R.C. 4928.143(F) requires the application of the test "*following the end of each annual period of the plan.*" The test is designed as a ratepayer protection against excessive ESP rate increases that are placed into effect and/or adjusted each year. The Commission is required to consider whether the ESP rate increases in each year resulted in significantly excessive earnings in that same year. Finally, the threshold for significantly excessive earnings must be determined each year because the underlying data necessarily will change each year, including the group of companies that will be considered comparable and their earnings.[76]

The Commission should remove the effects of any refunds in one year based on the significantly excessive earnings test for the prior year so that the refund is computed on a discrete annual basis and does not influence the actual earnings for another year.[77]

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[76] Direct Testimony of Lane Kollen p. 41.
[77] Direct Testimony of Lane Kollen pp. 32-33

Finally, the Commission should require the utilities to exclude the effects of fines and penalties, one-time writeoffs, costs and acquisition premiums related to mergers and acquisitions, and effects of mark-to-market accounting for derivative gains and losses.[78]

d. <u>Refunds of Excessive Earnings</u>

The statutory test suggests a limitation on the potential refunds by linking the excess earnings to the "*adjustments*" pursuant to any ESP. Subject to a correct understanding of the purpose of the test and the definition and application of the term "*adjustments*," the statute appears to limit potential refunds to the amount of the ESP increases recovered during the year subject to review. RC §4928.143(F) states:

> *"With regard to the provisions that are included in an electric security plan under this section, the commission shall consider, following the end of each annual period of the plan, if any such adjustments resulted in excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate."*

The total ESP rate increases or adjustments in any review year should be computed by multiplying the ESP riders by the actual billing determinants for the year. This yields the total ESP revenues in the review year. This annual dollar amount is the maximum amount of the utility's refund obligation during any review year of the ESP.[79]

Another interpretation would be to assume that the term "*adjustments*" refers both to ESP rate riders and to the specific incremental costs that justified the riders. Under this interpretation, the ESP rate increases and the incremental costs necessarily net to zero. There would be no effect on earnings and an ESP adjustment could never result in significantly excessive earnings. The Commission should reject this interpretation as inconsistent with the plain language of the statue and dismiss this interpretation under the long-held rule of statutory construction that provides that courts must construe the applicable statute in order to avoid unreasonable or absurd

[78] Direct Testimony of Lane Kollen p. 33.
[79] Direct Testimony of Lane Kollen p. 37.

results. *See*, e.g., *State ex rel. Leslie v. Ohio House Fin. Agency*, 105 Ohio St.3d 261 (2005); *State ex rel. Gaydosh v. Twinsburg*, 93 Ohio St.3d 576 (2001).

If the utilities' potential interpretation is adopted, there never could be any significantly excessive earnings. Their definition of the term "*adjustments*" to mean both ESP rate increases and the costs used to justify the increases would preclude any net effect on earnings. If this potential interpretation is adopted, the earnings test would be vitiated and there would be no meaningful ratepayer protection against excessive rate increases. Obviously the Legislature would not have included the significantly excessive earnings test in SB 221 if they intended it to be meaningless and offer no protection to consumers.[80]

If a refund is ordered, a gross-up for income taxes is necessary because the earnings are stated on an after tax basis, not on a before tax revenue basis. Such a gross-up for income taxes is similar to the historic use by the Commission of a gross revenue conversion factor to convert operating income deficiencies or surpluses into revenue deficiencies or surpluses. The objective is to determine the amount of revenue over-collections in the prior year that resulted in the significantly excessive earnings so that an equivalent amount can be refunded to ratepayers.[81]

In 2007, Columbus Southern earned **22.1%** and Ohio Power earned **11.7%** on a per books basis, assuming no ratemaking adjustments.[82] Thus far in 2008, the after-tax returns on common equity earned by the Companies for the first nine months of 2008 are **23.48%** for Columbus Southern and **13.5%** for Ohio Power.[83] Columbus would be over the significantly excessive earnings threshold for both 2007 and 2008 if the threshold is computed in the manner proposed by Mr. King and if the test had been applicable in these years. A 1% return on common equity is equivalent to approximately $19 million in increased revenues for Columbus Southern and $37 million for Ohio Power. Stated another way, if the Commission found that the utilities had excess earnings by 1%, then these are the amounts of refunds that would be required.[84]

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[80] Direct Testimony of Lane Kollen pp. 38-39..
[81] Direct Testimony of Lane Kollen p. 29.
[82] Direct Testimony of Lane Kollen, Exhibit___(LK-2).
[83] Rebuttal Testimony of Stephen Baron p. 2.
[84] Direct Testimony of Lane Kollen p. 42.

## III. CONCLUSION

For the first nine months of 2008, the after-tax returns on common equity earned by CSP and OPC were **23.48% and 13.5%,** respectively.[85] These extremely high earnings mean that the Companies are currently recovering all of their costs, plus a healthy profit, under existing rates. Their proposal to increase rates by **$2.816 billion annually by 2011, assuming the fuel adjustment clause increases are at the maximum annual amounts and that there are no deferrals** (total of **$5.823 billion** over three years) has not been justified as prudent or reasonable, especially in this time of state-wide economic depression.

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[85] Rebuttal Testimony of Stephen Baron p. 2.