ORIGINAL

IN THE SUPREME COURT OF OHIO

OHIO POWER COMPANY,	:	
	:	
Appellant/Cross-Appellee	:	**Case No. 2012-1484**
	:	
v.	:	
	:	**Appeal from the Public Utilities Commission of Ohio**
THE PUBLIC UTILITIES COMMISSION OF OHIO,	:	
	:	
	:	**Public Utilities Commission of Ohio Case Nos. 09-872-EL-FAC**
	:	**09-873-EL-FAC**
Appellee.	:	

APPENDIX TO MERIT BRIEF OF APPELLANT OHIO POWER COMPANY

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NOTICE OF APPEAL OF OHIO POWER COMPANY

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FILED
AUG 30 2012
CLERK OF COURT
SUPREME COURT OF OHIO

NOTICE OF APPEAL OF APPELLANT OHIO POWER COMPANY

Appellant, Ohio Power Company ("OPCo" or "Appellant"), hereby gives notice of its appeal, pursuant to R.C. 4903.11 and 4903.13, and Supreme Court Rule of Practice II, Section 2.3(B), to the Supreme Court of Ohio and Appellee, the Public Utilities Commission of Ohio ("Commission"), from an Opinion and Order entered on January 23, 2012 (Attachment A), an Entry on Rehearing entered on March 21, 2012 (Attachment B), an Entry on Rehearing entered on April 11, 2012 (Attachment C), a Third Entry on Rehearing entered on June 6, 2012 (Attachment D), and a Fourth Entry on Rehearing entered on July 2, 2012 (Attachment E), in PUCO Case Nos. 09-872-EL-FAC and 09-873-EL-FAC. The cases involved the 2009 annual audit of the accounting of OPCo's and Columbus Southern Power's fuel adjustment clause ("FAC") costs, as required by AEP Ohio's approved electric security plan. This appeal is filed within sixty days of the Commission's Fourth and final Entry on Rehearing on July 2, 2012.

OPCo is a party in Case Nos. 09-872-EL-FAC and 09-873-EL-FAC and timely filed an Application for Rehearing of the Commission's January 23, 2012 Opinion and Order in accordance with Ohio Rev. Code § 4903.10. OPCo also timely filed a notice of appeal in this Court, in accordance with Ohio Rev. Code § 4903.11, on June 8, 2012, in response to the Commission's April 11, 2012 Entry on Rehearing. See *Ohio Power Company v. Pub. Util. Comm.*, Case No. 12-0976. At the time OPCo filed its June 8, 2012 Notice of Appeal, an application for rehearing filed by an intervening party remained pending before the Commission. That application for rehearing was improperly and unnecessarily filed by the intervenor to reargue an issue fully addressed in the April 11, 2012 Entry on Rehearing and, therefore, did not extend the time for filing a notice of appeal in accordance with Ohio Rev. Code § 4903.11. That application for rehearing was denied in the Fourth Entry for Rehearing entered on July 2, 2012.

OPCo believes that it properly invoked this Court's jurisdiction by its June 8, 2012 Notice of Appeal Case No. 12-0976, and that the appeal time was not extended beyond sixty days from the April 11, 2012 Entry on Rehearing that resolved all issues before the Commission. The Commission, however, has moved to dismiss Case No. 12-0976 for lack of a final appealable order. Because the Court has not yet resolved the jurisdictional challenge to Case No. 12-0976, OPCo files this notice of appeal to protect its right to appeal the Commission's orders and to have the Court address the errors set forth below. If the Court denies the motion to dismiss in Case No. 12-0976 and retains jurisdiction over that appeal, OPCo would seek to voluntarily dismiss this proceeding.

The assignments of error listed below were raised in OPCo's Application for Rehearing. Further, in its April 11, 2012 Entry on Rehearing, the Commission granted rehearing regarding an issue jointly raised on rehearing by two intervenors in the proceeding below. OPCo actively opposed their rehearing request and the Commission's granting of their rehearing request harmed Appellant's interests. The Commission's January 23, 2012 Opinion and Order and April 11, 2012 Entry on Rehearing are unlawful and unreasonable in multiple respects.

I. The Opinion and Order engages in selective and unlawful retroactive ratemaking. *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.* 166 Ohio St. 254 (1957); *Lucas Cty. Commrs. v. Pub. Util Comm.*, 80 Ohio St.3d 344 (1997).

II. It was unreasonable and unlawful for the Commission to retroactively modify its prior adjudicatory decision in ESP I (Case Nos. 08-917/918-EL-SSO) to establish annual FAC audits to examine fuel procurement practices and expenses for the audit period. *Ohio Consumers' Counsel v. Pub. Util. Comm.* 111 Ohio St.3d 300, 318 (2006); *Ohio Consumers' Counsel. Pub. Util Comm.*, 16 Ohio St.3d 9, 10 (1985).

III. By reaching back into 2008 and using the results of fuel procurement activities in 2008 to offset fuel costs prudently incurred in 2009, the Commission unreasonably and unlawfully modified the FAC baseline that was fully litigated and decided in the ESP I Cases.

IV. OPCo prudently entered into the 2008 Settlement Agreement described in the Opinion and Order at 4, and the Commission has unreasonably and unlawfully impaired that agreement, especially given that the agreement was entered into by OPCo prior to commencement of the ESP's new FAC and before the 2009 audit period (i.e., during a period of unregulated fuel cost and when fuel contracts were not regulated).

V. The Commission unreasonably and unlawfully found that the 2008 production bonus agreement (identified and discussed in the April 11, 2012 Entry on Rehearing at 7-8), which increased fuel expenses in 2008, should not offset any adjustments to the deferred fuel costs resulting from the 2008 Settlement Agreement.

VI. The Opinion and Order unreasonably and unlawfully concluded that the value of the West Virginia coal reserve property acquired as a result of the 2008 Settlement Agreement should be offset against FAC costs because it is an OPCo asset on which ratepayers have no claim.

VII. The Opinion and Order is unreasonable to the extent that it does not include in the methodology to be used for the determination of the value of the coal reserve, as an alterative to valuation through appraisal, the sale of the property.

VIII. The Opinion and Order is unreasonable and unlawful to the extent that it concludes that the Delivery Shortfall Agreement and the Contract Support Agreement, identified and discussed in the Opinion and Order at 7-14, may be examined by a future audit.

IX. The Commission erred in determining on rehearing that OPCo should flow through to its customers a carrying charge component in applying a credit to its FAC under-recovery.

WHEREFORE, Appellant Ohio Power Company respectfully submits that the Commission's January 23, 2012 Opinion and Order and April 11, 2012 Entry on Rehearing are unlawful, unjust, and unreasonable and should be reversed. The case should be remanded to the Commission with instructions to correct the errors complained of herein.

Respectfully submitted,

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CERTIFICATE OF FILING

The undersigned counsel certifies that, in accordance with Supreme Court Rule of Practice XIV, Section 2 (C)(2), Ohio Power Company's Notice of Appeal has been filed with the docketing division of the Public Utilities Commission of Ohio and with the Chairman of the Public Utilities Commission of Ohio by leaving a copy at the office of the Chairman in Columbus, Ohio, in accordance with Rules 4901-1-02(A) and 4901-1-36 of the Ohio Administrative Code, on August 30, 2012.

Kathleen M. Trafford

Counsel for Appellant

ATTACHMENT A

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company.	)))	Case No. 09-872-EL-FAC Case No. 09-873-EL-FAC

OPINION AND ORDER

The Public Utilities Commission of Ohio, having considered the record in these matters and the stipulation and recommendation submitted by the signatory parties, and being otherwise fully advised, hereby issues its opinion and order.

APPEARANCES:

Steven T. Nourse, One Riverside Plaza, Columbus, Ohio 43215-2373, and Daniel R. Conway, Porter, Wright, Morris & Arthur, LLP, 41 South High Street, Columbus, Ohio 43215, on behalf of Columbus Southern Power Company and Ohio Power Company.

Mike DeWine, Ohio Attorney General, by William L. Wright, Section Chief, and Werner L. Margard and Thomas W. McNamee, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215, on behalf of the Staff of the Public Utilities Commission.

Janine L. Migden-Ostrander, Ohio Consumers' Counsel, by Maureen Grady, Melissa Yost, and Kyle Lynn Verrett, Assistant Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio 43215, on behalf of the residential utility consumers of Columbus Southern Power Company and Ohio Power Company.

McNees, Wallace & Nurick, by Samuel C. Randazzo, Joseph Clark, and Joseph Oliker, Fifth Third Center, Suite 1700, 21 East State Street, Columbus, Ohio 43215, on behalf of Industrial Energy Users of Ohio.

OPINION:

I. Background

Columbus Southern Power Company (CSP) and Ohio Power Company (OP) are public utilities as defined in Section 4905.02, Revised Code, and, as such, are subject to the jurisdiction of this Commission.

On March 18, 2009, the Commission issued its Opinion and Order in CSP's and OP's (jointly, AEP-Ohio or Companies) electric security plan (ESP) cases (ESP Order).[1] By entries on rehearing issued July 23, 2009, and November 4, 2009, the Commission affirmed and clarified certain issues raised in AEP-Ohio's ESP Order. In the ESP Order, the Commission approved fuel adjustment clauses (FAC) for the Companies including an annual audit of the FAC. Further, in the ESP cases, the Commission authorized 2010 rate increases of six percent for CSP and seven percent for OP and 2011 rate increases of six percent for CSP and eight percent for OP.

Pursuant to the Commission entry issued January 7, 2010, in Case Nos. 09-872-EL-FAC and 09-873-EL-FAC (2009 FAC cases), Energy Ventures Analysis, Inc., (EVA) was selected to perform AEP-Ohio's FAC audit for 2009. In accordance with the request for proposal, EVA is performing the audits for 2010 and 2011, unless the Commission determines otherwise. Pursuant to the request for proposal, the Commission reserves the right to rescind the award of future audits.

On May 14, 2010, both redacted and unredacted versions of EVA's management/performance (m/p) and financial audit of AEP-Ohio's FAC for 2009 (audit report) were filed in these cases. By entry issued June 29, 2010, the attorney examiner granted AEP-Ohio's motion for protective treatment regarding certain information contained in the audit report for a period of 18 months, ending on December 29, 2011.

The office of the Ohio Consumers' Counsel (OCC), Industrial Energy Users-Ohio (IEU-Ohio), and Ormet Primary Aluminum Company (Ormet) were granted intervention in the 2009 FAC cases in a Commission finding and order issued on January 7, 2010.

In accordance with the attorney examiner's June 29, 2010, entry, the hearing was held in these matters on August 23 and August 24, 2010, at the offices of the Commission. At the hearing, AEP-Ohio submitted a stipulation and recommendation (Ormet stipulation) which was filed in these dockets on August 23, 2010, and signed by the Companies, Staff, OCC, IEU-Ohio, and Ormet Primary Aluminum Corporation (Jt. Ex. 1). Additionally, at the hearing, AEP-Ohio submitted the public and rebuttal testimony of four individuals (AEP-Ohio Exs. 1 and 1A through 7 and 7A) while OCC and IEU-Ohio each offered the testimony of one witness (OCC Exs. 1 and 1A; IEU-Ohio Exs. 1 and 1A). In addition, the redacted and unredacted versions of the audit report were entered into the record without objection (Bench Exs. 1A and 1B).

As stated previously, a stipulation, signed by AEP-Ohio, Staff, OCC, IEU-Ohio, and Ormet was submitted on the record, at the hearing held on August 23, 2010. Through the stipulation, the parties agree that a determination on the collection of deferrals and

[1] *In re AEP-Ohio ESP cases*, Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, Opinion and Order (March 18, 2009).

carrying charges associated with an Ormet Interim Agreement is the subject of a pending case before the Commission, *In the Matter of the Application of Columbus Southern Power and the Ohio Power Company to Recover Commission-Authorized Deferrals Through each Company's Fuel Adjustment Clause*, Case No. 09-1094-EL-FAC, and that issues associated with the Ormet Interim Agreement will be addressed in that proceeding.

On November 30, 2010, a stipulation and recommendation intended to resolve all the issues in this FAC proceeding as well as in the Companies significantly excessive earnings proceeding, Case No. 10-1261-EL-UNC *In the Matter of the 2009 Annual Filing of Columbus Southern Power Company and Ohio Power Company Required by Rule 4901:1-35-10, Ohio Administrative Code*, was filed on behalf of AEP-Ohio, Staff, the Ohio Hospital Association, the Ohio Manufacturers' Association, The Kroger Company, and Ormet. On December 16, 2010, the Companies filed a notice of withdrawal from the November 30, 2010, stipulation and recommendation thus rendering the stipulation moot.

II. Summary of the Audit Report

The audit report submitted by EVA and its subcontractor Larkin and Associates PLLC (Larkin) presents the results of the m/p and financial audit for the fuel adjustment clause which is the mechanism being used to recover prudently incurred fuel, purchased power, and other miscellaneous expenses. The FAC includes: Account 501 (Fuel); Account 502 (Steam Expenses); Account 509 (Allowances); Account 518 (Nuclear Fuel Expense); Account 547 (Non-Steam Fuel); Account 555 (Purchased Power); Account 507 (Rents); Account 557 (Other Expenses); Accounts 411.8 and 411.9 (Gains and Loses from Disposition of Allowance); and Other Accounts. EVA and Larkin (jointly, auditors) conducted this audit through a combination of document review, interrogatories, site visits, and interviews. Additionally, EVA and Larkin visited the Conesville Coal Preparation Plant and the Conesville power plant. In its initial ESP application, the Companies proposed mitigating the rate impact of any FAC increases on customers by phasing in the new ESP rates by deferring a portion of the annual incremental FAC costs such that total bill increases to customers would not exceed 15 percent during each year of the ESP. The Commission's ESP order, issued on March 18, 2009, modified AEP-Ohio's proposal to mitigate the rate impact on customers by limiting the phase-in of any FAC increases on a total bill basis by seven, six, and six percent for CSP and by eight, seven, and eight percent for OP for years, 2009, 2010, and 2011, respectively. The Commission's ESP order also stated that the collection of any deferrals including carrying costs remaining at the end of the ESP shall occur from 2012 through 2018 as necessary to recover the actual fuel expense incurred plus carrying costs. (Jt. Ex. 1 at 1-2 through 1-3; ESP order at 23.)

The audit report found that AEP-Ohio's fleet is largely coal-based and coal procurement costs are by far the largest component of the FAC. The auditors noted that since mid-2007, the coal industry has demonstrated unprecedented volatility which has resulted in utility fuel procurement personnel facing enormous challenges. Additionally, from mid-2007 until the third quarter of 2008, a global coal supply/demand imbalance increased the demand for and price of United States (U.S.) coals. In the auditors' opinion, American Electric Power Service Corporation (AEPSC) did an exceptional job during this period particularly with those suppliers that faced financial difficulties. Since the third quarter of 2008, electricity demand slowed as a result of the severe economic recession thus leading many utilities to end up with more coal under contract than needed. Thus, from mid-2007 through the end of 2008, electric utilities went from having to acquire coal under contract to having to manage a surplus of coal inventories. In the auditors' view, AEPSC also did an outstanding job managing its excess coal inventories. The auditors found this to be the case based, in part, on the treatment AEPSC afforded its suppliers, many of which were willing to defer shipments at no cost. Additionally, the auditors noted, AEPSC chose to allow stockpiles to increase rather than pay for reduced shipments which should benefit ratepayers in the long term. AEP's coal costs in 2009 were, according to the auditors, comparable to the coal procurement costs of other nearby utilities. (Jt. Ex. 1 at 1-4 through 1-5.)

The audit report further determines that, at the end of the first year of the FAC, AEP-Ohio experienced a large under-recovery. The under-recovery amounts to $37.5 million for CSP and $297.6 million for OP. The auditors note that there many components contributing to the under-recovery but that two coal contract events alone explain more than half of OP's under-recovery. The first decision attributing to the under-recovery was the decision to increase the contract price under two contracts in 2009. This surcharge under the two contracts at issue was a well-considered decision at a difficult time according to the audit report. While expensive, the auditors note that, without the surcharge, an insolvency of this coal supplier would have led to greater expense for AEP-Ohio and ultimately its ratepayers. The second contributing factor was a buy-out of a coal contract in 2007 which resulted in an increase in 2009 fuel expenses. The 2007 buy-out was structured as a Settlement Agreement arising out of contract dispute. According to the auditors, a hindsight review of such a Settlement Agreement is always difficult because its merits need to be considered at the time it was entered into. This Settlement Agreement was effectively a buy-out of the contract with this supplier after 2008. Otherwise, shipments would have continued under the contract through the ESP period. In return for agreeing to the buy-out, AEP received a settlement and a coal reserve in West Virginia. AEP booked the coal reserve as an un-regulated asset in 2008. (*Id.* at 1-5.)

The audit report further found that AEPSC's fuel procurement operation is run in a professional manner using leading industry practices in acquiring coal and transportation. To support this position, the audit report notes that AEPSC uses a portfolio strategy to purchase coal such that its market exposure at any one time is limited. Moreover, AEPSC purchases most of its coal through competitive solicitations, and AEPSC uses active management of its coal supply to match deliveries and burn where possible. The auditors noted that AEPSC was in the process of revising its fuel procurement manual to guide its practices (*Id.*)

The audit report also addresses AEP-Ohio's coal supply and scrubber retrofit at various generating facilities as well as the reduction in the need for washed coal from the Conesville Coal Preparation Plant due to the conversion of an existing coal supply agreement from unwashed coal to washed coal. The audit report notes that AEP-Ohio has met its 2009 alternative energy obligations through compliance with reduced solar obligations, the purchase of non-solar renewable energy credits (RECs) from wind and landfill gas, purchased solar (RECs), solar installations on two AEP-Ohio service centers, and wind from two purchase power agreements (PPAs). During 2009, the Companies entered into three 20-year PPAs: two for wind and one for solar. The auditors note that the resulting power prices under all three PPAs are high compared to current power prices although competitive with current market prices for renewable power. These PPAs provide no market reopeners or early outs thereby obligating AEP-Ohio to these high rates for 20 years. The auditors note that AEPSC's strategy is to continue to examine all options including self-build options (*Id.* at 1-6.) Finally, the auditors found that the quarterly FAC filings were made in a timely manner and contained sufficient documentation to support the numbers therein. However, the back-up documentation was less well organized making the audit trail more difficult. Also, the auditors reported that AEPSC was notably well-prepared and responsive to the auditors (*Id.*)

III. Management Audit Recommendations[2]

A. Auditors' Recommendations

The audit report recommends that the Commission should review whether any proceeds from the Settlement Agreement (i.e., the 2008 lump sum payment AEP-Ohio received as well as the West Virgnia coal reserve) should be credited against OP's FAC under-recovery. The auditors note that this buy-out was unique as it occurred during a period in which fuel cost recovery was not regulated yet the entire value received was for tons of coal that would have been shipped during the ESP period. The auditors do not suggest any motivation on the part of AEPSC to transfer value from ratepayers in 2009 to 2011 to an earlier date. Clearly, it was the coal supplier who initiated the Settlement Agreement because the contract price was well below market. Nonetheless, the contract was an OP asset and the value associated with it would have flowed through to OP ratepayers through the ESP period had there not been an early termination of the contract. Further, the difference between the price of the replacement coal and the contract price is

2 The following is a summary of the recommendations from the audit report. The Commission notes that these summaries are in no way intended to replace or supplement the text of the audit report.

one factor behind the large OP FAC under-recovery. Equity suggests that the Commission should consider whether some of the realized value should be credited against the under-recovery according to the auditors. (*Id.* at 1-6; 2-21 through 2-22.)

The audit report also recommends that coal could become the new swing fuel; therefore, AEPSC should reconsider new coal procurement strategies to avoid over-commitments in the future. Further, the audit report recommends that the next m/p auditor review the Cardinal 1 scrubber situation and determine what, if any, FAC costs are due to this situation. AEPSC should also undertake a study to determine whether there is an economic justification for continuing to operate the Conesville Coal Preparation Plant. The auditors next recommend that AEPSC should finalize the update of its policies and procedures manual to reflect current business practices and that both the policies and procedures manual and the Conesville Coal Preparation Plant study should be reviewed in the next m/p audit. Lastly, the audit report recommends that prior to entering into long-term agreements for renewables with fixed pricing, AEP-Ohio should fully evaluate self-build and biomass co-firing alternatives and should explore contract options that would provide some protection in the event that the contract pricing for power and/or RECs diverge with market prices. (*Id.* at 1-7.)

B. AEP-Ohio's Position on Management Audit Recommendations

AEP-Ohio witnesses generally testified that the Companies are either in agreement with or not opposed to the auditor's m/p recommendations 2 through 6 found at pages 1-7 of the audit. Regarding m/p audit recommendation 2, the reconsideration of new coal procurement strategies, AEP-Ohio witness Rusk testified that the Companies agree with the recommendation and are currently undertaking such an effort (Co. Ex. 2 at 3). AEP-Ohio witness Nelson testified regarding m/p audit recommendation 3 that the Companies are not opposed to a review of the audit period operational issues concerning the Cardinal 1 scrubber in the next fuel adjustment clause proceeding (Co. Ex. 3 at 8-9). Regarding m/p audit recommendation 4, AEP-Ohio witness Rusk explained that AEPSC has already begun an effort to study the continued use of the Conesville Preparation Plant with the goal of formulating a recommendation on this facility for the next management performance audit (Co. Ex. 2 at 4). AEP-Ohio witness Rusk also testified regarding m/p audit recommendation 5. Mr. Rusk observed that AESPC is currently updating its fuel procurement policies and should have those updates in time for the next m/p audit. However, Mr. Rusk clarified that these revisions are focused on procurement policies and not focused on procurement procedures as the Companies believe that the current approach results in the efficient procurement of fuel at the lowest reasonable cost. (*Id.* at 5.) Regarding m/p audit recommendation 6, that the Companies should fully evaluate and explore self-build and biomass co-firing alternatives before entering long-term agreements for renewables with fixed pricing, AEP-Ohio witness Simmons testified the Companies are constantly exploring the most cost effective sources of renewable generation. Witness Simmons explained that bio-mass is one renewable already under consideration. The witness discussed two requests for proposal issued by AEPSC in 2010, one for bio-mass and one for a pre-blended bio-mass and coal mixture. Additionally, AEPSC is also considering other co-firing alternatives such as biodiesel. Finally, witness Simmons testified that the self-build option is being evaluated but is less likely without a clear cost recovery path. (Co. Ex. 4 at 4-6.) The sole m/p audit recommendation that generated substantial disagreement among the parties and was the primary focus of the hearing and post-hearing briefs involved m/p audit recommendation 1 discussed in detail below.

C. Disputed Management Audit Recommendation 1

Management audit recommendation 1 states that:

> EVA believes that the PUCO should review whether any proceeds from the Settlement Agreement should be a credit against OPCO's FAC under-recovery. This buy-out is somewhat unique as it occurred during a period in which fuel cost recovery was not regulated yet the entire value received was for tons that would have been shipped during the ESP period.

1. AEP-Ohio's Position

AEP-Ohio maintains that, contrary to the position of OCC and IEU-Ohio, it is important to note that the explicit language of m/p audit recommendation 1 is limited to deciding whether proceeds from the 2008 Settlement Agreement should be used to offset OP's under-recovery of fuel costs in 2009 (Jt. Ex. 1 at 1-6). The Companies explain that the proceeds of the 2008 Settlement Agreement include a lump sum payment (made in three equal payments) and a coal reserves asset located in West Virginia. AEP-Ohio witness Dooley testified that a substantial portion of the lump sum payment was already credited, in part, against 2009 fuel costs flowed through the FAC with the other portion to be credited against 2010 fuel costs flowed through the FAC (Cos. Ex. 1 at 4). Moreover, according to AEP-Ohio, the present value of the undeveloped, unpermitted coal reserve is simply not known, but, in any event, the coal reserve is an OP asset that ratepayers have no claim upon. Additionally, the Companies note, the auditor clarified that the separate 2008 Delivery Shortfall Agreement was not a part of the equity issue raised in m/p audit recommendation 1. The auditor further clarified, according to the Companies, that EVA was not making a recommendation but merely felt that the Commission should consider the issue (Tr. I at 38). AEP-Ohio states that, while the auditor may have had good intentions in raising this equity issue, it would be inappropriate for the Commission to entertain the notion because it creates a host of legal issues and because the issue is susceptible to expansion of the issue as OCC and IEU-Ohio have done.

Contrary to the positions of IEU-Ohio and OCC, discussed below, the Companies, citing to the ESP Cases order at 20-22, assert that the Commission fully understood and expected that the projected magnitude of the OP fuel deferrals by the end of the ESP was approximately $550 million and the Commission built this factor into the structure of the rate cap/phase-in plan as part of the modified ESP. AEP-Ohio claims that the opportunistic positions of OCC and IEU-Ohio constitute selective and unlawful retroactive ratemaking in violation of *Keco Industries, Inc., v. Cincinnati & Suburban Bell Tel. Co.* (1957), 166 Ohio St. 254 and *Lucas Cty. Commrs. v. Pub. Util. Comm.* (1997), 80 Ohio St.3d 344. Additionally, the Companies maintain that, pursuant to the determinations made in the ESP cases and the entry in this proceeding, the audit period is for 2009 and the prudence review must be limited to 2009 fuel procurement activities. These two key Commission determinations involving operation of the FAC mechanism during the ESP were fully adjudicated and decided as part of the Commission's decision in the ESP case. Thus, these determinations are res judicata and cannot be relitigated or reapplied on a retroactive basis. See *Ohio Consumers' Counsel v. Pub. Util. Comm.* (2006), 111 Ohio St.3d 300, 318; *Ohio Consumers' Counsel v. Pub. Util. Comm.* (1985), 16 Ohio St.3d 9, 10.

Moreover, the Companies assert that the FAC baseline was a hotly contested, fully litigated issue decided in the ESP cases and cannot now be modified in this case. AEP-Ohio asserts that the Commission and the parties understood in the ESP cases that adopting a lower FAC baseline created a higher non-FAC generation rate which when coupled with the rate caps adopted as part of the modified ESP resulted in large fuel deferrals recoverable in the future through a nonbypassable surcharge on all customers in order to mitigate a larger initial rate increase. These are the same fuel deferrals OCC and IEU-Ohio are challenging at the Ohio Supreme Court claims AEP-Ohio. Since these same issues have been appealed to the Ohio Supreme Court, the Companies aver that any attempt to collaterally attack the FAC in this proceeding should not be entertained. As a final matter AEP-Ohio opines that each of the 2008 agreements raised by OCC and IEU-Ohio were prudently adopted and the Commission should not disturb any continuing effects of those agreements, especially given that each agreement was entered into by OP prior to commencement of the ESP's new FAC and before the 2009 audit period.

2. IEU-Ohio's Position

IEU-Ohio maintains that the record reflects that the Companies received benefits or value in return for the voluntarily renegotiated contracts, that the Companies accounting failed to flow through the benefits of the voluntarily renegotiated contracts, and that, as a result, customers paid more in fuel costs in 2009 than they would have had AEP-Ohio not renegotiated certain contracts. Specifically, IEU-Ohio states that the Commission should credit to customers the full benefit of the voluntary 2008 Settlement Agreement. In this regard, IEU-Ohio recommends crediting the full lump sum cash payment resulting from the 2008 Settlement Agreement rather than only a portion of the lump sum payment as the Companies have done (IEU-Ohio Ex. 1 at 6). Additionally, IEU-Ohio argues that the Commission should direct the auditor in the next m/p audit to review and provide a current valuation of the West Virginia coal reserve to be credited against OP's FAC under-recovery that AEP-Ohio will begin collecting in 2012. In the meantime, however, IEU-Ohio recommends that the Commission use the booked value of the West Virginia coal reserve to make an initial downward adjustment to the OP FAC under-recovery. (*Id.* at 7.) Crediting the booked value to the under-recovery now, claims IEU-Ohio, will ensure that customers do not pay carrying costs associated with the booked value while the Commission works to ensure a more accurate valuation of the West Virginia coal reserve. Additionally, claims IEU-Ohio, the booked reserve credit will not impact rates or harm OP's cash flow due to OP's FAC under-recovery deferral. IEU-Ohio also maintains that the Commission should credit against the OP FAC under-recovery the full value of the note receivable by the Companies for the remaining 2008 tonnage that was never delivered as a result of the 2008 Buyout Agreement (*Id.* at 5).

As an alternative recommendation, IEU-Ohio states that the Commission credit against OP's FAC under-recovery the difference between the coal contract price under the contract subject to the 2008 Settlement Agreement and the price per ton paid for the replacement coal multiplied by the number of replacement tons of coal purchased during 2009 (*Id.* at 8). The primary benefit of this option is one of administrative convenience claims IEU-Ohio as it does not require either a future auditor or the Commission to make a subsequent determination of the value of the West Virginia coal reserve (*Id.*). Adopting this option would moot the need to determine whether the full benefit of the lump sum 2008 Settlement Agreement should be credited to customers, the need to properly determine the value of the West Virginia coal reserve, and a determination of whether to credit customers for the proceeds of from the subsequent 2008 Buyout Agreement (*Id.* at 9).

The last adjustment recommended by IEU-Ohio involves a 2008 Contract Support Agreement. Under the 2008 Contract Support Agreement, CSP agreed to increase the base price for a certain tonnage of coal during 2009 with the option for CSP to acquire coal at a discount off the market price per ton for two three-year extensions of the agreement beginning in 2013. IEU-Ohio recommends that the Commission require CSP to refund the increased price per ton that AEP-Ohio agreed to pay for coal during 2009 as part of the 2008 Contract Support Agreement to its FAC customers and account for the total increase as a deferred expense with no carrying costs (*Id.* at 11-12). Should the Commission determine that carrying costs on the deferred expense are appropriate, IEU-Ohio argues that the carrying costs should be a debt-only rate. The deferred expense would then be amortized if and when CSP actually exercises the options for the respective three-year extensions of the 2008 Contract Support Agreement beginning in 2013. (*Id.*) Without this adjustment, IEU-Ohio claims that the present customers incurred higher costs for coal in 2009 but have no assurance that they will receive any of the future benefits. IEU-Ohio concludes by noting that its recommendations more fairly balance the benefits and costs associated with the coal supply contracts.

In response to AEP-Ohio's case-in-chief, IEU-Ohio urges the Commission to direct the Companies to provide its customers the benefits due them from the voluntary coal contract negotiations. IEU-Ohio also took issue with the Companies' claims that the relief requested by the intervenors and by Staff involves retroactive ratemaking and is prohibited under *Keco* and *Lucas Cty*. *Keco* is inapplicable, argues IEU-Ohio, as that case involved traditional regulation and did not involve issues associated with a self-reconciling automatic adjustment clause. Even if the Commission were to find some credibility in AEP-Ohio's argument, IEU-Ohio maintains that the Commission could easily remedy that situation by merely repricing the coal as outlined in the testimony of IEU-Ohio witness Hess (*Id.* at 7-8).

IEU-Ohio also urges the Commission to reject the Companies' claims that the Commission is merely limited to looking at fuel procurement activities during calendar year 2009. IEU-Ohio notes that AEP-Ohio's own witness acknowledged that in conducting the 2009 audit that it was necessary for the auditor to determine whether contracts entered into prior to the audit period had any impact on audit period costs (Tr. I at 162-163). AEP-Ohio's claims of res judicata are also suspect, IEU-Ohio avers, as neither claim preclusion nor issue preclusion, two necessary components of res judicata, apply in this instance. IEU-Ohio next takes issue with the Companies' position that the parties are attempting to illegally relitigate the FAC baseline established in the ESP case. Neither the intervenors nor Staff advanced proposals to modify the FAC baseline asserts IEU-Ohio.

IEU-Ohio next disputes the Companies' argument that the intervenors are claiming a property ownership interest in the coal reserve for ratepayers. IEU-Ohio asserts that nowhere did the intervenors or Staff claim such an ownership interest but simply that the benefits that have been deprived of OP customers be netted against the costs that OP has billed and collected from customers. Next, IEU-Ohio maintains that it is not challenging the appropriateness of the accounting based on any conflict with GAAP, but rather makes a ratemaking recommendation for the Commission's consideration. Lastly, IEU-Ohio avers that, contrary to the Companies position, IEU-Ohio did consider the production bonus payment made in 2008 and agreed that the FAC customers had paid their fair share of the costs of that contract (Tr. II at 255). For these reasons, IEU-Ohio urges the Commission to adopt its recommendations to more fairly balance the benefits and the costs associated with the coal supply contracts discussed in this proceeding.

3. OCC's Position

OCC submits that AEP-Ohio is attempting to pass on to its customers all of the Companies costs under certain fuel procurement contracts, while keeping the majority of the benefits acquired in the contracts, thereby causing its customers to pay more fuel cost than authorized by law in violation of Section 4928.143(B)(2)(a), Revised Code, and Rule 4901:1-35-03(C)(9)(a)(ii), O.A.C. For example, similar to the position taken by IEU-Ohio, OCC asserts that the Companies 2008 Settlement Agreement produced added costs for customers while AEP-Ohio only shared a portion of the lump sum payments the Companies received as well as only a portion of the West Virginia coal reserve. Another example of AEP-Ohio passing along increased costs while keeping the majority of the benefits is the renegotiated coal procurement contract whereby AEP-Ohio agreed to pay the coal provider an increased price of coal per ton during 2009 while having the opportunity to receive a per ton discount on all tons of coal delivered from 2013-2018.

To prevent AEP-Ohio from recovering more fuel cost from its customers than the Companies should under law, OCC submits that the Commission should order that AEP-Ohio's customers receive the financial benefits from the Companies fuel procurement contracts through immediate credits to AEP-Ohio's FAC deferral balance. As previously discussed, those fuel procurement benefits that should be credited against the FAC deferral balance include the full lump sum payment and the fair value of the West Virginia coal reserve that was part of the settlement agreement as well as the fair value of the coal market price discount option for future coal delivery negotiated as part of the 2008 Contract Support Agreement. Any delay in applying these credits will unnecessarily increase the burden to the customers of OP because the carrying charges associated with OP's fuel cost deferral can exceed $10 million every three months (OCC Ex. 1 at 16).

Responding to the Companies' arguments, OCC asserts that the underlying ESP decision and the January 7, 2010, entry in this case do not limit the Commission's review of AEP-Ohio's fuel procurement contracts to only those entered into during the 2009 FAC period. Additionally, OCC argues that neither OCC nor IEU-Ohio are attempting to "claw back" revenue from a prior rate plan as argued by AEP-Ohio. Moreover, the FAC baseline is not relevant, claims OCC, to the issue of requiring AEP-Ohio to recover only its actual fuel cost nor does the FAC baseline constitute res judicata. OCC's final argument is that requiring AEP-Ohio to recover only its actual fuel cost does not constitute selective or retroactive ratemaking as argued by the Companies.

4. Staff's Position

As a general matter, Staff supports the findings and recommendations contained in the Audit Report and recommends that those recommendations be adopted by the Commission. Staff acknowledges that the Companies are entitled to recover the costs of fuel but only to recover the true cost incurred. In other words, Staff asserts that any proceeds received offsetting the cost of fuel should be credited against under-recoveries, regardless of the period in which the proceeds are recognized. Since the value of such credits cannot be determined at this time, Staff recommends that the Commission direct the auditor to evaluate the value of proceeds received by the Companies and not credited either to the FAC or to deferred under-recoveries and make recommendations in the next audit proceeding as to the value to be credited.

Responding to a number of AEP-Ohio arguments, Staff notes that arguments concerning *prohibited retroactive ratemaking and imprudence* are irrelevant and have not been raised by the auditor's report. AEP-Ohio's arguments concerning regulatory accounting are rejected by Staff as the Commission and not the Companies determine the appropriate accounting for regulatory purposes. Staff does agree with the Companies that Ohio ratepayers do not own the coal reserves that were part of the Settlement Agreement, however, Staff asserts that the value of the coal reserves is part of the cost of fuel and therefore should be examined by the next auditor.

D. Commission Conclusion on Management Audit Recommendations

Initially, the Commission notes that there were very few concerns raised by the parties as to the auditor's m/p recommendations 2 through 6 found at pages 1-7 of the audit. Therefore, the Commission will adopt the auditor's m/p recommendations 2 through 6 as outlined in the audit. The Commission notes that there were, however, widely contrasting positions taken by the parties concerning m/p audit recommendation 1 which recommends that the Commission should review whether any proceeds from the Settlement Agreement (*i.e., the 2008 lump sum payment AEP-Ohio* received as well as the West Virginia coal reserve) should be a credit against OP's FAC under-recovery.

Following a thorough review of the record and the arguments raised by the parties in this matter, the Commission determines that all of the realized value from the Settlement Agreement should be credited against OP's FAC under-recovery namely the portion of the $30 million 2008 lump sum payment not already credited to OP ratepayers as well as the $41 million value of the West Virginia coal reserve that AEP booked when the Settlement Agreement was executed. Additionally, because the value of the West Virginia coal reserve is not clear and because AEP had planned to begin the permitting process at the time of the audit which should enhance the value of the coal reserve, we direct AEP to hire an auditor specifically to examine the value of the West Virginia coal reserve and to make a recommendation to the Commission as to whether the increased value, if any above the $41 million already required to be credited against OP's under-recovery, should accrue to OP ratepayers beyond the value of the reserve that AEPSC booked under the Settlement Agreement. The Commission will issue by subsequent entry a Request for Proposal to hire the auditor discussed above.

In making the above determination the Commission notes that the record reflects that the Settlement Agreement was entered into in order to terminate a long-term coal supply agreement, entered into in 1992, because the price of coal under the agreement was significantly below market in mid-2007. This long-term agreement was replaced with a new agreement which resulted in OP ratepayers paying significantly more for coal beginning in 2009, the start of the ESP period, than would have been paid had the Settlement Agreement not been entered into. We recognize that this situation is somewhat unique given that OP's fuel costs were not regulated during the period when the buyout occurred and the benefits booked yet the value was realized from coal that should have been delivered during the ESP period. While we do not find any motivation by AEPSC to transfer value from ratepayers during the ESP to an earlier date, nevertheless, the long-term coal agreement was an OP asset for which the value would have flowed through to OP ratepayers through the ESP period but for the extraordinary circumstances related to the early contract termination. Given these factors, we agree with Staff that, in order to determine the real economic cost of coal used during the audit period, more of the value realized by AEP for entering into the Settlement Agreement should flow through to OP ratepayers through a credit to OP's under-recovery and deferrals.

Citing to the ESP cases (Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, Opinion and Order, March 18, 2009, at pages 14-15) and an earlier entry in this proceeding, AEP-Ohio argues that the Commission limited the audit period and the prudence review in this case to 2009 procurement activities and that the only relevant factor is the price the Companies paid for coal during 2009. The Commission disagrees. Contrary to the Companies argument, the Commission is not seeking to reach into another audit period in order to modify rates charged during the audit period but rather is rendering its decision in order to match the revenues and benefits incurred during the audit period. Nor has the Commission found that entering into the Settlement Agreement was imprudent. Again, the Commission is only finding that to determine the real economic cost of coal during the audit period, the Commission must consider both the revenues and the benefits received by the Companies pursuant to the Settlement Agreement and not rely solely on the price paid for coal during 2009. AEP-Ohio further claims that the parties in this case are attempting to illegally relitigate the FAC baseline established in the ESP cases. AEP-Ohio's claims are without merit as the Commission has not adjusted the baseline for the 2009 period as decided in the Companies ESP cases. Rather, the Commission, in this case, is engaging in a reconciliation and accounting which was explicitly contemplated by the ESP cases in future FAC proceedings. Otherwise, there would be no rationale for undertaking an annual audit. In this case, the Commission is making an accounting adjustment to recognize extraordinary events affecting 2009 costs such that the Companies 2009 real costs will be comparable to the proxy baseline selected in the ESP proceedings.

AEP-Ohio's arguments concerning the applicability of *Keco* and *Lucas Cty.* are likewise unavailing. According to the Companies, any attempt to credit amounts booked in 2008 during the prior rate plan would violate the longstanding prohibition against retroactive ratemaking established in *Keco*. However, *Keco* does not apply in this situation. The Commission is not considering modifying a previous rate established by a Commission order through the ratemaking process as the Court considered in *Keco*. Rather, the Commission, by ordering the Companies to credit more of the proceeds from the Settlement Agreement to OP's deferral balance, is establishing a future rate based upon the real cost of the coal used by the Companies to generate electricity during the 2009 FAC audit period. The proceeds AEP-Ohio received for entering into the Settlement Agreement are but one of the components which impact the Companies cost to provision electricity during 2009. Likewise, *Lucas Cty.* does not apply to the present situation. In *Lucas Cty.*, the Court held that the Commission was not statutorily authorized to order a refund of, or credit for, charges previously collected by a public utility where those charges were calculated in accordance with an experimental rate program which has expired. As noted above, the Commission has not made a determination modifying the rate the Companies collected during 2009. Additionally, there is no experimental rate program involved in the current case. Thus, *Lucas Cty.* does not apply in this matter.

As to any benefits associated with the delivery shortfall agreement and the contract support agreement that OCC and IEU-Ohio assert should also be factored into the Companies FAC under-recovery, the Commission determines that any effect these agreements may have had on AEP-Ohio's fuel costs, if any, would appear to apply in time periods outside of the current audit. Therefore, while those agreements may be examined by a future audit, those agreements will not be further examined as part of the current audit.

IV. Financial Audit Recommendations

The audit report also included six financial audit recommendations. In the first recommendation, the auditors submit that the FAC workbooks should be modified to include explanations that identify and/or explain differences between includable FAC amounts recorded in the general ledger versus includable FAC amounts derived from other sources (e.g., Monthly Purchase Summary Reports). Additionally, these explanations should also apply to issues such as timing differences and/or prior period adjustments. The second recommendation is that CSP and OP should include the reconciliation of the fuel and purchased power accounts that have been designated as includable FAC costs with the monthly FAC workbooks, to facilitate a clear audit trail. The third financial audit recommendation is that the Companies overall should provide a better audit trail for tracing costs. Fourth, the auditors suggest that the Commission may want to have AEP-Ohio explain further how the four generating units designated as "must run" units by PJM are affecting the costs that are recoverable in the FAC. The fifth financial audit recommendation is that the Companies should update and/or modify its systems in order to better indicate hourly or 24-hour dispatch costs and off-system sales cost information related to forced outages.

AEP-Ohio witness Dooley testified that the Companies agree with and plan to implement the auditors recommendations regarding financial audit items 1, 2, and 3 (Co. Ex. 1 at 6). The Companies' witnesses did not specifically address financial audit recommendations 4 and 5. The Companies otherwise did acknowledge, however, that AEP-Ohio agreed with and planned to implement the financial audit recommendations as clarified in the Companies' testimony (Cos. Brief at 51).

As AEP-Ohio does not challenge financial audit recommendations 1 through 5, the Commission will adopt such recommendations made in the audit report.

The final financial audit recommendation involves the River Transportation Division (RTD) and has 10 sub-components. The audit report suggests that RTD should respond to the following prior to the next audit and that the next auditor should review the results of this additional information:

(a) RTD should be required to explain and justify the rationale of the Net Investment Base and Cost of Capital Billing Adder formula presented in EVA 4-5, Confidential Attachments 1 and 2.

(b) RTD should be required to provide a procedure for updating the cost of capital and the Return on Equity (ROE) component that is commensurate with the risk of the operation.

(c) An Over Collection by RTD indicates that RTD collected too much from the affiliated companies for barge operations in a particular year. The Over Collection should be a subtraction from the Investment Base (rather than an addition to RTD's expenses).

(d) RTD should provide documentation that it corrected its calculation of the 2008 Working Capital Requirement and the 2009 Working Capital Requirement and the resulting credits $43,314 (2008) and $45,117 (2009) to RTD's customers were recorded in its 2nd Quarter's 2010 true up and credited to the operating companies in August 2010. OP's portion of these credits is $15, 298 (2008) and $17,325 (2009).

(e) Balance Sheet items such as Prepayments, Materials and Supplies inventory and Other Current and Accrued Liabilities, if considered in developing a utility's rate base, are typically added or subtracted on a 13-month average balance basis. RTD should be required to explain why its current methodology of dividing balance sheet items (such as prepayments, materials and supplies inventory, and other current and accrued liabilities) by eight to derive the Investment Base is a reasonable and appropriate method.

(f) OP, RTD and other AEP affiliates that utilize the RTD should work together to revise the RTD formula to conform with generally accepted public utility industry rate base and ratemaking standards. OP should report quarterly concerning the progress of these efforts by including a description of progress made in its quarterly FAC filings.

(g) The details of RTD charges including, but not limited to, Other Administration Expenses and "AEP Admin Charges" such as those provided by AEP in response to LA 7-17, should be reviewed in detail in the next audit period.

(h) RTD should prepare a justification for how RTD's income tax expense and Accumulated Deferred Income Taxes are handled.

(i) RTD should explain the Accumulated Deferred Income Taxes (ADIT) amounts on its Balance Sheet and identify any amounts and components related to the use of accelerated tax depreciation.

(j) To the extent that RTD has cost-free capital in the form of ADIT related to the use of accelerated tax depreciation (which would typically be associated with credit-balance ADIT amounts), RTD should prepare an explanation why that cost-free capital should not be subtracted in deriving the Investment Base, similar to how ADIT balances would be subtracted in deriving a utility's rate base.

Regarding financial audit recommendations 6a, 6e, 6f, and 6j, the Companies state that, although the current treatment is a reasonable approach, AEP-Ohio is willing to have the RTD division amend its calculation to be in accordance with the traditional base treatment recommended by the audit report starting January 1, 2011 (Co. Ex. 3 at 11). Financial audit recommendation 6b is unnecessary, says AEP-Ohio, because there is already a procedure in place for updating the cost of capital and Return on Equity component commensurate with the risk (*Id.*). AEP-Ohio witness Nelson testified that the ROE is adjusted on January 1 each year to the return allowed by FERC. In the absence of a recent FERC order, the ROE becomes that established by the Indiana Utility Regulatory Commission in its most recent order (*Id.* at 11-12). Regarding financial audit recommendations 6c and 6d, the Companies explain that RTD has made all necessary changes to correct the Working Capital Requirement for 2008 and 2009 and will appropriately credit the applicable operating companies including OP. Documentation will be available for the next audit states AEP-Ohio (Co. Ex. 1 at 6). Similarly, the Companies have no objections to financial audit recommendations 6g, 6h, and 6i. AEP-

Ohio commits that the necessary explanations will be available for the next audit (Co. Ex. 1 *at 6-7;* Co. Ex. 3 at 12).

Generally, the Companies agree with and plan to implement financial audit recommendations 6a through 6i. Regarding financial audit recommendation 6b, the Companies have adequately explained and thus have complied with the auditors' recommendation. Therefore, no further action is required by the Companies on financial audit recommendation 6b. The Commission adopts as its determinations in this matter, financial audit recommendations 6a through 6i with the exclusion of recommendation 6b discussed in the preceding sentence.

V. Ormet stipulation

Rule 4901-1-30, Ohio Administrative Code, authorizes parties to Commission proceedings to enter into a stipulation. Although not binding on the Commission, the terms of such an agreement are accorded substantial weight. *Consumers' Counsel v. Pub. Util. Comm.* (1992), 64 Ohio St.3d 123, 125, *citing Akron v. Pub. Util. Comm.* (1978), 55 Ohio St.2d 155. This concept is particularly valid where the stipulation is unopposed by any party and resolves all issues presented in the proceeding in which it is offered.

The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. *Cincinnati Gas & Electric Co.*, Case No. 91-410-EL-AIR (April 14, 1994); *Western Reserve Telephone Co.*, Case No. 93-230-TP-ALT (March 30, 1994); *Ohio Edison Co.*, Case No. 91-698-EL-FOR *et al.* (December 30, 1993); *Cleveland Electric Illum. Co.*, Case No. 88-170-EL-AIR (January 30, 1989); *Restatement of Accounts and Records (Zimmer Plant)*, Case No. 84-1187-EL-UNC (November 26, 1985). The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

(1) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(2) Does the settlement, as a package, benefit ratepayers and the public interest?

(3) Does the settlement package violate any important regulatory principle or practice?

The Ohio Supreme Court has endorsed the Commission's analysis using these criteria to resolve issues in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.* (1994), 68 Ohio St.3d 559, *citing*

Consumers' Counsel, supra, at 126. The court stated in that case that the Commission may place substantial weight on the terms of a stipulation, even though the stipulation does not bind the Commission (*Id.*).

We find that the Ormet stipulation entered into by the stipulating parties is reasonable and should be adopted. In making this determination, the Commission notes that the Ormet stipulation is a product of serious bargaining among capable, knowledgeable parties and is the product of an open process. Moreover, as a package, the Ormet stipulation benefits ratepayers and furthers the public interest as a more thorough examination involving the collection of deferrals and carrying charges associated with the provision of service to Ormet is already the subject of a pending case before the Commission in *In the Matter of the Application of Columbus Southern Power and the Ohio Power Company to Recover Commission-Authorized Deferrals Through each Company's Fuel Adjustment Clause,* Case No. 09-1094-EL-FAC (09-1094). Therefore, a detailed examination of the complex issues surrounding AEP-Ohio's provision of service to Ormet, the largest, most energy-intensive customer that the Companies serve in Ohio, does not have to be considered in this proceeding. Finally, the Commission finds that there is no evidence that the stipulation violates any important regulatory principle or practice and, therefore, the stipulation meets the third criterion. Accordingly, the Ormet stipulation is approved.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) CSP and OP are public utilities under Section 4905.02, Revised Code, and are subject to the jurisdiction of this Commission.

(2) These cases relate to the Commission's review of CSP and OP's fuel costs during the period from January 1, 2009, through December 31, 2009.

(3) By entry issued January 7, 2010, the Commission selected EVA to perform CSP and OP's audit for the period of January 1, 2009, through December 31, 2009. On May 14, 2010, EVA filed its audit report.

(4) On January 7, 2010, IEU-Ohio, OCC, and Ormet were granted intervention in these cases.

(5) A hearing in these matters was held on August 23 and August 24, 2010.

(6) Briefs and reply were filed on September 23, 2010, and October 15, 2010, respectively.

(7) At the hearing, a stipulation was submitted acknowledging that a determination on the collection of deferrals and carrying charges associated with an Ormet Interim Agreement is the subject of a pending case before the Commission and that the issues associated with the Ormet Interim Agreement would be addressed in that proceeding. The stipulation was signed by AEP-Ohio, Staff, OCC, IEU-Ohio, and Ormet. The stipulation meets the criteria used by the Commission to evaluate stipulations, is reasonable, and should be adopted.

ORDER:

It is, therefore,

ORDERED, That the Companies credit OP's FAC under-recovery as discussed herein. It is, further,

ORDERED, That the Companies hire an auditor as discussed herein. It is, further,

ORDERED, That the stipulation entered into by AEP-Ohio, Staff, OCC, IEU-Ohio, and Ormet be adopted and approved. It is, further,

ORDERED, That AEP-Ohio take all necessary steps to carry out the terms of this opinion and order. It is, further,

ORDERED, That nothing in this opinion and order shall be binding upon the Commission in any future proceeding or investigation involving the justness or reasonableness of any rate, charge, rule, or regulation. It is, further, ORDERED, That a copy of this opinion and order be served upon each party of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Paul A. Centolella

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

JRJ/vrm

Entered in the Journal

JAN 2 3 2012

Betty McCauley

Betty McCauley
Secretary

ATTACHMENT
B

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company.	)))	Case No. 09-872-EL-FAC Case No. 09-873-EL-FAC

ENTRY ON REHEARING

The Commission finds:

(1) On January 23, 2012, the Commission issued its Opinion and Order in these proceedings.

(2) Pursuant to Section 4903.10, Revised Code, any party who has entered an appearance in a Commission proceeding may apply for rehearing with respect to any matters determined by the Commission, within 30 days of the entry of the order upon the Commission's journal.

(3) Applications for rehearing of the Commission's January 23, 2012, Order were filed by Ohio Power Company (AEP-Ohio),[1] Industrial Energy Users-Ohio (IEU-Ohio), and the Office of Ohio Consumers' Counsel (OCC).

(4) On March 2, 2012, AEP-Ohio filed, and on March 5, 2012, IEU-Ohio and OCC filed, memorandum contra the various applications for rehearing.

(5) The Commission believes that sufficient reason has been set forth by AEP-Ohio, IEU-Ohio, and OCC to warrant further consideration of the matters specified in their applications for rehearing. Accordingly, the applications for rehearing filed by AEP-Ohio, IEU-Ohio, and OCC should be granted.

It is, therefore,

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1 The Commission notes that the merger of Columbus Southern Power Company with and into Ohio Power Company was approved by Order issued December 14, 2011, in *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case No. 11-346-EL-EL-SSO et al., and in *In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals*, Case No. 10-2376-EL-UNC, by Entry issued March 7, 2012.

ORDERED, That the applications for rehearing filed by AEP-Ohio, IEU-Ohio, and OCC be granted for further consideration of the matters specified in the applications for rehearing. It is, further,

ORDERED, That copies of this entry on rehearing be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Paul A. Centolella

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

GNS/vrm

Entered in the Journal
MAR 2 1 2012

Barcy F. McNeal
Secretary

ATTACHMENT C

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company.	)))	Case No. 09-872-EL-FAC Case No. 09-873-EL-FAC

ENTRY ON REHEARING

The Commission finds:

(1) Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio or the Companies)[1] are public utilities as defined in Section 4905.02, Revised Code, and, as such, are subject to the jurisdiction of this Commission.

(2) By opinion and order issued March 18, 2009, as clarified by the entry on rehearing issued July 23, 2009, in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, the Commission modified and approved AEP-Ohio's application for an electric security plan (ESP) for 2009 through 2011, which included approval of a fuel adjustment clause (FAC) mechanism for CSP and OP, under which the Companies recovered prudently incurred costs associated with fuel, including consumables related to environmental compliance, purchased power costs, emission allowances, and costs associated with carbon-based taxes and other carbon-related regulations (ESP 1 order).[2] The approved FAC mechanism provided for quarterly reconciliations to actual FAC costs incurred by the Companies, which established the FAC rates for the subsequent quarter, as well as an annual audit of the accounting of the FAC costs. The Commission also authorized a phase-in of AEP-Ohio's ESP rates during the term of the ESP by deferring a portion of the annual incremental FAC costs such that the amount of the incremental FAC expense to be recovered from customers would be limited so as not to exceed specified percentage increases on a total bill basis.

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1 By entry issued March 7, 2012, the Commission approved and confirmed the merger of CSP into OP. *In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals* (Merger Case), Case No. 10-2376-EL-UNC.

2 *In the Matter of the Application of Columbus Southern Power Company for Approval of an 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.

(3) On May 14, 2010, Energy Ventures Analysis, Inc. (EVA) filed, in the present cases, a management/performance (m/p) and financial audit report in response to its annual audit of AEP-Ohio's FAC mechanism for 2009 (audit report).

(4) On January 27, 2011, in Case No. 11-346-EL-SSO, *et al.*, AEP-Ohio filed an application for approval of a second ESP to begin on January 1, 2012 (ESP 2 cases).[3]

(5) On September 7, 2011, a stipulation and recommendation (ESP 2 stipulation) was filed by AEP-Ohio, Staff, and other parties to resolve the issues raised in the ESP 2 cases and several other cases pending before the Commission (consolidated cases).[4] The ESP 2 stipulation provided, *inter alia*, that the current FAC mechanism was to continue through May 31, 2015.

(6) On December 14, 2011, the Commission issued an opinion and order in the consolidated cases, modifying and adopting the ESP 2 stipulation (ESP 2 order).

(7) On January 23, 2012, the Commission issued its opinion and order in the present proceedings regarding the annual audit of AEP-Ohio's FAC mechanism for 2009 (FAC order). With respect to the financial audit recommendations contained in the audit report, the Commission adopted financial audit recommendations 1 through 5, as well as 6a through 6i, with the exclusion of 6b. The Commission also adopted m/p audit recommendations 2 through 6, as contained in the audit report.

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3 *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case Nos. 11-346-EL-SSO and 11-348-EL-SSO; *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority*, Case Nos. 11-349-EL-AAM and 11-350-EL-AAM.

4 Merger Case, Case No. 10-2376-EL-UNC; *In the Matter of the Application of Columbus Southern Power Company to Amend its Emergency Curtailment Service Riders*, Case No. 10-343-EL-ATA; *In the Matter of the Application of Ohio Power Company to Amend its Emergency Curtailment Service Riders*, Case No. 10-344-EL-ATA; *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC; *In the Matter of the Application of Columbus Southern Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144, Revised Code*, Case No. 11-4920-EL-RDR; *In the Matter of the Application of Ohio Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144*, Revised Code, Case No. 11-4921-EL-RDR.

In m/p audit recommendation 1, EVA recommended that the Commission consider whether any proceeds from a settlement agreement that American Electric Power Service Corporation (AEPSC) had executed with a coal supplier in 2007 (settlement agreement) should be credited against OP's FAC under-recovery for 2009. The settlement agreement was effectively a buy-out of the contract with the coal supplier after 2008. Pursuant to the terms of the settlement agreement, OP received a lump sum payment (made in three equal payments) and coal reserve in West Virginia. In the FAC order, the Commission determined that all of the realized value from the settlement agreement should be credited against OP's FAC under-recovery for 2009. The Commission specified that the portion of the $30 million lump sum payment not already credited to the ratepayers of OP, as well as the $41 million value of the West Virginia coal reserve booked when the settlement agreement was executed, should be credited against the FAC under-recovery. Additionally, because the present value of the West Virginia coal reserve is unknown and the permitting process is expected to enhance its value, the Commission indicated that a request for proposal (RFP) would be issued by subsequent entry to hire an auditor to examine the value of the West Virginia coal reserve. The Commission noted that the auditor would be expected to make a recommendation as to whether the increased value of the West Virginia coal reserve, if any, above the $41 million already required to be credited against OP's FAC under-recovery should accrue to ratepayers.

Finally, the Commission determined that the delivery shortfall agreement and the contract support agreement would not be further examined as part of the current audit. The Commission noted, however, that these agreements may be examined in a future audit, given that their impact on AEP-Ohio's fuel costs, if any, appeared to occur in time periods outside of the current audit.

(8) Section 4903.10, Revised Code, states that any party who has entered an appearance in a Commission proceeding may apply for a rehearing with respect to any matters determined therein by filing an application within 30 days after the entry of the order upon the Commission's journal.

(9) On February 22, 2012, applications for rehearing of the FAC order were filed by AEP-Ohio, Industrial Energy Users-Ohio (IEU-Ohio), and the Ohio Consumers' Counsel (OCC).

(10) On February 23, 2012, the Commission issued an entry on rehearing in the consolidated cases, granting rehearing in part (ESP 2 entry on rehearing). Finding that the signatory parties to the ESP 2 stipulation had not met their burden of demonstrating that the stipulation, as a package, benefits ratepayers and the public interest, as required by the Commission's three-part test for the consideration of stipulations, the Commission rejected the stipulation.

(11) On March 2, 2012, in the above-captioned cases, AEP-Ohio filed a memorandum contra the applications for rehearing of the FAC order filed by IEU-Ohio and OCC. On March 5, 2012, IEU-Ohio and OCC filed memoranda contra AEP-Ohio's application for rehearing of the FAC order.

(12) By entry on rehearing issued March 21, 2012, the Commission granted the applications for rehearing of the FAC order to allow further consideration of the matters specified in the applications.

(13) The Commission has reviewed and considered all of the arguments on rehearing. Any arguments on rehearing not specifically discussed herein have been thoroughly and adequately considered by the Commission and should be denied.

Re-adjudication of the ESP 1 Order

(14) In its fourth assignment of error, AEP-Ohio contends that the FAC order unreasonably and unlawfully modifies the ESP 1 order wherein the Commission directed that annual FAC audits examine fuel procurement practices and expenses for the audit period. AEP-Ohio offers that expanding the scope of the FAC audit, as litigated and decided in the ESP 1 order, violates the principles of res judicata and collateral estoppel. According to AEP-Ohio, the FAC audit period is strictly limited to January 2009 through December 2009. Similarly, in the Companies' fifth assignment of error, AEP-Ohio claims that through the FAC order, the Commission is unreasonably and unlawfully

retroactively modifying the decision in the ESP 1 order, which established the FAC baselines to facilitate the Companies' transition from a period without a FAC mechanism to a period with a FAC mechanism. With the establishment of the FAC baseline, AEP-Ohio asserts that the FAC order in this case is a retreat from the agreement with the Companies to implement fuel deferrals to stabilize recovery. AEP-Ohio reasons that the FAC baseline is res judicata and collateral estoppel prevents the Commission from revision of its decision in these proceedings. OCC and IEU-Ohio submit that these arguments are baseless. OCC states that the purpose of Commission audits, as was the case in these proceedings, is to assist the Commission in determining the prudence and true cost of a company's fuel-related purchases so that customers pay no more than what is reasonable for electricity. IEU-Ohio offers that the FAC order properly concluded that the Companies' claim of res judicata is without merit as 2009 fuel costs were not litigated in the first ESP proceedings.

(15) For the same reasons as stated in the FAC order, we again reject both of these arguments by the Companies. The scope and extent of the audit and the audit period were not revised or expanded as a result of the FAC order. As IEU-Ohio reasoned, the focus of the dispute in these proceedings is OP's 2009 fuel costs. OP's 2009 fuel costs were not litigated in the first ESP proceedings and could not have been litigated because the 2009 fuel costs were not known at that time. The purpose of the FAC audit was to evaluate 2009 fuel and fuel-related costs and the prudency of the Companies' fuel transactions, including the true costs and accounting accuracy of the fuel transactions. AEP-Ohio's claims to the contrary are without merit. Accordingly, we deny AEP-Ohio's fourth and fifth assignments of error.

Settlement Agreement

(16) In its first assignment of error, AEP-Ohio requests that the Commission clarify that the FAC order does not include the return of any amounts allocable to wholesale and non-Ohio retail jurisdictions.

(17) IEU-Ohio initially asserts that AEP-Ohio failed to offer evidence to support its jurisdictional argument as a part of the hearing and, is, therefore, precluded from raising the subject on rehearing. IEU-Ohio argues that AEP-Ohio selectively raises the jurisdictional argument, where it advocates just the opposite in its significantly excessive earnings proceedings,[5] and does so in this case to retain the benefits of the settlement agreement for its shareholders.

(18) We disagree with IEU-Ohio that AEP-Ohio is precluded from raising the jurisdictional issue at the rehearing stage. AEP-Ohio's claim is prompted by its interpretation of the language in the FAC order. AEP-Ohio witnesses and the financial auditor recognized that fuel expenses are allocated between Ohio retail expenses, non-Ohio retail expenses, or wholesale expenses. The same is true regarding the allocation of revenues. Therefore, we find that the record includes sufficient evidence to justify presentation of the claim by AEP-Ohio. We clarify that the 2009 FAC under-recovery need only be credited for the share of the settlement agreement allocable to Ohio's retail jurisdictional customers.

(19) In its third assignment of error, AEP-Ohio reasons that the FAC order's direction that all of the realized value from the settlement agreement should be credited against OP's FAC under-recovery amounts to selective and unlawful retroactive ratemaking in violation of *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.* (1957), 166 Ohio St. 254, and *Lucas Cty. Commrs. v. Pub. Util Comm.* (1997), 80 Ohio St.3d 344. OCC believes that OP's arguments are faulty. In this case, OCC argues, and the Commission agrees, that the FAC order did not modify a previously established rate as part of a ratemaking proceeding, as was the case in *Keco*, or direct the issuance of a refund of unlawfully collected rates, as was the case in *Lucas Cty*.

AEP-Ohio mischaracterizes the FAC order. Further, the Commission acknowledged the Companies' arguments on retroactive ratemaking and refunds, as summarized in the

5 See *In re AEP-Ohio*, Case No. 10-1261-EL-UNC, Order at 11-12 (January 11, 2011).

order (FAC order at 7-8). As explained in the order, the FAC adjustments ordered as a result of the settlement agreement are to align the fuel costs charged to ratepayers with the real economic cost of fuel for 2009. Nothing in OP's application for rehearing convinces the Commission that our decision should be reversed. Accordingly, OP's third assignment of error should be denied.

(20) In its sixth assignment of error, AEP-Ohio reasons that, since the auditor and the Commission did not find the settlement agreement to be imprudent, the FAC order unreasonably and unlawfully impairs the settlement agreement, which was executed by AEP-Ohio at a time when fuel costs and fuel contracts were not regulated. IEU-Ohio replies that the Companies' position is illogical as Rule 4901:1-35-03(C)(9)(a), Ohio Administrative Code, provides that a utility's FAC must include "any benefits available to the electric utility as a result of or in connection with such costs including but not limited to profits from emission allowance sales...." Thus, IEU-Ohio reasons that AEP-Ohio was required to account for the reduction in fuel costs.

(21) Despite AEP-Ohio's arguments to the contrary, it is not a condition precedent to reflecting the realized value of the Companies' fuel costs in the FAC, that the Commission find the settlement agreement imprudent. Pursuant to the requirements of division (B)(2) of Section 4928.143, Revised Code, to include the FAC mechanism as a part of the first ESP, AEP-Ohio was required to include "in the application any benefits available to the electric utility as a result of or in connection with such [FAC] costs including but not limited to profits from emission allowance sales and profits from resold coal contracts." The purpose of the FAC audit was to ensure and verify the FAC costs and expenses as well as to review the prudency of the Companies' transactions. Accordingly, we deny AEP-Ohio's sixth assignment of error.

(22) In its seventh assignment of error, AEP-Ohio argues that the FAC order selectively considers the settlement agreement, to direct a decrease in the fuel costs for 2009, but ignores the 2008 production bonus agreement also entered into when fuel contracts were not regulated. AEP-Ohio states that the 2008

production bonus agreement ensured that one of its suppliers remained in business and was able to provide the Companies' coal at below-market prices during 2008. AEP-Ohio admits that it did not seek to recover the $28.6 million dollar payment in 2009 FAC rates since it was incurred before the FAC regulatory structure was implemented. AEP-Ohio argues that this agreement is an example of why the Commission should not reach outside of the audit period to adjust AEP-Ohio's 2009 FAC under-recovered balance. Alternatively, AEP-Ohio states that the 2008 production bonus agreement fuel cost should be used to offset any "claw-back" into amounts relating to the settlement agreement. IEU-Ohio notes that AEP-Ohio overlooks the fact that the Companies received annual generation increases during the rate stabilization plan period (2005-2008),[6] which facilitated AEP-Ohio's recovery of increases in generation costs. As such, IEU-Ohio argues that customers paid their fair share of the total cost of the 2008 production bonus agreement.

(23) The Commission notes that the audit report did not recommend that the 2008 production bonus agreement be taken into consideration, in contrast to the auditor's recommendation in regards to the settlement agreement, nor recommend that the 2008 production bonus agreement be used as an offset to the benefits accrued as a result of the settlement agreement. Based on the generation rate increases built into the rate stabilization plan in effect prior to the first ESP in 2009, and the evidence of record in these proceedings, the Commission finds that the record does not support offsetting the adjustments to the deferred fuel costs for the settlement agreement, as directed in the FAC order, by the 2008 production bonus agreement. Accordingly, AEP-Ohio's seventh assignment of error is denied.

(24) In its first assignment of error, IEU-Ohio asserts that the FAC order unreasonably and unlawfully failed to require AEP-Ohio to include a carrying cost component in the value associated with the lump sum payment and West Virginia coal reserve to be credited against the FAC deferral balance. In its second

6 See *In re AEP-Ohio*, Case No. 04-169-EL-UNC, Order at 15-19 (January 26, 2005); and *In re AEP-Ohio*, Case No. 07-1132-EL-UNC, Order at 3 (January 30, 2008).

assignment of error, OCC makes a comparable argument that the Commission erred in failing to require AEP-Ohio to credit customers for the interest accrued from 2009 until the date of the FAC order on the value of the lump sum payment and the West Virginia coal reserve. In its memorandum contra, AEP-Ohio replies that the award of interest or the reduction of carrying charges would constitute retroactive ratemaking and an unlawful modification of the ESP 1 order, and would also inequitably add to the under-recovery of actual FAC expenses for 2009.

(25) In the FAC order, the Commission determined that all of the realized value from the settlement agreement should be credited against OP's FAC under-recovery. We noted the unique circumstances of the settlement agreement and determined that, in order to assess the real economic cost of coal used during the audit period, more of the value realized as a result of entering into the settlement agreement should flow through to ratepayers by way of a credit to the FAC under-recovery. (*FAC order at 12-13.*) In accordance with our finding that all of the realized value from the settlement agreement should be credited to the benefit of ratepayers, we find that AEP-Ohio should flow through to its customers a carrying charge component in applying the credit to OP's FAC under-recovery. Such carrying charge component should be calculated in a manner consistent with calculation of the FAC deferrals, as approved in the ESP 1 order, including use of the approved weighted average cost of capital.[7] Thus, the Commission disagrees with OP's argument that the award of interest or the reduction of carrying charges constitutes retroactive ratemaking because a calculation that is consistent with the approved FAC deferrals is, by definition, not a modification of a previously established rate, as was the case in *Keco*. Accordingly, we find that IEU-Ohio's first assignment of error and OCC's second assignment of error should be granted.

(26) IEU-Ohio's second assignment of error is that the Commission unlawfully and unreasonably failed to direct AEP-Ohio to recalculate its phase-in recovery rider (PIRR) rates to reflect the immediate reduction of the FAC deferral balance that is

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7 ESP 1 order at 23.

collected through the rider. OCC raises a similar argument in its first assignment of error. In particular, OCC contends that the Commission unreasonably failed to specify that AEP-Ohio should immediately credit to customers the full value of the settlement agreement and also credit the increased value of the West Virginia coal reserve as soon as the valuation is completed by the auditor. OCC notes that an immediate credit to the FAC deferral balance will minimize carrying charges and reduce the amount that customers are charged through the PIRR. In response, AEP-Ohio argues that it would be unreasonable and imprudent to reduce the PIRR rates immediately. AEP-Ohio claims that, if an immediate credit is implemented and the FAC order is subsequently found to be unlawful, excessive revenue and rate volatility would result. AEP-Ohio adds that it is impossible to reduce the PIRR immediately to reflect the value of the West Virginia coal reserve, as its value is unknown and can only be accurately determined through a sale of the asset. Finally, AEP-Ohio notes that the arguments of IEU-Ohio and OCC fail to account for the fact that the PIRR as approved in the ESP 2 order has been effectively vacated by the ESP 2 entry on rehearing.

(27) Pursuant to Section 4903.15, Revised Code, Commission orders are effective immediately upon entry in the journal. Additionally, in the FAC order, the Commission specifically directed AEP-Ohio to credit the FAC under-recovery as addressed in the order, and did not grant a stay of the order (FAC order at 19). To the extent necessary to resolve any confusion on the part of the parties, the Commission now makes explicit its intention that AEP-Ohio should immediately implement the credit to reduce the FAC deferral balance in accordance with the FAC order and this entry on rehearing. We also note that AEP-Ohio's PIRR rates are the subject of separate proceedings in which the Commission will consider recovery of the deferred FAC costs and determine the proper rates, including any adjustments that may be necessary in light of the present cases.[8] With this clarification, we find that

8 *In the Matter of the Application of Columbus Southern Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144, Revised Code*, Case No. 11-4920-EL-RDR; *In the Matter of the Application of Ohio Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144*, Revised Code, Case No. 11-4921-EL-RDR.

IEU-Ohio's second assignment of error and OCC's first assignment of error should be denied.

(28) In AEP-Ohio's eighth assignment of error, the Companies note that the West Virginia coal reserve is an OP asset properly accounted for as part of the settlement agreement. The valuation of the coal reserve directed in the FAC order, according to AEP-Ohio, is based on the unlawful and unreasonable premise that AEP-Ohio ratepayers have an ownership interest in the coal reserve, in contrast to Commission precedent.[9] The Companies argue that ratepayers do not acquire an ownership interest in utility assets by paying the rates for service. Accordingly, AEP-Ohio reasons there is no legal basis for the FAC order's seizure of the value of the coal reserve to reduce the 2009 fuel costs or any future fuel costs.

(29) AEP-Ohio made similar arguments in its brief and again takes the opportunity to mischaracterize the FAC order. The FAC order does not imply or recognize any ratepayer ownership interest in the coal reserve. We agree with AEP-Ohio that ratepayers do not earn or acquire an ownership interest in the utility's assets as a result of paying for utility services. An ownership interest is not necessary for the Commission to order, as it did in the FAC order, the alignment of fuel costs with the benefits of AEP-Ohio's fuel contracts. For these reasons, we again reject AEP-Ohio's claims and deny the request for rehearing.

Determination of Value of Coal Reserve

(30) In its second assignment of error, AEP-Ohio requests that the Commission clarify the methodology to be used to determine the value of the West Virginia coal reserve to include, as an alterative to the valuation by way of an appraisal, the sale of the property after a final, non-appealable decision is issued in these cases. The Companies reason that the only way to determine the proper value of the coal reserve is by sale. The Companies also request that the Commission recognize that the

9 *In the Matter of the Regulation of the Electric Fuel Component Contained Within the Rate Schedules of the Columbus Southern Power Company and Related Matters*, Case No. 88-102-EL-EFC, Order (October 28, 1988).

value of the coal reserve could be more or less than the $41.6 million net book value. IEU-Ohio reasons that an appraisal of the value of the coal reserve, as directed in the FAC order, is the most expedient means to determine the amount by which the FAC under-recovery should be credited.

(31) We reject AEP-Ohio's request to require the sale of the coal reserve to determine its value. It was not the intent of the FAC order to permanently terminate OP's ownership of the asset but to direct that the value of the coal reserve be determined by an independent, third-party. We expect that an independent appraisal will facilitate a more expedient resolution of the issue, even assuming more litigation, as the Companies imply, than the sale of the coal reserve. Nonetheless, we clarify that the value of the coal reserve, to be determined by an independent auditor, may be more or less than the $41.6 million net book value reflected on OP's books. Accordingly, we deny AEP-Ohio's request for rehearing on this issue.

Selection of Auditor

(32) In its third assignment of error, IEU-Ohio argues that the FAC order is unreasonable and unlawful because it did not direct Staff to hire and supervise an independent auditor and set a timeframe for the valuation of the West Virginia coal reserve. Asserting that the FAC order is unclear as to how the auditor will be selected, IEU-Ohio requests that the Commission provide clarification on this point to ensure that the audit is conducted in a fair, transparent, and timely manner. OCC, likewise, asserts in its third assignment of error that the Commission erred in directing AEP-Ohio to hire the auditor. OCC argues that the Commission should clarify that it will select an independent auditor to work under the direction of Staff and that OP's shareholders will pay for the audit. In response, AEP-Ohio maintains that the Commission should reject the requests of IEU-Ohio and OCC for an independent, Commission-hired auditor. AEP-Ohio contends that the value of the West Virginia coal reserve should be determined through a sale of the asset and that OP should be permitted to direct the sale.

(33) The Commission finds that the FAC order specifically indicated that an RFP would be issued by subsequent entry for the purpose of selecting and hiring an auditor to examine the value of the West Virginia coal reserve (FAC order at 12). Upon review of the proposals received in response to the RFP, the Commission will select an appropriate individual or firm with the technical expertise to independently determine the value of the West Virginia coal reserve. We note that both the auditor/appraiser and AEP-Ohio will be expected to adhere to the terms set forth in the entry selecting the auditor/appraiser. With this clarification, we find that the third assignments of error of IEU-Ohio and OCC should be denied.

<u>Delivery Shortfall Agreement and Contract Support Agreement</u>

(34) In its ninth assignment of error, AEP-Ohio argues that the Commission's conclusion that the delivery shortfall agreement and the contract support agreement may be examined in a future audit is unreasonable and unlawful for the same reasons asserted regarding its third through eighth assignments of error. In their memoranda contra, IEU-Ohio and OCC assert that the Commission properly determined that the delivery shortfall agreement and the contract support agreement may be considered in a future audit.

(35) In its fourth assignment of error, IEU-Ohio contends that the Commission unreasonably and unlawfully failed to direct AEP-Ohio to credit the benefits received under the contract support agreement against the FAC under-recovery. IEU-Ohio maintains that the contract support agreement contributed to increased fuel costs in 2009 and that, in the absence of a FAC mechanism, there will be little benefit to customers in future years when AEP-Ohio exercises its option to purchase coal at a discount off the market price beginning in 2013. Similarly, OCC asserts in its fourth assignment of error that the Commission erred in failing to credit customers for the increased price of coal that AEP-Ohio agreed to pay during 2009 pursuant to the contract support agreement and in failing to account for carrying charges. In its memorandum contra, AEP-Ohio contends that any benefit that it may receive from the contract support agreement will not ripen until it exercises its option to take the discounted pricing and will, therefore,

apply to time periods outside of the current audit, if the option is even fully exercised.

(36) The Commission finds that the fourth assignments of error of IEU-Ohio and OCC, as well as AEP-Ohio's ninth assignment of error, should be denied. We find that IEU-Ohio and OCC have raised no new arguments on rehearing that would warrant reconsideration of the FAC order and that there is no merit in AEP-Ohio's arguments for the reasons discussed above with respect to its third through eighth assignments of error. To the extent that a benefit is realized from the contract support agreement, such benefit will not accrue until after AEP-Ohio elects to exercise its option in 2013, which is well beyond the time period under review in the present proceedings. Therefore, although it is premature at this point to consider the purported benefits of the contract support agreement, we note that both the contract support agreement and the delivery shortfall agreement may be examined in a future audit of AEP-Ohio's fuel costs.

Fuel Procurement Procedures

(37) AEP-Ohio, in its tenth assignment of error, argues that AEPSC should not be required to add fuel procurement procedures as it completes the process of updating its policies and procedures manual. AEP-Ohio asserts that policies, not procedures, result in the most efficient procurement of fuel at the lowest reasonable price and, for that reason, the revisions to the manual are focused on procurement policies. AEP-Ohio requests that the Commission clarify that only the fuel procurement policies be updated in the manual and that the auditor is directed to review those updated policies in the next m/p audit proceeding. IEU-Ohio responds that AEPSC should be required to update the policies and procedures manual in accordance with EVA's recommendation. According to IEU-Ohio, the Commission should reject AEP-Ohio's attempt to avoid updating the manual to include fuel procurement procedures.

(38) In the FAC order, the Commission adopted m/p audit recommendation 5, which recommended that AEPSC finalize its update of its policies and procedures manual to reflect

current business practices and that the update be completed in time for it to be reviewed in the next m/p audit (FAC order at 6, 12; Commission-ordered Ex. 1A at 1-7). Although EVA enumerated eight items including certain procedural information that it hoped the updated manual would include, EVA recommended only that the update be completed and that the revised manual be reviewed in the next m/p audit (Commission-ordered Ex. 1A at 1-7, 2-11). Thus, we clarify that, in accordance with m/p audit recommendation 5, there is no specific requirement that AEPSC's policies and procedures manual include a formal procedural section. Upon review of the updated manual in the course of the next m/p audit, the auditor may recommend that the manual be further revised to include a procedural section, as the auditor deems necessary. With this clarification, AEP-Ohio's tenth assignment of error should be denied.

It is, therefore,

ORDERED, That the applications for rehearing filed by AEP-Ohio, IEU-Ohio, and OCC be granted or denied, as discussed above. It is, further, ORDERED, That a copy of this entry on rehearing be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

Lynn Slaby

GNS/SJP/sc

Entered in the Journal APR 11 2012

Barcy F. McNeal
Secretary

ATTACHMENT D

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company.	)))	Case No. 09-872-EL-FAC Case No. 09-873-EL-FAC

THIRD ENTRY ON REHEARING

The Commission finds:

(1) Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio or the Companies)[1] are public utilities as defined in Section 4905.02, Revised Code, and, as such, are subject to the jurisdiction of this Commission.

(2) By opinion and order issued on March 18, 2009, as clarified by the entry on rehearing issued on July 23, 2009, in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, the Commission modified and approved AEP-Ohio's application for an electric security plan (ESP) for 2009 through 2011, which included approval of a fuel adjustment clause (FAC) mechanism for CSP and OP, under which the Companies recovered prudently incurred costs associated with fuel, including consumables related to environmental compliance, purchased power costs, emission allowances, and costs associated with carbon-based taxes and other carbon-related regulations.[2] The approved FAC mechanism provided for quarterly reconciliations to actual FAC costs incurred by the Companies, which established the FAC rates for the subsequent quarter, as well as an annual audit of the accounting of the FAC costs. The Commission also authorized a phase-in of AEP-Ohio's ESP rates during the term of the ESP by deferring a portion of the annual incremental FAC costs such that the amount of the incremental FAC expense to be recovered from customers would be limited so as not to exceed specified percentage increases on a total bill basis.

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1 By entry issued on March 7, 2012, the Commission approved and confirmed the merger of CSP into OP. *In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals*, Case No. 10-2376-EL-UNC.

2 *In the Matter of the Application of Columbus Southern Power Company for Approval of an 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.

(3) On May 14, 2010, Energy Ventures Analysis, Inc. (EVA) filed, in the present cases, a management/performance (m/p) and financial audit report in response to its annual audit of AEP-Ohio's FAC mechanism for 2009 (audit report).

(4) On January 23, 2012, the Commission issued its opinion and order regarding the annual audit of AEP-Ohio's FAC mechanism for 2009 (FAC order). With respect to the financial audit recommendations contained in the audit report, the Commission adopted financial audit recommendations 1 through 5, as well as 6a through 6i, with the exclusion of 6b. The Commission also adopted m/p audit recommendations 2 through 6, as contained in the audit report.

In m/p audit recommendation 1, EVA recommended that the Commission consider whether any proceeds from a settlement agreement that American Electric Power Service Corporation had executed with a coal supplier in 2007 (settlement agreement) should be credited against OP's FAC under-recovery for 2009. The settlement agreement was effectively a buy-out of the contract with the coal supplier after 2008. Pursuant to the terms of the settlement agreement, OP received a lump sum payment (made in three equal payments) and coal reserve in West Virginia. In the FAC order, the Commission determined that all of the realized value from the settlement agreement should be credited against OP's FAC under-recovery for 2009. The Commission specified that the portion of the $30 million lump sum payment not already credited to the ratepayers of OP, as well as the $41 million value of the West Virginia coal reserve booked when the settlement agreement was executed, should be credited against the FAC under-recovery. Additionally, because the present value of the West Virginia coal reserve is unknown and the permitting process is expected to enhance its value, the Commission indicated that a request for proposal would be issued by subsequent entry to hire an auditor to examine the value of the West Virginia coal reserve. The Commission noted that the auditor would be expected to make a recommendation as to whether the increased value of the West Virginia coal reserve, if any, above the $41 million already required to be credited against OP's FAC under-recovery should accrue to ratepayers.

Finally, the Commission determined that the delivery shortfall agreement and the contract support agreement would not be further examined as part of the current audit. The Commission noted, however, that these agreements may be examined in a future audit, given that their impact on AEP-Ohio's fuel costs, if any, appeared to occur in time periods outside of the current audit.

(5) Section 4903.10, Revised Code, states that any party who has entered an appearance in a Commission proceeding may apply for a rehearing with respect to any matters determined therein by filing an application within 30 days after the entry of the order upon the Commission's journal.

(6) On February 22, 2012, applications for rehearing of the FAC order were filed by AEP-Ohio, Industrial Energy Users-Ohio (IEU-Ohio), and the Ohio Consumers' Counsel (OCC).

(7) On March 2, 2012, AEP-Ohio filed a memorandum contra the applications for rehearing of the FAC order filed by IEU-Ohio and OCC. On March 5, 2012, IEU-Ohio and OCC filed memoranda contra AEP-Ohio's application for rehearing of the FAC order.

(8) By entry on rehearing issued on March 21, 2012, the Commission granted the applications for rehearing of the FAC order to allow further consideration of the matters specified in the applications.

(9) On April 11, 2012, the Commission issued an entry on rehearing granting, in part, and denying, in part, the applications for rehearing filed by AEP-Ohio, IEU-Ohio, and OCC, as discussed in the entry (FAC entry on rehearing).

(10) On May 11, 2012, IEU-Ohio filed an application for rehearing of the FAC entry on rehearing.

(11) On May 21, 2012, AEP-Ohio filed a memorandum contra IEU-Ohio's application for rehearing.

(12) The Commission believes that sufficient reason has been set forth by IEU-Ohio to warrant further consideration of the matters specified in its application for rehearing. Accordingly, the application for rehearing filed by IEU-Ohio should be granted.

It is, therefore,

ORDERED, That the application for rehearing filed by IEU-Ohio on May 11, 2012, be granted for further consideration of the matters specified in the application for rehearing. It is, further,

ORDERED, That a copy of this third entry on rehearing be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

Lynn Slaby

SJP/sc

Entered in the Journal
JUN 06 2012

Barcy F. McNeal
Secretary

CERTIFICATE OF SERVICE

The undersigned counsel certifies that Ohio Power Company's Notice of Appeal was served by First-Class U.S. Mail upon counsel for all parties to the proceeding before the Public Utilities Commission of Ohio identified below and, pursuant to Section 4903.13 of the Ohio Revised Code, this 8th day of June 2012.

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COLUMBUS/1634428v.1

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company.	)))	Case No. 09-872-EL-FAC Case No. 09-873-EL-FAC

FOURTH ENTRY ON REHEARING

The Commission finds:

(1) Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio or the Companies)[1] are public utilities as defined in Section 4905.02, Revised Code, and, as such, are subject to the jurisdiction of this Commission.

(2) By opinion and order issued on March 18, 2009, as clarified by the entry on rehearing issued on July 23, 2009, in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, the Commission modified and approved AEP-Ohio's application for an electric security plan (ESP) for 2009 through 2011, which included approval of a fuel adjustment clause (FAC) mechanism for CSP and OP, under which the Companies recovered prudently incurred costs associated with fuel, including consumables related to environmental compliance, purchased power costs, emission allowances, and costs associated with carbon-based taxes and other carbon-related regulations.[2] The approved FAC mechanism provided for quarterly reconciliations to actual FAC costs incurred by the Companies, which established the FAC rates for the subsequent quarter, as well as an annual audit of the accounting of the FAC costs. The Commission also authorized a phase-in of AEP-Ohio's ESP rates during the term of the ESP by deferring a portion of the annual

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1 By entry issued on March 7, 2012, the Commission approved and confirmed the merger of CSP into OP. *In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals*, Case No. 10-2376-EL-UNC.

2 *In the Matter of the Application of Columbus Southern Power Company for Approval of an 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.

incremental FAC costs such that the amount of the incremental FAC expense to be recovered from customers would be limited so as not to exceed specified percentage increases on a total bill basis.

(3) On May 14, 2010, Energy Ventures Analysis, Inc. (EVA) filed, in the present cases, a management/performance (m/p) and financial audit report in response to its annual audit of AEP-Ohio's FAC mechanism for 2009 (audit report).

(4) On January 23, 2012, the Commission issued its opinion and order regarding the annual audit of AEP-Ohio's FAC mechanism for 2009 (FAC order). With respect to the financial audit recommendations contained in the audit report, the Commission adopted financial audit recommendations 1 through 5, as well as 6a through 6i, with the exclusion of 6b. The Commission also adopted m/p audit recommendations 2 through 6, as contained in the audit report.

In m/p audit recommendation 1, EVA recommended that the Commission consider whether any proceeds from a settlement agreement that American Electric Power Service Corporation had executed with a coal supplier in 2007 (settlement agreement) should be credited against OP's FAC under-recovery for 2009. The settlement agreement was effectively a buy-out of the contract with the coal supplier after 2008. Pursuant to the terms of the settlement agreement, OP received a lump sum payment (made in three equal payments) and coal reserve in West Virginia. In the FAC order, the Commission determined that all of the realized value from the settlement agreement should be credited against OP's FAC under-recovery for 2009. The Commission specified that the portion of the $30 million lump sum payment not already credited to the ratepayers of OP, as well as the $41 million value of the West Virginia coal reserve booked when the settlement agreement was executed, should be credited against the FAC under-recovery. Additionally, because the present value of the West Virginia coal reserve is unknown and the permitting process is expected to enhance its value, the Commission indicated that a request for proposal would be issued by subsequent entry to hire an auditor to examine the value of the West Virginia coal reserve. The Commission noted that the auditor would be expected to make a recommendation as to whether the increased value of the West Virginia coal reserve, if any, above the $41 million already required to be credited against OP's FAC under-recovery should accrue to ratepayers.

Finally, the Commission determined that the delivery shortfall agreement and the contract support agreement would not be further examined as part of the current audit. The Commission noted, however, that these agreements may be examined in a future audit, given that their impact on AEP-Ohio's fuel costs, if any, appeared to occur in time periods outside of the current audit.

(5) Section 4903.10, Revised Code, states that any party who has entered an appearance in a Commission proceeding may apply for a rehearing with respect to any matters determined therein by filing an application within 30 days after the entry of the order upon the Commission's journal.

(6) On February 22, 2012, applications for rehearing of the FAC order were filed by AEP-Ohio, Industrial Energy Users-Ohio (IEU-Ohio), and the Ohio Consumers' Counsel (OCC).

(7) On March 2, 2012, AEP-Ohio filed a memorandum contra the applications for rehearing of the FAC order filed by IEU-Ohio and OCC. On March 5, 2012, IEU-Ohio and OCC filed memoranda contra AEP-Ohio's application for rehearing of the FAC order.

(8) By entry on rehearing issued on March 21, 2012, the Commission granted the applications for rehearing of the FAC order to allow further consideration of the matters specified in the applications.

(9) On April 11, 2012, the Commission issued an entry on rehearing granting, in part, and denying, in part, the applications for rehearing filed by AEP-Ohio, IEU-Ohio, and OCC, as discussed in the entry (FAC entry on rehearing). With respect to AEP-Ohio's first assignment of error, the

Commission clarified that the 2009 FAC under-recovery need only be credited for the share of the settlement agreement allocable to Ohio's retail jurisdictional customers.

(10) On May 11, 2012, IEU-Ohio filed an application for rehearing of the FAC entry on rehearing. In its only assignment of error, IEU-Ohio asserts that the FAC entry on rehearing is unlawful and unreasonable in that the Commission limited the amount of the credit for the settlement agreement to the portion allocable to the Ohio retail jurisdiction. IEU-Ohio requests that the Commission grant rehearing on this issue or, alternatively, clarify that all of the credit is allocable to Ohio retail jurisdictional customers. IEU-Ohio contends that, because AEP-Ohio was required, pursuant to its ESP, to allocate its least cost fuel to standard service offer (SSO) customers, the entire credit from the settlement of the below-market coal contract should be allocated to SSO customers. IEU-Ohio notes that AEP-Ohio has not claimed that the coal contract was not its lowest cost fuel source. IEU-Ohio argues that the costs of the contract would have been fully allocated to the Ohio retail jurisdiction and that any benefits received as a result of a renegotiation of the contract should likewise be fully allocated to Ohio retail jurisdictional customers. IEU-Ohio adds that AEP-Ohio's jurisdictional argument is only relevant in a traditional cost-of-service ratemaking context, which is inapplicable under circumstances involving default generation service. IEU-Ohio also notes that AEP-Ohio has not shown that Ohio customers should not receive the full benefits of the settlement agreement, which were accepted by AEP-Ohio in exchange for higher fuel costs paid by such customers. IEU-Ohio adds that AEP-Ohio failed to raise its jurisdictional argument during the hearing or briefing and should thus be precluded from making the argument at this point in the proceedings. Finally, IEU-Ohio argues that AEP-Ohio's jurisdictional argument should be rejected because it is selectively advanced only when it works to the detriment of Ohio customers.

(11) On May 21, 2012, AEP-Ohio filed a memorandum contra IEU-Ohio's application for rehearing. AEP-Ohio responds that IEU-Ohio has raised no new arguments for the

Commission's consideration and that IEU-Ohio improperly seeks rehearing of an issue that has already been fully briefed and was merely clarified on rehearing. AEP-Ohio notes that IEU-Ohio raised the same arguments in its March 5, 2012, memorandum contra AEP-Ohio's application for rehearing. AEP-Ohio also asserts that the Commission properly found in the FAC entry on rehearing that the record supports AEP-Ohio's jurisdictional claim, noting that the testimony in the record is clear that the FAC involves only the retail share of AEP-Ohio's fuel costs and that the portion of the settlement agreement already passed through the FAC was based on the retail jurisdictional allocation. AEP-Ohio contends that the Commission's clarification that the 2009 FAC under-recovery need only be credited for the share of the settlement agreement allocable to Ohio's retail jurisdictional customers is required by state and federal law, prior Commission orders, and the record in these proceedings. AEP-Ohio notes that the Commission has no authority to regulate wholesale sales of electricity or the provision of retail electric service in other states. AEP-Ohio further notes that it has been consistent in recognizing the need to respect jurisdictional lines, contrary to IEU-Ohio's position. AEP-Ohio also adds that the supplier contract in question was not an available coal source from the outset of the ESP in 2009 and that AEP-Ohio fully complied with any obligation to allocate the lowest cost fuel actually available to it in 2009 to its SSO customers.

(12) By entry on rehearing issued on June 6, 2012, the Commission granted IEU-Ohio's application for rehearing to allow further consideration of the matters specified in the application.

(13) Upon review of the application for rehearing filed by IEU-Ohio on May 11, 2012, the Commission finds that the application should be denied. In the FAC entry on rehearing, the Commission clarified that the 2009 FAC under-recovery need only be credited for the share of the settlement agreement allocable to Ohio's retail jurisdictional customers. We explicitly disagreed with IEU-Ohio's argument that AEP-Ohio was precluded from raising this issue at the rehearing stage, finding that AEP-Ohio's claim was prompted by its interpretation of the FAC order and that there was

evidence in the record on this issue. We likewise find no merit in the arguments raised by IEU-Ohio in its May 11, 2012, application for rehearing and find that IEU-Ohio has raised no argument that was not already considered and rejected. In the FAC entry on rehearing, we properly clarified our intention that only the portion of the proceeds from the settlement agreement allocable to Ohio's retail jurisdictional customers must be applied to the 2009 FAC under-recovery. As in many cases before the Commission, it is necessary that certain allocations be made so that only the accounts, property, expenses, revenues, and so forth associated with rendering service to jurisdictional customers are included within the scope of the proceedings.

IEU-Ohio contends that, because AEP-Ohio was required pursuant to its ESP to allocate its least cost fuel to SSO customers, and the coal contract at issue was the Company's least cost fuel source, the Company should be required to allocate all of the settlement proceeds to SSO customers. In making its argument, IEU-Ohio points to the Commission's July 23, 2009, entry on rehearing in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, in which the Commission stated that FAC costs were "to continue to be allocated on a least cost basis to [provider of last resort] customers and then to other types of sale customers."[3] IEU-Ohio appears to infer a meaning from this statement beyond what the Commission intended. The entry on rehearing does no more than emphasize that AEP-Ohio was expected to continue its usual fuel cost accounting procedures for allocating costs to SSO customers on a least cost basis, which, as the Company notes, is dependent on the average dispatch cost associated with a unit for a particular period of time, rather than any one particular supply contract. Accordingly, we affirm our prior findings in the FAC entry on rehearing.

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3 *In the Matter of the Application of Columbus Southern Power Company for Approval of an 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, *et al.*, Entry on Rehearing (July 23, 2009), at 4.

It is, therefore,

ORDERED, That the application for rehearing filed by IEU-Ohio on May 11, 2012, be denied. It is, further,

ORDERED, That a copy of this fourth entry on rehearing be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Steven D. Lesser

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Barcy F. McNeal
Secretary

FILE

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company	)))	Case No. 09-872-EL-FAC Case No. 09-873-EL-FAC

APPLICATION FOR REHEARING OF OHIO POWER COMPANY

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APPLICATION FOR REHEARING OF OHIO POWER COMPANY[1]

On January 23, 2012, the Commission issued an Opinion and Order in the above-captioned cases (Opinion and Order). The Opinion and Order, among other things, determined that all of the realized value from a January 2008 settlement agreement (2008 Settlement Agreement) that terminated a 20-year coal procurement contract effective at the end of 2008 should be credited against Ohio Power Company's (OPCo's) 2009 Fuel Adjustment Clause (FAC) under-recovery and, thus, flowed through to the benefit of OPCo's retail customers that take standard service offer (SSO) generation service from OPCo. The "realized value" from the 2008 settlement agreement, according to the Opinion and Order, included both the portion of a 2008 lump sum payment from the coal supplier not already credited to OPCo's retail SSO customers as well as the purported value of a coal reserve that the coal supplier transferred in 2008 to OPCo.

Pursuant to § 4903.10, Ohio Rev. Code, and § 4901-1-35(A), Ohio Admin Code, OPCo (also referred to herein as "AEP Ohio") seeks rehearing of the January 23, 2012 Opinion and Order as further explained below. Specifically, the Compliance Entry is unlawful and unreasonable in the following respects:

I. The Commission should clarify that it did not intend to unreasonably and unlawfully flow through to the benefit of OPCo's Ohio retail customers amounts allocable to the wholesale and non-Ohio retail jurisdictions.

II. The Commission should clarify the methodology to be used for determination of the value of the coal reserve so that it can include, as an alternative to valuation

[1] As a result of the Commission's Opinion and Order in Case Nos. 11-346-EL-SSO et al., Columbus Southern Power and Ohio Power Company were merged effective December 31, 2011. Accordingly, references herein to Ohio Power Company, the surviving entity after the merger, include the predecessor interests of Columbus Southern Power.

through appraisal, the sale of the property after a final, non-appealable decision is reached in this case.

III. The Opinion and Order engages in selective and unlawful retroactive ratemaking. *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.* (1957), 166 Ohio St. 254; *Lucas Cty. Commrs. v. Pub. Util. Comm.* (1997), 80 Ohio St.3d 344.

IV. It is unreasonable and unlawful for the Commission to retroactively modify its prior adjudicatory decision in ESP I (Case Nos. 08-917/918-EL-SSO) to establish annual FAC audits to examine fuel procurement practices and expenses for the audit period. *Ohio Consumers' Counsel v. Pub. Util. Comm.* (2006), 111 Ohio St.3d 300, 318; *Ohio Consumers' Counsel v. Pub. Util. Comm.* (1985), 16 Ohio St.3d 9, 10

V. By reaching back into 2008 and using the results of fuel procurement activities in 2008 to offset fuel costs prudently incurred in 2009, the Opinion and Order unreasonably and unlawfully modified the FAC baseline that was fully litigated and decided in the *ESP I* Cases.

VI. OPCo prudently entered into the 2008 Settlement Agreement, and the Opinion and Order unreasonably and unlawfully impaired that agreement, especially given that the agreement was entered into by OPCo prior to commencement of the ESP's new FAC and before the 2009 audit period (*i.e.*, during a period of unregulated fuel cost and when fuel contracts were not regulated).

VII. The Opinion and Order unreasonably and unlawfully ignored the 2008 Production Bonus Agreement, which increased fuel expenses in 2008.

VIII. The Opinion and Order unreasonably and unlawfully concluded that the value of the coal reserve property acquired as a result of the 2008 Settlement Agreement should be offset against FAC costs because it is an OPCo asset on which ratepayers have no claim.

IX. The Opinion and Order erred by concluding that the Delivery Shortfall Agreement and the Contract Support Agreement may be examined by a future audit.

X. It is unnecessary to require AEP Ohio to add fuel procurement procedures as it updates its fuel procurement policy manual.

A memorandum in support is attached and sets forth the specific grounds supporting the above-listed errors.

Respectfully Submitted,

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MEMORANDUM IN SUPPORT

BACKGROUND

Enactment of SB 3 and Market-Based Pricing without FAC through 2008

Am. Sub. S.B. No. 3, effective October 5, 1999 (SB 3), restructured regulation of electric utilities and introduced retail customer choice for electric generation service, largely deregulating generation service in Ohio. Rates for competitive generation service were established based on a market-based pricing. Under SB 3, the Companies established a Rate Stabilization Plan (RSP) that was in effect from 2006 through 2008. Under the Companies' RSP, there was no fuel adjustment clause or comparable mechanism and there was no guarantee that the RSP's generation rates would cover the Companies' fuel costs during the RSP term. (Case No. 04-169-EL-UNC, January 26, 2005 Opinion and Order; March 23, 2005 Entry on Rehearing) As the Auditor in this proceeding stated, the RSP term was "a period in which fuel cost recovery was not regulated." (Audit Report at 1-6.) This was the status through the end of 2008.

Thus, the Companies were "on their own" with respect to recovery of fuel costs during the RSP period of 2006 through 2008. Indeed, during the RSP term, coal prices experienced unprecedented volatility and ***tripled*** between mid-2007 and mid-2008. (Audit Report at 2-4.) During the period from 2001 through 2008 when no FAC was in effect, the Companies' shareholders bore the total risk of increased fuel costs. The Auditor verified that during 2007-2008 period, coal prices in the United States reached all-time high prices. (Tr. I at 61.) As Companies witness Rusk testified, during the non-FAC period, not only did delivered costs for coal in Ohio increase dramatically, but there was also unprecedented volatility in coal markets.

(Cos. Ex. 2 at 15.) Material and volatile coal prices created ideal circumstances for having a FAC, but after AEP Ohio weathered this storm without one, the Commission now engages in "cherry picking" certain upside results achieved by AEP Ohio under its prior rate plan.

During this extraordinary historical period of coal procurement when fuel costs were not regulated, the Companies entered into several transactions to manage coal prices while maintaining a reliable supply. Included among the procurement transactions are four transactions that have been raised in this proceeding: (1) a January 2008 settlement agreement which terminated the 20-year contract with a coal supplier effective at the end of 2008 (2008 Buyout Agreement), (2) a November 2008 agreement with the same coal supplier for liquidated damages associated with a delivery shortfall occurring in 2008 (2008 Delivery Shortfall Agreement), (3) a 2008 agreement with a second coal supplier for contract support required to meet its financial covenants (2008 Contract Support Agreement), and (4) a February 2008 contract support agreement with a third coal supplier to help maintain the supplier's solvency through a production bonus payment and a temporary increase in the per ton price for coal (2008 Production Bonus Agreement). (Audit Report at 2-20 through 2-24.) None of these four transactions were found to be imprudent in the Audit Report or the Opinion and Order. In fact, the Auditor praised AEP management for its performance in managing this extraordinarily challenging period.

Enactment of SB 221 and the Adoption of a FAC mechanism for the Companies Starting in 2009

Am. Sub. S.B. No. 221, effective July 31, 2008 (SB 221), modified the method for setting standard service offer (SSO) rates for electric service and created new requirements for alternative energy, energy efficiency and peak demand reductions. On the effective date of SB 221, the Companies filed an Electric Security Plan in Case Nos. 08-917-EL-SSO and 08-918-

EL-SSO ("*ESP Cases*"). In deciding the *ESP Cases*, the Commission adopted a FAC mechanism for AEP Ohio, concluding as follows:

> The Commission believes that the *establishment of a FAC mechanism as part of an ESP is authorized pursuant to Section 4928.143(B)(2)(a), Revised Code, to recover prudently incurred costs associated with fuel*, including consumables related to environmental compliance, purchased power costs, emission allowance, and costs associated with carbon-based taxes and other carbon-related regulations. Given that the FAC mechanism is authorized pursuant to the ESP provision of SB 221, *we will limit our authorization, at this time, to the term of the ESP*.
>
> * * *
>
> Therefore, we find that the FAC mechanism with quarterly adjustments *as proposed by the Companies*, as well as an *annual prudency and accounting review recommended by Staff*, is reasonable and should be approved and implemented as set forth herein.

(*ESP Cases*, Opinion and Order at 14-15 (emphasis added).) Hence, the Commission approved the proposed FAC mechanism, pursuant to the new law that had been enacted for rate plans beginning January 1, 2009 (SB 221), for prospective operation during the term of the ESP (*e.g.*, the scope of the approved FAC was confined to begin in 2009 and end after 2011), with annual prudence reviews during the term of the FAC. The holding that the adopted FAC mechanism was strictly limited to the ESP term was reinforced in the entry initiating the RFP for the audit and again in the entry selecting the auditor for this proceeding. (*See* Case Nos. 09-872-EL-FAC and 09-873-EL-FAC, November 18, 2009 Entry at 1; ("The Commission limited its authorization of the fuel adjustment clause provisions to the term of the ESP."); January 7, 2010 Entry at 1 (same).)

In order to make the transition from a period where fuel costs were not regulated to an active FAC, the Commission needed to establish a FAC baseline to unbundle CSP's and OPCo's generation rates into fuel and non-fuel components. The Commission weighed the evidence carefully and found that a proxy is appropriate to establish a baseline, adopting Staff's method of using actual 2007 fuel costs and adjusting by 3% and 7% for CSP and OPCo, respectively. (*ESP*

Cases, Opinion and Order at 19.) On rehearing in the *ESP Cases*, the parties again advanced their positions and the Commission reiterated that it had fully considered the evidence and would not change its decision.

> [B]ased on the evidence presented in the record, the Commission determined that a proxy should be used to calculate the appropriate baseline. After making this determination, the Commission reviewed all evidence in the record and all parties' arguments, and adopted Staffs methodology and resulting value as the appropriate FAC baseline.

(*ESP Cases*, Entry on Rehearing at 6.)

Thus, the key FAC issues adjudicated and decided in the *ESP Cases* were that: (1) the FAC mechanism would be limited to the ESP period, excluding both the pre-ESP period and the post-ESP period; (2) annual prudence review of fuel costs would be conducted for fuel costs incurred in 2009, 2010 and 2011; and (3) the FAC baseline was set as a one-time determination to put the pre-ESP period fuel costs in the past and transition the Companies from a non-FAC period to an active FAC period. In short, establishment of the FAC baseline and other matters involving operation of the FAC mechanism during the ESP were hotly contested issues that the Commission fully adjudicated and decided in the *ESP Cases*. Notably, in establishing the FAC baseline and strictly confining the scope of the FAC mechanism to the ESP term, the Commission was explicitly aware at that time of the volatile coal prices and extraordinary coal procurement activities that occurred in 2008 in reaching its decision regarding the FAC baseline. (*ESP Cases*, Entry on Rehearing at 5.)

OVERVIEW OF ARGUMENT

As the Commission itself recognized, the 2007-2008 period involving volatile coal prices reaching all-time historical highs would have been an ideal time to have an active fuel clause mechanism. But AEP Ohio's rate plan at that time did not have an active fuel clause and the

Companies were on their own in managing fuel costs during this extraordinary period. AEP Ohio is not complaining because "a deal is a deal" and it agreed to the no-FAC Rate Stabilization Plan (RSP) in effect from 2006-2008. But the Opinion and Order sweepingly ignores this crucial fact and invite the Commission to selectively adjust rates that were charged during this period on a retroactive basis.

The Opinion and Order recognized this situation and noted the Auditor's high opinion of AEP's handling of the crisis:

> The auditors noted that since mid-2007, the coal industry has demonstrated *unprecedented volatility* which has resulted in *utility fuel procurement personnel facing enormous challenges*. Additionally, from mid-2007 until the third quarter of 2008, a global coal supply/demand imbalance increased the demand for and price of United States (U.S.) coals. *In the auditors' opinion, American Electric Power Service Corporation (AEPSC) did an exceptional job during this period particularly with those suppliers that faced financial difficulties.* Since the third quarter of 2008, electricity demand slowed as a result of the severe economic recession thus leading many utilities to end up with more coal under contract than needed. Thus, from mid-2007 through the end of 2008, electric utilities went from having to acquire coal under contract to having to manage a surplus of coal inventories. *In the auditors' view, AEPSC also did an outstanding job managing its excess coal inventories.*

(Opinion and Order at 3-4.) And the Commission specifically clarified (at 13) that it was not finding anything imprudent about AEP Ohio entering into the 2008 Settlement Agreement and was not finding any motivation by AEP Ohio to transfer value from ratepayers during the ESP to an earlier date.

The Opinion and Order unwisely accepted the invitation of IEU and OCC to "claw back" and to "claw forward" to capture transactions beyond the 2009 Audit Period. Specifically, in its Opinion and Order, at 12, the Commission "determine[d] that all of the realized value from the [2008] Settlement Agreement should be credited against OP's FAC under-recovery namely the portion of the $30 million 2008 lump sum payment not already credited to OP ratepayers as well as the $41 million value of the coal reserve that AEP booked when the Settlement Agreement was executed."

In addition, while recognizing that the value of the coal reserve is not known, the Commission also directed AEP to hire an auditor specifically to examine the value of the coal reserve and to make a recommendation to the Commission as to whether the increased value, if any above the $41 million already required to be credited against OP's [FAC] under-recovery, should accrue to OP ratepayers beyond the value of the reserve that AEPSC booked under the Settlement Agreement. (*Id.*)

The Commission further determined, as to the purported benefits associated with the Delivery Shortfall Agreement and the Contract Support Agreement that intervenors (IEU and OCC) asserted should be factored into OPCo's FAC under-recovery, "any effect these agreements may have had on AEP-Ohio's fuel costs, if any, would appear to apply in time periods outside of the current [2009] audit." The Commission concluded by stating that while they "may be examined by a future audit, those agreements will not be further examined as part of the current audit." (Id. at 14.)

The rationale that the Commission provided in its Opinion and Order, at12-13, for seizing the $30 million 2008 lump sum payment not already credited to OP ratepayers as well as the $41 million amount associated with the coal reserve that AEP booked when the Settlement Agreement was executed from the 2008 Settlement Agreement and crediting those amounts against OPCo's FAC under-recovery was as follows:

> In making the above determination the Commission notes that the record reflects that the Settlement Agreement was entered into in order to terminate a long-term coal supply agreement, entered into in 1992, because the price of coal under the agreement was significantly below market in mid-2007. This long-term agreement was replaced with a new agreement which resulted in OP ratepayers paying significantly more for coal beginning in 2009, the start of the ESP period,

> than would have been paid had the Settlement Agreement not been entered into. We recognize that this situation is somewhat unique given that OP's fuel costs were not regulated during the period when the buyout occurred and the benefits booked yet the value was realized from coal that should have been delivered during the ESP period. While we do not find any motivation by AEPSC to transfer value from ratepayers during the ESP to an earlier date, nevertheless, the long-term coal agreement was an OP asset for which the value would have flowed through to OP ratepayers through the ESP period but for the extraordinary circumstances related to the early contract termination. Given these factors, we agree with Staff that, in order to determine the real economic cost of coal used during the audit period, more of the value realized by AEP for entering into the Settlement Agreement should flow through to OP ratepayers through a credit to OP's under-recovery and deferrals.

Respectfully, the Commission's "real economic cost" basis for reaching back into 2008, selectively extracting amounts related to the 2008 Settlement Agreement, and offsetting those amounts against OPCo's fuel costs in 2009 (and future periods) does not have a legal or record basis.

First, substantial portions of the $30 million lump sum payment and the $41 million recorded net book value are not related in any way to the Ohio retail jurisdiction and should not be used as an offset against OPCo's Ohio retail jurisdiction's fuel costs incurred in 2009 (and subsequent periods). They are related to the wholesale or other non-Ohio retail jurisdictions. Just as the expenses incurred by OPCo are jurisdictionalized prior to being recovered through the FAC, any amount of the lump sum payments and coal reserve asset that is to flow back through the FAC must be limited to the retail jurisdictional share. [Assignment of Error I]

Second, the Commission should abandon the notion of doing an audit/appraisal to determine the hypothetical value of the coal reserve asset. Instead, it should simply conduct a sale after the decision becomes final and non-appealable. A sale is the only way to determine the true market value of the asset. [Assignment of Error II]

Third, the Commission's economic cost rationale for making offsets against 2009 fuel costs, even with regard to portions of the $30 million lump sum payment and the coal reserve that arguably are associated with the Ohio retail jurisdiction, is fundamentally flawed. The "real economic cost" of the fuel costs incurred in 2009 for Ohio retail jurisdiction FAC customers is accurately measured by the amounts recorded on OPCo's books of account for 2009. There is a presumption that the costs incurred for fuel in 2009 are prudent, and there is no evidence that the costs that OPCo incurred to procure fuel in 2009 were imprudent. Indeed, the testimony and evidence, as well as the Commission's findings, confirm that the costs OPCo incurred for fuel, and properly recorded on its books of account, for 2009 were prudently incurred. Moreover, there is no basis for the Commission's statement that, as a result of the 2008 Settlement Agreement, OPCo paid significantly more for coal beginning in 2009, the start of the ESP period, than would have been paid had the Settlement Agreement not been entered into. The evidence confirms that the probable result, absent the 2008 Settlement Agreement, was that the supplier for the underlying coal contract would have defaulted and OPCo would have had to procure replacement coal at higher market prices. In addition, the Commission's rationale ignores the fact that OPCo incurred substantial additional costs in 2008 to provide support to another supplier which enabled that supplier to avoid defaulting on its coal supply arrangement, which allowed OPCo to continue to obtain coal supplies in 2009 and beyond at costs below what would have been incurred if that supplier had defaulted. OPCo did not seek to recoup those supplier support costs in 2009 (or future periods) through the FAC since these costs were incurred prior to the period when the FAC was reinstated. In sum, the Commission's rationale for reducing OPCo's

2009 FAC costs based on the 2008 Settlement Agreement is baseless. [Assignment of Errors III-VIII]

Fourth, there is similarly no basis for considering, in future FAC audit proceedings, whether other amounts associated with the 2008 Delivery Shortfall Agreement and a Contract Support Agreement should be offset against costs prudently incurred during future periods. The Opinion and Order erred by concluding that those agreements may be examined by a future audit. [Assignment of Error IX]

Finally, as a separate matter, AEP Ohio requests that the Commission clarify, on rehearing, that it is required in a subsequent FAC proceeding to report on its updated fuel procurement procedures. As was explained in its testimony on the subject, while it is appropriate to review and update the policies, the use of procurement procedures will not result in the efficient procurement of fuel at the lowest reasonable cost. [Assignment of Error X]

ARGUMENT

I. The Commission should clarify that it did not intend to unreasonably and unlawfully flow through to the benefit of OPCo's Ohio retail customers amounts allocable to the wholesale and non-Ohio retail jurisdictions.

It is unreasonable and unlawful to net against 2009 fuel costs amounts improperly and selectively extracted from the 2008 Settlement Agreement. The several ways in which such netting is unreasonable and unlawful are explained in detail below in subsequent sections of this pleading. As an initial matter, though, it is necessary to correct a threshold error in the Opinion and Order's language used to direct that all amounts resulting from the 2009 Settlement Agreement should be offset against OPCo's 2009 fuel costs. While the Commission presumably did not intend to confiscate non-jurisdictional gains, the literal language used in the Opinion and

Order suggests otherwise. Therefore, it must be corrected. Specifically, even if it were not unreasonable and unlawful to offset against OPCo's 2009 Ohio jurisdictional fuel costs amounts resulting from the 2008 Settlement Agreement, the Opinion and Order's directive substantially overstates the jurisdictional amounts available to be used as offsets against such costs.

AEP Ohio accounting witness Dooley testified that the $13 million credited against fuel costs in 2009 and 2010 did not directly relate to the $30 million cash payments (versus the $41 million net book value of the reserve asset). (Tr. I at 122.) He also clarified that the FAC customers would have only received a portion (*i.e.*, the retail jurisdictional allocation) of the $13 million that was assigned to 2009 and 2010. (*Id.*) The Financial Auditor, Mr. Ralph C. Smith of Larkin & Associates, testified that he fully understood that expenses reflected in the AEP Ohio accounting ledgers were allocated as between retail and non-retail expenses before being included in the FAC. (Tr. I at 15-16.) AEP Ohio witness Nelson also addressed the notion of applying the entire proceeds of the 2008 Settlement Agreement to the FAC:

> All of the amounts that have been discussed in the Audit Report and in the Companies' testimony associated with the 2008 Settlement Agreement are total OPCo amounts. OPCo's total generation output greatly exceeds its retail sales. Therefore, had a fuel clause existed in 2008, the impact on the retail fuel deferral would have been only a portion of the total OPCo amounts that were discussed in the Audit Report.

(AEP Ohio Ex. 3 at 8.) In short, the record is clear that FAC-related expenses and revenues are always allocated into retail and non-retail jurisdictional buckets that cannot be indiscriminately lumped in together. Application of this fundamental ratemaking concept to the factual record in this case is a straightforward matter, as follows.

The total proceeds from the transaction at issue were $71.4 million ($30 million cash and the coal reserve, valued at $41.6 million). The transaction was recorded as a gain in 2008 of

$58.3 million and as a gain in 2009 and 2010 totaling $13.3 million.[2] None of the $58.3 million 2008 gain affected the FAC (it was used as an offset to 2008 fuel costs), but the Ohio retail share of the $13.3 million did reduce fuel costs and thereby the FAC in 2009 and 2010, respectively. The total company gain that has not been credited to FAC fuel costs is derived as follows:

Description	Amount (in millions)
Cash	$30.0
Coal Reserve	$41.6
Total Company Proceeds	$71.6
2009/2010 allocation of Proceeds to fuel costs	$13.3
Total Company Gain not credited to FAC fuel costs	$58.3

On rehearing, the Commission needs to clarify that only the *Ohio retail jurisdictional share* of the $58.3 million gain[3] may be considered for use as offsets against OPCo's retail jurisdictional fuel costs.

II. The Commission should clarify the methodology to be used for determination of the value of the coal reserve so that it can include, as an alternative to valuation through appraisal, the sale of the property after a final, non-appealable decision is reached in this case.

If the Commission is going to seize the value of the coal reserve asset over AEP Ohio's objections, it should be done through a sale of the asset – not by conducting an appraisal or estimating a hypothetical value. The only way to determine the actual value the coal reserve asset is to sell it. The Auditor had the same opinion and Staff counsel made a special point of bringing this out as their only redirect examination of the Auditor during the hearing:

By Mr. Margard:

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[2] $13.3 million credit to fuel expense in 2009 and 2010. See discussion of the record on this point on pages 30-31 of AEP Ohio Initial Brief.

[3] The $58.3 million gain used in this example incorporates the $41.6 million net book value. If the asset is sold rather than appraised (see Assignment of Error II below), the actual net proceeds would be used in this calculation to see what, if any, additional funds would flow through the FAC. For example, the actual net proceeds could be greater than or less than the $41.6 million net book value.

> Q. Ms. Medine, you were asked a number of questions about risks associated with valuing the reserve here. Are there any ways to minimize the risks in valuating the reserve?
> A. I think the best way to get a feel for how much the reserve is worth is actually to sell it because through, you know, an appropriate process where you get as much competition as possible, then you can actually get a full value of the reserve and eliminate the risks because a third party would be assuming the risks related to capital or the risks related to market.
> MR. MARGARD: That's all I have, your Honor. Thank you.

(Tr. I at 116 emphasis added.) Based on that exchange, AEP Ohio limited its re-cross examination to the following question:

> By Mr. Nourse:
> Q. If the Commission were to order Ohio Power to sell the coal reserve, do you think that would positively or negatively affect the price that could be obtained in the market?
> A. If the public knew that you had to sell the coal reserve, is that your question?
> Q. Yeah.
> A. Obviously, that shows that it's a true sale, so it might actually generate additional interest in the market because they know that, in fact, you're going to transact. You're not just doing it for paper purposes. But obviously there's the risk that people might think you could get it at a fire sale, but I think generally it would show that it was going to happen, it was a real sale, and it wasn't simply to put a value on it.

(*Id.*) Thus, the record demonstrates that a sale, not an audit or appraisal, is the best method for determining the value of the coal reserve asset.

Of course, sale of the asset would permanently terminate OPCo's ownership of the asset and should not be undertaken until after the Commission's decision in this case becomes final and non-appealable (*i.e.*, after rehearing and appeals are decided). Taking this approach would not only determine the true market value, it would also save all of the time and expense associated with conducting and litigating a third-party appraisal. AEP Ohio could hire an independent consultant/ sales broker selected by Staff to oversee and conduct the coal reserve asset sale. Based on this competitive approach, the process and outcome of the sale could not be challenged in any subsequent proceeding. The costs for hiring the broker/consultant would be deducted from the proceeds before allocating the net proceeds between retail and non-retail jurisdictions. Consistent with the discussion in Assignment of Error I above, only the retail jurisdictional share of the net sales proceeds would flow to retail customers.

Moreover, the Opinion and Order erred in providing that the audited value/ appraisal would examine whether "the increased value, if any above the $41 million already required to be credited against OP's under-recovery, should accrue to OP ratepayers beyond the value of the reserve that AEPSC booked under the Settlement Agreement." The appraisal of the current value may be less than the $41.6 million net book value and, if so, there should be an adjustment to any credit required under the Opinion and Order. The actual net proceeds would replace the $41.6 million net book value in the table above on page 14, to determine the retail share that should be credited, if any. Otherwise, requiring that the appraisal be done would be unfairly one-sided and would merely confirm that the Commission has not only confiscated the property but has required payment beyond its value.

III. The Opinion and Order engages in selective and unlawful retroactive ratemaking. *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.* (1957), 166 Ohio St. 254; *Lucas Cty. Commrs. v. Pub. Util. Comm.* (1997), 80 Ohio St.3d 344.

The Commission should avoid reversal by the Supreme Court by reconsidering and modifying the decision to confiscate OPCo's coal reserve asset and to retroactively modify the Commission-approved rate plan that was in effect during 2008. In Ohio, there is a constitutional prohibition against the retroactive application of statutes, see Section 28, Article II of the Ohio Constitution, and a statutory presumption in favor of prospective laws, see R.C. 1.48. SB 221 did not become effective until July 31, 2008 – the same date that the Companies filed their ESP application proposing a FAC mechanism starting in 2009. Because AEP Ohio's fuel costs were not regulated during the 2001 through 2008 period and because the ESP's FAC mechanism only became effective in January 2009, the FAC cannot be applied retroactively to encompass recognized transactions occurring in 2008. The same effect would result through any current prudence review of the 2008 contracts for the purpose of disallowing any portion of the ongoing cost impact of those contracts, which were entered into during a period of fuel deregulation when such contracts were not regulated. The Opinion and Order explicitly acknowledged (at 12-13) that "OP's fuel costs were not regulated during the period when the buyout occurred." Unfortunately, the Opinion and Order went on to clawback the value associated with the coal reserve asset.

The approach taken in the Opinion and Order violates the terms of the "FAC-less" RSP rate plan as well as the new FAC adopted in the *ESP Cases* and would amount to retroactive application of SB 221 in violation of the Ohio Constitution and Ohio Revised Code. The effect of the Opinion and Order is to retroactively increase 2008 fuel costs by confiscating the coal reserve asset value that was properly booked under GAAP as an offset to 2008 fuel costs.

This "clawback" credit amounts booked in 2008 during the prior rate plan (*i.e.*, the RSP period) would also violate the longstanding prohibition against retroactive ratemaking established in *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.* (1957), 166 Ohio St. 254. The key principles in the *Keco* decision form Ohio's version of the so-called "filed rate doctrine" and establish the following principles of strictly prospective ratemaking:

- Rates set by the Commission are lawful until such time as they are set aside by the Supreme Court and modified on remand by the Commission;

- A utility is entitled to and must collect the rates set by the Commission, unless a stay order is obtained; and
- No action for unjust enrichment lies to recover the rates that were subsequently determined to be unlawful because the comprehensive regulatory scheme in Title 49 abrogates any common law action in this regard.

(*Keco*, 166 Ohio St. at 256-259.)

The Supreme Court's decision in *Lucas Cty. Commrs. v. Pub. Util. Comm.* (1997), 80 Ohio St.3d 344, is part of the *Keco* progeny, *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 121 Ohio St. 3d 362, 367 (Ohio 2009), and is also instructive. The *Lucas County* decision stands for the proposition that, because the Commission may exercise only that jurisdiction conferred by statute and none of the statutes in Title 49 authorizes the Commission to order refunds based on expired programs, the Commission could not order a refund after a pilot program was terminated. Thus, even where the Commission in retrospect disapproves of a utility decision or activity or cost that has already been incurred and collected by the utility pursuant to rates approved by the Commission, the Commission cannot "clawback" any revenue collected under a prior rate.

In addressing an analogous situation, the United States Court of Appeals for the Eighth Circuit Court memorably concluded that the applicable law was like a "fence that is hog tight, horse high, and bull strong" preventing the federal agency from exceeding its regulatory jurisdiction. *Iowa Utilities Board v. FCC*, 120 F.3d 753, 800 (8th Cir. 1997) (reversed in part and affirmed in part). Likewise, the filed rate doctrine under *Keco* and progeny is a bedrock principle of Ohio regulatory law that forms an impenetrable barrier preventing the Commission from engaging in retroactive ratemaking. As discussed below, not only is the Commission's decision unlawful, it is selective and one-sided retroactive ratemaking, ignoring other significant fuel expenses and losses incurred in 2008.

In its Opinion and Order the Commission attempted to avoid the prohibition against retroactive ratemaking established by *Keko* and *Lucas County*, stating:

> *Keco* does not apply in this situation. The Commission is not considering modifying a previous rate established by a Commission order through the ratemaking process as the Court considered in *Keco*. Rather, the Commission, by ordering the companies to credit more of the proceeds from the Settlement Agreement to OP's deferral balance, is establishing a future rate based upon the real cost of the coal used by the Companies to generate electricity during the 2009 FAC audit period. The proceeds AEP-Ohio received for entering into the Settlement Agreement are but one of the components which impact the Companies cost to provision electricity during 2009. Likewise, *Lucas Cty.* does not apply to the present situation. In *Lucas Cty.*, the Court held that the Commission was not statutorily authorized to order a refund of, or credit for, charges previously collected by a public utility where those charges were calculated in accordance with an experimental rate program which has expired. As noted above, the Commission has not made a determination modifying the rate the Companies collected during 2009. Additionally, there is no experimental rate program involved in the current case. Thus, *Lucas Cty.* does not apply in this matter.

Respectfully, the Commission's efforts to avoid *Keco* and *Lucas County* fail. By offsetting prudently incurred 2009 costs with amounts related to 2008, the practical consequence is that Commission has retroactively reduced the rates that OPCo charged customers in 2008 for SSO generation service by the amount of the offset to the 2009 costs. The argument that the offsets are necessary to determine the "real cost" of 2009 fuel has no basis. The real cost of fuel in 2009 are the costs paid by OPCo for fuel used to generate electricity during 2009. There is no basis for concluding that the actual costs incurred were imprudently incurred or inaccurately recorded on OPCo's books of account. Also regarding application of *Keco*, the Opinion and Order's defense (at 13), that the Commission is not considering modifying a previous rate established by Commission order, is without merit. As explained above, the impact of the Commission's decision is to modify the RSP rate plan that was approved by the Commission, by reaching back into 2008 (when fuel costs were not regulated) and clawback the fuel cost offset properly booked in 2008. The fact that the "remedy" is a prospective adjustment to rates is unavailing as that is always true in cases involving unlawful retroactive ratemaking.

The effort to distinguish *Lucas County* is similarly flawed. The practical effect of the Commission's decision is to retroactively reduce the rates for generation service charged in 2008 by the amount of the offset made to costs in 2009. Because $58 million of the coal reserve asset value was properly booked as an offset to fuel costs in 2008 and the Commission is now unlawfully confiscating that asset, 2008 fuel costs have increased without any rate change or compensation to the Company, which is definitely an after-the-fact change to the RSP.

The Opinion and Order's statement (at 13) that it is merely engaging in fuel cost reconciliation and accounting, as was contemplated in the *ESP I* proceeding, is disingenuous. The Commission has not reconciled rates to prudently-incurred expenses as is normally done. Rather, it has increases the 2008 fuel expenses by retroactively modifying the Company's proper accounting without changing the rates actually charged and collected during that period. There was no reconciliation of FAC rates charged in 2009 to fuel costs incurred or booked in 2009. The latter is the purpose of an FAC mechanism and the former is unlawful retroactive ratemaking.

IV. It is unreasonable and unlawful for the Commission to retroactively modify its prior adjudicatory decision in *ESP I* (Case Nos. 08-917/918-EL-SSO) to establish annual FAC audits to examine fuel procurement practices and expenses for the audit period. *Ohio Consumers' Counsel v. Pub. Util. Comm.* (2006), 111 Ohio St.3d 300, 318; *Ohio Consumers' Counsel v. Pub. Util. Comm.* (1985), 16 Ohio St.3d 9, 10.

Two of the key FAC issues adjudicated and decided in the *ESP Cases* were that: (1) the FAC mechanism would be limited to the ESP period, excluding both the pre-ESP period and the post-ESP period; and (2) annual prudence review of fuel costs would be conducted for fuel costs incurred in 2009, 2010 and 2011. (*ESP Cases*, Opinion and Order at 14-15.) In adopting the annual financial audit and prudence reviews, the Commission relied upon Staff witness Strom's testimony:

> Additionally, Staff recommended that annual reviews of the prudency and appropriateness of the accounting of FAC costs be conducted (Staff Ex. 8 at 3-4) * * * Therefore, we find that the FAC mechanism with quarterly adjustments as proposed by the Companies, as well as an annual prudency and accounting review recommended by Staff, is reasonable and should be approved and implemented as set forth herein.

(*ESP Cases*, Opinion and Order at 14-15.) In the Staff testimony relied upon by the Commission in adopting the FAC mechanism, Mr. Strom described the annual financial audit and prudence review as follows:

> A review of the appropriateness of the accounting of FAC costs, and the prudence of decisions made relative to the components of the FAC, should be conducted annually. I would expect the audit activities associated with these reviews to begin shortly before the end of each calendar year, and be concluded with an audit report to be filed by early March.

(Staff Ex. 8 at 4.) Thus, there was to be an annual financial audit and prudence review for each of the three years of the ESP relative to fuel procurement activity covered by each audit period and the entire scope of the approved FAC is to be strictly limited to the three-year term of the ESP.

These two key matters involving operation of the FAC mechanism during the ESP were fully adjudicated and decided as part of the Commission's decision in the *ESP Case* – the determinations are *res judicata* and cannot be re-litigated or re-applied on a retroactive basis. *Ohio Consumers' Counsel v. Pub. Util. Comm.* (2006), 111 Ohio St.3d 300, 318 (*res judicata* and collateral estoppel can apply to adjudicative Commission proceedings); *Ohio Consumers' Counsel v. Pub. Util. Comm.* (1985), 16 Ohio St.3d 9, 10 (same). As such, the Commission was precluded from revisiting these issues during the term of the ESP – including in this 2009 FAC Audit proceeding.[4]

Indeed, the Commission confirmed in the Commission Entry initiating the RFP to select an auditor in this proceeding:

> The RFP sets forth a three-audit cycle in the Rider FAC audit process. *Audit 1 will be the Rider FAC in place from January 2009 through December 2009*. The scope for Audit 2 will be the Rider FAC in place during January 2010 through December 2010. The scope of Audit 3 will be the Rider FAC in place from January 2011 through December 2011.

(November 18, 2009 Entry at 1 (emphasis added).) This defined scope of audit is consistent with the decision in the *ESP Cases*, as described above, to review fuel procurement activities that occur during each annual audit period that occurs during the ESP term. The current proceeding involves Audit 1, reviewing activities "from January 2009 through December 2009."

The Audit Report issued by EVA also repeatedly acknowledged this limited scope of audit. (*See* Audit Report at 1-1 ("The initial audit covers the January through December 2009 period."), 1-3 ("the initial audit period should include the actual cost for the Rider FAC for the months January 1, 2009 through December 31, 2009").)

The Auditor agreed during cross examination that the scope of a FAC audit is generally constrained to reviewing costs incurred during the audit period. (Tr. I at 58.) Ms. Medine also agreed that, audits are normally limited to the audit period because there are discrete periods of

[4] By contrast, the Commission may *prospectively* change its prior decisions as a general matter, as along as it reasonably justifies the change. See e.g. *Ohio Consumers' Counsel v. Pub. Util. Comm.* (1984), 10 Ohio St.3d 49, 50-51. And the Commission may entertain what would otherwise be considered a collateral attack in the context of crafting a prospective remedy in a complaint case filed under R.C. 4905.26. *Allnet Comm. Servs., Inc. v. Pub. Util. Comm.* (1987), 32 Ohio St.3d 115, 117. But those types of changes are only permissible if the decisional changes are made prospectively. And there is also an important legal distinction when it comes to changing an approved ESP plan; once an ESP is adopted under R.C. 4928.143 for a specified term, there is no indication that the General Assembly intended to allow the Commission to unilaterally change the ESP during that term.

review applicable to each audit – the current audit reviews the prior year's activities and the next audit reviews this year's activity, and so on. (*Id.*) Just because there are long-term impacts of prior fuel-related actions of the Companies, that does not mean that the prior rate plan should be abrogated.

The prior rate plan, the RSP (without a FAC), covered 2008 and the current rate plan, the ESP (with a FAC), covers 2009 costs. The Commission adopted the FAC baseline (discussed in greater detail below) to transition from the RSP to the ESP and neither the ESP nor RSP decisions should be disturbed. Any fuel procurement decision made by AEP Ohio during the time AEP Ohio's fuel costs were unregulated and were not subject to a prudence review under the regulatory compact applicable at that time. Doing so now in order to address continuing costs or a decision from a prior review period is akin to disallowing a contract that was already subject to prudence review in a prior case.

Notably, the Auditor agreed that a long-term coal procurement contract is normally only reviewed once for prudence in an audit. (Tr. I at 85.) Ms. Medine was asked whether, in all of her experience, she has ever observed a regulator going back after a contract passes a prudence review and subsequently making a disallowance associated with the contract based on a new determination that the contract is no longer competitive due to intervening market developments. Her unequivocal response was that "I've *never seen that done* in a regulatory setting." (Tr. I at 87 (emphasis added).)

Nevertheless, the Commission's Opinion and Order reaches back into the prior RSP rate plan and extracted value from an arrangement (the 2008 Settlement Agreement) entered into when fuel cost recovery was unregulated and when there was no prudence review of fuel procurement activity. The Commission in essence revisited a procurement contract that had already been deemed prudent. The Opinion and Order, at 13, attempted to address this error as follows:

> [T]he Commission is not seeking to reach into another audit period in order to modify rates charged during the audit period but rather is rendering its decision in order to match the revenues and benefits incurred during the audit period. Nor has the Commission found that entering into the Settlement Agreement was imprudent. Again, the Commission is only finding that to determine the real economic cost of coal during the audit period, the Commission must consider both the revenues and the benefits received by the Companies pursuant to the Settlement Agreement and not rely solely on the price paid for coal during 2009.

Thus, the Commission once again attempts to rely upon its unsupported and (ironically) fictional "real economic cost" rationale to justify clawing back value from the prior rate plan for use as an offset against actual, prudently incurred, and accurately computed and recorded 2009 fuel costs. FAC costs and revenue for a given period are based on actual accounting book costs. The Company followed GAAP accounting for these costs and revenues and no party challenged the accounting as improper. For the reasons provided above, this rationale is without basis.

V. By reaching back into 2008 and using the results of fuel procurement activities in 2008 to offset fuel costs prudently incurred in 2009, the Opinion and Order unreasonably and unlawfully modified the FAC baseline that was fully litigated and decided in the *ESP I* Cases.

One of the key FAC issues litigated and decided in the *ESP Cases* was to establish the FAC baseline as a one-time determination to put the pre-ESP period fuel costs behind everyone and transition the Companies from a non-FAC period to an active FAC period. Establishment of the FAC baseline was a hotly contested issue that the Commission adjudicated and decided – the FAC baseline is *res judicata* and cannot be re-litigated or re-applied on a retroactive basis. *Ohio Consumers' Counsel v. Pub. Util. Comm.* (2006), 111 Ohio St.3d 300, 318 (*res judicata* and collateral estoppel can apply to adjudicative Commission proceedings); *Ohio Consumers' Counsel v. Pub. Util. Comm.* (1985), 16 Ohio St.3d 9, 10 (same). As such, the Commission is precluded from revisiting these issues during the term of the ESP – including in this 2009 FAC Audit proceeding.

As discussed above, the decision in the *ESP Cases* left no room for re-examination of fuel costs outside the ESP term or limiting recovery of fuel costs within the term based on activity that occurred during the time when AEP Ohio was not operating under a FAC; rather, there was a clear and definitive separation of the ESP period from both the pre-ESP period and the post-ESP period (which makes sense given that the prior rate plan did not have a FAC mechanism and the term of the ESP ended after 2011). The mechanism to transition AEP Ohio from a non-FAC period to an active FAC period was to unbundle the fuel and base generation components of the pre-ESP generation rate to establish FAC and the non-FAC generation rates; the going-in FAC rate level for the ESP was referred to as the "FAC baseline." The FAC baseline was the mechanism to transition from the RSP where no FAC existed to the ESP which did include a FAC.

In litigating the *ESP Cases*, there were widely varying recommendations as to the appropriate FAC baseline:

- Staff's recommended using the 2007 actual fuel costs after adjusting them upward by the annual generation rate increases under the RSP of 3% for CSP and 7% for OPCo, in order to calculate a proxy for 2008 fuel costs. *ESP Cases*, Opinion and Order at 19.
- The Companies' recommendation was based on a rate unbundling methodology starting with the 1999 rates and updating them through rate plan adjustments. *Id.*
- OCC recommended using 2008 actual costs and delay the decision if necessary. (*Id.*)

The Commission weighed the evidence carefully and found that "a proxy is appropriate to establish a baseline. Therefore based on the evidence presented, we agree with *Staff's resulting value as the appropriate FAC baseline.*" (*ESP Cases*, Opinion and Order at 19 (emphasis added) (citing Staff's Brief at 3).) In more explicit terms, the Commission specifically adopted Staff's calculation that 2.625 cents/kWh would be the FAC baseline for CSP and 1.757 cents/kWh would be the FAC baseline for OPCo. (*ESP Cases*, Nelson Rebuttal at 5.)[5]

The primary reason to unbundle AEP Ohio's previously bundled generation rate into FAC and non-FAC components, by (i) determining the FAC baseline and (ii) subtracting it from the generation rate to get the non-FAC rate. But the Staff Brief (at 3), expressly cited and relied upon by the Commission in establishing the FAC baseline (per page 19 of the Opinion and Order), also addressed another reason for establishing a FAC baseline:

> In 2009, the proposed FAC would reflect projected costs. The first step in determining the FAC is to establish a baseline. *This is necessary to ensure that the FAC does not recover fuel costs already being recovered in rates.* The difference between projected costs and the baseline would determine costs to be recovered through the FAC.

(Staff Initial Brief at 3.) Thus, Staff suggested in their position (as expressly adopted by the Commission), that not only would setting the FAC baseline too low render the non-FAC rate too high going into the ESP, but a secondary effect of a baseline set too low would also be that the 2009 FAC rate impact or "bump" experienced by customers would be higher. Conversely, not only would setting the FAC baseline too high render the non-FAC rate too low going into the ESP, but a secondary effect of a baseline set too high would also be that the 2009 FAC rate impact or "bump" experienced by customers would be lower. In addressing their claim that anything other than actual 2008 fuel costs would understate the FAC baseline, OCC witness Smith also raised the same two concerns in her testimony:

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[5] Because the Commission's ESP Cases relied explicitly on Staff's position regarding the FAC baseline in the *ESP Cases* and since questioning by AEP Ohio's legal counsel of Mr. Hess in this case (who was the lead Staff witness in the *ESP Cases*) was abbreviated with respect to Staff's testimony in the *ESP Cases* about the FAC baseline (Tr. II at 243-244), AEP Ohio requests, to the extent necessary, that the Commission take administrative notice of the ESP testimony in this regard to fully consider that issue in light of intervenors' ongoing attempts in this case to undermine these aspects of the Commission's decision in the *ESP Cases*.

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 the 2008 actual fuel cost number had been used. Another result will be that the calculated base generation amount will be larger.

(OCC Ex. 10 at 11-12.) The Commission explicitly referenced this testimony in the Opinion and Order (at 19) in the *ESP Cases*.

A third impact of the FAC baseline relates to the interaction of the first two impacts. Namely, the higher FAC baseline advocated by OCC and IEU would have resulted in a lower non-FAC generation rate and created more "head room" when the 2009 projected fuel costs were added to the non-FAC generation rate going into the ESP plan, so that a larger rate increase could have been implemented to achieve the actual rate levels approved in the *ESP Cases*. But the Commission adopted the lower FAC baseline advocated by Staff (which result was similar to the lower FAC baseline advocated by the Companies, though based on a different methodology). In addition to creating a higher non-FAC generation rate, the lower FAC baseline adopted by the Commission resulted in less "head room" for the initial ESP rate increase. When this situation was coupled with the rate caps adopted as part of the modified ESP, it was a sheer certainty that large fuel deferrals would accumulate through implementation of the ESP. The Commission was well aware of the magnitude of 2009 fuel cost deferral/under-recovery anticipated under the rate cap/phase-in plan it adopted, especially for OPCo. (*ESP Cases*, Entry on Rehearing at 5.) Backing away from the fuel deferrals now would violate the regulatory compact and retroactively modify the prior rate plan approved in the *ESP Cases* when the Commission approved the fuel deferrals for future recovery through a nonbypassable surcharge on all customers in order to mitigate a larger initial rate increase.

Notably, IEU understood all three of these related impacts and explicitly raised them on rehearing in the *ESP Cases*, as IEU again advocated for use of 2008 actual fuel costs to establish the FAC baseline:

> Since 2008 actual fuel costs are now known, since they are significantly higher than the "proxy" adopted by the Commission, and since the "proxy" is, by definition, not the prudently incurred costs authorized in Section 4928.143(B)(2)(a), Revised Code, *the Order results in [1] the non-FAC portion of rates being too high and [2] the risk of increases in the FAC portion as well as [3] the amount of deferrals too great.*

(*ESP Cases*, IEU Application for Rehearing at 12.)

Of course, these are the same fuel deferrals being challenged by OCC and IEU on appeal from the *ESP Cases* before the Supreme Court of Ohio. See *Ohio Consumers' Counsel v. Pub. Util. Comm.* (Case No. 2009-2022; *Industrial Energy Users – Ohio v. Pub. Util. Comm.* (Case No. 2010-730.) And it is the same fuel under-recovery that OCC and IEU are again attempting to reduce or eliminate the recovery for OPCo in this proceeding. OCC witness Duann readily acknowledged that OCC has "many issues" with the Commission's decision regarding the FAC in the *ESP Cases*. Some of the ongoing objections of OCC/IEU regarding the original FAC decision include: not using the offset for off system sales, adopting a weighted average carrying cost for deferrals and establishing a FAC baseline that did not use actual 2008 fuel costs. Tr. II at 207-208. Since OCC and IEU have appealed some of those same issues before the Supreme Court of Ohio, they both obviously have an ongoing interest in attacking those issues whenever possible.

The Commission attempted to rationalize its decision as engaging in a "reconciliation" that is specifically contemplated by its decision in AEP Ohio's *ESP Cases*:

> [T]he Commission has not adjusted the baseline for the 2009 period as decided in the Companies ESP cases. Rather, the Commission, in this case is engaging in a reconciliation and accounting which was explicitly contemplated by the ESP

cases in future FAC proceedings. Otherwise, there would be no rationale for adjustment to recognize extraordinary events affecting 2009 costs such that the Companies 2009 real costs will be comparable to the proxy baseline selected in the ESP proceedings.

What the Commission did was not a simple reconciliation of costs incurred in a prior FAC period with those collected in a subsequent FAC period. What the Commission did, as a practical matter was to "reconcile" the FAC baseline established in the *ESP Cases* into a higher value. That is not the type of "reconciliation" that the decisions in the *ESP Cases* contemplated. Whether the 2009 FAC-related increase in rates were reduced through adoption of a higher FAC baseline (as was advocated by OCC and IEU in the *ESP Cases*) or through a reduction of the current under-recovery/deferral (as is being advocated by certain intervenors in this case), the effect on OPCo is the same. In any case, the Commission established the FAC baseline to put the prior no-FAC period behind everyone and transition to the ESP's active FAC mechanism and it violates the decision in the *ESP Cases* to now reach back into 2008 for purposes of adjusting prudently-incurred costs in the current 2009 audit period. The decisions on these issues are *res judicata* and collateral estoppel prevents intervenors from re-litigating and the Commission from reversing its decision regarding the same issues in this proceeding.

VI. OPCo prudently entered into the 2008 Settlement Agreement, and the Opinion and Order unreasonably and unlawfully impaired that agreement, especially given that the agreement was entered into by OPCo prior to commencement of the ESP's new FAC and before the 2009 audit period (*i.e.*, during a period of unregulated fuel cost and when fuel contracts were not regulated).

The ESP plan was adopted prospectively to cover the 2009-2011 period and transition from the RSP period (where there was no fuel cost regulation) to the ESP period where the FAC mechanism was authorized to permit recovery of all prudently-incurred fuel costs. As such, any ongoing effect of the 2008 agreements in the current 2009 review period cannot be retroactively modified or disallowed in this proceeding.

The Companies supported the prudence of the 2008 transactions through the testimony of Companies witnesses Dooley, Rusk and Nelson. And neither the Auditor nor any intervenor witness even conducted a prudence review of the 2008 agreements, let alone supported the view that any aspect of the agreements was imprudent. On the contrary, the Audit Report categorically concludes regarding the unprecedented coal procurement challenges of the 2007-2008 period (at 1-4) that "AEPSC did an exceptional job during this period particularly with those suppliers that faced financial hardship." Moreover, the Companies submitted unrebutted evidence that the 2008 transactions were properly accounted for per GAAP during a period when fuel costs were unregulated.

Companies witness Nelson provided testimony regarding AEP Ohio's overall position on this issue:

> At the time the 2008 Settlement Agreement was entered into, there was no FAC and no way to know that the FAC would be reinstated for the Companies in 2009. Also there is no guarantee that the Companies will always have an FAC in the future. Consequently, the Companies maintain that the Commission should limit its review in this proceeding to the audit period. OPCo is comfortable that the review will confirm that it made the proper entries on its books and that payments made or compensation received were treated in accordance with FAC/ESP commencement on January 1, 2009.

(Cos. Ex. 3 at 5.)

Companies witness Rusk testified that the 2008 Settlement Agreement came about because the coal supplier sought payment for change in law claims related to safety expenditures, increases it claimed should be allowed under the existing agreement, and indicated that it may not be able to deliver the existing contractual tonnage due to mining costs in excess of the contractual sale price to OPCo. (Cos. Ex. 2 at 11.) The coal supplier indicated that the contract had been conceived without any expectation of its costs escalating so much and that this had resulted in revenues from the contract being less than their cost to produce. (*Id.* at 11-12.) In response, AEPSC performed an assessment of the claims. (*Id.*) While AEPSC expects its suppliers to honor the terms of their contracts, it also understands that disputes can result in litigation and that the contract in dispute will often not survive the legal process. (*Id.*) As Mr. Rusk testified, it was AEPSC's judgment that, in this instance, the best approach was to attempt to negotiate a resolution to the dispute that would optimize the value associated with the original agreement. (*Id.*)

The Commission specifically determined in its Opinion and Order, at 13, that it had not found that the Settlement Agreement was imprudent: "Nor has the Commission found that entering into the Settlement Agreement was imprudent." Utility decisions are presumed to be prudent. Accordingly, the presumption of imprudence coupled with the Commission's finding of no imprudence, in fact, confirmed the prudence of the Settlement Agreement. Yet, the practical effect of the Commission's decision is that it is amounts to a conflicting finding of imprudence with regard to OPCo entering into the Settlement Agreement. On rehearing this conflict must be resolved by reversing the directive to net amounts from the 2008 Settlement Agreement against 2009 fuel costs.

VII. The Opinion and Order unreasonably and unlawfully ignored the 2008 Production Bonus Agreement, which increased fuel expenses in 2008.

It is not reasonable to, on the one hand reach back to 2008 and bring value forward to the current review period, yet, on the other hand, to ignore the increased fuel costs resulting from other agreements during the pre-FAC time period. Yet, the Opinion and Order does just that with regard to the 2008 Production Bonus Agreement. (*See* Cos. Ex. 1 at 4-5; Cos. Ex. 2 at 16-

20; and Cos. Ex. 3 at 6.) The Commission's decision does not even mention the $28.6 million 2008 Production Bonus Agreement. Pursuant to this agreement, in order to assure that the supplier remained in business and able to provide coal at a below-market price levels during 2008 and after 2008, OPCo made a $28.6 million payment to the supplier. The payment increased 2008 fuel costs by that amount (and reduced 2008 earnings). OPCo properly did not seek to recover this cost, incurred during the pre-ESP/FAC regulatory structure, through 2009 FAC rates. However, this countervailing example supports OPCo's position that the Commission should not reach back beyond the audit period and extract value from the other 2008 agreements by reducing OPCo's 2009 FAC under-recovery balance. Alternatively, it provides an example of fuel costs incurred in 2008 that should be used to offset any claw back into 2009 of amounts relating to the 2008 Settlement Agreement.

VIII. The Opinion and Order unreasonably and unlawfully concluded that the value of the coal reserve property acquired as a result of the 2008 Settlement Agreement should be offset against FAC costs because it is an OPCo asset on which ratepayers have no claim.

The coal reserve is an asset sitting on OPCo's books and already properly accounted for in 2008 business. This asset was received in conjunction with the 2008 Settlement Agreement and properly accounted for in 2008.

Customers pay for electricity, not utility assets. Decades ago, the Commission settled the issue of whether ratepayers have an ownership in utility assets when CSP sold its ownership of the Conesville Coal Preparation Plant for a gain in 1988. In that case, the OCC argued that ratepayers should receive a portion of the gain because fuel clause ratepayers had purchased an ownership interest in the assets through their funding of the accumulated depreciation of the equipment. The Commission rejected OCC's argument and found as follows:

> The Commission believes that CSP's EFC ratepayers did not purchase an interest in the … equipment through the equipment rental component included in the cost of … coal. *The Commission does not find it appropriate to conclude that the actual nature of the rental component is similar to an installment sale.* The inclusion of an equipment rental component in the cost of coal does not confer the benefits or the risks of ownership of the equipment on those who pay EFC rates which include the cost of coal.

Case No. 88-102-EL-EFC, Opinion and Order (October 28, 1988) (emphasis added). In its December 20, 1988 Entry on Rehearing, the Commission again concluded that it "has no doubt that the ratepayers were not purchasing an ownership interest in the equipment" through the fuel clause rates and the Commission asked the rhetorical question of whether OCC would be before the Commission supporting a rate adjustment to the Company's favor based on this ownership theory had the equipment been sold at a loss.

The Commission's holding that customers do not enter into an installment sale for utility assets when they pay rates for service applies here with additional force, given that OPCo customers did not even pay a separate fuel rate for generation service during the pre-ESP period. Ratepayers have no claim on the coal reserve asset. In addition, there simply is no basis in the record to support a present value of the coal reserve asset. As Companies witness Rusk noted in his rebuttal testimony, the initial amount booked for the asset in 2008 was based on an October 2007 report done by an independent contractor and that was the only value known to AEPSC at the time the 2008 Settlement Agreement was entered into and accounted for. (Cos. Ex. 6 at 4-5.) Consequently, there is no legal basis for the Opinion and Order's seizure of value related to the coal reserve, which essentially converted it into a ratepayer-owned asset, and reducing 2009 (or future) fuel costs by the purported value of the asset.

Nor is there any basis for concluding that the reserve could be liquidated and sold for $41.6 million, let alone a higher amount. Yet, the Opinion and Order unreasonably and unlawfully concludes that the reserve is worth at least $41.6 million and reduced the 2009 FAC costs by that amount. Thus, on top of illegally reaching back before the ESP/FAC period to extract value from transactions outside of and unrelated to the FAC audit period, the Opinion and Order fabricates value related to the coal reserve and then imposes on OPCo the obligation of guaranteeing that the coal reserve has a minimum value (of $41.6 million). There is no legal or record basis for such a decision and the Commission committed an unexplained departure from its own precedent in reaching this decision.

IX. The Opinion and Order erred by concluding that the Delivery Shortfall Agreement and the Contract Support Agreement may be examined by a future audit.

The Commission further determined in its Opinion and Order, at 14, with regard to the purported benefits associated with the Delivery Shortfall Agreement and the Contract Support Agreement, both of which OPCO also executed in 2008, that "any effect these agreements may have had on AEP-Ohio's fuel costs, if any, would appear to apply in time periods outside of the current [2009] audit." The Commission concluded by stating that while they "may be examined by a future audit, those agreements will not be further examined as part of the current audit." This conclusion is also unreasonable and unlawful for the same reasons provided above with regard to Assignments of Error III –VIII. In particular, it would involve selective and unlawful retroactive ratemaking; it would unlawfully use the results of fuel procurement activities related to 2008 and use them to offset fuel costs prudently incurred subsequent periods; it would unlawfully modify the FAC baseline that was fully litigated and decided in the *ESP Cases*; it would unlawfully impair agreements that OPCO prudently entered into in 2008; and it would unreasonably and unlawfully ignore the 2008 Production Bonus Agreement that increased fuel costs in 2008.

X. It is unnecessary to require AEP Ohio to add fuel procurement procedures as it updates its fuel procurement policy manual.

In its Opinion and Order, at 12, the Commission adopted the auditor's management/performance (m/p) recommendations 2 through 6 as outlined in the audit. AEP Ohio generally agreed with, or did not oppose, the auditor's recommendations 2-6. However, there is one respect in which AEP Ohio seeks clarification of the Commission's adoption of recommendations 2-6. In particular, in recommendation 5 the auditor recommended that AEPSC should finalize the update of its policies and procedures manual to reflect current business practices and that both the policies and procedures manual (and Conesville Coal Preparation Plant study) should be reviewed in the next m/p audit.

AEP Ohio witness Rusk testified and the Opinion and Order noted, regarding m/p recommendation 5, that AEPSC is currently updating its fuel procurement policies and planned to have those updates completed in time for the next m/p audit. However, as the Opinion and Order also noted, Mr. Rusk clarified that those revisions are focused on procurement policies, and not focused on fuel procurement procedures because AEP Ohio believes that policies, not procedures, result in the most efficient procurement of fuel at the lowest reasonable price.

AEP Ohio requests the Commission to clarify, on rehearing, that it is not necessary for AEPSC to update the fuel procurement policy manual to include procedures. Rather, AEP Ohio requests that the Commission confirm that it is required only to finalize updates to the fuel procurement policies and that the auditor is directed to review those updated policies in the next m/p audit proceeding.

CONCLUSION

The Commission's Opinion and Order is unlawful and unreasonable in several respects, as outlined above, and must be reconsidered and reversed.

Respectfully Submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a copy of AEP Ohio's Application for Rehearing was served on the persons stated below via electronic mail this 22nd day of February 2012.

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of an 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

OPINION AND ORDER

The Commission, considering the above-entitled applications and the record in these proceedings, hereby issues its opinion and order in this matter.

APPEARANCES:

Marvin I. Resnik and Steven T. Nourse, American Electric Power Service Corporation, One Riverside Plaza, Columbus, Ohio 43215, and Porter, Wright, Morris & Arthur, by Daniel R. Conway, 41 South High Street, Columbus, Ohio 43215, on behalf of Columbus Southern Power Company and Ohio Power Company.

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Boehm, Kurtz & Lowry, by David F. Boehm and Michael L. Kurtz, 36 East Seventh Street, Suite 1510, Cincinnati, Ohio 45202, on behalf of Ohio Energy Group.

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Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff, Mike Settineri and Betsy L. Elder, 52 East Gay Street, Columbus, Ohio 43216-1008, and Bobby Singh, Integrys Energy, 300 West Wilson Bridge Road, Worthington, Ohio 43085, on behalf of Integrys Energy.

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Schottenstein, Zox & Dunn Co., LPA, by Gregory H. Dunn, Christopher L. Miller, and Andre T. Porter, 250 West Street, Columbus, Ohio 43215, on behalf of the Association of Independent Colleges and Universities of Ohio.

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Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff and Stephen M. Howard, 52 East Gay Street, Columbus, Ohio 43216-1008, on behalf of Direct Energy Services, LLC.

McDermott, Will & Emery, LLP, by Grace C. Wung, 600 Thirteenth Street, N.W., Washington, D.C. 20005, on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc., LP, Macy's, Inc., and BJ's Wholesale Club, Inc.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff and Stephen M. Howard, 52 East Gay Street, Columbus, Ohio 43216-1008, on behalf of Ohio Association of School Business Officials, Ohio School Boards Association, and Buckeye Association of School Administrators.

Michael R. Smalz and Joseph E. Maskovyak, Ohio State Legal Services Association, 555 Buttles Avenue, Columbus, Ohio 43215, on behalf of Appalachian People's Action Coalition.

OPINION:

I. HISTORY OF PROCEEDINGS

On July 31, 2008, Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio or the Companies) filed an application for a standard service offer (SSO) pursuant to Section 4928.141, Revised Code. The application is for an electric security plan (ESP) in accordance with Section 4928.143, Revised Code.

By entries issued August 5, 2008, and September 5, 2008, the procedural schedule in this matter was established, including the scheduling of a technical conference and the evidentiary hearing. A technical conference was held regarding AEP-Ohio's application on August 19, 2008. A prehearing conference was held on November 10, 2008, and the evidentiary hearing commenced on November 17, 2008, and concluded on December 10, 2008. The Commission also scheduled five local public hearings throughout the Companies' service area.

The following parties were granted intervention by entries dated September 19, 2008, and October 29, 2008: Ohio Energy Group (OEG); the Office of the Ohio Consumers' Counsel (OCC); Kroger Company (Kroger); Ohio Environmental Council (OEC); Industrial Energy Users-Ohio (IEU); Ohio Partners for Affordable Energy (OPAE); Appalachian People's Action Coalition (APAC); Ohio Hospital Association (OHA); Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc. (Constellation); Dominion Retail, Inc. (Dominion); Natural Resources Defense Council (NRDC); Sierra Club – Ohio Chapter (Sierra); National Energy Marketers Association (NEMA); Integrys Energy Service, Inc. (Integrys); Direct Energy Services, LLC (Direct Energy); Ohio Manufacturers' Association (OMA); Ohio Farm Bureau Federation (OFBF); American Wind Energy Association, Wind on Wires, and Ohio Advance Energy (Wind Energy); Ohio Association of School Business Officials, Ohio School Boards Association, and Buckeye Association of School Administrators (collectively, Schools); Ormet Primary Aluminum Corporation (Ormet); Consumer Powerline; Morgan Stanley Capital Group Inc.; Wal-Mart Stores East, LP and Sam's East, Inc., Macy's, Inc., and BJ's Wholesale Club, Inc. (collectively, Commercial Group); EnerNoc, Inc.; and the Association of Independent Colleges and Universities of Ohio.

At the hearing, AEP-Ohio offered the testimony of 11 witnesses in support of the Companies' application, 22 witnesses testified on behalf of various intervenors, and 10 witnesses testified on behalf of Staff. At the local public hearings held in this matter, 124 witnesses testified. Briefs were filed on December 30, 2008, and reply briefs were filed on January 14, 2009.

A. Summary of the Local Public Hearings

Five local public hearings were held in order to allow CSP's and OP's customers the opportunity to express their opinions regarding the issues in this proceeding. The hearings were held in the evenings in Marietta, Canton, Lima, and Columbus. Additionally, an afternoon hearing was held in Columbus. At those hearings, public testimony was heard from 21 customers in Marietta, 21 customers in Canton, 17 customers in Lima, 25 customers at the afternoon hearing in Columbus and 40 customers at the evening hearing in Columbus. In addition to the public testimony, numerous letters were filed in the docket by customers stating concern about the applications.

The principal concern expressed by customers, both at the public hearings and in letters, was over the increases in customer rates that would result from the approval of the ESP applications. Witnesses stated that any increase in rates would negatively impact low-income customers, the elderly, and those on fixed incomes. Customers cited the recent downturn in the economy as the primary source of their apprehension. It was noted by many at the hearings that customers are also facing increases in other utility charges, gasoline, food, and medical expenses and that the proposed increases would cause undue hardship. On the other hand, some witnesses at the public hearings and in the letters filed in the docket acknowledged AEP-Ohio as a good corporate partner in their respective communities.

B. Procedural Matters

1. Motion to Strike

On January 7, 2009, AEP-Ohio filed a motion to strike a section of the brief jointly filed by OCC and Sierra (collectively, OCEA). More specifically, AEP-Ohio filed to strike the sentence starting on line 2 of page 63 ["In fact,"] through the first two lines of page 64, including footnotes 244 to 248. AEP-Ohio argues that the above-cited portion of OCEA's brief, regarding the deferral of fuel expenses and the carrying charges and the tax effect thereof, relies upon testimony offered by OCC witness Effron in the FirstEnergy Distribution Case.[1] AEP-Ohio notes that Mr. Effron was not a witness in this ESP proceeding and, therefore, was not available for the Companies, or any other party, to cross-examine. Accordingly, the Companies argue that consideration of Mr. Effron's testimony in this matter would be a denial of the Companies' due process rights, and request that the specified portion of OCEA's brief be stricken. On January 14, 2009, OCC filed a memorandum contra the motion to strike. OCC agreed to withdraw the second and third sentences on page 63, the quoted testimony of Mr. Effron on page 63, and footnotes 244 to 248 on pages 63 and 64. However, OCC contends that AEP-Ohio's

1 *In re Ohio Edison Company, The Cleveland Electric Illuminating Company, and Toledo Edison Company*, Case No. 07-551-EL-AIR, et al. (FirstEnergy Distribution Case).

motion is overly broad and the remaining portion of the brief that AEP-Ohio seeks to strike is appropriate legal argument regarding deferrals on a net-of-tax basis and, therefore, should remain. AEP-Ohio filed a reply on January 16, 2009. AEP-Ohio first notes that because the memorandum contra was filed by OCC only and Sierra did not respond to the motion, it is not clear whether Sierra is also willing to withdraw the portions of the brief listed in the memorandum contra. AEP-Ohio also argues that the remaining portion of this particular argument in OCEA's brief should be stricken with the removal of the footnotes. With this removal, AEP-Ohio then argues that there is no longer any support in the brief for such arguments. By letter docketed January 22, 2009, Sierra confirmed that it joins OCC in OCC's withdrawal of the limited portions of the OCEA brief as stated by OCC in its January 14, 2009, reply.

The Commission grants, in part, and denies, in part, AEP-Ohio's motion to strike OCEA's brief. The Commission agrees with AEP-Ohio and OCC that the use of Mr. Effron's testimony filed in the FirstEnergy Distribution Case in this proceeding was inappropriate and, therefore, we accept OCC's and Sierra's withdrawal of that portion of their brief. As for the remaining portion of OCEA's brief that AEP-Ohio has requested to be stricken, we agree with OCC that the language that discusses the calculation of deferred fuel expenses on a net-of-tax basis could be construed to be legal argument on brief, which rationalized why the issue should be decided in OCEA's favor. Moreover, we can surmise that if OCEA had recognized its error in the drafting stage of the brief, that OCEA would have drafted similar legal arguments without referencing Mr. Effron's testimony. Accordingly, we will only strike the portions of OCEA's brief that OCC and Sierra have agreed to withdraw.

2. <u>Motion for AEP-Ohio to Cease and Desist</u>

On February 25, 2009, Integrys filed a motion with the Commission requesting that the Commission direct AEP-Ohio to cease and desist the Companies' refusal to process SSO retail customer applications to enroll in the Interruptible Load for Reliability (ILR) Program of PJM Interconnection, LLC (PJM). Integrys also filed a request for an expedited ruling; however, Integrys represented that counsel for AEP-Ohio objected to the expedited ruling request. Integrys is a registered curtailment service provider with PJM and as such receives notices from PJM and coordinates with retail customers to curtail load. Integrys argues that retail customer participation in PJM demand response programs was raised in the Companies' ESP application and has not yet been decided by the Commission. For this reason, Integrys contends that AEP-Ohio lacks the authority to refuse to process the ILR applications and the denial of the application violates the Companies' tariffs. Two other curtailment service providers in the AEP-Ohio service territory, Constellation and KOREnergy, Ltd., filed memoranda in support of Integrys' motion.[2]

On March 2, 2009, AEP-Ohio filed a memorandum contra the motion to cease and desist. AEP-Ohio affirms the arguments made in this proceeding to prohibit retail customers from participating in PJM's demand response programs. Further, AEP-Ohio argues, among other things, that despite the claims of Integrys andConstellation, AEP-Ohio is providing, in a timely manner, the load data required for customer enrollment in the PJM ILR program, informs the customer that AEP-Ohio is not consenting to the customer's participation in the program, and discloses that the matter is currently pending before the Commission.

On March 9, 2009, Integrys and Constellation filed a withdrawal of the motion to direct AEP-Ohio to cease and desist. The movants state that despite AEP-Ohio's assertions that the applicants were not eligible to participate in PJM's demand response programs, PJM rejected AEP-Ohio's opposition to the ILR applications and processed the ILR applications. Integrys and Constellation further state that, except for two pending applications, all their customers in the AEP-Ohio service territory have been certified for participation in the PJM programs.

As the parties acknowledge, this matter was presented for the Commission's consideration as part of the ESP application. The Commission, therefore, specifically addresses and discusses the issues raised concerning SSO retail customer participation in PJM demand response programs at Section VI.C of this opinion and order. Accordingly, we grant Integrys' and Constellation's request to withdraw their motion to cease and desist.

II. DISCUSSION

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 AEP-Ohio's application, the Commission is cognizant of the challenges facing Ohioans and the electric industry and will be guided by the policies of the state as established by the General Assembly in Section 4928.02, Revised Code, which was amended by Senate Bill 221 (SB 221).

Section 4928.02, Revised Code, states that it is the policy of the state, inter alia, to:

2 KOREnergy, Ltd., has not filed to intervene in this proceeding and, therefore, its memoranda in support will not be considered.

(1) Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service.

(2) Ensure the availability of unbundled and comparable retail electric service.

(3) Ensure diversity of electric supplies and suppliers.

(4) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service including, but not limited to, demand-side management (DSM), time-differentiated pricing, and implementation of advanced metering infrastructure (AMI).

(5) Encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems in order to promote both effective customer choice and the development of performance standards and targets for service quality.

(6) Ensure effective retail competition by avoiding anticompetitive subsidies.

(7) Ensure retail consumers protection against unreasonable sales practices, market deficiencies, and market power.

(8) Provide a means of giving incentives to technologies that can adapt to potential environmental mandates.

(9) Encourage implementation of distributed generation across customer classes by reviewing and updating rules governing issues such as interconnection, standby charges, and net metering.

(10) Protect at-risk populations including, but not limited to, when considering the implementation of any new advanced energy or renewable energy resource.

In addition, SB 221 amended Section 4928.14, Revised Code, which now provides that on January 1, 2009, electric utilities must provide consumers with an SSO, consisting of either a market rate offer (MRO) or an ESP. The SSO is to serve as the electric utility's default SSO. The law provides that electric utilities may apply simultaneously for both an

MRO and an ESP; however, at a minimum, the first SSO application must include an application for an ESP. Section 4928.141, Revised Code, specifically provides that an SSO shall exclude any previously authorized allowances for transition costs, with such exclusion being effective on and after the date that the allowance is scheduled to end under the electric utility's rate plan. In the event an SSO is not authorized by January 1, 2009, Section 4928.141, Revised Code, provides that the current rate plan of an electric utility shall continue until an SSO is authorized under either Section 4928.142 or 4928.143, Revised Code.

AEP-Ohio's application in this proceeding proposes an ESP, pursuant to Section 4928.143, Revised Code. Paragraph (B) of Section 4928.141, Revised Code, requires the Commission to hold a hearing on an application filed under Section 4928.143, Revised Code, to send notice of the hearing to the electric utility, and to publish notice in a newspaper of general circulation in each county in the electric utility's certified territory.

Section 4928.143, Revised Code, sets out the requirements for an ESP. Under paragraph (B) of Section 4928.143, Revised Code, an ESP must include provisions relating to the supply and pricing of generation service. The plan, according to paragraph (B)(2) of Section 4928.143, Revised Code, may also provide for the automatic recovery of certain costs, a reasonable allowance for certain construction work in progress (CWIP), an unavoidable surcharge for the cost of certain new generation facilities, conditions or charges relating to customer shopping, automatic increases or decreases, provisions to allow securitization of any phase-in of the SSO price, provisions relating to transmission-related costs, provisions related to distribution service, and provisions regarding economic development.

The statute provides that the Commission is required to approve, or modify and approve the ESP, if the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code. In addition, the Commission must reject an ESP that contains a surcharge for CWIP or for new generation facilities if the benefits derived for any purpose for which the surcharge is established are not reserved or made available to those that bear the surcharge.

The Commission may, under Section 4928.144, Revised Code, order any just and reasonable phase-in of any rate or price established under Section 4928.141, 4928.142, or 4928.143, Revised Code, including carrying charges. If the Commission does provide for a phase-in, it must also provide for the creation of regulatory assets by authorizing the deferral of incurred costs equal to the amount not collected, plus carrying charges on that amount, and shall authorize the deferral's collection through an unavoidable surcharge.

By finding and order issued September 17, 2008, in Case No. 08-777-EL-ORD (SSO Rules Case), the Commission adopted new rules concerning SSO, corporate separation, and reasonable arrangements for electric utilities pursuant to Sections 4928.06, 4928.14, 4928.17, and 4905.31, Revised Code. The rules adopted in the SSO Rules Case were subsequently amended by the entry on rehearing issued February 11, 2009.

B. <u>State Policy - Section 4928.02, Revised Code</u>

AEP-Ohio submits that, contrary to the views of the intervenors, Section 4928.02, Revised Code, does not impose additional requirements on an ESP and the ESP should not be modified or rejected because it does not satisfy all of the policies of the state. According to the Companies, "[t]he public interest is served if the ESP is more favorable in the aggregate than the expected results of an MRO" (Cos. Br. at 15).

OHA asserts that the Commission "must view the 'more favorable in the aggregate' standard through the lens of the overriding 'public interest,'" and that the public interest cannot be served if the result is not reasonable (OHA Br. at 10). OPAE/APAC seems to state that the ESP must be more favorable in the aggregate and comply with the state policy, but also recognizes that state policies are to be used to guide the Commission in its approval of an ESP (OPAE/APAC Br. at 3). OEG agrees that the policy objectives are required to be met prior to the approval of an ESP (OEG Br. at 1). The Commercial Group submits that costs must be properly allocated to ensure that the policies of the state are met, to improve price signals, and to ensure effective retail competition (Commercial Group Br. at 5).

In its reply brief, AEP-Ohio maintains that its proposed ESP is consistent with the policy of the state as delineated in Sections 4928.02(A) through (N), Revised Code, and is "worthy of approval, without modification" (Cos. Reply Br. a 7). According to the Companies, the ESP advances the general policy objectives of the policy of the state (Id. at 6-7). Furthermore, the Companies argue that the concerns raised by some intervenors regarding the impact of AEP-Ohio's ESP on the difficult economic conditions would have the Commission ignore the statutory standard for approving an ESP and, instead, establish rates based on the current economic conditions (Cos. Reply Br. at 7). While the Companies believe that aspects of the proposed ESP address these concerns (e.g., fuel deferrals), they argue that their SSO must be established in accordance with applicable ESP statutory provisions (Id.).

As explained above, and previously in our opinion and order issued in the FirstEnergy ESP proceeding,[3] the Commission believes that the state policy codified by the General Assembly in Chapter 4928, Revised Code, sets forth important objectives,

3 *In re Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company,* Case No. 08-935-EL-SSO, Opinion and Order at 12 (December 19, 2008) (FirstEnergy ESP Case).

which the Commission must keep in mind when considering all cases filed pursuant to that chapter of the code. As noted in the FirstEnergy ESP case, in determining whether the ESP meets the requirements of Section 4928.143, Revised Code, we take 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. Accordingly, we agree with AEP-Ohio and will use these policies as a guide in our decision-making in this case, just as we did in the FirstEnergy ESP Case (Cos. Reply Br. at 6).[4] The Commission has reviewed the ESP proposal presented by AEP-Ohio, 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.

C. Application Overview

In their application, the Companies are requesting authority to establish an SSO in the form of an ESP pursuant to the provisions of Sections 4928.141 and 4928.143, Revised Code. The proposed ESP is to be effective for a three-year period commencing January 1, 2009. According to the Companies, pursuant to the proposed ESP, the overall, estimated increases in total customer rates, including generation, transmission, and distribution, would be an average of 13.41 percent for CSP and 13 percent for OP in 2009, and 15 percent in 2010 and 2011 for both CSP and OP (Cos. Ex. 1, Exhibit DMR-1). The Companies also propose a 15 percent cap per year on the total allowable increases for each customer rate schedule should the actual costs be higher than expected, excluding transmission costs and costs associated with new government mandates (Cos. App. at 6).

III. GENERATION

A. Fuel Adjustment Clause (FAC)

The Companies contend that Section 4928.143(B)(2)(a), Revised Code, authorizes the implementation of a FAC mechanism to recover prudently incurred costs associated with fuel, including consumables related to environmental compliance, purchased power costs, emission allowances, and costs associated with carbon-based taxes and other carbon-related regulations (Cos. Ex. 7 at 4-7).

4 Some intervenors recognize that the state policy objective must be used as a guide to implement the ESP provision (IEU Br. at 19; OPAE/APAC Br. at 3).

1. FAC Costs

The Companies proposed to include in the FAC mechanism types of costs recovered through the electric fuel component (EFC) previously used in Ohio[5] (Cos. Ex. 7 at 3-4). In addition to those types of costs, the Companies stated that Section 4928.143(B)(2)(a), Revised Code, provides for a broader cost-based adjustment mechanism that authorizes the inclusion of all prudently incurred fuel, purchased power, and environmental components (Id. at 4). Companies' witness Nelson itemized and described the accounts that the Companies proposed to include in their FAC mechanism (Id. at 5-7).

Staff, OCC, and Sierra support the FAC mechanism that will be updated and reconciled quarterly (Staff. Ex. 8 at 3-4; OCEA Br. at 47-48, 67-68; OCC Ex. 11 at 4-5, 31-40). Specifically, Staff witness Strom testified that the costs proposed to be recovered through the FAC mechanism are appropriate and recovery of those costs through a FAC mechanism is logical (Staff Ex. 8 at 3). OCC and Sierra also agree that Section 4928.143(B)(2)(a), Revised Code, authorizes the enactment of a FAC mechanism to automatically recover certain prudently incurred costs (OCEA Br. at 47), and OCC does not seem to oppose the list of categories of accounts proposed to be included in the FAC by Companies witness Nelson (OCC Ex. 11 at 18-20). Additionally, Staff recommended that annual reviews of the prudency and appropriateness of the accounting of FAC costs be conducted (Staff Ex. 8 at 3-4), and OCC recommended that an interest charge be paid to customers on any over-recovered fuel costs in a quarterly period until the subsequent reconciliation occurs, similar to the carrying charge for any under-recovery that she believed the Companies were proposing to collect[6] (OCC Ex. 11 at 4). Kroger and IEU, however, seem to state that a FAC mechanism cannot be established until a cost-of-service or earnings test is completed (Kroger Br. at 9-10; IEU Br. at 12-15). IEU also questioned the appropriate term of the proposed FAC mechanism (IEU Br. at 13; Tr. Vol. IX at 143-146).

The Commission believes that the establishment of a FAC mechanism as part of an ESP is authorized pursuant to Section 4928.143(B)(2)(a), Revised Code, to recover prudently incurred costs associated with fuel, including consumables related to environmental compliance, purchased power costs, emission allowances, and costs associated with carbon-based taxes and other carbon-related regulations. Given that the FAC mechanism is authorized pursuant to the ESP provision of SB 221, we will limit our authorization, at this time, to the term of the ESP.

5 See Sections 4905.01(G), 4905.66 through 4905.69, and 4909.159, Revised Code (repealed January 1, 2001); Chapter 4901:1-11, Ohio Administrative Code (O.A.C.) (rescinded November 27, 2003).

6 In AEP's Brief, the Companies clarified that they did not propose to collect a carrying charge on any FAC under-recovery in one quarterly period until a reconciliation in the subsequent period occurred. The only carrying charge that they proposed was on the FAC deferrals that would not be collected until 2012-2018 (Cos. Br. at 27).

With regard to interest charges assessed on any over- or under-recoveries for FAC costs within the quarterly period until the subsequent reconciliation occurs, we agree with OCC witness Medine that symmetry should exist if interest charges were assessed on any under-recoveries (Tr. Vol. VI at 210). However, we do not conclude that any interest charges on either over- or under-recoveries are necessary as a deterrent to the creation of over- or under-recoveries as OCC witness Medine suggests (Id. at 210-211). As proposed by the Companies and supported by others, the FAC mechanism includes a quarterly reconciliation to actual FAC costs incurred, which will establish the new charge for the subsequent quarter. These quarterly adjustments combined with the annual review proposed by Staff to review the appropriateness of the accounting of the FAC costs and the prudency of decisions made are sufficient to control the over- or under-recoveries that may occur within a particular quarter. Therefore, we find that the FAC mechanism with quarterly adjustments as proposed by the Companies, as well as an annual prudency and accounting review recommended by Staff, is reasonable and should be approved and implemented as set forth herein.

(a) Market Purchases

As part of the FAC costs, the Companies proposed to purchase incremental power on a "slice of the system basis" equal to 5 percent of each company's load in 2009, 10 percent in 2010, and 15 percent in 2011 (Cos. Ex. 2-A at 21). The Companies argue that while these purchases will be included in the FAC mechanism, as the appropriate recovery mechanism for these costs, the purchases are permitted as a discretionary component of an ESP filing authorized by Section 4928.143(B)(2), Revised Code, which states: "The plan may provide for or include, without limitation, any of the following:" (emphasis added) (Cos. Br. at 37). To support its proposal, AEP-Ohio states that the purchases reflect the continued transition to market rates and represent an appropriate recognition of the Companies' incorporation of the loads of Ormet Primary Aluminum Company (Ormet) and the certified territory formerly served by Monongahela Power Company (MonPower) (Cos. Ex. 2-A at 21-22). The Companies further assert that, during the ESP, they should be able to continue to recover a market-based generation price for serving these loads, as was previously authorized by the Commission during the RSP period.

Staff supported market purchases sufficient to meet the additional load responsibilities that the Companies assumed for the addition of the former MonPower customers and Ormet to the Companies' system, which equals approximately 7.5 percent of the Companies' total loads (Staff Ex. 10 at 5). However, based on the size of the additional load assumed by the Companies, Staff only recommended that the incremental power purchases equal, on average, 5 percent of each company's load in 2009, 7.5 percent in 2010, and 10 percent in 2011 (Id.).

The Companies responded to Staff's reduction in the amount of market purchases by adding that the Companies also intended to utilize their proposed levels of market purchases to encourage economic development (Cos. Ex. 2-E at 7).

Various parties oppose the inclusion of incremental "slice of the system" power purchases in AEP-Ohio's ESP. OEG witness Kollen testified that the Commission should reject this provision of AEP-Ohio's ESP because the Companies have not demonstrated a need for the excess generation purchased on the market to meet its existing load, and such "purchases are not prudent because they will uneconomically displace lower cost Company owned generation and cost-based purchased power that is available to meet their loads" (OEG Ex. 3 at 3, 9-10). IEU witness Bowser agrees that this portion of the ESP should be rejected (IEU Ex. 10 at 9). Kroger witness Higgins also concurs, stating: "The only apparent purpose of these slice-of-system purchases is to serve as a device for increasing prices charged to customers" (Kroger Ex. 1 at 9). OCEA concurs with the testimony offered by these intervenor witnesses (OCEA Br. at 53-55). Intervenors also question this provision in light of the AEP Interconnection Agreement (OEG Ex. 3 at 10-14; OCEA Br. at 54-55).

Given that AEP-Ohio has explicitly stated that the purchased power is not a prerequisite for adequately serving the additional load requirements assumed by AEP-Ohio when adding Ormet and the MonPower customers to its system (Cos. Ex. 2-E at 7), the Commission finds that Staff's rationale for the support of the proposal, as well as the recommendation for a reduction in the amount of purchased power proposed to equal the additional load, fails. We struggle, along with the other parties, to find a rational basis to approve such a proposal in the absence of need. The Commission notes that while we appreciate AEP-Ohio's willingness and cooperation with regard to the inclusion of Ormet and MonPower customers into its system, we believe that the Companies have been able to prepare and plan for the additions to its system under the current regulatory scheme and have been compensated during the transitional period. As for the reliance on the market purchases to promote economic development, the Commission believes that this goal can be more appropriately achieved through other means as outlined in this opinion and order, the Commission's recently adopted rules, and SB 221. Accordingly, we find that AEP-Ohio's ESP shall be modified to exclude this provision.

(b) Off-System Sales (OSS)

Kroger and OEG contend that FAC costs must be offset by a credit for OSS margins, stating that other jurisdictions governing other operating companies of AEP Corporation require such an OSS offset to revenue requirements (Kroger Br. at 11-12; Kroger Ex. 1 at 3, 9, 10; OEG Br. at 10; OEG Ex. 3 at 14-15, 16-17). Kroger argues that it is incongruent to allow a rate increase based on certain costs without examining AEP-Ohio's net costs to determine that AEP-Ohio's costs have actually increased (Kroger Br. at 11-12). OEG notes that the Companies' profits for 2007 from off-system sales were $146.7 million for OP and $124.1 million for CSP (OEG Ex. 3 at 14). OEG reasons that because the cost of the power plants used to generate off-system sales are included in rates, all revenue from the power plants should be a rate credit (OEG Br. 10). OCEA raises similar arguments to those of OEG and Kroger in its brief (OCEA Br. at 57-59). More specifically, OCEA argues that the Companies' proposal to eliminate off-system sales expenses from Ohio ratepayers is not equivalent to providing customers the benefit of off-system sales margins. OCEA notes that, in other cases, the Commission has required electric utilities to share the benefits of off-system sales revenue with jurisdictional customers (OCEA Br. at 58-59).

Staff did not take a position in regard to the intervenors' arguments to offset FAC costs by the OSS margin. Staff, however, concluded that the costs sought to be recovered through the FAC are appropriate (Staff Ex. 10 at 4; Staff Ex. 8 at 3; Staff Br. at 2).

The Companies argue that an OSS offset to FAC charges is not required by Section 4928.143(B)(2)(a), Revised Code, or any other provision in SB 221 (Cos. Ex. 2-E at 8-9; Cos. Reply Br. at 12). The Companies also state that the regulatory or statutory regimes in other states have no bearing on Ohio or Ohio's statutory requirements (Id.). As to the other arguments raised by OEG and OCEA, the Companies argue that the intervenors' arguments ignore the fact that the Companies' ESP reduces the FAC and environmental carrying cost expenses for AEP-Ohio customers based on the calculation of the pool capacity payments in the FAC and use of the pool allocation factor (Cos. Ex. 7, Exhibits PJN-1, PJN-2, PJN-6 and PJN-8).

Upon a review of the record in this case, the Commission is not persuaded by the intervenors' arguments. We do not believe that the testimony presented offered adequate justification for modifying the Companies' proposed ESP to offset OSS margins from the FAC costs. Section 4928.143(B)(2)(a), Revised Code, specifically provides for the automatic recovery, without limitation, of prudently incurred costs for fuel, purchased power, capacity cost, and power acquired from an affiliate. As recognized by the Companies, the pertinent statutory provisions do not require that there be an offset to the allowable fuel costs for any OSS margins. Additionally, Ohio law governs the Companies' ESP application, and thus, we are not persuaded by the arguments of Kroger regarding how other jurisdictions handle OSS margins. Moreover, consistent with our discussion in Section VII of our opinion and order, we do not believe that OSS should be a component of the Companies' ESP, or factored into our decision in this proceeding. Intervenors cannot have it both ways: they cannot request that OSS margins be credited against the fuel costs (i.e., offset the expenses); and, at the same time, ask us to count the OSS margins as earnings for purposes of the significantly excessive earnings test (SEET) calculation.

(c) Alternate Energy Portfolio Standards (including Renewable Energy Credit program)

Section 4928.64, Revised Code, establishes alternative energy portfolio standards which consist of requirements for both renewable energy and advanced energy resources. Section 4928.64(B)(2), Revised Code, introduces specific annual benchmarks for renewable energy resources and solar energy resources beginning in 2009.

The Companies' ESP application included, as a part of the FAC costs, cost recovery for renewable energy purchases and renewable energy credits (RECs) with purchased power reflected in Account 555 and RECs reflected in Account 557 (Cos. Ex. 7 at 6-7, 14). The Companies stated that they plan to purchase almost all of the RECs required for 2009. The Companies further state that they will enter into renewable energy purchase agreements (REPAs) to meet compliance requirements for the remainder of the ESP period, for which they have already conducted a request for proposal (Cos. Ex. 9 at 10-11). The Companies also recognized that recovery of such costs to comply with Section 4928.64(E), Revised Code, is, as stated in the statute,avoidable. Therefore, the Companies explained that they intend to include all of the renewable energy costs within the FAC mechanism and not as part of any FAC deferral. The Companies, however, recognized that their request for proposal and procurement practices for renewable energy will be subject to a prudency review and the renewable purchases subject to a financial audit (Cos. Br. at 96-98).

Staff and OPAE/APAC express concern with the Companies' plan to include renewable energy purchases and RECs as a component of the FAC mechanism (Staff Ex. 4 at 6-7; Staff Br. at 4-5; OPAE/APAC Br. at 11).

The Commission notes that the renewable energy purchases and RECs requirements are based on Section 4928.64(E), Revised Code, and any recovery of such costs is, as the statute provides, bypassable. With the Companies' recognition that such costs must be accounted for separately from fuel costs, and is not to be deferred, the Commission finds that Staff's and OPAE/APAC's issue is adequately addressed. Accordingly, with that clarification, the Commission finds that this aspect of the Companies' ESP application is reasonable and should be adopted.

2. FAC Baseline

The Companies proposed establishing a baseline FAC rate by identifying the FAC components of the current SSO. The Companies started with the EFC rates that were unbundled as part of the electric transition plan (ETP) proceedings (those in effect as of October 5, 1999) (step #1), and then added calendar year 1999 amounts for the additional fuel, purchased power, and environmental accounts that are included in the requested

FAC mechanism for this proceeding (1999 data from FERC Form 1 and other financial records were used as the base period for the additional components that were not in the frozen EFC rates) (step #2) (Cos. Ex. 7 at 8). The Companies then adjusted the 1999 frozen EFC rates (step #1) and the 1999-level rates developed for the additional components (step #2) for subsequent rate changes (step #3) to get the base FAC component that is equal to the fuel-related costs presently embedded in the Companies' most recent SSO (i.e., the RSP) (Id.). The subsequent rate changes that occurred during the RSP period and reflected in step #3 of the Companies' calculation included annual increases of 7 percent for OP and 3 percent for CSP, an increase in CSP's generation rates for 2007 by approximately 4.43 percent through the Power Acquisition Rider, and a reduction in OP's base period FAC rate by the amount of the Gavin Cap and mine investment shutdown cost recovery component that was in OP's 1999 EFC rate given that the Regulatory Asset Charge (RAC) established in the ETP case expired (Id. at 9).

Staff argued that the actual costs should be used in determining the FAC baseline and, therefore, recommended using 2007 actual data, escalated by 3 percent for CSP and 7 percent for OP, as a reasonable proxy for 2008 (Staff Ex. 10 at 3-4). Staff explained that utilizing actual 2007 costs and updating them to 2008 is appropriate given that the resulting amounts should be the costs that the Companies are currently recovering for fuel-related costs (Id.). Additionally, Staff notes that this proposal produces a result that is very close to the result produced by utilizing the Companies' methodology (Staff Br. at 3).

OCC recommended the use of 2008 actual fuel costs to establish the FAC baseline, which will be reconciled to actual costs in the future FAC proceeding (OCC Ex. 10 at 11-14). OCC's witness testified that her concern is that if the FAC baseline is established too low, the base portion of the generation rates (the non-FAC portion) will be established too high (OCC Ex. 10 at 13). In its Brief, OPAE/APAC opposed the Companies' use of 1999 rates as the baseline and seems to support OCC's recommendation to use 2008 fuel costs (OPAE/APAC Br. at 11-12). The Companies' responded by explaining that they did not use 1999 rates as the baseline, rather the 1999 level was just the starting point to calculating the baseline (Cos. Reply Br. at 21). The Companies also stated that a variable baseline was not appropriate as it would result in a variable non-FAC generation rate as well since the non-FAC component of the current generation SSO was determined to be the residual after subtracting out the FAC component (Id.).

As noted by OCC's witness, the 2008 actual fuel costs were not known at the time of the hearing (OCC Ex. 10 at 14). Thus, the Companies and Staff proposed methodologies to obtain a proxy for 2008 fuel costs. While both had a different starting point to the calculation of the 2008 proxy, we agree that in the absence of known actual costs, a proxy is appropriate to establish a baseline. Therefore, based on the evidence presented, we agree with Staff's resulting value as the appropriate FAC baseline.

3. FAC Deferrals

The Companies proposed to mitigate the rate impact on customers of any FAC increases by phasing in their new ESP rates by deferring a portion of the annual incremental FAC costs during the ESP (Cos. App. at 4-5; Cos. Ex. 3 at 11; Cos. Ex. 1 at 13-15). The amount of the incremental FAC expense that would be recovered from customers would be limited so that total bill increases would not be more than 15 percent for each of the three years of the ESP (Id.). The 15 percent target for FAC does not include cost increases associated with the transmission cost recovery rider (TCRR) or with any new government mandates (the Companies' could apply to the Commission for recovery of costs incurred in conjunction with compliance of new government mandates, including any Commission rules imposed after the filing of the AEP-Ohio application (Cos. App. at 6)). The Companies proposed to periodically reconcile the FAC to actual costs, subject to the maximum phase-in rates (Cos. Ex. 1 at 14-15). Under the Companies' proposal, any incremental FAC expense that exceeds the maximum rate levels will be deferred. The Companies project the deferrals under the proposed ESP to be $146 million by December 31, 2011 for CSP and $554 million by December 31, 2011 for OP (Cos. Ex. 6, Exhibit LVA-1). If the projected FAC expense in a given period is less than the maximum phase-in FAC rates, the Companies proposed to give the Commission the option of charging the customer the actual FAC expense amount or increasing the FAC rates up to the maximum levels in order to reduce any existing deferred FAC expense balance (Id.). Any deferred FAC expense remaining at the end of 2011 would be recovered, with a carrying cost at the Weighted Average Cost of Capital (WACC), as an unavoidable surcharge from 2012 to 2018 (Id.).

As noted previously, Staff, OCC, and Sierra support the FAC mechanism that will be updated and reconciled quarterly (Staff. Ex. 8 at 3-4; OCC Ex. at 11 at 4-5, 31-40; OCEA Br. at 47-48, 67-68). Staff, OCC, and Sierra, however, oppose the creation of any long-term deferrals for fuel costs (Staff Ex. 10 at 5; OCEA Br. at 62). Similarly, the Commercial Group recommended that "customers pay the full cost of fuel during the ESP" (Commercial Group Ex. 1 at 9). Constellation argued that the deferral proposal should be rejected because it masks the true cost of the ESP generation, deferrals have the effect of artificially suppressing conservation, the carrying costs proposed by the Companies would be set at the Companies' cost of capital, which would include equity, and customers do not want to pay interest on any deferred amounts (instead, customers would rather pay when the costs are incurred so as to not pay the interest) (Constellation Br. at 8-9). The Schools also questioned the need for the phase-in of rates, as well as the avoidability of the surcharge that would be created to collect the deferred fuel costs, with carrying charges, from 2012 to 2018 (Schools Br. at 3).

If the Commission, however, authorizes such deferrals to levelize rates during the ESP period, Staff, OCC, and Sierra believe that the deferrals should be short-term deferrals that do not extend beyond the ESP period (Staff Ex. 10 at 5; OCEA Br. at 62). IEU also supports the use of a phase-in to stabilize rates, but does not believe that Section 4928.144, Revised Code, allows the deferrals to extend beyond the ESP term (IEU Br. at 27-29).

Furthermore, OCC opposed the Companies' use of WACC, stating that such an approach is not reasonable and results in excessive payments by customers (OCC Ex. 10 at 34). Through testimony, OCC asserts that the carrying charges on deferrals should be based on the current long-term cost of debt (OCC Ex. 10 at 34-35; Tr. Vol. VI at 157-158). However, in its joint brief, OCC seems to have modified its position and is now arguing that the carrying charges should be calculated to reflect the short-term actual cost of debt, excluding equity (OCEA Br. at 62). In reliance on OCC's testimony, Constellation submits that it is appropriate to use the long-term cost of debt (Constellation Br. at 8). The Commercial Group also opposed the use of WACC; instead, Commercial Group witness Gorman recommended that the Companies finance the FAC phase-in deferrals entirely with short-term debt given that the accruals are a temporary investment and not long-term capital (Commercial Group Ex. 1 at 9-11).

Additionally, the Commercial Group and OCC argued that the deferred fuel expenses should be calculated to reflect the net of applicable deferred income taxes (Commercial Group Ex. 1 at 9-10; OCEA Br. at 63). Commercial Group witness Gorman testified that if a company does not recover the fuel expense in the year that it was incurred, the company will reduce its current tax expense and record a deferred tax obligation. The deferred tax obligation would then represent a temporary recovery of the fuel expense via a reduction to the current income tax expense (Commercial Group Ex. 1 at 10). Commercial Group witness Gorman then goes on to recognize that the income tax will ultimately have to be paid after the incremental fuel cost is recovered from customers, but states that, while deferred, the company will partially recover its deferred fuel balance through the reduced income tax expense (Id.). To bolster their argument that deferred fuel expenses should be calculated on a net-of-tax basis, OCC and Sierra relied, in their brief, on a witness' testimony in an unrelated proceeding, which has been subsequently withdrawn as explained above. Neither OCC nor Sierra offered any record evidence to support its position.

AEP-Ohio, on the other hand, argued that the calculation of carrying charges for the deferrals should not be done on a net-of-tax basis. AEP-Ohio witness Assante testified that limiting the application of the carrying cost rate to a net-of-tax balance of FAC deferrals improperly utilizes a traditional cost-of-service ratemaking approach in a generation pricing proceeding (Tr. Vol. IV at 158-160). Additionally, while the Companies proposed the phase-in proposal to help mitigate increases and believe that their proposal is reasonable, in light of the opposition received from several parties, the Companies stated that they would accept a modification to their ESP that eliminated such deferrals (Cos. Reply Br. at 41-42).

To ensure rate or price stability for consumers, Section 4928.144, Revised Code, authorizes the Commission to order any just and reasonable phase-in of any electric utility rate or price established pursuant to 4928.143, Revised Code, with carrying charges, through the creation of regulatory assets. Section 4928.144, Revised Code, also mandates that any deferrals associated with the phase-in authorized by the Commission shall be collected through an unavoidable surcharge. Section 4928.144, Revised Code, does not, however, limit the time period of the phase-in or the recovery of the deferrals created by the phase-in through the unavoidable surcharge.

Contrary to OCC and others,[7] we believe that a phase-in of the increases is necessary to ensure rate or price stability and to mitigate the impact on customers during this difficult economic period, even with the modifications to the ESP that we have made herein. To this end, the Commission appreciates the Companies' recognition that over 15 percent rate increases on customers' bills would cause a severe hardship on customers. Nonetheless, given the current economic climate, we believe that the 15 percent cap proposed by the Companies is too high.[8] Therefore, we exercise our authority pursuant to Section 4928.144, Revised Code, and find that the Companies should phase-in any authorized increases so as not to exceed, on a total bill basis, an increase of 7percent for CSP and 8percent for OP for 2009, an increase of 6percent for CSP and 7percent for OP for 2010, and an increase of 6percent for CSP and 8percent for OP for 2011 are more appropriate levels.

Based on the application, as modified herein, the resulting increases amount to approximate overall average generation rates of 5.47 cents/kWh and 4.29 cents/kWh for CSP and OP, respectively in 2009; 6.07 cents/kWh and 4.75 cents/kWh for CSP and OP, respectively, in 2010; and 6.31 cents/kWh and 5.31 cents/kWh for CSP and OP, respectively, in 2011.

Any amount over the allowable total bill increase percentage levels will be deferred pursuant to Section 4928.144, Revised Code, with carrying costs. If the FAC expense in a given period is less than the maximum phase-in FAC rate established herein, the Companies shall begin amortization of the prior deferred FAC balance and increase the FAC rates up to the maximum levels allowed to reduce any existing deferred FAC expense balance, including carrying costs. As required by Section 4928.144, Revised Code, any deferred FAC expense balance remaining at the end of 2011 shall be recovered

7 See, e.g., OCC Reply Br. at 45-46; Constellation Br. at 6-9.

8 Numerous letters filed in the docket by various customers confirm our belief.

via an unavoidable surcharge. We believe that this approach balances our objectives of limiting the total bill increases that customers will be charged in any one year with minimizing the deferrals and carrying charges collected from customers.

Based on the record in this proceeding, we do not find the intervenors' arguments concerning the calculation of the carrying charges persuasive. Instead, for purposes of a phase-in approach in which the Companies are expected to carry the fuel expenses incurred for electric service already provided to the customers,[9] we find that the Companies have met their burden of demonstrating that the carrying cost rate calculated based on the WACC is reasonable as proposed by the Companies. As explained previously, Section 4928.144, Revised Code, provides the Commission with discretion regarding the creation and duration of the phase-in of a rate or price established pursuant to Sections 4928.141 through 4928.143, Revised Code. The Commission is not convinced by arguments that limit the collection of the deferrals to the term of the ESP. Limiting the phase-in to the term of the ESP may not ensure rate or price stability for consumers within that three-year period and may create excessive increases, which may defeat the purpose for establishing a phase-in. The limitation of any deferrals to the ESP term may also negate the cap established by the Commission herein to provide stability to consumers. Therefore, we find that the collection of any deferrals, with carrying costs, created by the phase-in that are remaining at the end of the ESP term shall occur from 2012 to 2018 as necessary to recover the actual fuel expenses incurred plus carrying costs.

Regarding OCC's, Sierra's, and the Commercial Group's recommendations that the tax deductibility of the debt rate be reflected in the carrying charges on a net-of-tax basis,[10] we have recently explained that this recommendation accounts for the deductibility of the debt rate, but does not account for the fact that the revenues collected are taxable.[11] If we were to adopt the net-of-tax recommendation, the Companies would not recover the full carrying charges on the authorized deferrals. We believe that this outcome would be inconsistent with the explicit directive of Section 4928.144, Revised

9 We agree with the Companies that this decision is consistent with our decision in the recent TCRR and accounting cases with regard to the calculation based on the long-term cost of debt. See *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-1202-EL-UNC, Finding and Order (December 17, 2008) and *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-1301-EL-UNC, Finding and Order (December 19, 2008). However, we believe that, with regard to the equity component, these cases are distinguishable from the current ESP proceeding, where we are establishing the standard service offer and requiring the Companies to defer the collection of incurred generation costs associated with fuel over a longer period. We also believe that this decision is reasonable in light of our reduction to the Companies' proposed FAC deferral cap, which may have the effect of requiring the Companies to defer a higher percentage of FAC costs than what was otherwise proposed.

10 OCEA Br. at 63-64; Commercial Group Ex. 1 at 9-10.

11 *In re Ohio Edison Co., The Cleveland Electric Illuminating Co., Toledo Edison Co.*, Case No. 07-551-EI-AIR, et al., Opinion and Order at 10 (January 21, 2009).

Code: "If the commission's order includes such a phase-in, the order also shall provide for the creation of regulatory assets pursuant to generally accepted accounting principles, by authorizing the deferral of incurred costs equal to the amount not collected, plus carrying charges on that amount." Therefore, we find that the carrying charges on the FAC deferrals should be calculated on a gross-of-tax rather than a net-of-tax basis in order to ensure that the Companies recover their actual fuel expenses. Accordingly, we modify the deferral provision of the Companies' ESP to lower the overall amount that may be charged to customers in any one year.

B. Incremental Carrying Cost for 2001-2008 Environmental Investment and the Carrying Cost Rate

A component of the non-FAC generation increase is the incremental, ongoing carrying costs associated with environmental investments made during 2001-2008. The Companies propose to include, as a part of their ESP, costs directly related to energy produced or purchased. While the Companies are not proposing to include the recovery of capital carrying costs on environmental capital investments in the FAC, the Companies are requesting recovery of carrying charges for the incremental amount of the environmental investments made at their generating facilities from 2001 to 2008. The Companies' annual capital carrying costs for the incremental 2001-2008 environmental investments not currently reflected in rates equals $84 million for OP and $26 million for CSP. The Companies' ESP includes capital carrying costs for 2001 through 2008 net of cumulative environmental capital expenditures for each company multiplied by the carrying cost rate.

Each company's capital expenditures in the ESP are determined by the expenditures made since the start of the market development period as offset by the estimate included in the Companies' rate stabilization plan (RSP) case, Case No. 04-169-EL-UNC, and the environmental expenditures included in the Companies' adjustments received in the RSP 4 Percent Cases[12] (Cos. Ex. 7 at 15-17, Exhibits PJN-8, PJN-12). The Companies calculated the carrying cost rate based on levelized investment and depreciation over the 25-year life of the environmental investment. CSP and OP utilized a capital structure of 50 percent common equity and 50 percent debt to calculate the carrying charges, asserting that such is consistent with the capital structure as of March 31, 2008, and consistent with the expected capital structure during the ESP period. Short-term debt and the Gavin Lease were excluded from OP's capital structure. AEP-Ohio asserts that such was the process in the RSP 4 Percent Cases. AEP-Ohio also argues that, for ratemaking purposes, the Gavin Lease is considered an operating lease as opposed to a component of rate base. Further, the Companies reason that the WACC incorporated a 10.5 percent ROE as used by the Commission in the proceeding to transfer

12 *In re Columbus Southern Power Company and Ohio Power Company*, Case Nos. 07-1132-EL-UNC, 07-1191-EL-UNC, and 07-1278-EL-UNC (RSP 4 Percent Cases).

MonPower's certified territory to CSP (MonPower Transfer Case)[13] (Cos. Ex. 7 at 16-17, 19, Exhibit PJN-8, Exhibits PJN-10 - PJN-13; Cos. Ex. 7-B at 7).

Staff testified that the Companies should be allowed to recover carrying costs associated with capitalized investments to comply with environmental requirements made between 2001-2008 that are not currently reflected in rates (Staff Ex. 6 at 2, 4-5). Staff confirmed that AEP-Ohio's estimated revenue increases for incremental carrying costs associated with additional environmental investments in the amounts of $26 million for CSP and $84 million for OP are not currently reflected in rates (Id.).

OCEA and OEG oppose the Companies' request for recovery of environmental carrying charges on investments made prior to January 1, 2009. OEG contends that the rates in the RSP Case included recovery for environmental capital improvements made through December 31, 2008, as reflected in the RSP 4 Percent Cases. Further, OCEA and OEG argue that SB 221 only permits the recovery of carrying costs associated with environmental expenditures that are prudently incurred and that occur on or after January 1, 2009, pursuant to Section 4928.143(B)(2)(b), Revised Code (OCEA Ex. 10 at 32; OEG Ex. 3 at 21). Thus, OCEA reasons that approval of such expenditures necessitates an after-the-fact review, which cannot be considered in this proceeding. OEG, however, is not opposed to the Companies' increases due to environmental capital additions made after January 1, 2009, in the ESP in accordance with Section 4928.143(B)(2)(b), Revised Code (OEG Ex. 3 at 20). OEG and Kroger argue that the Companies' assertion that existing rates do not reflect environmental carrying costs ignores the Companies' non-environmental investment and the effects of accumulated depreciation and, therefore, according to OEG and Kroger, fails to demonstrate any net under-recovery of generation costs in total by the Companies (OEG Ex. 3 at 21; Kroger Ex. 1 at 10-11). OCEA and APAC/OPAE agree that the Companies have failed to demonstrate that they lack the earnings to make the environmental investments (OCEA Ex. 10 at 32; APAC/OPAE Br. at 5-6).

Further, OCEA asserts that there are several reasons that the Companies' attempt to recover environmental carrying cost during the ESP is unlawful. OCEA contends that it is retroactive ratemaking[14] and Senate Bill 3, which was the governing law from 2001 to 2005, included rate caps pursuant to Section 4928.34(A)(6), Revised Code, and the RSP, applicable to 2006 through 2008, included limitations on the rate increases. Therefore, the Companies can not collect now for costs incurred during those periods. Further, OCEA

13 *In the Matter of the Transfer of Monongahela Power Company's Certified Territory in Ohio to the Columbus Southern Power Company*, Case No. 05-765-EL-UNC.

14 *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.* (1957), 166 Ohio St. 25.

states that allowing for recovery of such environmental carrying costs would also violate the Stipulation and the Commission's order in the ETP case.[15]

OCEA argues that, should the Commission allow AEP-Ohio to recover carrying costs on environmental investments, the Companies' carrying charges should be based on actual investments made, not actual and forecasted environmental expenditures, and the carrying costs should be adjusted. More specifically, OCEA recommends that because the Companies failed to provide any support or explanation of the calculation of the property taxes or general and administrative components of the carrying cost calculation, the Commission should not grant recovery of these aspects of the Companies' request. Additionally, OCEA and IEU argue that the proposed carrying cost rates do not reflect actual financing for environmental investments, which could impact the calculation of the carrying cost rates (IEU Br. at 21-22, citing IEU Ex. 7 at 132-133; Tr. Vol. XI at 111-113; OCEA Br. at 71-72). The carrying cost rates, according to IEU and OCEA, should be revised to reflect actual financing, including the use of pollution control bonds that have been secured by the Companies (Id.). To support their argument, IEU and OCEA rely on Staff witness Cahaan who testified at the hearing that "if specific financing mechanisms can be identified that would be appropriate and applicable to the assets being financed, I see no reason why those shouldn't be specifically used"[16] (IEU Br. at 21-22; OCEA Br. at 72-73). However, Staff witness Cahaan also stated that "[A]t the time when we looked at the carrying cost calculations it seemed reasonable, given the cost of debt and cost of equity of the company,"[17] which is consistent with his prefiled testimony that said: "I have examined the carrying costs rates provided to Mr. Soliman and found them to be reasonable" (Staff Ex. 10 at 7).

OCEA also recommends that the carrying costs for deferrals of environmental costs be revised to reflect actual short-term cost of debt, as opposed to WACC as proposed by the Companies, and that the calculated carrying charges should not be based on the original cost of the environmental investment but at cost minus depreciation. Thus, OCEA argues that the Companies are seeking a return on and a return of their investment as would be the case under traditional ratemaking, but overstating the depreciation component. OCEA also advocates that the carrying cost rates, 13.98 percent for OP and 14.94 percent for CSP, are too high in light of the economic environment at this time (OCEA Br. at 73-74). Finally, OCEA urges the Commission to offset the Companies' request for carrying charges by the Section 199 provision of the Internal Revenue Code (Section 199). Section 199 allows the Companies to take a tax deduction for "qualified production activities income" equal to 6 percent in 2009 and 9 percent in 2010 and

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15 *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues*, Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP, Opinion and Order (September 28, 2000).

16 Tr. Vol. XII at 237.

17 Id.

thereafter. IEU, OEG, and OCEA request that the Commission adjust the carrying costs for the Section 199 deduction as the Commission has found appropriate in the Companies' 07-63 Case[18] and in the FirstEnergy ESP Case. OCEA argues that while Section 4928.143(B)(2)(a), Revised Code, allows the Companies to automatically recover the cost of federally mandated carbon or energy taxes, which will be passed on to customers, customers should be afforded the benefits of the Section 199 tax deduction (OCEA Br. at 74-75; IEU Br. at 21; IEU Ex. 10 at 6; OEG Ex. 3 at 23).

The Companies emphasize that their request for carrying costs is for the incremental carrying charges on the 2001-2008 investments that the Companies will incur post-January 1, 2009. AEP-Ohio explained that the carrying costs themselves are the costs that the Companies will incur after January 1, 2009, and, therefore, the Companies reason that the "without limitation" language in Section 4928.143(B)(2), Revised Code, supports their request (Tr. Vol. XIV at 93, 114). AEP-Ohio stresses that Section 4928.143(B)(2), Revised Code, is the basis for the carrying cost request as opposed to paragraph (B)(2)(a) of Section 4928.143, Revised Code, as OCEA and OEG claim and, therefore, the arguments as to retroactive ratemaking are misplaced (Cos. Reply Br. at 29-30). Further, the Companies insist that Section 4928.143(B)(2)(b), Revised Code, supports their request, as the carrying charges are necessary to recover the ongoing cost of investments in environmental facilities and equipment that are essential to keep the generation units operating. The Companies assert that the operating costs of their generation units remain well below the cost of securing the power on the market (Cos. Ex. 7-B at 7).

As to the claims that the carrying costs are overstated, the Companies claim that the levelized depreciation approach used by the Companies is better for customers than traditional ratemaking given the relative newness of the environmental investments (Tr. Vol. V at 55-56; Tr. Vol. VII at 22-23). The Companies also argue that the Companies' investments in environmental compliance equipment during 2001-2008 were not factored into the rates unbundled in 2000 and capped under the ETP case as alleged. The rate increase approved, as part of the RSP, and the RSP 4 Percent Cases did not, according to the Companies, provide recovery of the carrying costs to be incurred during the ESP period (Cos. Ex. 7, Exhibits PJN-8 - PJN-9 and PJN-12). The Companies reply that the intervenors' request to adjust carrying charges for the Section 199 deduction is flawed. AEP-Ohio states that the Section 199 deduction is not a reduction to the statutory tax rate used in the WACC, a fact which AEP-Ohio asserts has been recognized by FERC and the Financial Accounting Standards Board. The Companies further note that IEU witness Bowser indeed confirmed that Section 199 does not reduce the statutory tax rate (Tr. Vol. XI at 271-273). The Companies also argue, and IEU witness Bowser agreed, that the Section 199 tax deduction is applicable to AEP Corporation as a whole and not to each operating subsidiary. The Companies note, therefore, that any deduction available to

18 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 07-63-EL-UNC, Opinion and Order (October 3, 2007) (07-63 Case).

AEP-Ohio is reduced if one of the other AEP Corporation operating affiliates is not eligible for the Section 199 deduction (Cos. Br. 36; Tr. Vol. XI at 266-267). Accordingly, the Companies state that AEP-Ohio has not been able to take the full deduction (Tr. Vol. XIV at 115-117). Further, the Companies argue that the intervenors have misinterpreted the Commission's decision in the FirstEnergy ESP Case to imply that the Commission made an adjustment to account for the Section 199 deduction. For these reasons, the Companies request that the Commission reconsider adjusting carrying charges for the potential Section 199 deduction.

Upon review of the record, we agree with Staff that AEP-Ohio should be allowed to recover the incremental capital carrying costs that will be incurred after January 1, 2009, on past environmental investments (2001-2008) that are not presently reflected in the Companies' existing rates, as contemplated in AEP-Ohio's RSP Case. Further, the Commission finds that this decision regarding the recovery of continuing carrying costs on environmental investments, based on the WACC, is consistent with our decision in the 07-63 Case and the RSP 4 Percent Cases. Additionally, we agree with Staff that the levelized carrying cost rates proposed by AEP-Ohio are reasonable and, therefore, should be approved. We further find, as we concluded in the FirstEnergy ESP Case, that adequate modifications to the Companies' ESP application have been made in this order to account for the possibility of any applicable Section 199 tax deductions.

C. Annual Non-FAC Increases

The Companies proposed to increase the non-FAC portion of their generation rates by 3 percent for CSP and 7 percent for OP for each year of the ESP to provide a recovery mechanism for increasing costs related to matters such as carrying costs associated with new environmental investments made during the ESP period, increases in the general costs of providing generation service, and unanticipated, non-mandated generation-related cost increases. Specifically, as part of this automatic increase, the Companies intend to recover the carrying costs associated with anticipated environmental investments that will be necessary during the ESP period (2009-2011) (Cos. Br. at 27; Cos. Reply Br. at 46-49). The Companies argued that the annual increases are not cost-based and are avoidable for those customers who shop. The Companies also proposed two exceptions to the fixed, annual increases, one for generation plant closures and the other for OP's lease associated with the scrubber at the Gavin Plant, which would require additional Commission approval during the ESP. After establishing the FAC component of the current generation SSO to get a FAC baseline, the Companies determined that the remainder of the current generation SSO would be the non-FAC base component.

The intervenors oppose automatic annual increases in the non-FAC component of the generation rate, and argue that any generation increases should be cost-based (IEU Br.

at 24; OPAE/APAC Br. at 6; OEG Br. at 12; OCEA Br. 29-31). OEG contends that since the Companies have not provided any support for the automatic annual increases, which could result in total rate increases over the three-year period of $87 million for CSP and $262 million for OP, the annual increases should be disallowed (OEG Ex. 3 at 18-19); Similarly, Kroger argues that AEP-Ohio did not appropriately account for costs associated with the non-FAC component of the proposed generation rates (Kroger Br. at 14).

Staff opposes CSP's and OP's recommended annual, non-FAC increases of 3 and 7 percent, respectively (Staff Ex. 10 at 4). Instead, Staff stated that it believes a more appropriate escalation of the non-FAC generation component would be half of the proposed amounts; therefore, recommending annual increases of 1.5 percent for CSP and 3.5 percent for OP (Id.). Staff witness Cahaan rationalized the proposed reduction by stating that "an average of 5% for the two companies may have been a reasonable expectation of cost increases at the time that the ESP was contemplated, but not now. With the recent financial crises, we are entering a recessionary, and possibly a deflationary, period and any expectations of price increases need to be revised downward" (Id.). Furthermore, while recognizing that the ultimate balancing of interests lies with the Commission, Staff witness Cahaan testified that Staff's recommended reduction in the proposed increases was a reasonable balance between the Companies' obligation and costs to serve customers and the current economic conditions (Tr. Vol. XII at 211). The Companies rejected Staff's rationalization for the reduction in their proposed non-FAC increases (Cos. Reply Br. at 49). IEU also rejected Staff's rationalization for the reduction, arguing that no automatic increases are warranted (IEU Br. at 24).

Stating that it is in the public interest for the Companies to continue investing in environmental equipment and to be in compliance with current and future environmental requirements, Staff witness Soliman also recommended that AEP-Ohio be permitted to recover carrying costs for anticipated environmental investments made during the ESP period (Staff Ex. 6 at 5). Staff recommended that this recovery occur through a future proceeding upon the request of the Companies for recovery of additional carrying costs associated with actual environmental investment after the investments have been made (Staff Br. at 6-7). Specifically, Staff suggested that the Commission require the Companies to file an application in 2010 for recovery of 2009 actual environmental investment cost and annually thereafter for each succeeding year to reflect actual expenditures (Tr. Vol. XII at 132; Staff Ex. 10 at 7). OCEA seems to agree with Staff's recommendation (OCEA Br. at 71).

The Companies further respond that Section 4928.143, Revised Code, does not require that the SSO price be cost-based and, instead, Section 4928.143(B)(2)(e), Revised Code, authorizes electric utilities to include in their ESP provisions for automatic increases in any component of the SSO price (Cos. Reply Br. at 48-49).

The Commission finds Staff's approach with regard to the recovery of the carrying costs for anticipated environmental investments made during the ESP to be reasonable, and, therefore, we direct the Companies to request, through an annual filing, recovery of additional carrying costs after the investments have been made.

We also agree with Staff that the economic conditions must be balanced against the Companies' provision of electric service under an ESP. In balancing these two interests, as well as considering all components of the ESP, we believe that it is appropriate to modify this provision of the Companies' ESP and remove the inclusion of any automatic non-FAC increases. As recognized by several intervenors, the record is void of sufficient support to rationalize automatic, annual generation increases that are not cost-based, but that are significant, equaling approximately $87 million for CSP and $262 million for OP (see, i.e., OCEA Br. at 29-30, citing Tr. Vol. XIV at 208-209). We also believe the modification is warranted in light of the fact that we have removed one of the Companies' significant costs factored into establishing the proposed automatic increases. Accordingly, we find that the ESP should be modified to eliminate any automatic increases in the non-FAC portion of the Companies' generation rates.

IV. DISTRIBUTION

A. Annual Distribution Increases

To support initiatives to improve the Companies' distribution system and service to customers, the Companies proposed the following two plans, which will result in annual distribution rate increases of 7 percent for CSP and 6.5 percent for OP:

1. Enhanced Service Reliability Plan (ESRP)

The Companies proposed to implement a new, three-year ESRP pursuant to 4928.143(B)(2)(h), Revised Code,[19] which includes an enhanced vegetation initiative, an enhanced underground cable initiative, a distribution automation initiative, and an enhanced overhead inspection and mitigation initiative (Cos. Ex. 11 at 3). While noting that they are providing adequate and reliable electric service, the Companies justify the need for the ESRP by stating that customers' service reliability expectations are increasing, and in order to maintain and enhance reliability, the ESRP is required (Id. at 3, 8, 10-14). AEP-Ohio further states that the three-year ESRP, consisting of the four reliability

19 On page 72 of its brief, the Companies rely on Section 4928.154(B)(2)(h), Revised Code, to support their request to receive cost recovery for the incremental costs of the incremental ESRP activities. We are assuming that the reference was a typographical error and that the Companies intended to cite to Section 4928.143(B)(2)(h), Revised Code (see Cos. Reply Br. at 50-51).

programs, is designed to modernize and improve the Companies' distribution infrastructure (Id.).

(a) Enhanced vegetation initiative

The Companies state that the purpose of this new initiative is to improve the customer's overall service experience by reducing and/or eliminating momentary interruptions and/or sustained outages caused by vegetation. The Companies proposed to accomplish this goal by balancing its performance-based approach to reflect a greater consideration of cycle-based factors (Id. at 26-28). The Companies state that under their proposed vegetation initiative, they will employ additional resources (approximately double the current number of tree crews in Ohio), employ greater emphasis on cycle-based planning and scheduling, increase the level of vegetation management work performed so that all distribution rights-of-way can be inspected and maintained, and utilize improved technologies to collect tree inventory data to optimize planning and scheduling by predicting problem areas before outages occur (Id. at 28-29).

(b) Enhanced underground cable initiative

The Companies state that the purpose of this initiative is to reduce momentary interruptions and sustained outages due to failures of aging underground cable. The Companies' plan to target underground cables manufactured prior to 1992 to replace and/or restore the integrity of the cable insulation (Id. at 31).

(c) Distribution automation (DA) initiative

The Companies explain that DA is a critical component of their proposed gridSMART distribution initiative that is described below. DA is an advanced technology that improves service reliability by minimizing, quickly identifying and isolating faulted distribution line sections, and remotely restoring service interruptions (Id. at 34-35).

(d) Enhanced overhead inspection and mitigation initiative

The Companies state that the purpose of this initiative is to improve the customer's overall service experience by reducing equipment-related momentary interruptions and sustained outages. The Companies intend to accomplish this goal through a comprehensive overhead inspection process that will proactively identify equipment that is prone to fail (Id. at 18). The Companies also state that the new program will go beyond the current inspection program required by the electric service and safety (ESSS) rules, which is a basic visual assessment of the general condition of the distribution facilities, by conducting a comprehensive inspection of the equipment on each structure via walking the circuit lines and physically climbing or using a bucket truck to inspect (Id. at 19). In conjunction with this program, AEP-Ohio proposes to focus on five targeted overhead asset initiatives, including cutout replacement, arrester replacement, recloser replacement, 34.5 kV protection, and fault indicator (Id. at 20-22).

Generally, numerous intervenors and Staff opposed the distribution initiatives and cost recovery of such initiatives through this proceeding. Many parties advocated for deferral of these distribution initiatives, and the ESRP as a whole, for consideration in a future distribution base rate case (Staff Br. at 7; Staff Ex. 1 at 6-7; OPAE/APAC at 19; IEU Br. at 25-26; Kroger Br. at 18; OHA Br. at 17; OMA Br. at 6). Further, OCEA argued that the Companies have not demonstrated that the ESRP is incremental to what the Companies are required to do and spend under the current ESSS rules and current distribution rates (OCEA Br. at 44; OCC Ex. 13 at 8-11). While supporting several aspects of the Companies' ESRP programs, Staff witness Roberts also questioned the incremental nature of the proposed ESRP programs (Staff Ex. 2 at 4-6, 13, 17, 18; Tr. Vol. VIII at 70-77).

The Commission agrees, in part, with Staff and the intervenors. The Commission recognizes that Section 4928.143(B)(2)(h), Revised Code, authorizes the Companies to include in its ESP provisions regarding single-issue ratemaking for distribution infrastructure and modernization incentives. However, while SB 221 may have allowed Companies to include such provisions in its ESP, the intent could not have been to provide a 'blank check' to electric utilities. In deciding whether to approve an ESP that contains provisions for distribution infrastructure and modernization incentives, Section 4928.143(B)(2)(h), Revised Code, specifically requires the Commission to examine the reliability of the electric utility's distribution system and ensure that customers' and the electric utilities' expectations are aligned, and to ensure that the electric utility is emphasizing and dedicating sufficient resources to the reliability of its distribution system. Given AEP-Ohio's proposed ESRP, the only way to examine the full distribution system, the reliability of such system, and customers' expectations, as well as whether the programs proposed by AEP-Ohio are "enhanced" initiatives (truly incremental), is through a distribution rate case where all components of distribution rates are subject to review. Therefore, at this time, the Commission denies the Companies' request to implement, as well as recover costs associated therewith, the enhanced underground cable initiative, the distribution automation initiative, and the enhanced overhead inspection and mitigation initiative. With regard to these issues, we concur with OHA: "The record in this case reflects the fact that the distribution prong of AEP's electric service deserves further Commission scrutiny - but not in the context of this accelerated ESP proceeding" (OHA Br. at 17).

Nonetheless, the Commission finds that AEP-Ohio has demonstrated in the record of this proceeding that it faces increased costs for vegetation management and that a specific need exists for the implementation of the enhanced vegetation initiative, as proposed as part of the three-year ESRP, to support an incremental level of reliability activities in order to maintain and improve service levels. The Companies' current approach to its vegetation management program is mostly reactive (Staff Ex. 2 at 10). While we recognize the difficulties that recent events have caused, we believe that it is important to have a balanced approach that not only reacts to certain incidents and problems, but that also proactively limits or reduces the impact of weather events or incidents. In addition to reacting to problems that occur, it is imperative that AEP-Ohio implements a cycle-based approach to maintain the overall system. To this end, the Companies have demonstrated in the record that increased spending earmarked for specific vegetation initiatives can reduce tree-caused outages, resulting in better reliability (Cos. Ex. 11 at 27-31). OCC witness Cleaver also recognized a problem with the current vegetation management program, and supported the adoption of a new, hybrid approach that incorporates a cycle-based tree-trimming program with a performance-based program (OCC Ex. 13 at 30, 35). Staff witness Roberts further supported the move to a new, four-year cycle-based approach and recommended that the enhanced vegetation initiative include the following: end-to-end circuit rights-of-way inspections and maintenance; mid-point circuit inspections to review vegetation clearance from conductors, equipment, and facilities; greater clearance of all overhang above three-phase primary lines and single-phase lines; removal of danger trees located outside of rights-of-ways where property owner's permission can be secured, and using technology to collect tree inventory data to optimize planning and scheduling (Staff Ex. 2 at 13).

The Commission is satisfied that the Companies have demonstrated in the record that the costs associated with the proposed vegetation initiative, included as part of the proposed three-year ESRP, are incremental to the current Distribution Vegetation Management Program and the costs embedded in distribution rates (Cos. Ex. 11 at 26-31). Specifically, the Companies proposed to employ additional resources in Ohio, place a greater emphasis on cycle-based planning and scheduling, and increase the level of vegetation management work performed (Id. at 28-29). Although OCC's witness questions the incremental nature of the costs proposed to be included in the enhanced vegetation initiative, OCC offered no evidence that the proposed initiative is already included in the current vegetation management program, and thus, is not incremental (OCC Ex. 13 at 30-36). Rather, OCC seems to quibble with the definition of "enhanced." OCC witness Cleaver stated: "I recommend that the Commission rule that the Company's proposed Vegetation Management Programs, while an improvement over its current performance based program, is *not an enhancement* but *rather a reflection of additional* tree trimming needed as a result of their prior program" (Id. at 35 (emphasis added)). Furthermore, we believe that the record clearly reflects customers' expectations as to tree-caused outages, service interruptions, and reliability of customers' service.[20] We also believe that, presently, those customer expectations are not aligned with the Companies' expectations. However, as required by Section 4928.143(B)(2)(h), Revised Code, we believe that the Companies' proposal for a new vegetation initiative more closely aligns

20 A common theme from the customers throughout the local public hearings was that outages due to vegetation have been problematic.

the customers' expectations with the Companies' expectations as it relates to tree-caused outages, importance of reliability, and the increasing frustration surrounding momentary outages with the emergence of new technology.

Accordingly, in balancing the customers' expectations and needs with the issues raised by several intervenors, the Commission finds that the enhanced vegetation initiative proposed by the Companies, with Staff's additional recommendations, is a reasonable program that will advance the state policy. To this end, the Commission approves the establishment of an ESRP rider as the appropriate mechanism pursuant to Section 4928.143(B)(2)(h), Revised Code, to recover such costs. The ESRP rider initially will include only the incremental costs associated with the Companies' proposed enhanced vegetation initiative (Cos. Ex. 11 at 31, Chart 7) as set forth herein. Consistent with prior decisions,[21] the Commission also believes that, pursuant to the sound policy goals of Section 4928.02, Revised Code, a distribution rider established pursuant to Section 4928.143(B)(2)(h), Revised Code, should be based upon the electric utility's prudently incurred costs. Therefore, the ESRP rider will be subject to Commission review and reconciliation on an annual basis.

As for the recovery of any costs associated with the Companies' remaining initiatives (i.e., enhanced underground cable initiative, distribution automation initiative, and enhanced overhead inspection and mitigation initiative), the ESRP rider will not include costs for any of these programs until such time as the Commission has reviewed the programs, and associated costs, in conjunction with the current distribution system in the context of a distribution rate case as explained above. If the Commission, in a subsequent proceeding, determines that the programs regarding the remaining initiatives should be implemented, and thus, the associated costs should be recovered, those costs may, at that time, be included in the ESRP rider for future recovery, subject to reconciliation as discussed above.

2. <u>GridSMART</u>

The Companies propose, as part of their ESP, to initiate Phase 1 of gridSMART, a three-year pilot, in northeast central Ohio. GridSMART will include three main components, AMI, DA, and Home Area Network (HAN). The AMI system features include smart meters, two-way communications networks, and the information technology systems to support system interaction. AEP-Ohio contends that AMI will use internal communications systems to convey real-time energy usage and load information to both the customer and the company. According to the Companies, AMI will provide the capability to monitor equipment and convey information about certain malfunctions and operating conditions. DA will provide real-time control and monitoring of select

21 *In re Ohio Edison Co., The Cleveland Electric Illuminating Co., Toledo Edison Co.*, Case No. 08-935-EL-SSO, Opinion and Order at 41 (December 19, 2008).

electrical components with the distribution system, including capacitor banks, voltage regulators, reclosers, and automated line switches. HAN will be installed in the customer's home or business and will provide the customer with information to allow the customer to conserve energy. HAN includes providing residential and business customers who have central air conditioning with a programmable communicating thermostat (PCT) and a load control switch (LCS), which is installed ahead of a major electrical appliance and will turn the appliance on and off or cycle the appliance on and off. AEP-Ohio reasons that central air conditioners are typically the largest piece of electrical equipment in the home and will yield the most significant demand response benefit (Tr. Vol. III at 304). LCS will provide customers who have a direct load control or interruptible tariff the ability to receive commands from the meter and the option to respond and signal the appropriate action to the meter for confirmation. The Companies propose a phased-in implementation of Phase 1 gridSMART to approximately 110,000 meters and 70 distribution circuits in an approximately 100 square mile area within CSP's service territory (Cos. Ex. 4 at 9, 12-13; Tr. Vol. III at 303-304). The Companies further propose to extend the installation of DA to 20 circuits in areas beyond the gridSMART Phase 1 program. The Companies propose a phased-in approach to fully implement gridSMART throughout their service area over the next 7 to 10 years, if granted appropriate regulatory treatment. The Companies estimate the net cost of gridSMART Phase 1 to be approximately $109 million (including the projected net savings of $2.7 million) over the three-year period (Cos. Ex. 4 at 15-16, KLS-1). The rate design for gridSMART includes the projected cost of the program over the life of the equipment. The Companies have requested recovery during the ESP of only the costs to be incurred during the three-year term of the ESP (Cos. Ex. 1 at DMR-4). Thus, AEP-Ohio asserts that it is inappropriate to consider the long-term operational cost savings when the long-term costs of gridSMART have not been included in the ESP for recovery.

Although Staff generally supports the Companies' implementation of gridSMART, particularly the AMI and DA components, Staff raises a few concerns with this aspect of the Companies' ESP application. Staff is concerned that the overhead costs for meter purchasing is overstated and recommends that the overhead costs be reviewed before approval to ensure that the costs are not duplicative of the overhead meter purchasing costs currently recovered in the Companies' rates (Staff Ex. 3 at 3). Staff argues that there is no reason for the Companies to restrict the PCTs to customers with air conditioning only, and recommends that the device be offered to any customer that desires to own this type of thermostat to control air conditioning or other electrical appliances (Staff Br. at 12). Staff and OCC also argue that customers who have invested in advanced technological equipment for gridSMART will not benefit from dynamic pricing and time differentiated rates if the Companies do not simultaneously file tariffs for such services (Staff Ex. 3 at 5; OCEA Br. at 82). Staff recommends that the Companies offer some form of a critical peak pricing rebate for residential customers, and some form of hedged price for commercial customers for a fixed amount of the customers' demand (Staff Ex. 3 at 5).

Further, Staff argues that the Companies' gridSMART proposal does not contain sufficient information regarding any risk-sharing between the ratepayers and shareholders, operational savings, or a cost/benefit analysis, and states that AEP-Ohio did not quantify any customer or societal benefits of the proposed gridSMART initiative (Staff Br. at 12-13). Staff notes that according to the Companies, DA will not be implemented until 2011, the third year of the ESP, and that the ESP proposes to install DA beyond the Phase I gridSMART area (Tr. Vol. III at 246). Staff opposes DA outside of the Phase I area because the Companies' cannot estimate the expected reliability improvements associated with the installation of DA. Staff also argues that DA costs should be recovered through a DA rider. The cost of gridSMART, per AEP-Ohio's proposal, is to be recovered by adjusting distribution rates. Staff is opposed to increasing distribution rates in this proceeding (Staff Ex. 5 at 6). Instead, Staff recommends that a rider be established and set at zero. The Staff argues that a rider has several benefits over the proposed increase to distribution rates, including separate accounting for gridSMART costs, an opportunity to approve and update the plan annually, assurance that expenditures are made before cost recovery occurs, and an opportunity to audit expenditures prior to recovery. Finally, Staff also advocates that the Companies share the financial risk of gridSMART between ratepayers and shareholders, as there is a benefit to the Companies. Additionally, Staff questions whether gridSMART will meet minimum reliability standards. Lastly, Staff asserts that AEP-Ohio should conduct a study that quantifies both customer and societal benefits of its gridSMART plan (Staff Br. at 14).

OCC, Sierra, and OPAE/APAC argue that the Companies' ESP fails to demonstrate that its gridSMART program is cost-effective as required by Sections 4928.02(D) and 4928.64(E), Revised Code, and state that AEP-Ohio's assumption that the societal and customer benefits are self-evident is misplaced (OCEA Br. at 77-80; OPAE/APAC Br. at 17-18). OCC, Sierra, and OPAE/APAC note that there are a number of factors about the program that the Companies have not determined or evaluated, which are essential to the Commission's consideration of the plan. OCC, Sierra, and OPAE/APAC state that the Companies have failed to include any full gridSMART implementation plan or costs, the anticipated life cycle of various components of gridSMART, a methodology for evaluating performance of gridSMART Phase I, an estimate of a customer's bill savings, or the positive impact to the environment or job creation (OCEA Br. at 79-80; OPAE\APAC Br. at 17-18). Further, OCC's witness states that the ESP fails to acknowledge that full system implementation is required before many of the benefits of gridSMART can actually be realized (OCC Ex. 12 at 6). OCC recommends that Phase I have its own set of performance measures, a more detailed project plan, including budget, resource allocation, and life cycle operating cost projections for the full 7-10 year implementation period of gridSMART and beyond, and performance measures for the Commission's approval (OCC Ex. 12 at 18).

AEP-Ohio regards the Staff's proposal to offer PCTs to any customer as overly generous, particularly given that Staff is recommending that the rider be set initially at zero (Cos. Br. at 68-69). AEP-Ohio also submits that it has committed to offering new service tariffs associated with Phase I of gridSMART once the technology is installed and the billing functionalities available (Cos. Ex. 1 at 6; Tr. Vol. III at 304-305; Cos. Br. at 68-69). Further, regarding Staff's policy of risk-sharing, the Companies contend that the assertion that the gridSMART investment benefits CSP just as much as it does customers is not true and, given that the operational savings do not equal or exceed the cost of the program, is without any basis presented in the record. Thus, AEP-Ohio argues that discounting the net cost to be recovered by CSP is unfair and inappropriate (Cos. Reply Br. at 63-64). The Companies are unclear how the Staff expects to determine whether gridSMART meets the minimum reliability standards and contend that this issue was first raised in the Staff's brief. Nonetheless, the Companies argue that imposing reliability standards as to gridSMART Phase 1 is inappropriate, primarily because strict accountability for achieving the expected reliability impacts does not take into account the many dynamic factors that impact service reliability index performance. Moreover, accurate measurement and verification of the discrete impact of gridSMART deployment on a particular reliability index would be difficult. The Companies also explain that the expected reliability impacts provided to the Staff were based on good faith estimates of the full implementation of gridSMART Phase 1 as proposed by the Companies. Thus, the Companies would prefer the establishment of deployment project milestones as opposed to specific reliability impact standards.

Although the Companies maintain that their percentage of distribution increase is reasonable and an appropriate part of the ESP package, in recognition of Staff's preference for a distribution rider and to address various parties' concerns regarding the accuracy of AEP-Ohio's cost estimates for gridSMART Phase I, the Companies would agree to a gridSMART Phase I rider set at the 2009 revenue requirement subject to annual true-up and reconciliation based on CSP's prudently incurred net costs (Cos. Reply Br. at 70; Cos. Ex. 1, Exhibit DMR-4).

The Commission believes it is important that steps be taken by the electric utilities to explore and implement technologies, such as AMI, that will potentially provide long-term benefits to customers and the electric utility. GridSMART Phase I will provide CSP with beneficial information as to implementation, equipment preferences, customer expectations, and customer education requirements. A properly designed AMI system and DA can decrease the scope and duration of electric outages. More reliable service is clearly beneficial to CSP's customers. The Commission strongly supports the implementation of AMI and DA, with HAN, as we believe these advanced technologies are the foundation for AEP-Ohio providing its customers the ability to better manage their energy usage and reduce their energy costs. Thus, we encourage CSP to be more expedient in its efforts to implement these components of gridSMART. While we agree that additional information is necessary to implement a successful Phase I program, we do not believe that all information is required before the Commission can conclude that the program is beneficial to ratepayers and should be implemented. Therefore, we will approve the development of a gridSMART rider, as we agree with the Staff that a rider has several benefits over the proposed annual increase to distribution rates, including separate accounting for gridSMART, an opportunity to approve and update the plan each year, assurance that expenditures are made before cost recovery occurs, and an opportunity to audit expenditures prior to recovery. The Commission notes that recent federal legislation makes matching funds available to smart grid projects. Accordingly, the Companies' gridSMART proposal contained in its proposed ESP to recover $109 million over the term of ESP, should be revised to $54.5 million, which is half of the Companies' requested amount. Additionally, we direct CSP to make the necessary filing for federal matching funds under the American Recovery and Reinvestment Act of 2009 for the balance of the projected costs of gridSMART Phase I. The gridSMART rider shall be initially established at $33.6 million for the 2009 projected expenses subject to annual true-up and reconciliation based on the company's prudently incurred costs.

With the creation of the ESRP rider and the gridSMART rider, the Commission finds that annual distribution rate increases in the amounts of 7 percent for CSP and 6.5 percent for OP to recover the costs for the ESRP and gridSMART programs are unnecessary and should be rejected. Accordingly, the Commission finds that AEP-Ohio's proposed ESP should be modified to include the ESRP rider and the gridSMART rider, as approved herein, and to eliminate the annual distribution rate increases.

B. Riders

1. Provider of Last Resort (POLR) Rider

The Companies proposed to include in their ESP a distribution non-bypassable POLR rider (Cos. App. at 6-8). The POLR charge was proposed to collect a POLR revenue requirement of $108.2 million for CSP and $60.9 million for OP (Cos. Ex. 2-A at 34; Cos. Ex. 1, Exhibit DMR-5). The Companies stated that they have a statutory obligation to be the POLR,[22] and thus, the proposed POLR charge is based on a quantitative analysis of the cost to the Companies to provide to customers the optionality associated with POLR service (Cos. Ex. 2-A at 25-26). AEP-Ohio argued that this charge covers the cost of allowing a customer to remain with the Companies, or to switch to a Competitive Retail Electric Service (CRES) provider and then return to the Companies' SSO after shopping (Id.). To further support the proposed increase, the Companies added that their current POLR charge is significantly below other Ohio electric utilities' POLR charges (Cos. Ex. 2 at 8). The Companies utilized the Black-Scholes Model to calculate their cost of fulfilling

[22] See Section 4928.141(A) and 4928.14, Revised Code.

the POLR obligation, comparing the customers' rights to "a series of options on power" (Cos. Br. at 43; Cos. Ex. 2-A at 31). AEP-Ohio listed the five quantitative inputs used in the Black-Scholes Model: 1) the market price of the underlying asset; 2) the strike price; 3) the time frame that the option covers; 4) the risk free interest rate; and 5) the volatility of the underlying asset (Id.). The Companies assert that the resulting POLR charge is conservatively low (Cos. Br. at 44).

The numerous intervenors and Staff opposed the level of POLR charge proposed by the Companies, as well as the use of the Black-Scholes Model to calculate the POLR charge (OPAE/APAC Br. at 14-17; OCC Ex. 11 at 8-14). Specifically, OCC and others questioned the use of the LIBOR rate as the input for the risk-free interest rate (Tr. Vol. X at 165-182, 188-189; Tr. Vol. XI at 166-182). Staff questioned the risk that the POLR charge was intended to compensate the Companies for, explaining that there are only two risks involved: one risk is the risk of customers returning to the SSO and the other risk is that the customers leave and take service from a CRES provider (migration risk) (Staff Ex. 10 at 6). Staff witness Cahaan testified that the risk associated with customers returning to the SSO could be avoided by requiring the customer to return at a market price, instead of the SSO rate, which would either be paid directly by the returning customer or any incremental cost of the purchased power could be flown through the FAC (Id.). Staff witness Cahaan admitted that if customers are permitted to return at the SSO rate, without paying the market price or without compensating the Companies for any incremental costs of the additional purchased power that they would be required to purchase, then the Companies would be at risk (Tr. Vol. XIII at 36-37). Thus, Staff witness Cahaan concluded that, if the risk of returning is addressed, then the migration risk is the only risk that should be compensated through a POLR charge (Id. at 7).

The Companies responded that their risk is not alleviated by customers agreeing to return at market price, arguing that future circumstances or policy considerations may require them to relieve customers of their promises to pay market price when circumstances change (Cos. Ex. 2-A at 27-30). AEP-Ohio's witness expressed skepticism as to a future Commission upholding such promises (Id). AEP-Ohio also opposed recovering any costs for market purchases incurred for returning customers through the FAC as an improper subsidization of those customers who chose to shop, and then return to the electric utility, by non-shopping customers (Cos. Ex. 2-E at 14-16). Furthermore, the Companies claim that their risk of being the POLR exists, regardless of historic or current shopping levels (Id.). Nonetheless, AEP witness Baker testified that, even adopting Staff witness Cahaan's theory that the Companies are only at risk for migration (the right of customers to leave the SSO), migration risk equals approximately 90 percent of the Companies' POLR costs pursuant to the Black-Scholes model (Tr. Vol. XIV at 204-205; Cos. Ex. 2-E at 15-16).

As the POLR, the Commission believes that the Companies do have some risks associated with customers switching to CRES providers and returning to the electric utility's SSO rate at the conclusion of CRES contracts or during times of rising prices. However, we agree with the intervenors and Staff that the POLR charge as proposed by the Companies is too high, but we do not agree that there is no risk or a very minimal risk as suggested by some. As noted by several intervenors and Staff, the risk of returning customers may be mitigated, not eliminated, by requiring customers that switch to an alternative supplier (either through a governmental aggregation or individual CRES providers) to agree to return to market price, and pay market price, if they return to the electric utility after taking service from a CRES provider, for the remaining period of the ESP term or until the customer switches to another alternative supplier. In exchange for this commitment, those customers shall avoid paying the POLR charge. We believe that this outcome is consistent with the requirement in Section 4928.20(J), Revised Code, which allows governmental aggregations to elect not to pay standby service charges, in exchange for agreeing to pay market price for power if they return to the electric utility. Therefore, based on the record before us, we conclude that the Companies' proposed ESP should be modified such that the POLR rider will be based on the cost to the Companies to be the POLR and carry the risks associated therewith, including the migration risk. The Commission accepts the Companies' witness' quantification of that risk to equal 90 percent of the estimated POLR costs,[23] and thus, finds that the POLR rider shall be established to collect a POLR revenue requirement of $97.4 million for CSP and $54.8 million for OP. Additionally, the POLR rider shall be avoidable for those customers who shop and agree to return at a market price and pay the market price of power incurred by the Companies to serve the returning customers. Accordingly, the Commission finds that the POLR rider, which is avoidable, should be approved as modified herein.

2. Regulatory Asset Rider

The Companies proposed to begin the recovery of a variety of regulatory assets that were authorized in various Commission proceedings regarding the Companies' electric transition plan (ETP), rate stabilization plan (RSP), line extension program, green pricing power program, and the transfer of the MonPower's service territory to CSP. In their application, the Companies proposed to begin the amortization of these regulatory assets in 2011 and complete the amortization over an eight-year period. The projected balances at the end of 2010 to amortize are $120.5 million for CSP and $80.3 million for OP. AEP-Ohio asserts that these projected balances, or the value on June 30, 2008, were not challenged by any party. To recover these regulatory assets, the Companies created a RAC rider to be collected from customers in 2011 through 2018. The rider revenues will be reconciled on an annual basis for any over- or under-recoveries.

[23] See Cos. Ex. 1, Exhibit DMR-5.

Staff proposed that the eight-year amortization period proposal be deferred until the Companies' next distribution rate case where all components of distribution rates are subject to review (Staff Ex. 1 at 4). AEP-Ohio responded that SB 221 authorizes single-issue ratemaking related to distribution service, which is what it is proposing. AEP-Ohio also notes that the only opposition to the Companies' proposal is with regard to the collection of the historic regulatory assets, which was by Staff (Cos. Reply Br. at 94). The Companies submit that Staff's preference to deal with this issue in a distribution rate case is irrelevant and inconsistent with the statute.

The Commission finds that the Companies have not demonstrated that the creation of the RAC rider in its proposed ESP, as a single-issue ratemaking item for distribution infrastructure and modernization incentives, fulfills the requirements of SB 221 or advances the state policy. Therefore, the Commission finds that the RAC rider should not be approved in this proceeding. We note, however, that we agree with Staff that the consideration of the requested amortization of regulatory assets is more appropriate within the context of a distribution rate case where all distribution related costs and issues can be examined collectively. Accordingly, the Commission finds that AEP-Ohio's proposed ESP should be modified to eliminate the RAC rider.

3. Energy Efficiency, Peak Demand Reduction, Demand Response, and Interruptible Capabilities

(a) Energy Efficiency and Peak Demand Reduction

Section 4928.66, Revised Code, requires the electric utilities to implement energy efficiency programs that will achieve energy savings and peak demand programs designed to reduce the electric utility's peak demand. Specifically, an electric utility must achieve energy savings in 2009, 2010, and 2011 of .3 percent, .5 percent, and .7 percent, respectively, of the normalized annual kWh sales of the electric utility during the preceding three calendar years. This savings continues to rise until the cumulative savings reach 22 percent by 2025. Peak demand must be reduced by one percent in 2009 and by .75 percent annually until 2018.

CSP and OP include, as part of their ESP, an unavoidable Energy Efficiency and Peak Demand Reduction Cost Recovery Rider (EE/PDR rider). The estimated annual DSM program cost (including both EE and PDR) is to be trued-up annually to actual cost and compared to the amortization of the actual deferral on an annual basis via the EE/PDR rider (Cos. Ex. 6 at 47-48).

(b) Baselines and Benchmarks

In the ESP, the Companies have established the baselines for meeting the benchmarks for statutory compliance by weather normalizing retail sales, excluding economic development load, accounting for the load of former MonPower service territory and the Ormet/Hannibal Real Estate load, accounting for future load growth due to the Companies' economic development efforts, and accounting for increased load associated with the funds for economic development purposes pursuant to the order in Case No. 04-169-EL-ORD (RSP Order)[24] (Cos. Ex. 8 at 4; Cos. Ex. 2A at 46-51). The Companies contend that its process is consistent with Sections 4928.64(B) and 4928.66(A)(2)(a), Revised Code. The Companies request that the methodology be adopted in this proceeding so as to provide the Companies clear guidance with statutory compliance mandates. Further, the Companies reserve their right to request additional adjustments due to regulatory, economic, or technological reasons beyond the reasonable control of the Companies.

As to the calculation of the Companies' baseline, Staff asserts that the former MonPower load was acquired prior to the three-year period (2006 to 2008) and is not truly economic development. Therefore, Staff contends that the MonPower load is not a reasonable adjustment to the baseline. Staff suggests that the Companies' savings and peak demand reductions for 2009 be as set forth by Staff witness Scheck (Staff Ex. 3 at 6-8, Ex. GCS-1 and Ex. GCS-2). Staff recommends that CSP and OP make a case-by-case filing with the Commission to receive credit for the energy savings and peak demand reduction efforts of the electric utility's mercantile customers. Staff argues that because programs like PJM's demand response programs are not committed for integration into the electric utilities' energy efficiency and peak reduction programs, such credits should not count towards AEP-Ohio's annual benchmarks and retail customers who have such agreements should not receive an exemption from AEP-Ohio's energy efficiency cost recovery mechanism (Staff Br. at 17-19; Staff Ex. 3 at 6-11).

Kroger recommends an opt-out provision of the rider for non-residential customers that are above a threshold aggregate load (10 MW at a single site or aggregated at multiple sites) within the AEP-Ohio service territories. Kroger proposes that, at the time of the opt-out request, the customer would be required to self-certify or attest to AEP-Ohio that for each facility, or aggregated facilities, the customer has conducted an energy audit or analysis within the past three years and has implemented or plans to implement the cost-effective measures identified in the audit or analysis. Kroger argues that the unavoidable rider penalizes customers who have implemented cost efficient DSM measures. Kroger contends that this is consistent with the intent of Section 4928.66(A)(2)(c), Revised Code (Kroger Ex. 1 at 13-14).

IEU notes that the Commission has previously rejected a proposal similar to Kroger's opt-out proposal with a demand threshold for mercantile customers in Duke's

24 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 04-169-EL-ORD, Opinion and Order (January 26, 2005) (RSP Order).

ESP case.[25] IEU urges the Commission, consistent with Section 4928.66, Revised Code, and its determination in the Duke ESP case, to reject Kroger's request (IEU Reply Br. at 22).

The Commission concludes that the acquisition of the former MonPower load should not be excluded from baseline. The MonPower load was not a load that CSP served and would have lost, but for some action by CSP. Therefore, we find that the Companies' exclusion of the MonPower load in the energy efficiency baseline is inappropriate. The Commission does not believe that all economic development should automatically result in an exclusion from baseline. On the other hand, we agree with the Companies' adjustment to the baseline for the Ormet load. We note that the Companies and Staff agree that the impact of customer-sited specific DSM resources will be included in the Companies' compliance benchmarks and adjusted for any existing resources that had historic implication during the years 2006-2008. The Commission also recognizes that Staff and the Companies agree that the appropriate approach would be for the Companies to make case-by-case filings with the Commission to receive credit for contributions by mercantile customers.

In regards to Kroger's recommendation, for an opt-out process for certain commercial or industrial customers, the Commission finds Kroger's proposal, as advocated by Kroger witness Higgins, too speculative. It is best that the Commission determine the inclusion or exemption of a mercantile customer's DSM on a case-by-case basis. We note that Section 4928.66(A)(2)(c), Revised Code, provides, in pertinent part, the following:

> Any mechanism designed to recover the cost of energy efficiency and peak demand reduction programs under divisions (A)(1)(a) and (b) of this section may exempt mercantile customers that commit their demand-response or other customer-sited capabilities, whether existing or new, for integration into the electric distribution utility's demand-response, energy efficiency, or peak demand reduction programs, if the commission determines that that exemption reasonably encourages such customer to commit those capabilities to those programs.

This provision of the statute permits the Commission to approve a rider that exempts mercantile customers who commit their capabilities to the electric utility. However, the statute does not dictate a minimum consumption level. For these reasons, the Commission rejects Kroger's proposal.

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25 *In re Duke Energy Ohio, Inc.*, Case No. 08-920-EL-SSO, et al., Opinion and Order (December 17, 2008) (Duke ESP Order).

(c) Energy Efficiency and Peak Demand Reduction Programs

The Companies propose ten energy efficiency and peak demand reduction programs that will be refined and supplemented at the completion of the Market Potential Study through the creation of a working collaborative group of stakeholders.

As part of the Companies' energy efficiency and peak demand reduction plan, the Companies propose to spend $178 million on the following programs: (1) Residential Standard Offer Program, Small Commercial and Industrial Standard Offer Program, Commercial and Industrial Standard Offer Program; (2) Targeted Energy Efficient Weatherization Program; (3) Low Income Weatherization Program; (4) Residential and Small Commercial Compact Fluorescent Lighting Program; (5) Commercial and Industrial Lighting Program; (6) State and Municipal Light Emitting Diode Program; (7) Energy Star® New Homes Program; (8) Energy Star® Home Appliance Program; (9) Renewable Energy Technology Program; (10) Industrial Process Partners Program (Cos. Ex. 4 at 20-22). OEG supports the Companies EE/PDR rider as a reasonable proposal (OEG Ex. 2 at 13). OPAE generally supports the Companies proposed programs as reasonable for low-income and moderate income customers. However, OPAE requests that the Companies be required to empower the collaborative to design appropriate programs, provide funding for existing programs that can rapidly provide energy efficiency and demand response reductions, and to retain a third-party administrator to manage program implementation (OPAE Ex. 1 at 16-17; OPAE/APAC Br. at 21-22).

Staff also generally approves of the Companies' demand-side management and energy efficiency programs. However, Staff notes that certain of AEP-Ohio's programs are expensive and should be required to comply with the Total Resources Cost Test (Staff Br. at 17-19; Staff Ex. 3 at 6-11).

OCC makes five specific recommendations (OCC Ex. 5 at 9). First, OCC contends that the Companies DSM programs for low-income residential customers are adequate but should be available to all residential customers in Ohio. Second, OCC recommends that AEP-Ohio work with Columbia Gas of Ohio, Inc., to develop a one-stop home performance program in year two of the ESP. Third, OCC recommends that programs for consumers above 175 percent of the federal poverty level should be competitively bid and customers charged for services according to a sliding fee scale based on income. Fourth, like Staff, OCC contends that all programs should be evaluated for cost-effectiveness pursuant to the Total Resource Cost Test. Finally, OCC expresses concern regarding the administrative costs of the programs, in comparison to energy efficiency programs offered by other Ohio utilities and recommends that the administrative cost of the DSM program (administrative, educational, and marketing expenses) be determined by the collaborative, and limited to 25 percent of the program costs to ensure that the majority of the program dollars reach the customers (Id.).

The Commission directs, as the Companies submit in their ESP, that the collaborative process be used to contain administrative cost of the EE/PDR programs and to ensure, with the possible exception of low-income weatherization programs, that all programs comply with the Total Resource Cost Test. We do not agree with OPAE/APAC that a third-party administrator is necessary to act as a liaison between the Companies and the collaborative. Thus, the Companies should proceed with the proposed EE/PDR programs proposed in its ESP as justified by the market project study and as refined by the collaborative.

(d) Interruptible Capacity

The Companies count their interruptible service towards their peak demand reduction requirements in accordance with Section 4928.66(A)(2)(b), Revised Code. More specifically, the Companies propose to increase the limit of OP's Interruptible Power-Discretionary Schedule (Schedule IRP-D) to 450 Megawatts (MW) from the current limit of 256 MW and to modify CSP's Emergency Curtailable Service (ECS) and Price Curtailable Service (PCS) to make the services more attractive to customers. The Companies request that the Commission recognize the Companies' ability to curtail customer usage as part of the peak demand reductions (Cos. Ex. 1 at 5-6).

Staff advocates that any credits awarded for the annual peak demand reduction targets for the Companies' interruptible programs should only apply when actual reductions occur (Staff Ex. 3 at 11). OCEA argues that interruptible load should not be counted toward AEP-Ohio's peak demand reduction as it is contrary to the intent of SB 221 to improve grid reliability and would be based on load under the control of the customer rather than AEP-Ohio. Further, OCEA argues that the Companies would reap an inequitable benefit from interruptible load (possibly in the form of off-system sales) that is not reduced at peak which would allow the Companies to sell the load or avoid buying additional power. OCEA contends that any such benefit is not passed on to customers (OCEA Br. at 102-103; Tr. Vol. IX at 68-69).

The Companies argue that capacity associated with interruptible customers should be counted toward compliance with the requirements of Section 4928.66, Revised Code, as the ability to interrupt is a significant demand reduction resource to AEP-Ohio. Further, the Companies state that interruptions have a real impact on customers and the Companies do not want to interrupt service when there is no system or market requirement to do so (Cos. Ex. 1 at 6). The Companies note that Section 4928.66(A)(1)(b), Revised Code, requires the electric utility to implement programs "designed to achieve" a specified peak demand reduction level as opposed to "achieve" a specified level of energy savings as required by Section 4928.66(A)(1)(a), Revised Code. Staff witness Scheck admits that the plain meaning of "designed to achieve" and "achieve" are different (Tr. Vol. VIII at 208). The Companies argue that the different language in the statutory requirements is intended to recognize the differences between energy efficiency programs and peak demand reduction programs. As such, the Companies contend that Staff's position is not supported by the language of the statute and it does not overcome the policy rationale presented by the Companies. The Companies also note that, in the context of integrated resource planning, interruptible capabilities are counted as capacity and evaluated in the need to plan for new power facilities. Finally, the Companies note that the Commission defines native load as internal load minus interruptible load.[26] For these reasons, the Companies contend that their interruptible capacity should be counted toward their compliance with the peak demand reduction benchmarks (Cos. Br. 114-115; Cos. Reply Br. at 90-93).

Further, the Companies claim that interruptible customers receive a benefit in the form of a reduced rate for taking interruptible service irrespective of whether their service is actually curtailed. AEP-Ohio notes that it includes such interruptible service as a part of its supply portfolio, unlike the PJM demand response programs, which is based on PJM's zonal load. Therefore, AEP-Ohio asserts there is no disparate treatment between counting interruptible capabilities as part of peak demand reduction compliance requirements and prohibiting retail participation in wholesale PJM demand reduction programs (Cos. Reply Br. at 90-91). Further, as to OCEA's claims regarding interruptible customer load, the Companies argue that the assertions are without merit or basis in the statute. The Companies argue that counting interruptible load fits squarely within the stated intent of the statute that programs be "designed to achieve" peak demand reduction and facilitates the ability to avoid the construction of new power plants. As to the customer's control of interruptible load argument, the Companies note that the customer has a choice to "buy through" to obtain replacement power at market prices to avoid curtailment and in such situations the Companies' supply portfolio is not affected. Regarding OCEA's assertion that the Companies might benefit from the associated interruption, AEP-Ohio acknowledges that off-system sales are indirectly possible, as are other circumstances, based on the market price. Nonetheless, AEP-Ohio argues that such does not alter the fact that AEP-Ohio's retail supply obligation is reduced and the supply portfolio is not accessed to serve the retail customer. Accordingly, AEP-Ohio asserts that interruptible tariff capabilities should count toward the Companies' peak demand reduction compliance requirements.

The Commission agrees with the Staff and OCEA that interruptible load should not be counted in the Companies' determination of its EE/PDR compliance requirements unless and until the load is actually interrupted. As the Companies recognize, it is imperative, with regard to the PJM demand response programs, that the Companies have

[26] See proposed Rule 4901:5-5-01(Q), O.A.C., *In the Matter of the Adoption of Rules for Alternative and Renewable Energy Technologies and Resources, and Emission Control Reporting Requirements, and Amendment of Chapters 4901:5-1, 4901:5-3, 4901:5-5, and 4901:5-7 of the Ohio Administrative Code, Pursuant to Chapter 4928, Revised Code, to Implement Senate Bill No. 221*, Case No. 08-888-EL-ORD (Green Rules).

some control or commitment from the customer to be included as a part of AEP-Ohio's Section 4928.66, Revised Code, compliance requirements.

Further, the Commission emphasizes that we expect that applications filed pursuant to Section 4928.66(A)(2)(b), Revised Code, to be initiated by the electric utility only when the circumstances are justified. At the time of such filing by an electric utility, the Commission will determine whether the electric utility's continued compliance is possible under the circumstances.

4. Economic Development Cost Recovery Rider and the Partnership with Ohio Fund

The Companies' ESP application includes an unavoidable Economic Development Rider as a mechanism to recover costs, incentives and foregone revenue associated with new or expanding Commission-approved special arrangements for economic development and job retention. The Companies propose quarterly filings to establish rates based on a percentage of base distribution revenue subject to a true-up of any under- or over-collection in subsequent quarterly filings. In addition, the Companies propose the development of a "Partnership with Ohio" fund from shareholders. The fund would consist of a $75 million commitment, $25 million per year of the ESP, from shareholders. The Companies' goal is for approximately half of the fund to be used to provide assistance to low-income customers, including energy efficiency programs for such customers, and the balance to be used to attract and retain business development within the AEP-Ohio service area (Cos. Ex. 1 at 12; Cos. Ex. 3 at 15-16; Cos. Ex. 6 at 49; Tr. Vol. III at 115-119).

OCC proposes that the Commission continue its policy of dividing the recovery of forgone revenue subsidies equally from AEP-Ohio's shareholders and customers or require shareholders to pay a larger percentage. Further, OCC expresses some concern that the rider may be used in an anti-competitive manner as it is not likely that incentives and/or discounts will be offered to shopping customers. To address OCC's anticompetitive concerns, OCC proposes that the Commission make the economic development rider avoidable or establish the charge as a percentage of the customer's entire bill rather than a percentage of distribution charges. OCC also recommends that all parties participate in the initial and annual review of the economic development contracts and that, at the annual review, if the customer has not fulfilled its obligation, the arrangement be cancelled, the subsidy paid back, and the Companies directed to credit the rider for the discounts (OCC Ex. 14 at 4-8; OCEA Br. at 104-106).

The Companies contend that Section 4905.31, Revised Code, as amended by SB 221, explicitly provides for the recovery of foregone revenues for entering into reasonable arrangements for economic development and, thus, OCC's recommendation to continue the Commission's previous policy is misplaced. Further, the Companies note that the

Commission's approval of any special arrangement will include a public interest determination. Thus, the Companies argue that OCC's recommendation for all parties to initially and annually review economic development arrangements is unnecessary, bureaucratic and burdensome, and should be rejected. The Companies contend that economic development and full recovery of the foregone revenue for economic development is consistent with SB 221 and a significant feature of the Companies' ESP, which should not be modified by the Commission (Cos. Br. at 132).

The Commission finds that OCC's concerns are unfounded and unnecessary at this stage. The Commission is vested with the authority to review and determine whether or not economic development arrangements are in the public interest. OCC's request is denied.

OPAE and APAC argue that the Companies have not provided any assurances that the $75 million will be spent from the Partnership with Ohio fund if the Commission modifies the ESP and fails to state how much of the fund will be spent on low-income, at-risk populations (OPAE/APAC Br. at 19-20). The Companies submit that, if the ESP is modified, they can then evaluate the modified ESP in its entirety to determine whether this fund proposal contained in the ESP requires elimination or modification (Tr. Vol. III at 137-138; Tr. Vol. X at 232-233).

While the Partnership with Ohio fund is a key component of the economic development proposal, in light of the modifications made to the ESP pursuant to this opinion and order, we find that the Companies' shareholders should fund the Partnership with Ohio fund, at a minimum of $15 million, over the three-year ESP period, with all of the funds going to low-income, at-risk customer programs. Accordingly, we direct AEP-Ohio to consult with Staff to administer the program established herein.

C. Line Extensions

In its ESP, AEP-Ohio proposes to modify certain existing line extension policies and charges included in its schedules (Cos. Ex. 10 at 5-14). Specifically, the Companies requested a modification to their definition of line extension and system improvements, a continuation of the up-front payment concept established in Case No. 01-2708-EL-COI,[27] an increase in the up-front residential line extension charges, implementation of a uniform, up-front line extension charge for all nonresidential projects, the elimination of the end use customer's monthly surcharge, and the elimination of the alternative construction option (Id. at 3-4, 6-7, 10-12).

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[27] *In the Matter of the Commission's Investigation into the Policies and Procedures of Ohio Power Company, Columbus Southern Power Company, The Cleveland Electric Illuminating Company, Ohio Edison Company, The Toledo Edison Company and Monongahela Power Company Regarding the Installation of New Line Extensions,* Case No. 01-2708-EL-COI, et al., Opinion and Order (November 7, 2002).

Staff testified that distribution-related issues and costs, such as those related to line extensions, be examined in the context of a distribution rate case (Staff Ex. 13 at 4). IEU concurred with Staff's position (IEU Br. at 25). OCC also agreed and added that AEP-Ohio should be required to demonstrate in that rate proceeding that its costs related to line extensions have substantially increased, thereby justifying AEP-Ohio's proposed increase to the up-front residential line extension charges (OCEA Br. at 87).

Per SB 221, the Commission is required to adopt uniform, statewide line extension rules for nonresidential customers within six months of the effective date of the law. The Commission adopted such rules for nonresidential and residential customers on November 5, 2008.[28] Applications for rehearing were filed, which the Commission is still considering. Accordingly, the new line extension rules are not yet effective.

The Commission finds that AEP-Ohio has not demonstrated that its proposal to continue, in its ESP, its existing line extension policies regarding up-front payments, with modifications, is consistent with SB 221 or advances the policy of the state. Therefore, in light of the SB 221 mandate that the Commission adopt statewide line extension rules that will apply to AEP-Ohio, we do not believe that it makes sense to adopt a unique policy for AEP-Ohio at this time. As such, the Companies' ESP should be modified to eliminate the provision regarding line extensions, which would have the effect of also eliminating the alternative construction option as requested by the Companies. AEP-Ohio is, however, directed to account for all line extension expenditures, excluding premium services, in plant in service until the new line extension rules become effective, where the recovery of such will be reviewed in the context of a distribution rate case. The Companies may continue to charge customers for premium services pursuant to their existing practices.

V. TRANSMISSION

In its ESP, the Companies requested to retain the current TCRR, except the marginal loss fuel credit will now be reflected in the FAC instead of the TCRR. We concur with the Companies' request. We find the Companies' request to be consistent with our determination in the Companies' recent TCRR Case,[29] and thus, approve the TCRR rider as proposed by the Companies. Additionally, as contemplated by our prior order in the TCRR Case, any overrecovery of transmission loss-related costs, which has

[28] See *In the Matter of the Commission's Review of Chapters 4901:1-9, 4901:1-10, 4901:1-21, 4901:1-22, 4901:1-23, 4901:1-24, and 4901:1-25 of the Ohio Administrative Code*, Case No. 06-653-EL-ORD, Finding and Order (November 5, 2008), Entry on Rehearing (December 17, 2008) (06-653 Case).

[29] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Adjust Each Company's Transmission Cost Recovery Rider*, Case No. 08-1202-EL-UNC, Finding and Order (December 17, 2008) (TCRR Case).

occurred due to the timing of our approval of the Companies' ESP and proposed FAC, shall be reconciled in the over/underrecovery process in the Companies' next TCRR rider update filing.

VI. OTHER ISSUES

A. Corporate Separation

1. Functional Separation

In its ESP application, AEP-Ohio requested to remain functionally separated for the term of the ESP, as was previously authorized by the Commission in the Companies' rate stabilization plan proceeding,[30] pursuant to Section 4928.17(C), Revised Code (Cos. App. at 14; Cos. Br. at 86). The Companies also requested to modify their corporate separation plan to allow each company to retain its distribution and, for now, transmission assets and that, upon the expiration of functional separation, the Companies would sell or transfer their generation assets to an affiliate (Id.).

Staff testified that the Companies' generating assets have not been structurally separated from the operating companies (Staff Ex. 7 at 2-3). Staff also recommended that, in accordance with the recently adopted corporate separation rules issued by the Commission in the SSO Rules Case,[31] the Companies should file for approval of their corporate separations plan within 60 days after the rules become effective. Furthermore, Staff proposes that the Companies' corporate separation plan should be audited by an independent auditor within the first year of approval of the ESP, the audit should be funded by the Companies, but managed by Staff, and the audit should cover compliance with the Commission's rules on corporate separation (Staff Ex. 7 at 3-4). No party opposed AEP-Ohio's request to remain functionally separate.

Accordingly, the Commission finds that, while the ESP may move forward for approval, as noted by Staff, in accordance with our recently adopted rules in the SSO Rules Case, the Companies must file for approval of their corporate separation plan within 60 days after the rules become effective.

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30 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 04-169-EL-UNC, Opinion and Order at 35 (January 26, 2005).

31 *In the Matter of the Adoption of Rules for Standard Service Offer, Corporate Separation, Reasonable Arrangements, and Transmission Riders for Electric Utilities Pursuant to Sections 4928.14, 4928.17, and 4905.31, Revised Code, as amended by Amended Substitute Senate Bill No. 221*, Case No. 08-777-EL-ORD, Finding and Order (September 17, 2008), and Entry on Rehearing (February 11, 2009) (SSO Rules Case).

2. Transfer of Generating Assets

The Companies request authorization for CSP to sell or transfer two recently acquired generating facilities (Waterford Energy Center and the Darby Electric Generating Station) that have not been included in rate base for ratemaking purposes and the costs of operating and maintaining the plants are not built into the current rates) (Cos. Ex. 2-A at 42; Cos. Ex. 2-E at 20). CSP purchased the Waterford Energy Center, a natural gas combined cycle power plant, on September 28, 2005, which has a generating capacity of 821 MW (Cos. App. at 14). On April 25, 2007, CSP purchased the Darby Electric Generating Station, a natural gas simple cycle generating facility, with a generating capacity of 480 MW and a summer capacity of approximately 450 MW (Id.). Although AEP-Ohio is requesting authority to transfer these generating assets pursuant to Section 4928.17(E), Revised Code, CSP has no immediate plans to sell or transfer the generating facilities. If AEP-Ohio obtains authorization to sell these generating assets through this proceeding, AEP-Ohio will notify the Commission prior to any such transaction (Id. at 15).

Through its application, the Companies also notify the Commission of their contractual entitlements/arrangements to the output from the Ohio Valley Electric Corporation generating facilities and the Lawrenceburg Generation Station that the Companies intend to sell or transfer in the future, but argue that any sale or transfer of those entitlements do not require Commission authorization because the entitlements do not represent generating assets wholly or partly owned by the Companies pursuant to Section 4928.17(E), Revised Code (Id.).

The Companies argue that, if the Commission does not grant authorization to transfer these plants or entitlements, then any expense related to the plants or entitlements not recovered in the FAC should be recovered in the non-FAC portion of the generation rate (Cos. Br. at 89; Cos. Ex. 2-E at 20-21). AEP-Ohio states that this rate recovery would include approximately $50 million of carrying costs and expenses related to the Waterford Energy Center and the Darby Electric Generating Station annually, and $70 million annually for the contract entitlements (Id.).

Staff witness Buckley testified that, while Staff does not necessarily disagree with the proposal to transfer the Waterford Energy Center and the Darby Electric Generating Station facilities, Staff believes that the transfers could have a potential financial and policy impact at the time of the transfer (Staff Ex. 7 at 3). Thus, Staff recommended that the Companies file a separation application, in accordance with the Commission's SSO rules, at the time that the transfer will occur (Id.). Several other parties agree that, in the absence of a current plan to sell or transfer, the Commission should not approve a future sale or transfer. Rather, the parties argue that the Companies should seek approval, pursuant to Section 4928.17(E), Revised Code, at the time of the actual sale or transfer (OCEA Br. at 100; IEU Br. at 26-27; OEG Br. at 16).

The Commission agrees with Staff and the intervenors that the request to transfer the Waterford Energy Center and the Darby Electric Generating Station facilities, as well as any contractual entitlements/arrangements to the output of certain facilities, is premature. AEP-Ohio should file a separate application, in accordance with the Commission's rules, at the time that it wishes to sell or transfer these generation facilities. The Commission, however, recognizes that these generating assets have not and are not included in rate base and, thus, the Companies cannot collect any expenses related thereto, even if the facilities or contractual outputs have been used for the benefit of Ohio customers. If the Commission is going to require that the electric utilities retain these generating assets, then the Commission should also allow the Companies to recover Ohio customers' jurisdictional share of any costs associated with maintaining and operating such facilities. Accordingly, we find that while the Companies still own the generating facilities, they should be allowed to obtain recovery for the Ohio customers' jurisdictional share of any costs associated therewith. Thus, we believe that any expense related to these generating facilities and contract entitlements that are not recovered in the FAC shall be recoverable in the non-FAC portion of the generation rate as proposed by the Companies. The Commission, therefore, directs AEP-Ohio to modify its ESP consistent with our determination herein.

B. <u>Possible Early Plant Closures</u>

The Companies include as a part of their application in these cases a request for authority to establish a regulatory asset to defer any unanticipated net cost associated with the early closure of a generating unit or units. The Companies assert that, during the ESP period, generating units may experience failures or safety issues that would prevent the Companies from continuing to cost-effectively operate the generation unit prior to the end of the depreciation accrual (unanticipated shut down) (Cos. App. at 18-19; Cos. Ex. 2-A at 51-52). The Companies request authority to include net early closure cost in Account 182.3, Other Regulatory Assets. In the event of an unanticipated shut down, the Companies state they will timely file a request with the Commission for recovery of such prudent early closure costs via a non-bypassable rider over a relatively short period of time. The Companies are requesting that the rider include carrying cost at the WACC rate (Cos. App. at 18-19; Cos. Ex 6 at 25-26). The Companies also request authority to come before the Commission to determine the appropriate treatment for accelerated depreciation and other net early closure costs in the event that the Companies find it necessary to close a generation plant earlier that otherwise expected (earlier than anticipated shut down) (Cos. Ex. 6 at 28).

OCEA posits that the Companies' request for accounting treatment for early plant closure is wrong and should be rejected. OCEA reasons that the plant was included in rate base under traditional ratemaking regulation to give the Companies the opportunity to earn a return on the investment and the Companies accepted the risk that the plant might not be fully depreciated when it was removed from service. OCEA asserts it is not appropriate to guarantee the Companies recovery of their investment. If the Commission determines to allow the Companies to establish the requested accounting treatment, OCEA asks that the Commission adopt the Staff's "offset" recommendation (OCEA Br. at 102).

Staff argues that the value of the generation fleet was determined in the Companies' ETP cases,[32] wherein, pursuant to the stipulation, AEP-Ohio agreed not to impose any lost generation cost on switching customers during the market development period. Staff notes that, although the economic value of the generation plants was never specifically addressed by the Commission, it is reasonable to assume that the net value of the Companies' fleet was not stranded. Accordingly, Staff opposes the Companies' requests to impose on customers the cost or risk of uneconomic plants without accounting for the offset of the positive economic value of the rest of the Companies' generation plants (Staff Ex. 1 at 8).

Based on the record in this proceeding, the Commission is not convinced that it is appropriate to approve the Companies' request for recovery of net cost associated with an unanticipated shut down. Despite the arguments of the Companies to the contrary, we are persuaded by the arguments of the Staff that there may be offsetting positive value associated with the Companies generation fleet. Accordingly, while we will grant the Companies the authority to establish the accounting mechanism to separate net early closure cost, the Companies must file an application before the Commission for recovery of such costs. Accordingly, this aspect of the Companies' ESP application is denied. As to the Companies' request for authority to file with the Commission to determine the appropriate treatment associated with an earlier-than-anticipated shut down, the Commission finds this aspect of the application to be reasonable and, accordingly, the request should be granted.

C. PJM Demand Response Programs

Through the ESP, the Companies propose to revise certain tariff provisions to prohibit customers receiving SSO from participating in the demand response programs offered by PJM, either directly or indirectly through a third-party. Under the PJM programs retail customers can receive payment for being available to curtail even if the

[32] *In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues*, Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP, Opinion and Order at 15-18 (September 28, 2000).

customer's service is not actually curtailed. AEP-Ohio argues that allowing its retail customers receiving SSO to also participate in PJM demand response programs is a no-win situation for AEP-Ohio and its other customers and inconsistent with the requirements of SB 221. The Companies contend that PJM demand response programs are intended to ensure the proper price signal to wholesale customers, not to address retail rate issues (Cos. Ex. 1 at 5-7). AEP-Ohio argues that retail customers should participate through AEP-Ohio-sponsored and Commission-approved programs. The Companies contend that FERC has granted state commissions, or- more precisely, the "relevant electric retail regulatory authority," the authority to preclude retail customer participation in wholesale demand response programs. *Wholesale Competition in Regions with Organized Electric Markets* (Docket Nos. RM07-19-000 and AD07-7-000), 125 FERC ¶ 61,071 at 18 CFR Part 35 (October 17, 2008) (Final Rule) (Cos. Br. at 119)

AEP-Ohio notes that it has consistently challenged retail customers' ability to participate in such programs and argued that the terms and conditions of its tariff prohibited such and, therefore, demand response retail participants should not be surprised by the Companies' position in this proceeding (Tr. Vol. IX at 212). AEP-Ohio argues that Ohio businesses participating in PJM's demand response programs have not invested their own capital or assets, taken any financial risk, or added any value to the services for which they are being compensated through PJM. The Companies assert, as stated by Staff witness Scheck, that the PJM demand response programs cost AEP-Ohio's other customers as the load of such PJM program participants continues to count toward the Companies' Fixed Resource Requirements (FRR) option and such cost is reflected in AEP-Ohio's retail rates (Tr. Vol. VIII at 165-166). Further, the PJM program participant/customer's ability to interrupt is of no use to AEP-Ohio, as the Companies claim that PJM's curtailment request is based on PJM's zonal load and not AEP-Ohio's peak load (Cos. Br. at 122-123).

The Companies reason that SB 221 includes a process whereby mercantile customer-sited resources can be committed to the utility to comply with the peak demand reduction benchmarks as set forth in Section 4928.66(A)(2)(d), Revised Code. Further, AEP-Ohio argues that it is unclear how the interruptible capacity of a customer participating in PJM's demand response program can count toward the Companies' benchmarks without being under the control of the Companies and "designed to achieve" peak demand reductions as required by the statue. As such, the Companies argue that, if participation in the PJM demand response program is allowed, PJM will be in direct competition with the electric distribution companies' efforts to comply with energy efficiency and peak demand reduction benchmarks and thus, render the mercantile customer commitment provisions largely ineffective. For these reasons, AEP-Ohio states that it should incorporate participation in PJM's demand response programs through AEP-Ohio and AEP-Ohio would then be in a position to pass some of the economic benefits associated with participation in PJM programs on to retail customers through complementary retail tariff programs and to pursue mercantile customer-sited arrangements to achieve benchmark compliance, thus allowing the Companies to avoid duplicate supply costs (Cos. Br. at 124-126).

This aspect of the Companies' ESP proposal is opposed by Integrys, OMA, Commercial Group, OEG, and IEU. Most of the intervenors contend that AEP-Ohio, in essence, considers retail customer participation in PJM programs the reselling of power provided to them by AEP-Ohio. Integrys makes the most comprehensive arguments opposing AEP-Ohio's request for approval to prohibit customer participation in the PJM demand response programs. Integrys argues that 18 C.F.R. 35.28(g) only permits this Commission to prohibit a retail customer's participation in demand response programs at the wholesale level through law or regulation. Section 18 C.F.R. 35.28(g) states:

> Each Commission-approved independent system operator and regional transmission organization must permit a qualified aggregator of retail customers to bid demand response on behalf of retail customers directly into the Commission-approved independent system operator's or regional transmission organization's organized markets, *unless the laws and regulations of the relevant electric retail regulatory authority expressly do not permit a retail customer to participate.* [Emphasis added.]

Thus, Integrys reasons that a ban on participation in wholesale demand response programs through AEP-Ohio's tariff is not equivalent to an act of the General Assembly or rule of the Commission. Accordingly, Integrys reasons that any attempt by the Commission to prohibit participation in this proceeding is beyond the authority granted by FERC and will be preempted. Further, Integrys and Constellation argue that AEP-Ohio has failed to state under what authority the Commission could bar customer participation in PJM's demand response and reliability programs. Constellation and Integrys posit that it is not in the public interest for the Commission to approve the prohibition from participation in such programs (Constellation Br. at 20-23; Constellation Ex. 2 at 18; Integrys Ex. 2 at 15; Integrys Br. at 2).

Even if the Commission concludes that it has the authority to grant AEP-Ohio's request to revise the tariff as requested, Integrys asserts that the Companies have not met their burden to justify prohibiting participation in PJM demand response programs. Integrys asserts that the request is not properly a part of the ESP applications and should have been part of an application not for an increase in rates pursuant to Section 4909.18, Revised Code. Nonetheless, Integrys concludes that under Section 4928.143 or Section 4909.18, Revised Code, the burden of proof is on the electric utility company to show that its proposal is just and reasonable.

The Companies, according to Integrys and the Commercial Group, have failed to present any demonstration that the Companies' programs are more beneficial to customers than the PJM programs. On the other hand, Integrys asserts that the PJM programs are more favorable to customers than the programs offered by AEP-Ohio as to notification, the number of curtailments per year, the hours of curtailments, payments and payment options, and penalties for non-compliance (Integrys Ex. 2 at 10-12; Commercial Group Br. at 9). In addition, certain interveners note, and the Companies agree, that PJM has not curtailed any customers since AEP-Ohio joined PJM (Tr. Vol. IX at 48). Furthermore, the intervenors contend that participation in the demand response programs provides improved grid reliability and improved efficiency of the market due to competition (Integrys Ex. 2 at 8).

Integrys also notes that the Ohio customers receive significant financial benefits from load serving entities beyond Ohio (Tr. Vol. IX at 52-52, 118). Integrys argues that AEP-Ohio wishes to ban customer participation in wholesale demand response programs to facilitate the increase in OSS of capacity to the benefit of the Companies' shareholders. Integrys reasons that because AEP-Ohio can count load enrolled in its interruptible service offerings as a part of the PJM ILR demand response program, the Companies will receive credit against its FRR commitment. The Companies, according to Integrys, hope that additional load will come from the customers currently participating in PJM's demand response programs in Ohio (Tr. Vol. IX at 53-58; Integrys Br. at 20-22). Integrys proposes, as an alternative to prohibiting customer participation in wholesale demand response programs, that the Commission count participation in the programs towards AEP-Ohio's peak demand reduction goals in accordance with the requirements of Section 4928.66, Revised Code. Integrys argues that the load can be certified, as it is today with the PJM demand response programs, or the electric services company could be required to register the committed load with the Commission.

Furthermore, Integrys reasons that the Commission can not retroactively interfere with existing contracts between customers and the customer's electric service provider in relation to the commitment contracts with PJM. With that in mind and if the Commission decides to grant AEP-Ohio's request to prohibit participation in wholesale demand response programs, Integrys requests that customers currently committed to participate in PJM programs for the 2008-2009 planning period and the 2009-2010 planning period be permitted to honor their commitments (Integrys Br. at 27-28).

Integrys argues that the Companies' claim that taking SSO and participating in a wholesale demand response program is a resale of power and a violation of the terms and conditions of their tariffs is misplaced. Integrys opines that there is no actual resale of energy, but, instead, there is a reduction in the customer's consumption of energy upon a call from the regional transmission operator (in this case, PJM). The customer is not purchasing energy from AEP-Ohio, so any energy purchased by AEP-Ohio can be transferred to another purchaser. Thus, Integrys asserts that AEP-Ohio's argument regarding participation in a wholesale demand response program is fiction and not based on FERC's interpretation of participation in such programs. Finally, Integrys contends that AEP-Ohio's proposal is a violation of Section 4928.40(D), Revised Code, as such prohibits electric utilities from prohibiting the resale of electric generation service.

The Commercial Group asserts, that because AEP-Ohio has not performed any studies or analyses, the Companies' assertion that wholesale demands response programs must be different from a demand response program offered by AEP-Ohio is unsupported by the record (Tr. Vol. IX at 47). The Commercial Group requests that the Companies be directed to design energy efficiency and demand response programs that incorporate all available programs (Commercial Group at Br. 9).

OEG argues that, to the extent there are real benefits to the Companies as well as to their retail customers in the form of improved grid reliability, AEP-Ohio should be required to offer PJM demand response programs to its large industrial customers by way of a tariff rider or through a third-party supplier (OEG Ex. 2 at 13). IEU adds that the Companies currently use the capabilities of their interruptible customers to assist the Companies in satisfying their generation capacity requirements to PJM. According to IEU, SB 221 gives mercantile customers the option of whether or not to dedicate their customer-sited capabilities to the Companies for integration into the Companies' portfolio (IEU Ex. 1 at 12).

Constellation argues that AEP-Ohio's proposal violates Section 4928.20, Revised Code, and the clear intent of SB 221. Further, Constellation argues that approving AEP-Ohio's request to prohibit Ohio businesses from conservation programs during this period of economic hardship is ill-advised, especially considering that other businesses with which Ohio businesses' must compete are able to participate in the PJM programs. As such, consistent with the Commission's decision in Duke's ESP case (Case No. 08-920-EL-SSO, et al.), Constellation encourages the Commission to reject AEP-Ohio's request to prohibit SSO customers from participating in PJM demand response programs and give Ohio's business customers all available opportunities to reduce demand, conserve energy, and invest in conservation equipment (Constellation Br. at 23). OMA supports the claims of Constellation (OMA Br. at 10).

First, we will address the claims regarding the Commission's authority, or as claimed by Integrys, the lack of authority, for the Commission to determine whether or not Ohio's retail customers are permitted to participate in wholesale demand response programs. The Commission finds that the General Assembly has vested the Commission with broad authority to address the rate, charges, and service issues of Ohio's public utilities as evidenced in Title 49 of the Revised Code. Accordingly, we consider this Commission the entity to which FERC was referring in the Final Rule when it referred to the "relevant electric retail regulatory authority." We are not convinced by Integrys' arguments that a specific act of the General Assembly is necessary to grant the Commission the authority to determine whether or not Ohio's retail customers are permitted to participate in the RTO's demand response programs.

Next, the Commission acknowledges that the PJM programs offer benefits to program participants. We are, however, concerned that the record indicates that PJM demand response programs cost AEP-Ohio's other customers as the load of AEP-Ohio's FRR and the cost of meeting that requirement is reflected in AEP-Ohio's retail rates. Finally, we are not convinced, as AEP-Ohio argues that a customer's participation in demand response programs is the resale of energy provided by AEP-Ohio. For these reasons, we find that we do not have sufficient information to consider both the potential benefits to program participants and the costs to Ohio ratepayers to determine whether this provision of the ESP will produce a significant net benefit to AEP-Ohio consumers. The Commission, therefore, concludes that this issue must be deferred and addressed in a separate proceeding, which will be established pursuant to a subsequent entry. Although we are not making a determination at this time as to the appropriateness of such a provision, we direct AEP to modify its ESP to eliminate the provision that prohibits participation in PJM demand response programs.

D. Integrated Gasification Combined Cycle (IGCC)

In Case No. 05-376-EL-UNC, the Commission concluded that it was vested with the authority to establish a mechanism for recovery of the costs related to the design, construction, and operation of an IGCC generating plant where that plant fulfills AEP-Ohio's POLR obligation and, therefore, approved the Phase I cost recovery mechanism included in the Companies' application.[33] Applications for rehearing of the Commission's IGCC Order were timely filed and by entry on rehearing issued June 28, 2006, the Commission denied each of the applications for rehearing (IGCC Rehearing Entry). Further, the IGCC Rehearing Entry conditioned the Commission's approval of the application, stating that: (a) all Phase I costs would be subject to subsequent audit(s) to determine whether such expenditures were reasonable and prudently incurred to construct the proposed IGCC facility; and (b) if the proposed IGCC facility was not constructed and in operation within five years after the date of the entry on rehearing, all Phase I charges collected must be refunded to Ohio ratepayers with interest.

In this ESP proceeding, AEP-Ohio witness Baker testified that, although the Companies have not abandoned their interest in constructing and operating an IGCC facility in Meigs County, Ohio, certain provisions of SB 221 are a barrier to construction and operation of an IGCC facility. As AEP-Ohio interprets SB 221, the Companies may be

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33 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 05-376-EL-UNC, Opinion and Order (April 10, 2006) (IGCC Order).

required to remain in an ESP to assure an opportunity for cost recovery for an IGCC facility; the construction work in process (CWIP) provision which requires the facility to be at least 75 percent complete before it can be included in rate base; the limit on CWIP as a percentage of total rate base which the witness contends causes particular uncertainties since the concept of a generation rate base has no applicability under SB 221; and the effect of "mirror CWIP" (Cos. Ex. 2-A at 52-56). The Companies assert that not only are these barriers to the construction of an IGCC facility but also to any base load generation facility in Ohio. Nonetheless, the Companies state that they are encouraged by the fact that SB 221 recognizes the need for advanced energy resources and clean coal technology, such as an IGCC. Finally, the Companies' witness notes that, since the time the Companies proposed the IGCC facility, CSP has acquired additional generating capacity. According to Company witness Baker, the Companies hope to work with the Governor's administration, the General Assembly, and other interested parties to enact legislation that will make an IGCC facility in Meigs County a reality (Cos. Ex. 2-A at 55-56).

OCEA opines that SB 221 did not eliminate the existing requirement that electric utilities must satisfy to earn a return on CWIP and, since the Companies do not ask for the Commission to make any determination in this proceeding or at any definite time in the future as to the IGCC facility, the Commission should take no action on this issue (OCEA Br. at 98-99).

The Commission notes that the Ohio Supreme Court remanded, in part, the Commission's IGCC Order, for further proceedings and, accordingly, the matter is currently pending before the Commission. Further, as OCEA asserts, there does not appear to be any request from the Companies as to the IGCC facility in this proceeding. Accordingly, we find it inappropriate to rule, at this time, on any matter regarding the Meigs County IGCC facility in this proceeding. We will address the matter as part of the pending IGCC proceeding.

E. Alternate Feed Service

As part of the ESP, the Companies propose a new alternate feed service (AFS) schedule. For customers who desire a higher level of reliability, a second distribution feed, in addition to the customer's basic service, will be offered. Existing AEP-Ohio customers that are currently paying for AFS will continue to receive the service at the same cost under the proposed tariff. Existing customers who have AFS and are not paying for the service will continue to receive such service until AEP-Ohio upgrades or otherwise makes a new investment in the facilities that provide AFS to that customer. At such time, the customer will have 6 months to decide to discontinue AFS, take partial AFS, or continue AFS and pay for the service in accordance with the effective tariff schedule (Cos. Ex. 1 at 8). While OHA supports the implementation of an AFS schedule offering with clearly defined terms and conditions, OHA takes issue with two aspects of the AFS proposal. OHA witness Solganick testified that it is his understanding that the customer will have six months after the customer is notified by the company to make a decision (OHA Ex. 4 at 15). However, OHA witness Solganick advocated that six months was insufficient because critical-use customers, like hospitals, require more lead time to evaluate their electric supply infrastructure and needs (Id.). As such, he argued that 24 months would be more appropriate for planning purposes (Id.). Moreover, OHA argued that, because this issue involves the overall management and cost of operating AEP-Ohio's distribution system, the Commission should defer consideration of the proposed AFS until AEP-Ohio's next distribution rate case where there will be a more deliberate treatment of the issue as opposed to this 150-day proceeding (OHA Br. at 23). OHA believes that a distribution rate proceeding would better ensure that the underlying rate structure for AFS is correct, similar to the argument for deferring decision on other distribution rate issues presented in this ESP proceeding (Id.). Staff and IEU also agree that the issue should be addressed in a distribution rate case (Staff Ex. 1 at 4; IEU Ex. 10 at 11). However, IEU further recommends that the Commission deny the Companies' request because it is not based on prudently incurred costs (IEU Br. at 25-26).

The Companies retort that, while they may have some flexibility as to the notice provided customers, such notice is limited by the Companies' planning horizon for distribution facilities and the lead time required to complete construction of upgraded AFS facilities (Cos. Reply Br. at 122). The Companies reason that, while more than 6 months may be feasible, anything more than 12 months would not be prudent and, in certain rare circumstances, would not facilitate the construction of complex facilities (Id.). Nonetheless, the Companies stated that they will commit to 12 months notice to existing AFS customers for the need to make an election of service (Id.). However, the Companies vehemently opposed deferring approval of their proposed AFS schedule to some future proceeding, stating that the proposed AFS tariff codifies existing practices currently being addressed on a customer-by-customer contract addendum basis (Id.). Further, the Companies argue that IEU has not presented any basis to support the implication that the AFS schedule will recover imprudently incurred costs (Id. at 123). Thus, AEP-Ohio contends there is no good reason to delay implementation of the AFS schedule with the understanding that the Companies will provide up to 12 months notice to existing customers (Id. at 122-123).

As previously noted in this order in regards to other distribution rate issues, the Commission believes that the establishment of various distribution riders and rates, including the proposed new AFS schedule, is best reviewed in a distribution rate case where all components of distribution rates are subject to review.

F. Net Energy Metering Service

The Companies' ESP application includes several tariff revisions. More specifically, the Companies propose toeliminate the one percent limitation on the total rated generation capacity for customer-generators on the Companies' Net Energy

Metering Service (NEMS) and add a new Net Energy Metering Service for Hospitals (NEMS-H). The Companies note that, at the time the ESP application was filed, they had filed a proposed tariff modification to the NEMS and Minimum Requirements for Distribution System Interconnection and Standby Service in Case No. 05-1500-EL-COI.[34] The Companies state that upon approval of the modifications filed in 05-1500, the approved modifications will be incorporated into the tariffs filed in the ESP case (Cos. Ex. 1 at 8-9).

OHA identifies two issues with the Companies' proposed NEMS-H schedule. First, OHA asserts the conditions of service are unduly restrictive to the extent that NEMS-H requires the hospital customer-generator's facility must be owned and operated by the customer and located on the customer-generator's premises. OHA asserts that this requirement prevents hospitals from benefiting from economies of scale by utilizing the expertise of distributed generation or cogeneration companies, centralized operation and maintenance of such facilities, and shared expertise and expenses. Further, OHA asserts that the requirement that the facility be located on the hospital's premises is a barrier because space limitations and legal and/or financing requirements may suggest that a generation facility be located on property not owned by the hospital. OHA argues that the Companies do not cite any regulatory, operational, financial, or other reason why the ownership requirement is necessary. Therefore, OHA requests that the Commission delete this condition of service and require only that the hospital contract for service and comply with the Companies' interconnection requirements (OHA Ex. 4 at 8-10).

AEP-Ohio responds that the requirement that the generation facility be on-site and owned and operated by the customer is a provision of the currently effective NEMS schedule. Further, the Companies argue that economies of scale may be accomplished with multiple hospitals contracting with a third-party to operate and maintain the generation facilities of each hospital. Further, AEP-Ohio argues that there is no support for the claim that efficiencies can not be had if the hospital, rather than a third-party developer, is the ultimate owner of such facilities (Cos. Br. at 128). As to OHA's opposition to the requirement that the hospital own and operate the generation facility on its premises, AEP-Ohio contends that such is required based on the language in the definitions of a customer-generator, net metering system, and self-generator at Section 4928.02(A)(29) to (32), Revised Code (Cos. Reply Br. at 124-125).

Second, OHA argues that the payment for net deliveries of energy should include credits for transmission costs that are avoided and energy losses on the subtransmission and distribution systems that are avoided or reduced. Further, OHA requests that such payments for net deliveries should be made monthly without a requirement for the

34 *In the Matter of the Application of the Commission's Review to Provisions of the Federal Energy Policy Act of 2005 Regarding Net Metering, Smart Metering, Demand Response, Cogeneration, and Power Production*, Case No. 05-1500-EL-COI (05-1500).

customer-generator to request any net payment. The Companies propose to make such payment annually upon the customer's request (OHA Ex. 4 at 11-12). The Companies assert that OHA assumes that the customer-generator's activities will reduce transmission, subtransmission, and distribution line losses and there is no support for OHA's contention. Further, AEP-Ohio argues that annual payment is in compliance with Rule 4901:1-10-28(E)(3), Ohio Administrative Code (O.A.C.) (Cos. Reply Br. at 124). OHA witness Solganick conceded that the annual payment requirement is in compliance with the Commission's rule (Tr. Vol. X at 118-119).

Staff submits that the Companies' proposed NEMS-H tariff is premature given that requirements for hospital net metering are currently pending rehearing before the Commission in the 06-653 Case. Thus, Staff proposes, and OHA supports, that the Companies withdraw their proposed NEMS-H and refile the tariff once the new requirements are effective or with the Companies' next base rate proceeding, whichever occurs first (Staff Ex. 5 at 9; OHA Reply Br. at 9). AEP-Ohio argues that the status of the 06-653 Case should not postpone the implementation of one of the objectives of SB 221 and notes that, if the final requirements adopted in the 06-653 Case impact the Companies' NEMS-H, the adopted requirements can be incorporated into the NEMS-H schedule at that time.

As the Commission is in the process of determining the net energy meter service requirements pursuant to SB 221 in the 06-653 Case, the Commission finds AEP-Ohio's revisions to its net energy metering service schedules premature. Therefore, the Commission finds, as proposed by Staff and supported by OHA, the Companies should refile their net metering tariffs to be consistent with the requirements adopted by the Commission in the 06-653 Case or with the Companies' next base rate proceeding.

G. Green Pricing and Renewable Energy Credit Purchase Programs

OCEA proposes that the Commission order AEP-Ohio to continue, with the input of the DSM collaborative, the Companies' Green Pricing Program and to require the Companies to develop a separate residential and small commercial net-metering customer renewable energy credit (REC) purchase program. OCC witness Gonzalez recommended a market-based pricing for RECs. On brief, OCEA proposes an Ohio mandatory market-based rate for in-state solar electric application and a different rate for in-state wind and other renewable resources. OCEA asserts that the programs will assist customers with the cost of owning and using renewable energy and assist the Companies in meeting the renewable energy requirements (OCC Ex. 5 at 10-11; Tr. Vol. IV at 232-234; OCEA Br. at 97-98).

The Companies argue that, pursuant to the stipulation agreement approved by the Commission in Case No. 06-1153-EL-UNC,[35] the Green Pricing Program expired December 31, 2008. Further, the Companies note that the Commission approved the expiration of the Green Pricing Program by the Finding and Order issued in Case No. 08-1302-EL-ATA.[36] However, the Companies state that they intend to offer a new green tariff option during the ESP term (Cos. Ex. 3 at 13). Accordingly, the Companies request that the Commission OCEA's request to detail or adopt a new green tariff option at this time. In regards to OCEA's REC proposal, the Companies assert that the prescriptive pricing recommendation presented on brief is at odds with the testimony of OCC's witness. Further, the Companies note that OCC's witness acknowledged the administrative and cost-effective issues associated with the proposal. Thus, the Companies note that, as OCC's witness acknowledged, the proposal requires further study before being implemented.

While the Commission believes there is merit to green pricing and REC programs and, therefore, encourages the Companies to evaluate the feasibility and benefits to implementing such programs as soon as practicable , we decline to order the Companies to initiate such programs as part of this ESP proceeding, as it is not necessary that these optional requests be pursued by the Companies at this time. Accordingly, we find that it is unnecessary to modify AEP-Ohio's ESP to include any green pricing and REC programs, and we decline to do such modification at this time.

H. Gavin Scrubber Lease

The Companies note that in the Gavin Scrubber Case,[37] the Commission authorized OP to enter into a lease agreement with JMG Funding, L.P. (JMG) for a scrubber/solid waste disposal facilities (scrubber) at the Gavin Power Plant. Under the terms of the lease agreement, the agreement may not be cancelled for the initial 15-year term. After the initial 15-year period, under the Gavin lease agreement, OP has the option to renew or extend the lease for an additional 19 years. OP entered into the lease on January 25, 1995. Therefore, the initial lease period ends in 2010, and at that time, OP will have the option of renewing the Gavin scrubber lease for an additional 19 years, until 2029. On April 4, 2008, OP filed an application for authority to assume the obligations of JMG and restructure the financing for certain JMG obligations in the OP and JMG case.[38] In the OP and JMG case, the Commission approved OP's request subject to two conditions: OP must seek Commission approval to exercise the option to purchase the

35 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 06-1153-EL-UNC (May 2, 2007).

36 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-1302-EL-ATA (December 19, 2008).

37 *In re Ohio Power Company*, Case No. 93-793-EL-AIS, Opinion and Order (December 9, 1993).

38 *In re Ohio Power Company*, Case No. 08-498-EL-AIS, Finding and Order (June 4, 2008).

Gavin scrubbers or terminate the lease agreement; and OP must provide the Commission with details of how the company intends to incorporate the project into its ESP (Cos. Ex. 2-A at 56-58).

As part of the Companies' ESP application, OP requests authority to return to the Commission to recover any increased costs associated with the Gavin lease (Cos. Ex. 2-A at 56-58). The Companies state that a decision on the Gavin scrubber lease has not been made because the market value of the scrubbers and the analysis to determine the least cost option is not available at this time.

The Commission recognizes that additional information is necessary for the Companies to evaluate the options of the Gavin lease agreement and, to that end, we believe that AEP-Ohio should be permitted to file an application to request recognition of the Gavin lease at the time that it makes its decision as to purchasing or terminating the lease. Once the Companies have made their election, they should conduct a cost-benefit analysis and file it with the Commission prior to seeking recovery of any incremental costs associated with the Gavin scrubber lease.

I. Section V.E (Interim Plan)

The Companies assert that this provision is part of the total ESP package and should be adopted. The Companies requested that the Commission authorize a rider to collect the difference between the ESP approved rates and the rates under the Companies' current SSO for the length of time between the end of the December 2008 billing month and the effective date of the new ESP rates.

We find Section I.E of the proposed ESP to be moot with this opinion and order. The Commission issued finding and orders on December 19, 2008, and February 25, 2009, interpreting the statutory provision in Section 4928.14(C)(1), Revised Code, and approving rates for an interim period until such time as the Commission issues its order on AEP's proposed ESP.[39] Those rates have been in effect with the first billing cycle in January 2009. Consistent with Section 4928.141, Revised Code, which requires an electric utility to provide consumers, beginning on January 1, 2009, a SSO established in accordance with Section 4928.142 or 4928.143, Revised Code, and given that AEP-Ohio's proposed ESP term begins on January 1, 2009, and continues through December 31, 2011, we are authorizing the approval of AEP's ESP, as modified herein, effective January 1, 2009. However, any revenues collected from customers during the interim period must be recognized and offset by the new rates and charges approved by this opinion and order.

39 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-1302-EL-ATA, Finding and Order at 2-3 (December 19, 2008) and Finding and Order at 2 (February 25, 2009).

VII. SIGNIFICANTLY EXCESSIVE EARNINGS TEST (SEET)

Section 4928.143(F), Revised Code, requires that, at the end of each year of the ESP, the Commission shall consider if any adjustments provided for in the ESP:

> ...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.

AEP-Ohio's proposed ESP SEET process may be summarized as follows: The book measure of earnings for CSP and OP is determined by calculating net income divided by beginning book equity. The Companies then propose that the ROE for CSP and OP should be blended as the book equity amounts for AEP-Ohio is more meaningful since CSP and OP are supported by AEP Corporation. To develop a comparable risk peer group, including public utilities, with similar business and financial risk, AEP-Ohio's process includes evaluating all publicly traded U.S. firms. By using data from both Value Line and Compustat, AEP-Ohio applies the standard decile portfolio technique, to divide the firms into 10 different business risk groups and 10 different financial risk groups (lowest to highest). AEP-Ohio would then select the cell which includes AEP Corporation. To account for the fact that the business and financial risks of CSP and OP may differ from AEP Corporation, this aspect of the process is repeated for CSP and OP and taken into consideration in determining whether CSP's or OP's ROEs are excessive. The ESP evaluates business risk by using unlevered Capital Asset Pricing Model betas (or asset betas) and the financial risk by evaluating the book equity ratio. The Companies assert that the book equity ratio is more stable from year to year and, therefore, is considered by fixed-income investors and credit rating agencies. The ESP utilized two standard deviations (which is equivalent to the traditional 95 percent confidence level) about the mean ROEs of the comparable risk peer group and the utility peer group to determine the starting point for which CSP's or OP's ROE may be considered excessive (Cos. Ex. 5 at 13-42). Finally, AEP-Ohio advocates that the earnings for each year the SEET is applied should be adjusted to exclude the margins associated with OSS and accounting earnings for fuel adjustment clause deferrals for which the Companies will not have collected revenues (Cos. Ex. 2-A at 37-38; Cos. Ex. 6 at 16-17; Cos. Ex. 2 at 39-40).

OCC, OEG, and the Commercial Group each take issue with the development of the comparable firms and the threshold of significantly excessive earnings. Kroger and OCEA argue that the Companies' statistical process for determining when CSP and OP have earned significantly excessive earnings improperly shifts the burden of proof set forth in the statute from the company to other parties.

OCC witness Woolridge developed a proxy group of electric utilities to establish the business and financial risk indicators, then uses Value Line to develop a data base of companies with business and financial risk indicators within the range of the electric utility proxy group. Woolridge suggests computing the benchmark ROE for the comparable companies and adjusting the benchmark ROE for the capital structure of Ohio's electric utility companies and adjusting the benchmark by the FERC 150 basis points ROE adder to determine significantly excessive earnings (OCC Ex. 2 at 5-6, 20). AEP-Ohio argues that OCC's process is contrary to the language and spirit of Section 4928.143(F), Revised Code, as the statute requires the comparable firms include non-utility firms. The SEET proposed by OCC witness Woolridge results in the same comparable list of firms for each Ohio electric utility evaluated (Cos. Ex. 5-A at 5-6).

OEG proposes a method to establish the comparable group of firms by utilizing the entire list of publicly traded electric utilities in Value Line's Datafile,[40] and one group of non-utility firms. The comparable non-utility group is composed of Companies' with gross plant to revenue between 1.2 and 5.0, gross plant in excess of $1 billion and companies for which Value Line has a beta (OEG Ex. 4 at 4-6). OEG then calculates the difference in the average beta of electric utility group and the non-utility group and adjust it by the average historical risk premium for the period 1926 to 2008, which equals 7.0 percent to determine the adjustment to account for the reduced risk associated with utilities. Thus, for example, for the year 2007 OEG determined that the average non-utility earned return of 14.14 percent yields a risk-adjusted return of 12.82 percent. OEG then applies an adjustment to recognize the financial risk differences of AEP-Ohio to the utility and non-utility comparison groups. Finally, to determine the level at which earnings are "significantly excessive," OEG suggests an adder of the 200 basis points to encourage investments (OEG Ex. 4 at 7-9). OEG argues that the use of statistical confidence ranges as proposed by AEP-Ohio would severely limit any finding of excessive earnings as a two-tailed 95 percent confidence interval would mean that only 2.5 percent of all observations of all the sample company groups would be deemed to have excessive earnings. Further, OEG argues that as a statistical analysis the AEP-Ohio-proposed method eliminates most, if not all, of the Commission's flexibility to adjust to economic circumstances and determine whether the utility company's earnings are significantly excessive (OEG Ex. 4 at 9-10).

AEP-Ohio contends that OEG's SEET method fails to comply with the statutory requirements for the SEET, fails to control for financial risk of the comparable sample groups, fails to account for business risk and will, like the process proposed by OCC,

40 OEG would eliminate one company with a significant negative return on equity for 2007.

produce the same comparable non-utility and utility group for each of the Ohio electric utilities (Cos. Ex. 5-A at 8-9).

The Commercial Group asserts that AEP-Ohio's proposed SEET methodology will produce volatile earned return on equity thresholds and, therefore, does not meet the primary objective of an ESP which is to stabilize rates and support the economic development of the state. Further, AEP-Ohio's SEET method, according to the Commercial Group, fails to compose a comparable proxy group with business risk similar to CSP and OP, including unregulated nuclear subsidiaries and deregulated generation subsidiaries. Thus, Commercial Group recommends a comparable group consist of publicly traded regulated utility companies as determined by the Edison Electric Institute (EEI). Commercial Group witness Gorman notes that using EEI's designated group of regulated entities and Value Lines earned return on common equity shows that the regulated companies had an average return on equity of approximately 9 percent for the period 2005 through 2008. Witness Gorman contends that over the period 2005 through 2008 and projected over the next 3 to 5 years, approximately 85 percent of the earned return on equity observations for the designated regulated electric utility companies will be at 12.5 percent return on equity or less. Therefore, Commercial Group recommends that the SEET test be based on the Commission-approved return on equity plus a spread of 200 basis points. Commercial Group witness Gorman reasons that the average risk, extreme risk and beta spread over AEP-Ohio's proxy group suggest that a 2 percent/200 basis points is a conservative determination of the excessive earnings threshold (Commercial Group Ex. 1 at 3, 12-17).

AEP-Ohio argues that the Commercial Group's proposed SEET fails to develop a comparable group as required by the SEET and ignores the fact that the rate of return is a forward-looking analysis and the SEET is retrospective. Thus, AEP-Ohio concludes that this method does not address the measurement of financial and business risk (Cos. Ex. 5-A at 9-10).

OCC opposes the exclusion of accounting earnings for fuel adjustment clause deferrals and the deduction of revenues associated withOSS, as OSS are not one-time write-offs or non-recurring items (OCC Ex. 2 at 21). OCC contends that revenues associated with the deferrals are reported during the same period with the Companies fuel-related expenses and to eliminate the deferrals, as AEP-Ohio proposes, would reduce the revenues for the period without deducting for the underlying expense (OCC Reply Br. 69-70). Similarly, Kroger proposes that AEP-Ohio credit the fuel adjustment clause for the margin generated by OSS and notes that AEP Corporation's West Virginia and Virginia electric distribution subsidiaries currently do so despite AEP-Ohio's assertion that such is in violation of federal law (Kroger Ex. 1 at 9).

Staff advocates a single SEET methodology for all electric distribution utilities as to the selection of comparable firms and, further, proposes a workshop or technical conference to develop the process to determine the "comparable group earnings" for the SEET. Staff witness Cahaan reasons that the SEET proposed by AEP-Ohio as a technical, statistical analysis, if incorrectly formulated shifts the burden of proof from the company to the other parties. Staff also contends that the Companies' SEET proposal is based upon a definition of significance which would create internal inconsistencies if applied to the statute. Further, Staff believes the "zone of reasonable" earnings can be framed by a return on equity with an adder in the range of 200 to 400 basis points. Further, Staff recognizes that if, as AEP-Ohio suggests, revenues from OSS are excluded from SEET, other adjustments would be required. Staff believes it would be unreasonable to predetermine those other adjustments as this time. Thus, Staff proposes that this proceeding determine the method of establishing the comparable group and specify the basis points that will be used to determine "significantly excessive earnings." Staff claims that under its proposed process, at the end of the year, the ROE of the comparable group could be compared to the electric utility's 10-K or FERC-1 and, if the electric utility's ROE is less than that of the sum of the comparable group's ROE plus the adder, it will be presumed that the electric utility's earnings were not significantly excessive. Further, Staff asserts that any party that wishes to challenge the presumption would be required to demonstrate otherwise. If, however, the electric utility's earned ROE is greater than the average of the comparable group plus the adder, the electric utility would be required to demonstrate that its earnings are not significantly excessive (Staff Ex. 10 at 8, 16, 19, 21-24, 26-27; Staff Br. at 27).

OCEA, OMA, and the Commercial Group recommend that the comparable firm process for the SEET be determined, as Staff proposes, as part of a workshop (OCEA Br. at 110; OMA Br. at 13; Commercial Group Br. at 9).

The Commission believes that the determination of the appropriate methodology for the SEET is extremely important. As evidenced by the extensive testimony in this case concerning the test, there are many different views concerning what is intended by the statute and what methodology should be utilized. However, as pointed out by several parties, whatever the ultimate determination of what the methodology should be for the test, the test itself will not be actually applied until 2010 and, as proposed by the Companies, will not commence until August 2010, after Compustat information is made publicly available (Cos. Ex. 5 at 11-12). Therefore, consistent with our opinion and order issued in the FirstEnergy ESP Case,[41] the Commission agrees with Staff that it would be wise to examine the methodology for the excessive earnings test set forth in the statute within the framework of a workshop. This is consistent with the Commission's finding that the goal of the workshop will be for Staff to develop a common methodology for the

41 *In re Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company*, Case No. 08-935-EL-SSO, Opinion and Order (December 19, 2008).

excessive earnings test that should be adopted for all of the electric utilities and then for Staff to report back to the Commission on its findings. Despite AEP-Ohio's assertions that FirstEnergy's ESP is no longer applicable since the FirstEnergy companies rejected the modified ESP, the Commission finds that a common methodology for significantly excessive earnings continues to be appropriate given that other ESP applications are currently pending and, even under AEP-Ohio's ESP application, the SEET information is not available until the July of the following year. Accordingly, the Commission finds that Staff should convene a workshop consistent with this determination. However, notwithstanding the Commission's conclusion that a workshop process is the method by which the SEET will be developed, we recognize that AEP-Ohio must evaluate and determine whether to accept the ESP as modified herein or reject the modified ESP and, therefore, require clarification of our decision as to OSS and deferrals (Cos. Reply Br. at 134). We find that a determination of the Companies' earnings as "significantly excessive" in accordance with Section 4928.143(F), Revised Code, necessarily excludes OSS and deferrals, as well as the related expenses associated with the deferrals, consistent with our decision regarding an offset to fuel costs for any OSS margins in Section III.A.1.b of this order. The Commission believes that deferrals should not have an impact on the SEET until the revenues associated with deferrals are received. Further, although we conclude that it is appropriate to exclude off-system sales from the SEET calculation, we do not wish to discourage the efficient use of OP's generation facilities and, to the extent that the Companies' earnings result from wholesale sources, they should not be considered in the SEET calculation.

VIII. MRO V. ESP

The Companies argue that "[t]he public interest is served if the ESP is more favorable in the aggregate than the expected results of an MRO" (Cos. Br. at 15). The Companies' further argue that the state policy set forth in Section 4928.02(A), Revised Code, is satisfied if the price for electric service, as part of the ESP as a whole, is more favorable than the expected results of an MRO (Id.). The Companies aver that not only is the SSO proposed under the ESP more attractive than the SSO resulting froman MRO, other non-SSO factors exist adding to the favorability of the ESP over the MRO (Cos. Ex. 2-A at 4, 8; Cos. Ex. 3 at 14-19). Specifically, AEP calculated the market price competitive benchmark for the expected cost of electricity supply for retail electric generation SSO customers in the Companies' service territories for the next three years as $88.15 per MWH for CSP and $85.32 per MWH for OP for full requirements service (Cos. Ex. 2-A at 5). These competitive benchmark prices were calculated by AEP using market data from the first five days of each of the first three quarters of 2008, and averaging the data (Id. at 15).

AEP-Ohio witness Baker then compared the ESP-based SSO with the MRO-based SSO, analyzing the following components: market prices for 2009 through 2011; the phase-in of the MRO over a period of time pursuant to Section 4928.142, Revised Code, at 10 percent, 20 percent, and 30 percent; the full requirements pricing components of the states of Delaware and Maryland; PJM costs; incremental environmental costs, POLR costs, and other non-market portions of an MRO-based SSO (Cos. Ex. 2-A at 3-17). AEP-Ohio witness Baker also considered non-SSO costs in the comparison, such as the distribution-related costs of $150 million for CSP and $133 million for OP (Id. at 16-17). AEP-Ohio concluded that the cost of the ESP is $1.2 billion and the cost of the MRO is $1.5 billion for CSP, while the cost of the ESP is $1.4 billion and the cost of the MRO is $1.7 billion for OP (Cos. Ex. 2-B, Revised Exhibit JCB-2). Therefore, AEP-Ohio states that the ESP for the Companies in the aggregate and for each individual company is clearly more favorable for customers, and would result in a net benefit to the customers under the ESP as compared to the MRO of $ 292 million for CSP and $262 million for OP (Id.; Cos. Br. at 135).

The Companies state that, in addition to the generation component, the ESP has other elements that, when taken in the aggregate, make the ESP considerably more favorable to customers than an MRO alternative (Cos. Ex. 2-A at 17-18). AEP-Ohio explains that the benefits in the ESP that are not available in an MRO, include: a shareholder-funded commitment focused on economic development and low-income customer assistance programs; price certainty and stability for generation service for a specified three-year period; and gridSMART and enhanced distribution reliability initiatives (Cos. Ex. 2-A at 17-18; Cos. Ex. 3 at 16-18; Cos. Br. at 135-137).

The Companies contend that once the Commission determines that the ESP is more favorable in the aggregate, then the Commission is required to approve the ESP. If the Commission determines that the ESP is not more favorable in the aggregate, then the Commission may modify the ESP to make it more favorable or it may disapprove the ESP application.

Staff states that, as a general principle, Staff believes that the Companies' proposed ESP is more favorable than what would be expected under an MRO (Staff Br. at 2). However, Staff explains that modifications to the proposed ESP are necessary to make the ESP reasonable (Id.). With Staff's proposed adjustments to the ESP rates, Staff witness Hess testified that the Companies' proposed ESP "results in very reasonable rates" (Staff Ex. 1 at 10). Furthermore, Staff witness Hess demonstrated, utilizing Staff witness Johnson's estimated market rates, that the ESP is more favorable in the aggregate as compared to the expected results of an MRO (Staff Ex. 1-A, Revised Exhibit JEH-1; Staff Br. at 26).

Several intervenors are critical of various components of AEP-Ohio's proposed ESP and thus conclude that the ESP, as proposed, is not more favorable in the aggregate and should be rejected or substantially modified, or that AEP-Ohio has failed to meet its burden of proof under the statute that the proposed ESP, in the aggregate, is more favorable than an MRO (OPAE Br. at 3, 22-23; OMA Br. at 3; Kroger Br. at 4; OHA Br. at 11; Commercial Group Br. at 2-3; OEG Br. at 2-3; Constellation Br. at 16-18). More specifically, OHA contends that the Commission must take into account all terms and conditions of the proposed ESP, not just pricing (OHA Br. at 8-9). OHA further explains that the Commission must weigh the totality of the circumstances presented in the proposed ESP with the totality of the expected results of an MRO (Id. at 9). OHA also states that the proposed ESP fails to mitigate the harmful effects of new regulatory assets, proposed deferrals, and rate increases on hospitals and, therefore, the ESP does not provide benefits that make it more favorable than a simple MRO (Id. at 11). IEU asserts that both the Companies' and Staff's comparison of the ESP to an MRO are flawed because the comparisons fail to reflect the projected costs of deferrals, assume the maximum blending percentages allowed under 4928.142, Revised Code, and fail to demonstrate the incremental effects of the maximum blending percentages on the FAC costs (IEU Br. at 33, citing Cos. Ex. 2-A, Staff Ex. 1, Exhibit JEH-1, Tr. Vol. XI at 78-82, and Tr. Vol. XIII at 87-88).

OCEA disputes the Companies' comparison of the ESP to the MRO, stating that the Companies have overstated the competitive benchmark prices (OCC Ex. 10 at 15; OCEA Br. at 19-24). Based on data from the fourth quarter 2008, and taking in consideration adjustments for load shaping and distribution losses, OCC calculates that the updated competitive benchmark prices should be $73.94 for CSP and $71.07 for OP (OCC Ex. 10 at 15-24). OCEA also questioned other underlying components of AEP witness Baker's comparison of the MRO to the ESP regarding the proposed ESP, as well as the exclusion of certain costs in the MRO calculation (Id. at 37-40). Nonetheless, OCEA ultimately concludes that AEP's ESP, if appropriately modified, is more favorable than an MRO (OCEA Br. at 19-24; OCC Ex. 10 at 39). Constellation also submits that the forward market prices for energy have fallen significantly since the Companies' filed their application and submitted their supporting testimony (Constellation Ex. 2 at 16).

Contrary to the position taken by Constellation and OCEA,[42] AEP-Ohio contends that the market price analysis supplied in support of the ESP does not need to be updated in order for the Commission to determine whether the ESP is more favorable that the expected result of the MRO. Furthermore, AEP-Ohio responds that the appropriate method is to look over a longer period of time, and not just focus on the recent decline in forward market prices. (Cos. Reply Br. at 130-131).

Contrary to arguments raised by various intervenors, AEP-Ohio avers that the legal standard to approve the ESP is not whether the Commission can make the ESP even more favorable, whether the rates are just and reasonable, whether the costs are prudently

42 Constellation Br. at 17; OCEA Br. at 19-24.

incurred, whether the plan provisions are cost-based, or whether each provision of the plan is more favorable than an MRO (Cos. Reply Br. at 1-6). The Companies contend that the Commission only has authority to modify a proposed ESP if the Commission determines that the ESP is not more favorable than the expected results of an MRO (Id. at 4). As some intervenors have recognized,[43] the Commission does not agree that our authority to make modifications is limited to an after-the-fact determination of whether the proposed ESP is more favorable in the aggregate. Rather, the Commission finds that our statutory authority includes the authority to make modifications supported by the evidence in the record in this case. Based upon our opinion and order and using Staff witness Hess' methodology of the quantification of the ESP v. MRO comparison, as modified herein, we believe that the cost of the ESP is $673 million for CSP and $747 million for OP, and the cost of the MRO is $1.3 billion for CSP and $1.6 billion for OP.

Accordingly, upon consideration of the application in this case and the provisions of Section 4928.143(C)(1), Revised Code, the Commission finds that the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, as modified by this order, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

IX. CONCLUSION

The Commission believes that it is essential that the plan we approve be one that provides rate stability for the Companies, provides future revenue certainty for the Companies, and affords rate predictability for the customers. Upon consideration of the application in this case and the provisions of Section 4928.143(C)(1), Revised Code, the Commission finds that the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, as modified by this order, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code. Therefore, the Commission finds that the proposed three-year ESP should be approved with the modifications set forth in this order. To the extent that intervenors have proposed modifications to the Companies' ESP that have not been addressed by this opinion and order, the Commission concludes that the requests for such modifications are denied.

Furthermore, the Commission finds that the Companies' should file revised tariffs consistent with this order, to be effective with bills rendered January 1, 2009. In light of the timing of the effective date of the tariffs, the Commission finds that the revised tariffs shall be approved upon filing, effective January 1, 2009, as set forth herein, and contingent upon final review by the Commission.

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43 OEG Br. at 3.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) CSP and OP are public utilities as defined in Section 4905.02, Revised Code, and, as such, the companies are subject to the jurisdiction of this Commission.

(2) On July 31, 2008, CSP and OP filed applications for an SSO in accordance with Section 4928.141, Revised Code.

(3) On August 19, 2008, a technical conference was held regarding AEP-Ohio's applications and on November 10, 2008, a prehearing conference was held in these matters.

(4) On September 19, 2008, and October 29, 2008, intervention was granted to: OEG; OCC; Kroger; OEC; IEU-Ohio; OPAE; APAC; OHA; Constellation; Dominion; NRDC; Sierra; NEMA; Integrys; Direct Energy; OMA; OFBF; Wind Energy; OASBO/OSBA/BASA; Ormet; Consumer Powerline; Morgan Stanley Capital Group Inc.; Commercial Group; EnerNoc, Inc.; and AICUO.

(5) The hearing in these proceedings commenced on November 17, 2008, and concluded on December 10, 2008. Eleven witnesses testified on behalf of AEP-Ohio, 22 witnesses testified on behalf of various intervenors, and 10 witnesses testified on behalf of the Commission Staff.

(6) Five local hearings were held in these matters at which a total of 124 witnesses testified.

(7) Briefs and reply briefs were filed on December 30, 2008, and January 14, 2009, respectively.

(8) AEP-Ohio's applications were filed pursuant to Section 4928.143, Revised Code, which authorizes the electric utilities to file an ESP as their SSO.

(9) The proposed ESP, as modified by this opinion and order, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

ORDER:

It is, therefore,

ORDERED, That the Companies' application for approval of an ESP, pursuant to Sections 4928.141 and 4928.143, Revised Code, be modified and approved, to the extent set forth herein. It is, further,

ORDERED, That the Companies file their revised tariffs consistent with this opinion and order and that the revised tariffs be approved effective January 1, 2009, on a bills-rendered basis, contingent upon final review and approval by the Commission. It is further,

ORDERED, That each company is authorized to file in final form four complete, printed copies of its tariffs consistent with this opinion and order, and to cancel and withdraw its superseded tariffs. The Companies shall file one copy in this case docket and one copy in each Company's TRF docket (or may make such filing electronically, as directed in Case No. 06-900-AU-WVR). The remaining two copies shall be designated for distribution to Staff. It is, further,

ORDERED, That the Companies notify all affected customers of the changes to the tariff via bill message or bill insert within 45 days of the effective date of the tariffs. A copy of this customer notice shall be submitted to the Commission's Service Monitoring and Enforcement Department, Reliability and Service Analysis Division at least 10 days prior to its distribution to customers. It is, further, ORDERED, That a copy of this opinion and order be served on all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

Cheryl L. Roberto

KWB/GNS:vrm/ct

Entered in the Journal
MAR 1 8 2009

Reneé J. Jenkins
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

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

CONCURRING OPINION OF CHAIRMAN ALAN R. SCHRIBER

AND COMMISSIONER PAUL A. CENTOLELLA

We agree with the Commission's decision and write this concurring opinion to express additional rationales supporting the Commission's decision in two areas.

gridSMART Rider

The Order sets the initial amount to be recovered through the gridSMART rider based on the availability of federal matching funds for smart grid demonstrations and deployments under the American Recovery and Reinvestment Act of 2009. AEP-Ohio should promptly take the necessary steps to apply for available federal funding. Additionally, AEP-Ohio should work with staff and the collaborative established under the Order to refine its Phase 1 plan and initiate deployments in a timely and reasonable manner.

The foundation of a smart grid is an open-architecture communications system which, first, provides a common platform for implementing distribution automation, advanced metering, time-differentiated and dynamic pricing, home area networks, and other applications and, second, integrates these applications with existing systems to improve reliability, reduce costs, and enable consumers to better control their electric bills.

These capabilities can provide significant consumer and societal benefits. In the near term, participating consumers will have new capabilities for managing their energy usage to take advantage of lower power costs and reduce their electric bills. AEP-Ohio will be able to provide consumers feedback regarding their electric usage patterns and improved customer service. And, the combination of distribution automation and advanced metering should enable AEP-Ohio to rapidly locate damaged and degraded distribution equipment, reduce outages, and minimize the duration of any service interruptions. We expect that consumers will experience a material improvement in service and reliability.

SB 221 made it state policy to encourage time-differentiated pricing, implementation of advanced metering infrastructure, development of performance standards and targets for service quality for all consumers, and implementation of distributed generation. Section 4928.02 of the Revised Code. The Commission's Order advances these policies.

AEP-Ohio and its customers are likely to face significant challenges over the next decade from rising costs, requirements for improved reliability, and environmental constraints. Our Order will enable AEP-Ohio to take a first step in developing a modern grid capable of providing affordable, reliable, and environmentally sustainable electric service into the future.

PJM Demand Response Program

First, we wish to emphasize that the Commission supports demand response initiatives.

Second, it is essential that consumers benefit from demand response in terms of a reduction in the capacity for which AEP-Ohio customers are responsible. We encourage AEP-Ohio to work with PJM, the Commission, and interested stakeholders to ensure that predictable consumer demand response is recognized as a reduction in capacity that it must carry under PJM market rules.

Finally, consumers should have the opportunity to see and respond to changes in the cost of the power that they use. While an ESP may set the overall level of prices, consumers should have additional opportunities to benefit by reducing consumption when wholesale power prices are high. We would encourage the companies to work with staff to develop additional dynamic pricing options for commercial and industrial SSO customers who have the interval metering needed to support such rates. Such options should enable eligible consumers to directly manage risk and optimize their energy usage.

Alan R. Schriber

Paul A. Centolella

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post-Market Development Period Rate Stabilization Plan.	))))	Case No. 04-169-EL-UNC

OPINION AND ORDER

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OPINION AND ORDER

The Commission, having considered the evidence, the arguments of the parties, and the applicable law, hereby issues its opinion and order in this proceeding.

APPEARANCES

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Robert P. Mone, Scott A. Campbell, and Kurt P. Helfrich, Thompson Hine LLP, 10 West Broad Street, Suite 700, Columbus, Ohio 43215-3435, on behalf of Buckeye Power Inc. and Ohio Rural Electric Cooperatives Inc.

Joseph Condo, Calpine Corporation, 250 Parkway Drive, Suite 380, Lincolnshire, Illinois 60069, on behalf of Calpine Corporation.

Stephen J. Smith, Gregory J. Dunn, and Christopher L. Miller, Schottenstein, Zox & Dunn, 41 South High Street, Columbus, Ohio 43215, on behalf of City of Dublin.

Jeanine Amid, City Attorney, and Tom Lindsey, First Assistant City Attorney, 3600 Tremont Road, Upper Arlington, Ohio 43221, on behalf of City of Upper Arlington.

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Michael L. Kurtz, Boehm, Kurtz & Lowry, 36 East Seventh Street, Suite 2110, Cincinnati, Ohio 45202, on behalf of The Kroger Company.

Ellis Jacobs, Advocates for Basic Legal Equality Inc., 333 West First Street, Suite 500B, Dayton, Ohio 45402, on behalf of Lima/Allen Council on Community Affairs and WSOS Community Action.

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Janine L. Migden-Ostrander, Ohio Consumers' Counsel, and Colleen L. Mooney, Kimberly J. Bojko, Eric B. Stephens, and Larry Sauer, Assistant Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio 43215-3485, on behalf of the residential customers of Columbus Power Company and Ohio Power Company.

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Sally W. Bloomfield and Thomas J. O'Brien, Bricker & Eckler LLP, 100 South Third Street, Columbus, Ohio 43215-4291, on behalf of Ohio Manufacturers' Association.

David C. Rinebolt, Ohio Partners for Affordable Energy, 337 South Main Street, 4th Floor, Suite 5, P.O. Box 1793, Findlay, Ohio 45839-1793, on behalf of Ohio Partners for Affordable Energy.

Craig A. Glazer and Janine Durand, PJM Interconnection L.L.C., 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403-2497, on behalf of PJM Interconnection L.L.C.

Shawn P. Leyden, 80 Park Plaza, 19th Floor, Newark, New Jersey 07102, on behalf of PSEG Energy Resources and Trade LLC.

Peter J.P. Brickfield and Emily W. Streett, Brickfield, Burchette, Ritts & Stone PC, 1025 Thomas Jefferson Street NW, 8th Floor – West, Washington, DC 20007, on behalf of Wheeling-Pittsburgh Steel Corporation.

OPINION

I. Background

In June 1999, the Ohio General Assembly passed legislation (Amended Substitute Senate Bill No. 3 of the 123rd General Assembly, referred to as SB3) requiring the restructuring of the Ohio electric utility industry and providing for competition for the generation component of electric service. That legislation was signed by the governor in July 1999. Pursuant to SB3, the Commission received and reviewed proposed plans by Columbus Southern Power Company and Ohio Power Company (collectively AEP) to transition from the then-existing regulatory framework to the restructured SB3 framework. *In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues*, Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP, Opinion and Order (September 28, 2000) and Entry on Rehearing (November 21, 2000).

Ohio electric choice (a short-hand term for the competitive electric generation component in Ohio) began on January 1, 2001. Under Section 4928.40, Revised Code, a period of time was established to allow a competitive electric market to develop for the generation component of electric service (market development period, MDP). The default expiration date of the MDPs was December 31, 2005, unless otherwise determined by the Commission in conformance with certain statutory criteria. Since electric choice began, three competitive retail electric service providers have been certified to serve customers in AEP's service territories, with only one actually serving customers (nonresidential) (Tr. I, 34, 127). There has been at most 3.4 percent shopping in Columbus Southern's service territory and zero percent shopping in Ohio Power's territory (Tr. II, 175; OCC Ex. 8; GMEC Ex. 5, at first set discovery requests 25 and 26 and third set discovery requests 1 and 2). AEP's MDP is currently scheduled to expire on December 31, 2005.

In September 2003, the Commission (while addressing a proposed stipulated plan for the competitive market in The Dayton Power and Light Company service territory) encouraged all other electric distribution utilities (EDUs) in the state to consider continuation of their MDPs, a plan for rate stabilization, and/or a market-based standard service offer as a means for allowing time for their competitive electric markets to grow. *In the Matter of the Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company*, Case No. 02-2779-EL-ATA, Opinion and Order at 29 (September 2, 2003). Then later that month, the Commission elaborated further that such proposals should balance three objectives: rate certainty, financial stability for the EDU, and further competitive market development. *In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of Tariff Adjustments*, Case No. 03-1461-EL-UNC, Entry at 4-5 (September 23, 2003).

On February 9, 2004, AEP filed an application with the Commission for approval of a rate stabilization plan (RSP) to follow its competitive electric MDP. AEP proposes a plan to substitute for a post-MDP, market-based standard service offer and to eliminate a competitive bidding process from 2006 through 2008.

Twenty-five entities filed motions to intervene in this proceeding. Those requests were all granted and the intervenors are:

Appalachian People's Action Coalition (APAC)[1]	Buckeye Power Inc.
Calpine Corporation	City of Dublin
City of Upper Arlington	Constellation NewEnergy Inc.[2]
Constellation Power Source Inc.	Green Mountain Energy Company (Green Mountain or GMEC)
Industrial Energy Users-Ohio (IEU-Ohio)	The Kroger Company
Lima/Allen Council on Community Affairs	MidAmerican Energy Company
National Energy Marketers Association (NEMA)	Ohio Consumers' Counsel (OCC)
Ohio Energy Group (OEG)[3]	Ohio Hospital Association
Ohio Manufacturers' Association	Ohio Partners for Affordable Energy (OPAE)
Ohio Rural Electric Cooperatives Inc.	PJM Interconnection L.L.C. (PJM)
PSEG Energy Resources and Trade LLC (PSEG)	Strategic Energy LLC
Wheeling-Pittsburgh Steel Corporation	WPS Energy Services Inc.
WSOS Community Action	

By entry dated March 11, 2004, the Commission established a procedural schedule for this proceeding. A technical conference was held on March 24, 2004. Objections to the application were filed on April 8, 2004. By entry dated April 27, 2004, the examiner slightly modified that procedural schedule, changing deadlines for prefiling expert testimony, discovery cut-off, the local hearing dates (to be held in Canton and Columbus), and the evidentiary hearing date. In May 2004, the parties prefiled their expert testimony under the revised schedule.

Pursuant to the revised schedule, the local, public hearing in Canton, Ohio, was conducted on May 19, 2004. However, the examiner discovered after that hearing that the Commission had not properly sent any of the publication notices to the newspapers in AEP's service territory. Therefore, the examiner scheduled another local hearing in Canton, Ohio, for July 7, 2004, and rescheduled the local hearing in Columbus for July 1, 2004.

On May 24, 2004, OCC filed a motion to dismiss the application on various legal grounds. On May 25, 2004, AEP filed a motion to extend the time to respond to OCC's motion. IEU-Ohio supported an extension of the time to respond to OCC's motion. By

1 Appalachian People's Action Coalition, Lima/Allen Council on Community Affairs, Ohio Partners for Affordable Energy, and WSOS Community Action are collectively referenced in this decision as the low-income advocates or LIA.

2 Constellation NewEnergy Inc., MidAmerican Energy Company, Strategic Energy LLC, and WPS Energy Services Inc. are collectively referenced in this decision as the Ohio Marketers Group or OMG.

3 OEG is composed of AK Steel Corporation, BP Products North America Inc., The Procter and Gamble Co., Ford Motor Company, and International Steel Group Inc.

entry dated June 1, 2004, the examiner granted the request to defer a ruling on OCC's motion to dismiss, stating that all parties shall have the opportunity to argue the legality of AEP's proposal in post-hearing briefs.

The evidentiary hearing began on June 8, 2004, and continued to June 14, 2004. AEP presented the testimony of five witnesses. The staff and OCC each presented the testimony of two witnesses. APAC, Lima/Allen Council on Community Affairs, and WSOS Community Action jointly sponsored the testimony of one witness and OEG presented the testimony of one witness. At the July 1 and 7, 2004 local hearings, three people provided testimony in opposition to AEP's proposed RSP. The parties filed post-hearing briefs on July 13 and 30, 2004.

II. The Law

Section 4928.14, Revised Code, states in pertinent part:

> (A) After its market development period, an electric distribution utility in this state shall provide consumers, on a comparable and nondiscriminatory basis within its certified service territory, a market-based standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service....
>
> (B) After that market development period, each electric distribution utility also shall offer customers within its certified territory an option to purchase competitive retail electric service the price of which is determined through a competitive bidding process....At the election of the electric distribution utility, and approval of the commission, the competitive bidding option under this division may be used as the market-based standard offer required in division (A) of this section. The commission may determine at any time that a competitive bidding process is not required, if other means to accomplish generally the same option for customers is readily available in the market and a reasonable means for customer participation is developed.

Also relevant, the Commission approved a request filed by AEP to temporarily waive the need for it to propose a market-based standard service offer and/or competitive bidding process (CBP). *In the Matter of the Request for a Temporary Waiver by Columbus Southern Power Company and Ohio Power Company from the Requirements of Chapter 4901:1-35, Ohio Administrative Code,* Case No. 04-888-EL-UNC, Entry (June 23, 2004). The Commission agreed that AEP need not make such proposal(s) until 30 days after the final order is issued in this proceeding.

III. Certain Elements of the Approved Electric Transition Plan

In moving to electric choice in Ohio, the Commission had to address a number of financial and regulatory concerns so that each of the electric utilities could transition into utilities providing monopoly distribution service, while competing to provide the generation component. In the course of making that transition, the bundled rates and services of the electric utilities had to be separated, or unbundled, into generation, distribution and transmission components in the electric transition plan (ETP) proceedings.

Most of the parties to the AEP ETP proceedings agreed upon a resolution of the issues. The Commission reviewed that proposed resolution and approved it, with some minor modifications and with a reservation of a ruling upon the independent transmission plan. For purposes of better understanding the proposed RSP, several relevant components of the ETP are:

(1) All distribution rates effective December 31, 2005 will be frozen through 2007 for Ohio Power and 2008 for Columbus Southern. However, during that period, distribution rates can adjust to reflect costs of complying with certain changes (e.g., environmental, tax and regulatory changes) and for relief from storm damage or emergencies.

(2) Columbus Southern and Ohio Power agreed to absorb the first $20 million of actual consumer education, customer choice implementation and transition plan filing costs, but the remainder of such were permitted to be deferred, plus a carrying charge, as regulatory assets for recovery in future distribution rates (via a rider).

(3) Regulatory asset recovery was approved for the companies' MDP and for the subsequent three years for Columbus Southern and the subsequent two years for Ohio Power. Recorded regulatory assets at the beginning of the MDP, which exceeded specific regulatory asset dollar amounts in the stipulation, were amortized during the MDP and recovered through existing frozen and unbundled rates.

(4) Columbus Southern made available to the first 25 percent of the switching residential customers a shopping incentive. Any unused portion of that incentive as of December 31, 2005, will be credited to Columbus Southern's regulatory transition cost recovery.

(5) AEP reduced by five percent its generation component (including the regulatory transition costs). AEP agreed to not seek to reduce that five percent reduction for residential customers during the MDP. The first 20 percent of Ohio Power residential customer load as of December 31, 2005, that switches will not be charged the regulatory transition charge in 2006 and 2007.

(6) AEP shall transfer, by no later than December 15, 2001, operational control of its transmission facilities to a Federal Energy Regulatory Commission (FERC) approved regional transmission organization (RTO). AEP established a fund (up to $10 million) for costs associated with transmission charges imposed by PJM and/or the Midwest

Independent System Operator (MISO) on generation originating in the service territories of PJM or MISO as such costs may be incurred.

IV. Elements of the Proposed Rate Stabilization Plan

AEP proposes a plan from 2006 through 2008 to substitute for a post-MDP market-based standard service offer and to eliminate a competitive bidding process (Tr. I, 27). The RSP states that all provisions of the approved ETP that are not changed by the RSP will not be changed. The RSP proposal can be quickly summarized as follows:

(1) Keeps distribution rates in effect on December 31, 2005, frozen through 2008, except for changes allowed by 12 categories.

(2) Continues to defer pre-2006 consumer education, customer choice implementation and transition plan filing expenses beyond $20 million. Defer post-2005 consumer education, customer choice implementation and transition plan filing expenses and all RSP filing costs. All will be recovered as distribution regulatory assets, along with carrying charges, after the RSP.

(3) Allows deferral and recovery in RSP distribution rates of: (a) RTO administrative charges from the date of integration in PJM through 2005, along with a carrying cost; (b) full carrying charges for construction expenses in Accounts 101 (electric plant in service) and 106 (completed construction not classified) from 2002 through 2005; and (c) 2004 and 2005 equity carrying charges for expenditures from 2002 through 2005 in Account 107 (construction work in progress).

(4) Increases generation rates for all customer classes by three percent for Columbus Southern and seven percent for Ohio Power each year of the plan. Also, generation rates can be adjusted in the event that any of five situations arise, but the sum of the generation increases shall not be greater than seven percent for Columbus Southern and 11 percent for Ohio Power in any one of the years. As an alternative to the increases for residential customers, AEP offers that the Commission can terminate the five percent residential generation rate discount on June 30, 2004 (which will, instead, increase generation rates for residential customers by 1.6 percent for Columbus Southern and 5.7 percent for Ohio Power each year of the plan). These generation rate increases are avoidable for customers who choose another competitive generation supplier.

(5) Allows adjustments of transmission components for changes in costs directly or indirectly imposed on the companies during the RSP.

(6) Recovers amortized generation-related transition regulatory assets under the ETP rates.

(7) Makes the Columbus Southern 2.5 mills per kilowatt-hour (kWh) shopping incentive available during the RSP to the first 25 percent of the Columbus Southern residential load. Any unused portion will not be credited to the regulatory asset charge, but will become income to Columbus Southern. Still for 2006 and 2007, the first 20 percent of Ohio Power residential load that switches will not be charged the regulatory asset charge.

(8) Includes other terms addressing post-RSP Commission action, functional separation, an allowance for AEP to participate in the CBPs of other companies, and minimum stay requirements for all categories of customers.

AEP provided estimated revenue amounts expected from the fixed generation rate increases and the new deferrals to be recovered during the RSP (AEP Ex. 3, at 10):

Company	2006	2007	2008	Total
Columbus Southern	$48 million	$74 million	$100 million	$222 million
Ohio Power	$112 million	176 million	$247 million	$535 million

If the potential four percent generation increase were also added to the calculation, AEP acknowledges that the total estimated revenue amount combined for both companies becomes $1.17 billion (Tr. II, 78).

V. OCC's Motion to Dismiss

As noted earlier, OCC filed, on May 24, 2004, a motion to dismiss the application in this proceeding on two grounds, namely that the application will violate several statutes and it illegally proposes to repudiate the ETP stipulation. In the context of describing the various components of the RSP, we will also explain and address the legal and policy arguments raised by the parties, including the specific arguments made by OCC.

VI. Positions of the Intervening Parties and Commission Discussion

Of the parties who have expressed a position in this proceeding, nearly all agree that a competitive market has not adequately developed in AEP's service territories (AEP Ex. 1, at 4; AEP Ex. 2, at 24; Tr. I, 201; Staff Ex. 2, at 3; Tr. IV, 151; OEG Ex. 2, at 5; Tr. III, 208; GMEC Initial Br. 2, 5; IEU-Ohio Initial Br. 8-10; LIA Reply Br. 2, 9). Moreover, many also believe that some action needs to be taken by the Commission to avoid a "flash-cut" in 2006 to a freely competitive electric generation market (OEG Ex. 2, at 5; Tr. III, 208; 7/7/04 Tr. 6-7, 9; IEU-Ohio Reply Br. 7). Some of these parties openly fear that, without some Commission action, generation rates will escalate and fluctuate dramatically, which could hurt consumers, hurt the development of a competitive market, and harm the market participants (AEP Ex. 1, at 4; Staff Ex. 2, at 7; Staff Initial Br. 1, 12). The disagreement here is over the specific approach that the Commission should take to spur competition in AEP's service territories, while balancing the interests of the different market participants. As already noted, the Commission has determined that the objectives of an RSP are to develop a plan providing for: rate certainty, financial stability for the EDU, and further competitive market development.

A. Market-Based Standard Service Offer and Competitive Bidding Process

AEP has not conducted any studies or surveyed the market to determine the impact of its RSP upon shopping or participation by competitive suppliers (Tr. II, 177; GMEC Ex. 2). However, AEP believes that the proposed rate increases will create some opportunity for increased shopping (Tr. II, 178). Staff also agreed (Tr. IV, 23, 243-244). Moreover in AEP's view, its RSP will cover AEP's need to spend approximately $1.3 billion on environmental controls after 2005 and address AEP's environmental expenditures of roughly $1.0 billion between 2002 and 2004 (AEP Ex. 3, at 8, 11; Tr. I, 234-235). Additionally, AEP states that the RSP addresses transmission expenses, customer switching and future uncertainty (AEP Initial Br. 11). It is for those reasons that AEP believes its RSP is a reasonable proposal and good substitute for a market-based standard service offer and CBP.

AEP's RSP contains no CBP; instead, AEP seeks to substitute its RSP for a CBP. AEP takes the position that a CBP is not practical and not worth the effort (Tr. I, 96-97, 104-105). As noted earlier, the Commission has waived, temporarily, the current requirement for the filing of a CBP while the proposed RSP is under consideration. AEP believes that its proposed increased generation rates are reasonable substitutes for market-based rates. In AEP's view, if the market exceeds those rates, customers will benefit by having a fixed rate and, if the market rates fall below the increase levels, customers can avoid them by switching to another supplier (AEP Initial Br. 23, 65-66). Staff concurs that the generation rates constitute a reasonable proxy of market-based rates because of prices in the current wholesale market, prices in AEP's area, and shopping levels (Tr. IV, 20-21, 26-27, 244; Staff Initial Br. 4, 6). Moreover, staff believes that a next step (RSP) that provides generation rate stability and gradual, predictable increases is the best approach (Staff Reply Br. 3).

OEG and IEU-Ohio agree with the Commission's stated objectives and the concept of an RSP. However, neither agrees with AEP's RSP. Instead, they each advocate that their own proposed rate plan be adopted by the Commission (OEG Ex. 2, at 7-9; OEG Initial Br. 15-18; IEU-Ohio Initial Br. 6, 14, 37-40). OEG's rate plan basically provides: (a) no new transmission and distribution deferrals beyond that authorized in the ETP decision; (b) no transmission and distribution increases except for costs to comply with environmental (distribution-related), tax and regulatory laws or regulations, relief from storm damage expenses, or an emergency; (c) transmission and distribution rate increases after 2005 only upon a fully evaluated rate case; and (d) fixed generation rate increases after 2005 through a monthly rider designed to recover incremental environmental and governmentally mandated costs that have passed an earnings test (OEG Ex. 2, at 7-9; OEG Initial Br. 15-18). OEG's plan also addresses allowed components of rate base, components of operating expenses and rate of return (OEG Initial Br. 23-26).[4] OEG considers its plan to appropriately balance several things: (a) new environmental and

4 Green Mountain disagrees with OEG's proposed RSP because the increases are cost-based, not market-based (GMEC Reply Br. 6).

generation-related costs are balanced with timely recovery, while the rates increase to reasonable levels based upon earned returns; (b) allows gradual and steady monthly rate increases when needed for financial stability; (c) ensures market development through moderate generation rate increases; and (d) ensures that earned returns do not increase through piecemeal, single-issue, distribution rate increases (*Id.* at 18; OEG Reply Br. 23-24).

IEU-Ohio recommends various modifications to AEP's RSP that focus upon the price certainty and financial stability objectives identified by the Commission (IEU-Ohio Initial Br. 38-40). In particular, IEU-Ohio recommends that: (a) AEP establish its standard service offer prices as the current generation charge[5] of each rate schedule; (b) AEP continue to collect transition costs; and (c) AEP be permitted to seek adjustment of the current generation charges (either as confiscatory or as requiring increases due to increased jurisdictional costs from fuel prices, environmental actions, tax laws, or judicial/administrative orders).[6] In the alternative, IEU-Ohio urges the Commission to consider extending and lowering the current fixed rates, as was found to be acceptable in Virginia (IEU-Ohio Reply Br. 11). AEP responds to both OEG's and IEU-Ohio's proposed plans, stating among other things that those parties simply want to keep AEP's low rates for another period of time and their plans do not take into account all three Commission goals (AEP Reply Br. 14, 25-26).

OCC argues that AEP's proposed RSP does not meet the requirements of Sections 4928.02 or 4928.14, Revised Code, because the RSP is not a market-based standard service offer and/or a CBP (OCC Motion to Dismiss 3-4, 11; OCC Initial Br. 35-36; OCC Reply Br. 22). Thus, in OCC's view, the Commission has no authority to approve the RSP. Similarly, OCC argues that the generation rate component of the RSP is improper because it contains no CBP, as required by Section 4928.14(B), Revised Code (OCC Initial Br. 35). Also, OCC contends that, since the RSP addresses service during the MDP that conflicts with the approved ETP, it violates Section 4928.33(C), Revised Code (OCC Motion to Dismiss 12). OMG, NEMA, PSEG, Green Mountain, and LIA concur with these criticisms (OMG/NEMA Initial Br. 2-6, 15; OMG/NEMA Reply Br. 3-5; PSEG Br. 3-4, 8-9; GMEC Initial Br. 6; GMEC Reply Br. 4; LIA Initial Br. 9-11). In their view, the RSP cannot be an acceptable substitute because it is not based on market prices. OCC, OMG and NEMA acknowledge that the RSP was proposed as an alternative to the market-based standard service offer, but argue that, legally, an alternative cannot be substituted because the statute does not allow for such (OCC Initial Br. 38; OMG/NEMA Initial Br. 5-6; OMG/NEMA Reply Br. 4-5). LIA and Green Mountain state that, instead of illegally seeking RSP proposals, the Commission should have followed the path set forth in Section 4928.06, Revised Code, and provided an evaluation to the legislature (LIA Initial Br. 12-14; LIA Reply Br. 8; GMEC Reply Br. 6). OCC recommends that a CBP be filed as soon as

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5 In IEU-Ohio's proposal, it references the "little g" instead of current generation charges. When AEP's rates were unbundled prior to the start of electric choice, the amounts that were categorized as generation-related (or the "big G") were the amounts not distribution-related, transmission-related, other unbundled amounts, and tax valuation adjustments. Section 4928.34(A)(4), Revised Code. For AEP, the "little g" is the difference between the "big G" and the amounts allotted for the regulatory transition charge. The "little g" is what is reflected in AEP's charges as the current generation charges.

6 Green Mountain also disagrees with IEU-Ohio's proposed RSP because the MDP rates are not market-based rates (GMEC Reply Br. 5).

possible and recommends a particular format (OCC Ex. 10, at 10, Attach. A; OCC Reply Br. 24-25).

PSEG and OEG argue that the Commission's goals for a RSP are not fulfilled by AEP's proposal. Specifically, PSEG states that rate certainty is not assured because of the many exceptions that are contained in the RSP for possible future events (PSEG Br. 6). OEG states that rate stability is not included in the RSP because the $1.17 billion potential increase cannot constitute stability (OEG Initial Br. 5). Next, they both contend that the RSP really just provides financial stability to AEP and PSEG believes it will benefit AEP's competitive activities, rather than financial stability of its regulated functions (PSEG Br. 7; OEG Initial Br. 5). Moreover, PSEG claims that the RSP will do nothing to foster development of the competitive electric market (PSGE Br. 8). OCC quantifies the impact on the residential class for some of the costs over the three years as $266 million if the additional generation increase is not included and $410 million if it is included (OCC Ex. 5, at 3-4, Schedule FRP-1). OCC recommends that the entire RSP be rejected (OCC Initial Br. 64)

If the RSP is not rejected for failure to use market-based rates, OMG, NEMA and PSEG recommend that the Commission require a competitive bid to test the market (as it did with the FirstEnergy EDUs) and establish a basis for that market's prices (OMG/NEMA Reply Br. 6-8, 11; PSEG Br. 9).[7] Moreover, OMG and NEMA point out that, pursuant to Section 4928.14(B), Revised Code, AEP must either provide for a competitively bid generation service or demonstrate that such would be duplicative to available services. They argue that AEP cannot make such a demonstration and, therefore, a CBP must be scheduled like the Commission has done with other EDUs (OMG/NEMA Reply Br. 8-9). If the Commission decides to require a CBP, Green Mountain advocates a retail CBP (bidding for customers) as done in Pennsylvania, instead of a wholesale CBP (bidding to provide generation) (GMEC Reply Br. 10-12). IEU-Ohio took the opposite position, stating that providing customers with a CBP in the current state of the market would elevate form over substance (IEU-Ohio Initial Br. 40). Instead, IEU-Ohio believes the Commission should ask the legislature to delay the CBP option until the Commission concludes that the market is sufficiently mature to warrant the time and resources needed for CBPs (*Id.*).

Commission Discussion

At the outset, we will note that AEP proposed an RSP because we requested it. All parties to this proceeding are aware of the direction that this Commission has taken and the concerns it has with the post-MDP competitive electric environment. In fact, many of

7 The Commission ordered a CBP for the FirstEnergy EDUs in *In the Matter of the Applications of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges Including Regulatory Transition Charges Following the Market Development Period*, Case No. 03-2144-EL-ATA (June 9, 2004). On December 8, 2004, the CBP took place (an auction). The Commission concluded, on December 9, 2004, that the CBP auction price should be rejected because the previously approved RSP price is more favorable for consumers than the clearing price of the auction, which represented the best available market-based price to cover FirstEnergy's retail load. *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Competitive Bid Process to Bid Out Their Retail Electric Load*, Case No. 04-1371-EL-ATA, Finding and Order.

the parties in this proceeding have participated in several other proceedings involving the MDPs and post-MDP activities for other EDUs. Many of the parties readily acknowledge that a competitive electric generation market has not developed thus far in AEP's service territories and will not adequately develop by the time AEP's MDP expires in December 2005. With so few participants, so very little shopping having taken place in Columbus Southern's territory and no shopping at all having taken place in Ohio Power's territory, we do not want to simply allow market forces to be unfettered. We believe, in AEP's territory, a controlled transition is not only appropriate, but very much needed. We also believe that many, if not all parties, agree with this fundamental starting point.

The difference of opinion occurs with the manner in which to handle the near term. OCC, OMG, NEMA and LIA argue that Section 4928.14, Revised Code, provides the only mechanisms available to the Commission (adoption of a market-based standard service offer and a service developed through a CBP) and the proposed RSP is neither. Even with those two mechanisms identified in Section 4928.14, Revised Code, the parties disagree what should be done. However, AEP, staff, OEG and IEU-Ohio believe greater flexibility is available, namely, the Commission can adopt an RSP. We agree. AEP takes the position that a CBP is not practical and not worth the effort. Staff and IEU-Ohio agreed. We also agree and, as is within our authority, we conclude that a CBP is not warranted for AEP at the conclusion of its MDP. The record reflects that, in the past several years, only three competitive suppliers have been certified to provide competitive electric service in AEP's territory and only one is actually serving customers (Tr. I, 34, 127). Plus, there has been at most 3.4 percent shopping in Columbus Southern's service territory and zero percent shopping in Ohio Power's territory (Tr. II, 175; OCC Ex. 8; GMEC Ex. 5, at first set discovery requests 25 and 26 and third set discovery requests 1 and 2). This level of inactivity leads us to seriously doubt the efficacy of initiating a competitive bid. Instead, we conclude that an RSP (and in particular the one we adopt today) will accomplish, generally, the same as a CBP for customers and provide a reasonable means for customers to participate in that competitive environment as it continues to develop. As further explained in this decision, we agree to increase generation rates (which are avoidable to customers who choose another competitive generation supplier). These components of the RSP, along with continuation of the unaffected provisions of the ETP, we believe will prompt the competitive market and continue to provide customers a reasonable means for customer participation. Therefore, we conclude that, at this time, a CBP is not required for AEP between 2006 and 2008.

Many parties argue that AEP's proposed RSP is not a market-based standard service offer because it is not based upon the market. OMA and NEMA have argued that the RSP is not based upon a willing buyer and a willing seller. AEP proposes its RSP as a substitute for a market-based standard service offer (Plan at 3). Staff presented evidence that the RSP is a reasonable proxy of market-based rates based upon its evaluation (Tr. IV, 20-21, 26-27, 244). OCC's witness acknowledged that the Commission has the discretion to determine an appropriate proxy for a market-based standard service offer, given that both the retail electric choice market and the wholesale market have not sufficiently developed (Tr. III, 147). For the period involved (2006 through 2008), we conclude that the generation rates that we approve in this RSP today will constitute an appropriate market-based standard service offer, as required by Section 4928.14(A), Revised Code. We will evaluate any subsequent, additional generation rate adjustments (which are limited to only the enumerated categories). Additionally, we conclude that the RSP that we approve today complies with the requirements of Section 4928.14, Revised Code. None of the arguments raised to the contrary convinces us otherwise. Finally, we note that there is greater flexibility under Section 4928.14, Revised Code, than what some parties have advocated in this proceeding. The Ohio Supreme Court recently recognized, in *Constellation NewEnergy, Inc. v. Pub. Util. Comm.*, ____ Ohio St.3d ___, 2004-Ohio-6767 (December 17, 2004), that an RSP could satisfy Section 4928.14, Revised Code.

Next, we conclude that our decision today will fulfill our previously identified RSP goals. Throughout this decision, as we address the various components of the proposed RSP, we specifically explain how and why we believe that various approved components are acceptable, including how they meet or fulfill our intended goals.

B. Generation Rates and Charges (Provisions Two and Three of the RSP)

1. Three and Seven Percent Increases

AEP proposes in the RSP that, for all customer classes, the generation rates will increase each year (2006, 2007, and 2008) by three percent for Columbus Southern and by seven percent for Ohio Power. These increases will generate $151 million for Columbus Southern and $376 million for Ohio Power (AEP Ex. 3, at 10). AEP contends that the three and seven percent generation rate increases are reasonable to address the Commission's three objectives of a RSP. These generation rate increases are based upon the companies' judgment (AEP Ex. 2, at 12). Given that AEP has low generation rates currently, AEP contends that fixed increases will spur market competition and be preferable to customers, rather than imposition of full market-based rates (*Id.* at 13). AEP further notes that the generation rate increases complement the companies' substantial investments to comply with environmental requirements. AEP noted that it plans to spend $1.3 billion beyond normal capital expenditures after 2005 on generation-related environmental controls (AEP Ex. 2, at 14; AEP Ex. 3, at 11). Next, AEP points to other EDU generation rates and contends that its increased rates would still be below the current lowest average residential generation rates of those EDUs (AEP Ex. 5, at 13; Tr. III, 31).[8] When that comparison is made, AEP argues that its proposed generation rate increases are reasonable (AEP Ex. 5, 13; AEP Initial Br. 24, 67-68).

Staff supports the fixed generation rate increases as reasonable in magnitude and because they are completely avoidable if a competitor can beat the price and customers shop (Staff Ex. 2, at 8; Tr. IV, 152, 154-155, 163-164, 248-249; Staff Reply Br. 4). Staff evaluated this portion of the plan in the context of the current market, the expectation that generation rates will rise and the magnitude of the proposed numbers for company financial integrity (Tr. IV 156, 158; Staff Ex. 2, at 8). Moreover, staff noted that AEP's rates are low compared to the Ohio market and keeping them frozen would impede supplier entry in the territory (Tr. IV, 248).

8 Staff notes that AEP is distinguishable from other EDUs in Ohio because it has lower cost generation supplies and has an infrastructure to allow it to move power within a seven-state region (Staff Initial Br. 4). Staff suggests that AEP's proposal here should be evaluated separately from the other RSPs (*Id.*).

OEG, Green Mountain, LIA, OCC, and IEU-Ohio disagree with the proposed fixed, generation rate increases. OEG and IEU-Ohio object to the three and seven percent generation rate increases on the ground that they will generate excessive earnings, while AEP has been already receiving very healthy returns (OEG Ex. 2, at 14-16; OEG Reply Br. 4, 6; IEU-Ohio Initial Br. 7). OEG contends that the fixed generation increases will engender 3.6 times more revenues than the companies' projected costs for the environmental expenditures identified (OEG Ex. 2, at 15). OEG and OCC are also skeptical that customers will really avoid the increased generation rates on the ground that the market is defective now and even AEP anticipates that it will remain defective for a period of time (OEG Reply Br. 22-23; OCC Reply Br. 20). Thus, in OEG's and OCC's view, customers will only have an option to shop in a defective market or take generation service from AEP at increasing rates (*Id.*). Moreover, OCC highlights that the identified projected costs for the environmental expenditures are not costs just for these companies; rather, they will be allocated throughout the entire AEP system, but AEP did not account for such allocation (Tr. I, 79; OCC Ex. 10, at 8; OCC Initial Br. 28). AEP and staff respond that, after the MDP, generation service is no longer subject to cost-based regulation and, thus, AEP's generation rates and charges need not be cost-based (AEP Initial Br. 31; Staff Initial Br. 4; Tr. IV, 154, 158, 165-166, 245). OEG counters by noting that AEP justified many aspects of the proposed RSP by relying solely on the cost of service for those items (e.g., additional generation-related expenses to be recovered through generation rate increases and deferrals) (OEG Reply Br. 17-18).

Green Mountain argues that the RSP's rates are below market (GMEC Inititial Br. 8). Green Mountain further argues that AEP should be required to prove the cost basis of its generation rates (and distribution and transmission rates) since AEP has justified its RSP by pointing to various costs/expenses and Section 4905.33(B), Revised Code, prohibits service for less than actual cost for purposes of destroying competition (*Id.* at 18).

IEU-Ohio contends that justification for the fixed generation rate increases is weak because it is not clear that AEP will spend all estimated amounts on environmental compliance, the estimated expenditures only modestly affect production costs during the RSP period, and those expenditures will be allocated among the various operating companies as production costs (Tr. I, 58-60; IEU-Ohio Initial Br. 5-6). IEU-Ohio points out that the proposed fixed generation rate increases will allow AEP to collect $527 million more than current generation rates allow, in addition to the $702 million in transition costs allowed under the ETP decision (IEU-Ohio Initial Br. 3). IEU-Ohio points out that this RSP asks the Commission to approve generation rate increases on the basis that the current generation rates are below market, while in 1999, AEP claimed that the generation component was at above-market prices and, therefore, asked for regulatory transition costs (IEU-Ohio Initial Br. 17-18, 22; IEU-Ohio Reply Br. 7).

IEU-Ohio acknowledges that electric generation service (after the MDP) shall not be subject to traditional cost-of-service supervision or regulation, but it also believes that the Commission has a duty to ensure that the standard service offer prices are just and reasonable (IEU-Ohio Initial Br. 25-29; IEU-Ohio Reply Br. 3-5). In IEU-Ohio's view, the RSP's proposed generation rates are too high and not reasonable, particularly since AEP's financial condition has been very favorable over the last few years. Next, IEU-Ohio contends that these rate increases will simply fund investments and growth on earnings and are not necessary for financial stability (IEU-Ohio Initial Br. 30-31). IEU-Ohio also noted that, in Virginia, price caps have been extended and Ohio should realize that raising retail prices in Ohio (while other states extend rate caps) will not benefit Ohio as it strives to compete in the global economy (IEU-Ohio Reply Br. 8).

OCC argues that this portion of the RSP violates Section 4928.38, Revised Code, because it seeks recovery of additional generation-related costs not authorized in the ETP at the time when AEP is supposed to be on its own with respect to recovery of generation-related costs (OCC Motion to Dismiss 5). OCC further argues that these fixed generation rate increases are not cost-based or justified because a complete picture of current costs has not been made (some prior costs may no longer exist, while some new costs and benefits have developed) (Tr. I, 173-174, 222; OCC Initial Br. 28-31; OCC Reply Br. 16, 17). OCC supports OEG's estimated rates of return and argues that they demonstrate that the fixed generation rate increases alone will cause extremely high returns for AEP that should not be permitted (OCC Initial Br. 32, 39; OCC Reply Br. 16-17). In other words, OCC states that AEP should not be earning higher returns on equity than they could possibly be allowed in a regulatory environment when a developed competitive market is absent (*Id.* at 39).

LIA also disagrees with the generation rate increases in the RSP (LIA Initial Br. 16). On legal grounds, LIA argues that, since the RSP involves an increase in rates, AEP has violated Sections 4909.17 and 4909.19, Revised Code, by not following rate increase procedures (*Id.* at 9). Moreover, LIA contends that AEP's actions/inactions regarding RTO membership have caused a competitive market to not develop and, therefore, AEP does not have "clean hands" and should not be rewarded with excessive increases in rates (LIA Reply Br. 2). From a public policy perspective, LIA contends that the companies already have high profit margins and do not need rate increases, and yet do not propose any programs to mitigate the impact of the RSP on low-income customers (LIA Initial Br. 16, 20, 31; LIA Reply Br. 3-4, 6). LIA notes that AEP is the only Ohio utility to ever terminate funding for low-income energy efficiency programs (APAC Ex. 1, at 7; Tr. IV, 182; LIA Initial Br. 32). LIA further contends that the RSP will exacerbate the already high amounts of percentage of income payment plan (PIPP) arrearages for AEP customers (*Id.* at 26). If the Commission proceeds with an RSP, LIA and OCC argue the Commission must consider the impact of the RSP on the low-income consumers and vulnerable populations in order to promote rate stability and certainty (*Id.* at 20, 34; OCC Initial Br. 62). Specifically, LIA urges: (a) the Commission to allow PIPP customer pools to participate in CBPs during the RSP; (b) AEP to negotiate with the Ohio Department of Development, Commission staff, and low-income intervenors to develop "an approach to arrearages that reinforces good payment behavior by PIPP program participants and reduces the PIPP debt to a manageable level that can conceivably be repaid"; and (c) the Commission require funding by AEP of $1.5 million per year for a low-income energy efficiency program in AEP's service territory (APAC Ex. 1, at 8, 12; Tr. IV, 197, 201; LIA Initial Br. 29, 32; LIA Reply Br. 7-8). OCC supports these three recommendations (OCC Initial Br. 62).

Commission Discussion

Certainly, to some extent, the generation rate increases will provide additional funds to the companies and assist in their financial stability. As noted, AEP will be incurring large generation-related expenses above normal capital expenditure levels during the RSP period. However, we also believe that the RSP package as a whole supports our goals of helping to develop the competitive market and providing some rate stability. We reach this conclusion because we believe that the generation rate increases are a reasonable approximation of the future market conditions. With the RSP's structured, periodic generation rate increases, customers will not be subjected to significant swings in generation rates in an emerging competitive market for AEP. We believe this provision is not only very important to spurring a competitive market, but also to protecting customers from the risks and dangers associated with price volatility and a nascent competitive market.

We also accept our staff's conclusion that the percentage increases are reasonable in magnitude. Many of the parties object to this provision because they contend that AEP is already earning too much. However, these parties seem to forget that, with the expiration of the MDP, generation rates are subject to the market (not the Commission's traditional cost-of-service rate regulation) and that the plan was an option that AEP voluntarily proposed. Section 4928.05(A)(1), Revised Code. We make this observation to point out that, under the statutory scheme, company earnings levels would not come into play for establishing generation rates - market tolerances would otherwise dictate, just as AEP argued (AEP Reply Br. 26-27). We are strongly committed to encouraging the competitive market in AEP's service territories as it is the policy of this state, per Section 4928.02, Revised Code. Given that commitment, we do not feel that the earnings levels evidence or cost-based analyses and arguments presented by OEG, OCC, IEU-Ohio or LIA justify rejection of this provision. We believe that this provision will establish generation rates that are appropriate for the RSP period, spur the competitive market, and also protect customers from dramatic or volatile generation rate price changes. We do not agree that this provision violates any of the cited statutes.

While we have found the proposed generation rate increases to be reasonable, both in concept and in number, it is also appropriate to point out that these increases will be avoidable during the rate stabilization period. Customers who choose another competitive generation supplier can avoid AEP's increased generation rates (because those customers will pay, instead, the rates of their chosen supplier). We believe this is an important point to note.

We do realize that rate increases can be difficult for some customers to handle, as LIA has argued. We are not ignoring these concerns. In fact, we believe that the structured nature of the generation rate increases will be more helpful to the low-income customers in AEP's territory than would otherwise likely occur without the RSP. Ideally, we agree that rate increases are not preferred, but we are weighing and balancing several competing interests and we believe that the proposed generation rate increases will result in the most balanced and reasonable generation rates for all customers in AEP's service territories during the three years following the MDP. For these additional reasons, we accept this provision. Despite that conclusion, we agree that low-income customers, in particular, can be disproportionately affected by the RSP. To alleviate that concern, we conclude that low-income customers should receive some additional assistance. Therefore, we have provided for additional funding of low-income and economic development programs during the RSP period as set forth in Section VI.G of this decision.

2. Elimination of Five Percent Residential Discount

For all residential customers, AEP proposes an additional generation rate increase each year of 1.6 percent for Columbus Southern and 5.7 percent for Ohio Power, if the five percent generation discount terminates on June 30, 2004. This would end the five percent residential rate reduction 18 months earlier than what was agreed upon in the ETP stipulation (Tr. I, 28). If elimination of the five percent discount to residential customers is included, AEP calculates that the generation rate increases will be 8.5 percent for Columbus Southern residential customer and 13.2 percent for Ohio Power residential customers in 2006 (AEP Ex. 2, at 11). This would amount to roughly a $6 million increase for residential rates (Tr. I, 29). AEP supports this proposal by noting that Section 4928.40(C), Revised Code, allows the Commission to terminate the discount if it is "unduly discouraging market entry by [...] alternative suppliers." Despite the proposed June 30, 2004 date having passed, AEP has noted that the alternative is still viable, but the later termination of the discount (still prior to the end of the MDP) will result in reduced fixed increases for residential customers (AEP Initial Br. at footnote 11). AEP, staff and Green Mountain believe that the current generation rates, along with the existing temporary discount, unduly discourages market entry because of the small price differential between AEP's generation rates and others' generation supplies (AEP Ex. 2, at 12; Tr. IV, 23; GMEC Br. at 16-17). Staff and Green Mountain urge the Commission to eliminate the temporary discount (Staff Ex. 2, at 9; GMEC Initial Br. 17).

OCC opposes elimination of the five percent discount on the ground that the ETP stipulation requires the companies to retain the discount for residential customers through the MDP (OCC Initial Br. 32; OCC Reply Br. 17).[9] The ETP stipulation states that the companies will "not seek to reduce the [five percent] reduction in the generation component rate reduction for residential customers during the market development period" (OCC Ex. 1, at 6). OCC also contends that AEP has not demonstrated that the discount is unduly discouraging market entry, as required by Section 4928.40(C), Revised Code (OCC Ex. 10, at 5; OCC Reply Br. 18). In fact, AEP could not say that elimination of the discount would result in suppliers entering the residential market (AEP Ex. 2, at 12; Tr. I, 137-138). AEP contends that its RSP does not ask to remove the five percent discount during the MDP; it only noted that it was an option that the Commission could consider in the context of the RSP's proposed generation rate increases (AEP Initial Br. 27-28, 68, 78).

IEU-Ohio states that the Commission should consider elimination of AEP's five percent residential discount in a "stand-alone" proceeding that is "focused on the

9 OCC argues that the Commission lacks authority to approve any portion of the RSP that impacts any term in the ETP decision (OCC Motion to Dismiss 2; OCC Initial Br. 2-3). Staff disagrees with that argument because the Commission retains ongoing jurisdiction over its orders, including the authority to change or modify its earlier decisions as it deems necessary in the best interests of the utility and customers (Staff Initial Br. at footnote 1).

residential customer sector and the full range of conditions that are affecting market entry by alternate suppliers" (IEU-Ohio Initial Br. 41).

Commission Discussion

OCC correctly cites the ETP stipulation. We also believe that AEP's argument that its RSP does not ask to remove the five percent discount is an attempt at "hair-splitting". AEP's RSP proposed eliminating the five percent discount and it previously agreed that it would not make such a request during the MDP.

Notwithstanding the language in the ETP stipulation and our acceptance of that stipulation, we have the ability to evaluate the impact of the five percent residential discount under Section 4928.40(C), Revised Code. Section 4928.40(C), Revised Code, gives the Commission the flexibility to eliminate the five percent residential discount if it unduly discourages market entry in AEP's service territories. We believe that an early ending to the discount is not warranted and, rather, it is appropriate that the five percent residential discount in both companies' territories, end effective December 31, 2005. We further note that ending the five percent residential discount on December 31, 2005, is in keeping with SB3 (including Section 4928.40, Revised Code) and is consistent with the timing required of the residential discounts of four other EDUs. *Ohio Edison*, Case No. 03-2144-EL-ATA, *supra* at 24-25 and *In the Matter of the Application of The Cincinnati Gas & Electric Company to Modify its Nonresidential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish an Alternative Competitive-Bid Service Rate Option Subsequent to the Market Development Period*, Case No. 03-93-EL-ATA, Opinion and Order at 36-37 (September 29, 2004).

3. Additional Generation Rate Increases

AEP's RSP allows generation rates to further increase, after a Commission hearing, for: (a) increased expenditures incurred through an affiliate pooling arrangement for complying with changes in laws/rules/regulations related to environmental requirements, security, taxes, and new generation-related regulatory requirements imposed by statute/rule/ regulation/administrative order/court order; or (b) customer load switches that materially jeopardize either company's ability to recover the anticipated generation revenues. Total generation rate increases cannot be greater than seven percent for Columbus Southern and 11 percent for Ohio Power in any given year (if the five percent residential discount is not eliminated).[10] The additional generation adjustments are effectively capped at four percent. The RSP proposes a 90-day time frame, after which the proposed increase will become effective on an interim basis until the Commission's final order is implemented.

AEP points out that this aspect of the RSP only gives the company the flexibility to ask for additional, limited generation rate increases in the event of changes in the two enumerated categories; it does not pre-approve or guarantee rate increases (AEP Ex. 2, 16-

10 If the five percent residential discount would have been eliminated as of June 30, 2004, any additional generation rate increases would be at most four percent above the residential customers' fixed annual increase, which would be at most 5.6 percent for Columbus Southern residential customers and 9.7 percent for Ohio Power residential customers (AEP Ex. 2, at 18).

17; AEP Initial Br. 35). AEP characterizes this provision as a means to manage the risk it faces relative to the fixed generation rate increases (AEP Reply Br. 28). At this point in time, AEP does not expect to ask for additional rate increases (Tr. I, 198). Also, AEP mentions that any additional increases that might be authorized by the Commission could be avoided for customers who choose another competitive supplier (AEP Initial Br. 35).

Staff, Green Mountain and IEU-Ohio do not fully support or fully object to this provision. They believe that any request for additional generation rate increases should be evaluated by looking at the company's overall financial health (not just the events that triggered the proposed further increase) and not be limited to four percent (Staff Ex. 2, at 9-10; GMEC Reply Br. 12-13; IEU-Ohio Initial Br. 42; Tr. IV, 33, 153, 231, 245). Staff recognizes that the proposed additional generation increases would be sought for many of the same reasons that AEP had based its proposed three and seven percent increases and, thus, believes automatic additional increases should only be considered after looking at the whole company (Tr. IV, 153, 245-247). AEP responded by stating that a look at the overall financial health of the company is contrary to Section 4928.05(A)(1), Revised Code, because generation pricing will not be subject to cost-of-service ratemaking principles (AEP Initial Br. 38). Additionally, AEP predicts that holding generation rates down because of a strong "wires business" is likely to result in rate shock in 2009, which is what the Commission is trying to avoid today (*Id.*; Tr. I, 247).

OCC argues that the proposed four percent additional increase does not result from changes in market prices and, thus, is not market-based (OCC Ex. 10, at 9). Like staff, OCC characterizes this provision as improper single-issue ratemaking and also criticizes the ambiguity of the phrase "materially jeopardizes either or both companies' ability to recover the increased revenues" (*Id.*).

OEG worries that this portion of the RSP could permit recovery twice for the same expenses; essentially that the same costs used to justify the fixed increases arguably could justify the proposed additional increases (OEG Ex. 2, at 16-17). Plus, because the companies will continue to have very high earnings, OEG believes that the additional generation rate increases are not needed to maintain financial stability (OEG Initial Br. 8). AEP notes that this criticism is really a concern over the Commission's ability to judge any proposed additional generate rate increase and not a sufficient basis for rejecting this portion of the RSP (AEP Initial Br. 39).

<u>Commission Discussion</u>

We find this portion of the RSP to be acceptable. We agree with AEP that this portion of the RSP will allow AEP to seek additional generation rate increases; it does not pre-approve them (although it does limit any approved amount). We understand staff's and IEU-Ohio's preference that subsequent generation rate increases be viewed in the context of the company's overall financial health, but that position ignores the requirements of Section 4928.05(A)(1), Revised Code. Thus, we find this portion of the RSP to appropriately temper potentially large generation rate increases (by limiting the dollar amounts), while also recognizing AEP's interest in financial stability. This provision is a compromise position that takes into consideration the competing interests. We understand the criticism raised with the phrase "materially jeopardizes either or both companies' ability to recover the increased revenues." In the event that further increases are requested by AEP, we will evaluate this. Similarly, we understand OEG's concern that AEP could request further generation-related rate increases for items that it is already recovering. But, as AEP states, the concern does not justify rejecting the provision; it is really a question of whether the proposed further increase is properly evaluated. For these reasons, none of the comments raised in this proceeding convinces us that this portion of the RSP should be rejected.

C. Distribution Rates and Charges (Provision One of the RSP)

Under the RSP, AEP distribution rates and charges in effect on December 31, 2005, would remain in effect through 2008 (except for the universal service fund rider, energy efficiency fund rider, and certain cost-based charges such as right-of-way charges). These "frozen" distribution charges could be also adjusted in the event of an emergency, changes in transmission/distribution allocations under the FERC's seven-factor test, or if the companies experience increased distribution-related expenses due to: (a) changes in laws/rules/regulations related to environmental requirements; (b) security; (c) taxes; (d) O&M due to new requirements imposed by federal or state legislative or regulatory bodies after March 31, 2004; and (e) major storm damage service restoration. Furthermore, the "frozen" distribution rates will be adjusted, if the Commission approves, to recover certain deferred RTO administrative costs (deferred in 2004 and 2005) plus carrying costs and certain deferred carrying costs on certain environmental expenditures since 2002, plus carrying costs.

AEP points out that the RSP only freezes distribution rates for an additional one-year period for Ohio Power, because the ETP froze them previously (AEP Ex. 2, at 5). AEP acknowledges that, in addition to what is contained within the ETP, the RSP would add some additional categories for which the "frozen" distribution rates would/could be adjusted (*Id.*; Tr. I, 31-32). AEP contends that, at least with the proposed adjustments for security expenses and the specified O&M expenses, they are justified because of the unforeseen security issues that previously developed and the likelihood that O&M expenditures will be needed since the ETP was approved (AEP Ex. 2, at 6).

Staff, IEU-Ohio and OEG state that a distribution rate case should be conducted, instead of freezing distribution charges from 2006 to 2008 (Staff Ex. 2, at 7-8; Tr. IV, 230; IEU-Ohio Initial Br. 42; OEG Ex. 2, at 22-23). They reach this conclusion because these distribution rates were established in 1991 and 1994 rate cases (Staff Ex. 2, at 8). More specifically, OEG believes that AEP's returns on common equity have been very high over the last several years and the proposed RSP will only perpetuate them (OEG Ex. 2, at 11-14). AEP took issue with OEG's rate of return calculations, alleging a number of errors (AEP Initial Br. 31-35).

OCC also opposes this provision. OCC contends that the additional exceptions to the distribution rate freeze (security and O&M expenses) are unwarranted (OCC Ex. 10, at 6). In OCC's view, AEP accepted the risk that increasesd expenses for these two items would occur when it signed the ETP stipulation and AEP should not now be permitted to illegally attempt to modify the ETP or violate Sections 4909.18 and 4909.19, Revised Code

(OCC Ex. 10, at 6-7; OCC Motion to Dismiss at 9).[11] Moreover, OCC contends that these exceptions to the distribution rate freeze constitute single-issue ratemaking, which is not appropriate public policy because the exceptions do not recognize other cost-related changes (OCC Ex. 10, at 6-7; Tr. III, 187-188). In response, AEP states that OCC's position conflicts with its position that the Commission set a post-MDP generation rate at something other than market levels (AEP Initial Br. 14).

LIA disagrees with the distribution rate provision in the RSP because it will also allow rate increases (LIA Initial Br. 16).

Commission Discussion

We find that Provision One of the RSP is acceptable. The additional exceptions to the distribution rate freeze are, in the context of considering the RSP as a package, reasonable. We understand OCC's contention that the additional exceptions to the rate freeze can be considered single-issue ratemaking, but we also must point out that OCC previously agreed to other exceptions to the distribution rate freeze, which can also be considered single-issue ratemaking. The next question then is whether the additional exceptions are justified. We do accept AEP's contention that, in 1999 and 2000, security expenses and the specified O&M expenses were not fully foreseeable. In this respect, we believe that allowing for these additional exceptions to the distribution rate freeze during the RSP is acceptable. We view the extension of the distribution rate freeze as a positive aspect of the RSP, which meets our goal of fostering a competitive market and still balancing rate stability with financial certainty for AEP.

We appreciate the position taken by staff, IEU-Ohio and OEG about the need for a distribution rate case. They have correctly noted that a rate proceeding has not taken place for either company for a period of time. AEP believes that, after the RSP, it would be appropriate for the Commission to initiate rate proceedings (Tr. I, 102). AEP explained that a rate proceeding at this point would frustrate the Commission's goals of rate stability and financial stability over the next few years (*Id.*). We agree that embarking on a rate proceeding at this point could run counter to our ultimate goals. Therefore, we do not accept that position.

D. Deferral Requests (Provisions One, Five and Six of the RSP)

The companies propose to defer the costs of several items during the RSP (AEP Ex. 2, at 8-9; AEP Ex. 4, at 4-6, 10-12). These items are:

(a) RTO administrative charges (adjusted for net congestion costs) from the time of integration into PJM[12] through 2005, plus a carrying charge (based on the weighted average cost of capital).

(b) The 2004 and 2005 equity carrying charges on expenditures begun in 2002 through 2005 for expenditures located in Account 107, construction work in process (CWIP).

11 OCC contends that, after the MDP, EDU distribution rates can only be adjusted through properly filed applications under Chapter 4909, Revised Code (OCC Motion to Dismiss 10).

12 AEP integrated into PJM on October 1, 2004.

(c) The full carrying charges (based on the weighted average cost of capital) on expenditures begun in 2002 through 2005 for all functions in Accounts 101 (electric plant in service) and 106 (completed construction not classified), except line extension expenditures, which are already subject to carrying cost deferrals.

(d) Consumer education, customer choice implementation, and transition plan filings through 2005, plus a carrying charge.

(e) Consumer education, customer choice implementation, and transition plan filing costs incurred after 2005, and all RSP filing costs, plus a carrying charge.

Most of the expenditures in the second and third categories are associated with environmental control equipment (nitrogen oxide burners, flue gas desulphurization, and selective catalytic reduction) for generation facilities (Tr. II, 14-18; OCC Ex. 3). AEP estimated the total amounts of these proposed deferrals over the RSP as follows (AEP Ex. 4, at 3, 6-7; AEP Ex. 3, at 4-5, 7; AEP Ex. 2, at 8):

Proposed Deferral	Columbus Southern	Ohio Power
RTO Admin. Costs[13]	$11.9 million	$15.6 million
RTO Admin. Costs Carrying Costs	2.5 million	3.2 million[14]
CWIP Carrying Costs	1.0 million	9.0 million
In-Service Plant Carrying Costs	13.0 million	50.0 million
Addl. Carrying Costs for CWIP and In-Service Plant	2.0 million	9.0 million[15]
Pre-2006 Education, Choice Impl. and Transition Plan Filing Costs[16]	40.6 million	45.5 million
Post-2005 Education, Choice Impl., Transition Plan Filing and all RSP Filing Costs[17]	18.2 million	19.7 million
Total	$89.2 million	$152 million

13 These estimates do not include an adjustment for congestion costs, as those are unknown (AEP Ex. 3, at 3; AEP Ex. 2, at 8).

14 AEP's estimate of the RTO administrative costs totaled $14.4 million for Columbus Southern and $18.8 million for Ohio Power, while the revenues to be produced by this aspect of the RSP are estimated to be $48 million for Columbus Southern and $60 million for Ohio Power (AEP Ex. 3, at 7, 10). However, we note that AEP's brief reflects instead that the anticipated revenues to be produced by this aspect of the RSP will be $16.8 million for Columbus Southern and $20.7 million for Ohio Power (AEP Initial Br. Attachment A at 3 and Attachment B at 3).

15 AEP's estimates of the carrying costs of the CWIP and in-service plant totaled $16 million for Columbus Southern and $68 million for Ohio Power, while the revenues to be produced by this aspect of the RSP are estimated to be $23 million for Columbus Southern and $99 million for Ohio Power (AEP Ex. 3, at 7, 10).

16 These estimates were made by AEP in May 2000 (OCC Ex. 1, at 4). They do not include carrying charges. No updated estimates were presented as evidence in this proceeding.

17 The companies did not estimate RSP filing costs (AEP Ex. 3, at 5).

In AEP's view, these are new, significant costs that cannot be capitalized and were not built into current rates (AEP Ex. 4, at 7). It should be noted, however, that AEP would amortize these new deferrals over the three-year RSP and begin recovering those amounts as regulatory assets through distribution charges in 2006, except for the consumer education, customer choice implementation, transition plan filing costs incurred, and all RSP filing costs, plus a carrying charge (AEP Ex. 2, at 21; AEP Ex. 4, at 4).

1. Regional Transmission Organization Administrative Costs

Staff calculated an average of the RTO deferral rider to be .27 mills/kWh for both companies and found it to be a reasonable level for what it considers to be a new service (Tr. IV, 63-64, 67-68, 112, 253). OMG and NEMA do not fully object to this proposed deferral, but contend that recovery of it during the RSP will cause some shopping customers to be charged twice for those same costs (OMG/NEMA Initial Br. 9-11). OCC also agrees with this criticism, but still otherwise objects to the deferral, as detailed further below (OCC Initial Br. 8-9; OCC Reply Br. 8). More specifically, OMG and NEMA explain that any shopping customer will pay the pre-2006 RTO administrative charges to his/her generation supplier as part of the cost of receiving that generation supply and, then, also pay AEP when it assesses the deferral during the RSP. OMG and NEMA state that an easy solution is to require that AEP customers who shop after October 1, 2004, get a credit for PJM administrative charges until the end of the MDP, but impose the deferrals upon them during the RSP (OMG/NEMA Initial Br. 11-12). Green Mountain agrees (GMEC Reply Br. 9). AEP responds to this suggestion, stating that it is impossible to segregate how much each customer's bill will recover the deferral and, thus, the suggestion is not possible (AEP Reply Br. 19-20).

OCC objects to the RTO administrative cost deferral for several other reasons. OCC first contends that this proposed deferral should be rejected because it violates the intent of the distribution service rate cap (set forth in Section 4928.34(A)(6), Revised Code); it is simply an attempt to recover costs that were to be recovered by the capped distribution rates (OCC Ex. 10, at 7; OCC Initial Br. 5-6, 9; OCC Reply Br. 2-3; OCC Motion to Dismiss 7). OCC also considers this provision to violate the part of the ETP decision which freezes distribution rates beyond the MDP. OCC points out that a utility can recover transmission costs through an increase to the transmission component, which will correspondingly decrease the distribution component during the MDP (OCC Initial Br. at 6). AEP even acknowledged this possibility (Tr. I, 171). Second, OCC argues that AEP is proposing single-issue ratemaking contrary to Chapter 4909, Revised Code (OCC Initial Br. 7; OCC Reply Br. 12-13). OCC does not believe that the Commission should consider this single ($33.2 million) charge in isolation of overall transmission rates.

OCC next contends that the proposed deferral of the RTO administrative charges would improperly allow AEP to recover transmission-related expenses through nonbypassable distribution rates (OCC Reply Br. 7-8). AEP acknowledges that the RTO administrative charges are transmission-rated (AEP Ex. 2, at 7; AEP Ex. 4, at 16; Tr. I, 240). However, AEP contends that these costs benefit all customers (switching and non-switching customers) because all customers benefit with AEP's participation in an RTO. AEP explains that the only means to allocate cost recovery among all customers in a competitively neutral fashion is a nonbypassable distribution charge (AEP Ex. 2, at 7; AEP Ex. 4, at 18). AEP also explained that, without the requested authority or FERC authority, the RTO administrative charges would not be recovered (Tr. I, 237). Moreover, AEP stated that, while the RTO administrative costs could be recovered via a change in state transmission charges (and thereby reduce distribution rates), AEP would effectively not be able to recover those transmission expenses (Tr. I, 238). Finally, in OCC's view, it "strains credibility that the companies did not know there would be RTO administrative costs when they agreed to join an RTO in the ETP stipulation" (OCC Initial Br. 10). OCC also does not consider the RTO administrative costs to be a new service, as staff indicated, or rate stabilization charges. OCC believes these are MDP-incurred transmission charges proposed to be recovered through a distribution rider after the MDP (*Id.*).

LIA argues that a deferral of the pre-2006 RTO administrative costs is tantamount to an increase in the MDP-capped distribution rates (LIA Initial Br. 4, 6). LIA states that Section 4928.38, Revised Code, prohibits the creation of new deferrals associated with distribution service construction, and Section 4928.34(A)(6), Revised Code, and the ETP decision are also violated (*Id.* at 5, 7). In LIA's view, this deferral constitutes a "back door" attempt to raise distribution rates, regardless of when the deferral is collected (*Id.* at 6).

OEG contends that the RTO administrative cost deferral proposes to adjust frozen distribution rate under circumstances not permitted by the ETP decision (OEG Initial Br. 13). OEG also believes that the effect of the deferral request is to avoid a rebalancing of transmission and distribution rate levels, which is required by Section 4928.34(A)(1), Revised Code, to remain at the MDP levels (*Id.*). Next, OEG takes issue with the dollar amounts in this proposed deferral for two reasons. OEG points out that AEP does not plan to recognize, in the amount of RTO administrative deferrals, the benefit that AEP will receive from making additional off-system sales as a member of PJM (Tr. I, 173). Further, OEG highlights that these administrative costs will include costs related to the companies' efforts to participate in the MISO (Tr. I, 248; OEG Initial Br. 14).

IEU-Ohio states that these RTO administrative costs were considered when transition costs were developed in the ETP proceeding and the companies' current financial condition does not justify creation of new regulatory assets (IEU-Ohio Initial Br. at 44). For this reason, IEU-Ohio contends that the proposed deferral should be denied. IEU-Ohio also noted that, in July 2004, an AEP affiliate in Virginia agreed to forego recovery of RTO administrative costs, certain congestion costs, and ancillary service cost increases, except through a base rate case (IEU-Ohio Reply Br. 7-8, Attachment). That affiliate also agreed to not seek to defer such Virginia-specific costs. Furthermore, that affiliate agreed to not seek to recover development and implementation costs that were then being deferred, other than through a base rate case. IEU-Ohio makes the point that other treatment of RTO administrative costs has been agreeable to an AEP company.

Commission Discussion

The RTO administrative charges involved in this proposed deferral will be charges incurred from October 2004 through 2005. We do not believe that this proposed deferral is a rate increase. Accord, *Consumers' Counsel v. Pub. Util. Comm.* (1983), 6 Ohio St.3d 377. Recovery of the deferred RTO administrative charges would be based upon accruals during AEP's MDP. As a result, we will not approve the proposed deferral of 2004 and 2005 RTO administrative charges.

The Commission recognizes that AEP's expenditures for RTO membership during the MDP have been and will continue to be instrumental in enabling AEP to efficiently fulfill its provider of last resort (POLR) responsibilities during the rate stabilization period. AEP is required to provide that function after the MDP. Section 4928.14(A) and (B), Revised Code. The Commission has also recognized in other cases that the POLR responsibility of the EDU is one for which the EDU incurs necessary costs and which warrants compensation during rate stabilization periods. See, *Dayton, supra* at 28, and *Ohio Edison*, Case No. 03-2144-EL-ATA, *supra* at 23-24. The Supreme Court of Ohio recently upheld an earlier Commission conclusion that the existence of POLR costs makes it reasonable to apply a charge to customers during a RSP period. *Constellation, supra*. Our staff also made this argument in this proceeding (but in relation to the CWIP and in-service plant deferrals). We believe the proposed RTO administrative charge amounts for collection during the rate stabilization period constitute reasonable and not excessive compensation to AEP for part of the cost of fulfilling its POLR responsibilities and, accordingly, approve the collection of these amounts as part of a POLR charge. This POLR charge will be established as part of a separate unavoidable rider that is applicable to all distribution customers.

We reach this conclusion based upon the specific circumstances before us in this proceeding. Nothing in this decision is intended to be precedent-setting or to be construed as ruling upon the other RTO charge-related deferral requests that we have recently received from other EDUs. See, *In the Matter of the Application of The Dayton Power and Light Company for Authority to Modify its Accounting Procedures*, Case No. 04-1645-EL-AAM, and *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company to Modify their Accounting Procedures*, Case No. 04-1931-EL-AAM.

2. Carrying Costs of Construction Work in Progress and In-Service Plant Expenditures

Staff supports the CWIP and in-service plant deferrals as well (Staff Ex. 2, at 11). Staff considers such deferrals to be equivalent to POLR charges (Tr. IV, 108-109, 147, 148, 171). Staff reaches this conclusion because the RSP is providing an option to switch and avoid charges for AEP customers and creating a risk for AEP that customers will switch, for which it is reasonable, in staff's view, for AEP to collect POLR charges (Tr. IV, 149-150). AEP concurs that these costs function as POLR costs (AEP Initial Br. 47, 79; AEP Reply Br. 16). Moreover, staff noted that, when compared to similar charges proposed by other EDUs, staff felt that AEP's proposed levels were reasonable (*Id.*). Staff calculated the amounts per kWh to be .38 mills for Columbus Southern and 1.16 mills for Ohio Power, for an average of .84 mills (Tr. IV, 108-109). Staff also stated that allowing AEP to recover a part of what it would be able to obtain under traditional regulatory process when competition has not really arrived is reasonable (Staff Ex. 2, at 11). Staff further acknowledges that, if these costs are allowed as rate stabilization charges, it is fair for the charges to be bypassable (that is to say, a customer who chooses another supplier and is not returning would not be subject to the charge while purchasing another's generation) (Tr. IV, 254-255).

OCC objects to this portion of the RSP for a host of reasons. OCC argues that, if these generation-related deferrals are permitted for recovery after the MDP, then the rate freeze is meaningless (OCC Initial Br. at 14, 51; OCC Reply Br. 2-3). OCC believes that, after the MDP, new distribution deferrals are not permitted under Ohio law because distribution rates are subject to rate regulation under Chapter 4909, Revised Code (OCC Initial Br. 14-15, 52). Additionally, OCC contends that AEP assumed the risk of these expenditures when it agreed to freeze distribution rates in the ETP proceeding (*Id.* at 15, 17-19). OCC points to OEG's evidence that AEP does not need the deferrals to provide financial stability. OCC also claims that distribution rates should not be increased to recover generation costs, per the ETP decision and Sections 4928.15, 4928.17(A), 4928.34(A)(6) and 4928.38, Revised Code (*Id.* at 15-16; OCC Motion to Dismiss 8; OCC Reply Br. 10-11). Like the RTO administrative costs, OCC contends that the Commission should not approve these single-issue ratemaking deferrals without looking at the full picture and because shopping customers will then pay a portion of AEP's generation costs even though they will be taking generation service from a competitor (OCC Initial Br. 15, 22; OCC Reply Br. 12-13).

OEG and OCC argue that these deferrals constitute retroactive ratemaking (a rate increase during the MDP) because the deferral relates to amounts in existence prior to the date of the decision in this case (OEG Ex. 2, at 18-19; OCC Initial Br. 17-19). Also, OEG and LIA contend that these two deferrals take away one of the primary incentives of implementing electric choice in Ohio (a cap on distribution rates during the MDP) contrary to Section 4928.34(A)(6), Revised Code (OEG Initial Br. 9-11; LIA Initial Br. 4). Further, OEG, LIA and OCC believe these deferrals violate the ETP decision because they are generation-related expenses used to adjust distribution rates during the period allowed by the ETP decision for frozen distribution rates (LIA Initial Br. 5, 7; OEG Initial Br. 12-13; OCC Initial Br. 16). AEP disagrees, noting that the Commission has allowed deferrals for periods that precede the date of a decision (AEP Initial Br. 46). Also, AEP argues that accounting deferrals are not rate increases and, thus, cannot constitute retroactive ratemaking (*Id.*; AEP Initial Br. 70; AEP Reply Br. 17).

OEG also argues that these deferrals do not recover distribution-related costs and should not be deferred for recovery in distribution charges (OEG Ex. 2, at 20-22). AEP agrees that these deferrals are not recovering distribution costs and, thus, argues that the distribution rate freeze cannot preclude them (AEP Initial Br. 47). In AEP's and staff's view, recovery of these deferrals will function as POLR charges, not distribution service charges (*Id.*; AEP Reply Br. 16; Tr. IV, 108, 147).

Green Mountain has a different point of view. It argues that generation-related increases should not be as limited as set forth in the RSP (GMEC Initial Br. 15-16). Instead, Green Mountain contends that any generation-related costs that AEP seeks to recover should be included in generation rates. However, if the Commission accepts another recovery mechanism (such as the proposed deferrals), then the established recovery mechanism should be bypassable (*Id.*; GMEC Reply Br. 9).

IEU-Ohio states that these CWIP and in-service plant expenditures were considered when transition costs were developed in the ETP proceeding and the companies' current financial condition does not justify creation of new regulatory assets (IEU-Ohio Initial Br. at 44). For this reason, IEU-Ohio contends that these proposed deferrals should be denied.

Commission Discussion

Similar to our reasoning for the RTO administrative charges, we do not believe that this proposed deferral is a rate increase. However, recovery of the deferred CWIP and in-service plant carrying charges would be based upon accruals during AEP's MDP. The Commission recognizes that AEP's expenditures for CWIP and in-service plant during the MDP have been and will continue to be instrumental in enabling AEP to efficiently fulfill its POLR responsibilities during the rate stabilization period, which warrants compensation during rate stabilization period. Section 4928.14(A) and (B), Revised Code, requires AEP to provide that function after the MDP. We believe these carrying charge amounts proposed for collection during the rate stabilization period constitute a reasonable and not excessive compensation to AEP for part of the cost of fulfilling its POLR responsibilities and, accordingly, approve the collection of these amounts as part of a POLR charge. As noted earlier, this POLR charge will be established as part of a separate unavoidable rider that is applicable to all distribution customers.

3. Consumer Education, Customer Choice Implementation, Transition Plan Filing Costs, and all Rate Stabilization Plan Filing Costs

Staff supports this deferral provision (Staff Ex. 2, at 10). IEU-Ohio does not believe that the Commission needs to address most of this deferral because it was already addressed in the ETP decision (IEU-Ohio Initial Br. 43). Also, IEU-Ohio does not believe that the Commission should authorize increases for isolated categories of costs, even if expected (*Id.* at 44). OCC argues that, aside from the agreement in the ETP decision to allow some of these deferrals, the Commission should reject additional deferrals in this case (OCC Initial Br. at 52). OCC reaches this conclusion because new distribution deferrals and rate riders for single issues have no basis in Ohio law; the Commission can only adjust regulated distribution rates through a properly filed rate case.

Commission Discussion

We already allowed deferral for most of the costs in this category (in the ETP proceeding). This RSP provision would further defer those costs and also allow deferral of the RSP filing costs. In the context of considering the RSP package and our stated RSP goals, we are willing to accept this provision of AEP's plan.

E. Transmission Rates and Charges (Provision Four of the RSP)

This part of the proposed RSP states the AEP may adjust state transmission charges (attributable to the applicable company, affiliated company or RTO open access transmission tariff [OATT]) to reflect FERC-approved rates and charges during the RSP, whether imposed directly on the companies or through an approved RTO. These include RTO administrative changes imposed, amortization of RTO start-up costs, and/or surcharges for recovery of lost transmission revenues. Such rate changes would be effective 30 days after filing, unless delayed by the Commission (but no longer than a period of 60 days).

AEP characterizes this portion of the RSP as an affirmation of the companies' existing right to make a filing for recovery of FERC-approved costs (AEP Initial Br. 40, 60). AEP believes the proposed expedited review process of such applications is warranted because the Commission should look at new transmission charges and should allow the pass-through of FERC-approved transmission charges (Tr. I, 242-243). Furthermore, AEP believes these costs will be significant, new costs, which are not currently in rates (AEP Ex. 3, at 4; AEP Initial Br. 40). A preliminary estimate of at least some of the anticipated costs in this area is $10.4 million per year for Columbus Southern and $13.1 million per year Ohio Power (AEP Ex. 3, at 4).

Staff expressly supports this provision of the RSP (Staff Ex. 2, at 10). IEU-Ohio recommends that this provision be rejected because transmission costs were taken into consideration when the ETP decision was issued and there are indications that AEP's integration into PJM will create additional transmission revenues. Thus, IEU-Ohio believes that there is no need for this provision (IEU-Ohio Initial Br. 43). Similarly, OEG and OCC argue that this provision will allow AEP to be reimbursed for RTO expenses, but it does not take into account certain savings that will simultaneously be realized, e.g., off-system sales (OEG Reply Br. 19; OCC Reply Br. 13-14). OEG contends that the corresponding savings should be recognized so that the provision is truly a "pass through" (*Id.*). Also, OCC contends that there should be no authorization for additional transmission charges that have not been authorized by FERC or that AEP selects apart from charges in the PJM RTO OATT (OCC Initial Br. 46).

<u>Commission Discussion</u>

We find that this provision of AEP's RSP is reasonable, except as discussed below. In concept, any FERC-approved transmission rates and charges during the RSP should be passed through. We will look at them and ensure that "pass through" is appropriate. Despite IEU-Ohio's, OEG's and OCC's comments, we believe this aspect of Provision Four is appropriate. We do, however, have concerns with the Commission review process set forth in Provision Four. If viewed in isolation, we would not necessarily believe that the 30-day/60-day automatic process was problematic. However, we and our staff will be receiving similar types of applications from more than just AEP. For that reason, we believe that the time period proposed is not as workable as it should be. Therefore, we conclude that the applications to adjust state transmission charges (attributable to the applicable company, affiliate company or RTO OATT) to reflect FERC-approved rates and charges during the RSP (whether imposed directly on the companies or through an approved RTO) shall be automatically approved on the 61st day after filing, unless the Commission rejects, modifies or suspends the filing. We believe this approval process fairly and adequately balances: (1) the desire for a definitive conclusion from the Commission in a prompt manner, (2) the ability of other interested persons to participate, and (3) the concerns for adequate amounts of time to review the anticipated applications in the context of other Commission work.

F. Current Regulatory Asset Recovery (Provision Five of the RSP)

The RSP proposes that AEP continue to recover amortized generation-related transition regulatory assets under the approved ETP. Staff accepts this provision, describing this term as simply continuing practices established in the ETP decision (Staff Ex. 2, at 10). OCC supports this portion of the RSP because it continues one part of the ETP decision. However, OCC does argue that, if the Commission will not require AEP to keep the rest of the ETP bargain, the Commission should revisit this and other aspects of the ETP decision (OCC Ex. 10, at 4; OCC Initial Br. 47). To this argument, AEP contends that an examination of the regulatory assets recovery should not be a consequence of filing the RSP as requested (AEP Reply Br. 42). OCC notes that the bulk of the transition regulatory assets for Ohio Power (associated with mining operations) may no longer represent a liability to Ohio Power (Tr. II, 27, 36). IEU-Ohio is not opposed to this provision, if the Commission accepts its proposed RSP (IEU-Ohio Reply Br. 10, Footnote 11).

Commission Discussion

We also agree with Provision Five and find it appropriate to allow AEP to continue to recover amortized generation-related transition regulatory assets under the approved ETP. We note that no direct opposition to this portion of the RSP was raised by any of the parties.

G. Shopping Incentives and Credits (Provision Seven of the RSP)

AEP proposes in the RSP that Ohio Power will still not charge the regulatory asset charge rider, from January 1, 2006 to December 31, 2007, to the first 20 percent of the Ohio Power residential customer load that switches, as was agreed in the ETP stipulation.[18] Columbus Southern will, through the MDP and 2008, make available to the first 25 percent of the residential class load an incentive of 2.5 mills/kWh that the qualifying customers will receive as a credit. Any unused amount of the incentive money at December 31, 2005, will not be credited to regulatory asset charge recovery. Thus, as proposed under the RSP, Columbus Southern will receive as income any unused shopping incentive balance and not offset the incentive balance against the transition regulatory asset.

18 Although both the ETP stipulation and the RSP state that there will be no shopping incentive for Ohio Power customers, the provision to not charge certain shopping Ohio Power customers the regulatory asset charge rider was included in the RSP's Provision Seven under the heading "Shopping Incentives". Nothing in our decision should be construed as converting that term into a shopping incentive or characterizing it otherwise. We have simply chosen to discuss the entirety of Provision Seven at one time.

Columbus Southern's unused shopping incentive through January 2004 was roughly $12.9 million (Tr. II, 108; OCC Ex. 4). The RSP extends the Columbus Southern shopping incentive through 2008. As a trade off, AEP also proposes to alter the manner in which the unused portion of Columbus Southern's shopping incentive is handled (AEP Ex. 2, at 23-24; AEP Ex. 4, at 5; Tr. I, 33). To be clear, AEP's proposal to extend this shopping incentive is tied to the new proposed treatment of its unused balance (AEP Reply Br. 32). AEP argues that the extended shopping incentive, along with increased generation rates, should result in more shopping (AEP Initial Br. 48).

Staff believes that the unused Columbus Southern shopping incentive should be treated as a regulatory liability and flowed back to customers (Staff Ex. 2, at 12). IEU-Ohio concurs (IEU-Ohio Initial Br. 45). AEP believes that this position does not adequately acknowledge that the companies are proposing to extend the shopping incentive (AEP Initial Br. 49).

OCC believes Provision Seven of the plan violates the ETP decision by altering the treatment of the unused Columbus Southern shopping incentive (OCC Ex. 10, at 8; OCC Initial Br. 53). AEP points out that the effect of OCC's position is that no shopping incentive would be available to Columbus Southern residential customers during the RSP (AEP Initial Br. 49).

Green Mountain contends that the RSP's shopping incentive will be inadequate to spur shopping. AEP calculated that the average residential price to compare for the generation component (under the RSP and its shopping incentive terms) will be as follows (GMEC Ex. 5, at fourth set discovery request 1):

Company	2006	2007	2008
Columbus Southern			
With Three Percent Increase	4.26	4.38	4.51
With Termin. of Resid. Discount	4.20	4.27	4.33
Ohio Power			
With Seven Percent Increase	3.73	3.98	3.94
With Termin. of Resid. Discount	3.69	3.89	3.79

In Green Mountain's view, the residential incentive values may be at their highest during the RSP, but they will still not spur shopping (GMEC Initial Br. 10; GMEC Reply Br. 8). In addition to greater shopping incentives, Green Mountain also advocates for shopping credits (avoidable charges) set at market prices (GMEC Initial Br. 11). Green Mountain further advocates that the $10 switching fees be waived, market support generation be provided, a voluntary enrollment process be instituted, new partial payment priority changes be made, and reasonable/nondiscriminatory credit arrangements be created (*Id.* at 10-15, 19-20). AEP states in response to these additional requests that there is no evidence to support them and they should be rejected (AEP Reply Br. 40-14).

Commission Discussion

First, we accept again the term of this provision related to Ohio Power's residential customers who shop in 2006 and 2007. We continue to believe that this term will be beneficial to Ohio Power customers in the near future. No arguments were raised against this part of Provision Seven, except those raised by Green Mountain (in relation to the amount and impact), which we address further below.

The first criticism raised about Provision Seven of the RSP is that AEP proposes to not credit the unused Columbus Southern shopping incentive to regulatory asset charge recovery (and instead extends the incentive through 2008, with any remaining amounts becoming income to Columbus Southern). AEP correctly notes that, if the Commission does not accept this aspect of Provision Seven, there will be no shopping incentive for Columbus Southern's residential customers. Shopping credits and incentives were established to promote customer switching and effective competition. Sections 4928.37 and 4928.40, Revised Code. Accord, *Constellation, supra*. Shopping credits and incentives are not mandated by statute after the MDP. Certainly, however, the idea of having a Columbus Southern shopping incentive during the RSP is attractive, particularly since we are trying to spur further development of the competitive market in AEP's service territories. However, we must weigh that against AEP's clear statements that its proposed extension of the Columbus Southern shopping incentive is contingent upon any remaining amounts at the end of the RSP becoming income to Columbus Southern.

We do not agree that the unused amount of the Columbus Southern shopping incentive at the end of the RSP should become income to that company on the basis that it is a fair trade-off to offering to extend that incentive during the period, as AEP has argued. Under the ETP, Columbus Southern was not going to receive income if that shopping incentive was not completely used during the MDP. Instead, AEP previously agreed to flow those dollars back to customers (by making a reduction to the remaining regulatory asset amounts equivalent to the amount of the unused shopping incentive). Moreover, we do not believe that Columbus Southern should earn income when customers have not shopped sufficiently to utilize the same shopping incentive over an extended period. Furthermore, as explained below, we do not believe that the RSP must include a shopping incentive for Columbus Southern customers either. Therefore, the proposed Columbus Southern shopping incentive portion of Provision Seven of the RSP is rejected.

As previously noted, the ETP decision requires that the unused balance of the Columbus Southern shopping incentive at the end of the MDP be credited back to Columbus Southern customers (via an adjustment to the level of regulatory asset recovery). We agree that customers should benefit in the event that Columbus Southern customers do not shop sufficiently by the end of this year (which is the end of the MDP). We believe that most parties, if not all, would agree that sufficient shopping is very unlikely to occur by the end of the MDP and, thus, an unused dollar amount will exist. However, we conclude a redirected application of the unused shopping incentive monies is more appropriate, while yet still in line with the goal of benefiting customers. LIA and OCC have asked in this proceeding for specific dollars targeted to low-income customer issues because that segment of the customer base may be disproportionately affected by the RSP. As we noted in section VI.B.1 of this decision, we believe that it is appropriate to assist the AEP low-income customers. Therefore, we conclude that $14 million should be should be allotted by AEP for the benefit of the Columbus Southern and Ohio Power low-income customers, as well as for economic development during the RSP period. We will require AEP to work with our Service Monitoring and Enforcement Department staff to develop the details for the use of those sums. Our staff will consult with the Ohio Department of Development in relation to the use of that money in AEP's service territories.

Green Mountain has alleged that the shopping incentives (as identified for Columbus Southern customers above and a zero incentive for Ohio Power customers) will not be sufficient to spur shopping in either company's territory. As we have already noted, shopping incentives are not mandated after the MDP. In any event, the shopping incentives are only one manner of further developing the competitive market and we believe that, in the full context of the proposed RSP, our decision to require monetary assistance for low-income and economic development issues is an appropriate conclusion. With regard to Green Mountain's argument related to partial payment priority, the Commission is not willing to alter its established payment priority scheme just because AEP is seeking to establish a RSP. Green Mountain has also asked for several other specific alterations (establish other credits via avoidable charges, waiver of the $10 switching fees, provision of market support generation and institution of a voluntary enrollment process). We do not believe that these items are needed at this point. Accordingly, we will not adopt them.

H. Other Items (Provisions Eight through Eleven of the RSP)

1. Additional Future Proceedings

AEP recommends (in Provision Eight) that the Commission conduct a proceeding to determine the "manner in which electric generation service should be provided to the companies' customers" after the RSP and report the results to the legislature by December 31, 2005. AEP explains that this provision is intended to avoid facing the same situations at the end of the RSP as we face today (AEP Ex. 2, at 24-25). Staff and IEU-Ohio agree (Staff Ex. 2, at 13; IEU-Ohio Initial Br. 45). OMG and NEMA also appear to agree. Specifically, OMG and NEMA state that, if the Commission approves a RSP for AEP, it should establish a re-opener during 2007 in order to make adjustments to assist market development and to plan for the end of the rate stabilization period (to meet the statutory goals of market-base rates) (OMG/NEMA Initial Br. 12). OCC disagrees that the Commission should complete a report by 2005, arguing that any report completed by that date will not likely provide any valuable information for the post-RSP period (OCC Initial Br. 55-56).

Commission Discussion

This provision of the RSP is acceptable as a recommendation on steps the Commission should consider by the end of the RSP period. The Commission has a mandate to consider all possible options for implementation at the end of the rate stabilization period.

2. Functional Versus Structural Separation

In Provision Nine, the companies would continue functional separation (one corporate entity with separate groups to handle each function). AEP explained that it has not yet received authorization from the Securities and Exchange Commission to structurally separate, although AEP has made that request (AEP Ex. 2, at 25-26). At this point, AEP "does not contemplate structurally separating" the generation assets (*Id.*) because restructuring has slowed down. Staff concurs with this provision, particularly since structural separation could limit or preclude options in the future (Staff Ex. 2, at 13; Tr. IV, 250). IEU-Ohio does not oppose this provision (IEU-Ohio Initial Br. 45).

OCC, OMG, NEMA and Green Mountain state that AEP must structurally separate per Section 4928.17, Revised Code (OCC Initial Br. 56; OMG/NEMA Initial Br. 13-14; GMEC Initial Br. 21). PSEG states that it makes little sense for the Commission to approve the RSP based upon risks/volatility of the competitive market and not protect customers by requiring AEP to implement corporate separation (PSEG Br. 7-8). Green Mountain argues that to continue functional separation seeks something that AEP never lawfully had (because the ETP approved only structural separation) (GMEC Initial Br. 21). Green Mountain states that the Commission should not permit AEP to continue functional separation if the RSP is not implemented (*Id.*).

Commission Discussion

We are willing to accept this term of the RSP for several reasons. First and foremost, AEP has been unable to structurally separate, as it had planned, because it does not have the necessary federal authority to do so. We simply cannot force structural separation when other agencies also must give their approval and that approval has not been forthcoming. Second, we would be remiss if we did not recognize that many expectations surrounding a competitive electric market in Ohio and around the country have changed from 2000, which is when we approved AEP's plan in its ETP proceeding to structurally separate its generation functions from the remainder of its functions. Third, Sections 4928.17(C) and (D), Revised Code, allow the Commission to modify a previously approved corporate separation plan. OCC, OMG and NEMA seem to have overlooked that aspect of the corporate separation statute. More specifically, we conclude that good cause has been shown to allow AEP to operate on a functional separation basis for the RSP period and such functional separation can still provide compliance with the state's policies associated with competitive retail electric service, as enumerated in Section 4928.02, Revised Code.

3. Participation in Other CBPs

Provision 10 of the RSP allows the companies to submit bids in other EDU's CBPs. AEP argues that Section 4928.14(B), Revised Code, compels the Commission to grant this provision of the RSP and the Commission has acknowledged such previously (AEP Initial Br. 52). Staff agrees with this provision and IEU-Ohio believes current law already allows AEP to participate in the CBPs of other EDUs (Staff Ex. 2, 13; IEU-Ohio Initial Br. 46).

Green Mountain contends that AEP should not be permitted to participate in other CBPs until it has structurally separated (GMEC Initial Br. 21-22).

Commission Discussion

AEP correctly notes that we have refused to limit participation in CBPs to non-EDU affiliate participants because of the language in Section 4928.14(B), Revised Code. *In the Matter of the Commission's Promulgation of Rules for the Conduct of a Competitive Bidding Process for Electric Distribution Utilities Pursuant to Section 4928.14, Revised Code*, Case No. 01-2164-EL-ORD, Finding and Order at 9 (December 17, 2003). We find this provision of the RSP to be reasonable. Nothing that Green Mountain has argued on this provision convinces us that this aspect of the RSP should not be approved.

4. Minimum Stay Requirements

Also, the RSP addresses in Provision 11 the topic of minimum stay. It provides that, during the RSP, residential and small commercial customers that return to the standard service must remain through April 15 of the following year, if the customer took generation service from the company between May 16 and September 15. During the RSP, a 12-month minimum stay would be required for large commercial and industrial customers that return under the standard service tariff.

This RSP provision corresponds with AEP's current minimum stay tariff provisions, but those tariff provisions have not been in effect due to a Commission moratorium.[19] AEP believes that minimum stay requirements are needed to avoid seasonal impacts of switching when AEP's prices are essentially annual average rates (AEP Ex. 5, at 5). Staff finds AEP's approach to be reasonable, but also recommends that the alternative mentioned in those tariffs be more fully detailed (Staff Ex. 2, at 14).

OMG and NEMA argue that, before the minimum stay provisions are triggered, the Commission should require that shopping customers be able to return to the standard service offer three times (OMA/NEMA Initial Br. 15). They note that AEP agreed to such a term in its ETP and, since no real shopping has taken place, it makes sense to require this term during the RSP (*Id.*). AEP points out that the Commission did not accept this part of the ETP settlement and nothing was presented in this proceeding to warrant its acceptance now (AEP Reply Br. 39).

IEU-Ohio contends that this topic should be addressed by the Commission on a generic basis, not in this RSP proceeding (IEU-Ohio Initial Br. 46). OCC contends that AEP has not demonstrated a need for the minimum stay or any harm from the moratorium (any alleged harm will only occur if customers actually shop and then return to AEP) and, therefore, the moratorium should remain in place (OCC Initial Br.60).

19 The Commission issued a moratorium on any minimum stay requirements for residential and small commercial customers on March 21, 2002, in *In the Matter of the Establishment of Electronic Data Exchange Standards and Uniform Business Practices for the Electric Utility Industry*, Case No. 00-813-EL-EDI. That moratorium has continued indefinitely. While another proposal is pending before the Commission on the matter, we have not issued a definitive ruling on the matter.

Commission Discussion

We are willing to accept this provision of the RSP. We realize that we still have not addressed the pending minimum stay proposal (which differs from AEP's minimum stay requirements) in the generic proceeding. For the short three-year period of the RSP, we are willing to allow AEP to implement these minimum stay requirements. It will allow us the opportunity to evaluate participation, gaming of enrollments, and the impact of our originally approved minimum stay requirements. We consider this approval to essentially test the debate that has been raised with us for quite a period of time.

VII. Conclusion

Based upon the foregoing, we conclude that the proposed RSP should be adopted (with the exception of the RSP's proposed elimination of the five percent residential discount in Provision Two, the proposed deferral of RTO administrative charges, the proposed deferral of CWIP and in-service plant carrying charges, the proposed review period associated with FERC-approved transmission rate changes, and the proposed treatment of the Columbus Southern shopping incentive) for the reasons set forth herein. We also conclude that OCC's motion to dismiss the application should be denied. Additionally, we conclude that, AEP shall allot $14 million for low-income customers and economic development, and work with our Service Monitoring and Enforcement Department staff to work out the details for those dollars. AEP is, furthermore, allowed to establish a POLR charge.

As we have already mentioned, we believe certain changes are warranted as the MDP ends for AEP. This decision will move AEP to market-based rates for the 2006-2008 period in an appropriate and balanced fashion and conforms with the state's electric policy (Section 4928.02, Revised Code) and this Commission's stated goals. Circumstances are not the same as when we issued our ETP decision and we recognize that fact and have reached conclusions today that we believe are most appropriate for the 2006-2008 period. To the extent any arguments were raised in this proceeding and they are not expressly addressed in this decision, they have been rejected.

As noted earlier in this Order, AEP will be held forth as the POLR to consumers who either fail to choose an alternative supplier or who choose to return to AEP's system after taking service from another energy company. Consistent with Ohio law, the POLR designation places expectations upon EDUs; the companies must have sufficient capacity to meet unanticipated demand. Additionally, the Commission is among many state agencies that have been charged by the Governor to enhance the business climate in Ohio as it competes on a regional, national, and global basis for economic development projects. One of the Commission's roles in this endeavor has been to focus on reliable energy. We believe that, consistent with Section 4928.02, Revised Code, Ohio consumers are entitled to a future secure in the knowledge that electricity will be available at competitive prices. We also feel strongly that electric generators of the future should be both environment-friendly and capable of taking advantage of Ohio's vast fuel resources. With the recognition that new technologies must be forthcoming to replace the utilities' aging generation fleet, we urge AEP to move forward with a plan to construct an integrated gasification combined-cycle (IGCC) facility in Ohio. AEP should engage the Ohio Power

Siting Board in pursuit of such a plant. We are encouraged by emerging information that suggests that the IGCC technology will be economically attractive. It is worth noting that the Commission is exploring regulatory mechanisms by which utilities, given their POLR responsibilities, might recover the costs of these new facilities.

FINDINGS OF FACT AND CONCLUSIONS OF LAW

(1) On February 9, 2004, AEP filed an application with the Commission for approval of a rate stabilization plan for the period 2006 through 2008.

(2) Twenty-five entities filed motions to intervene in this proceeding. All those requests were granted.

(3) A technical conference was held on March 24, 2004. Objections to the application were filed on April 8, 2004.

(4) A local, public hearing in Canton, Ohio, was conducted on May 19, 2004. However, the Commission had not properly sent any of the publication notices to the newspapers in AEP's service territory. Therefore, the examiner scheduled another local hearing in Canton, Ohio, for July 7, 2004 and rescheduled the local hearing in Columbus, Ohio, for July 1, 2004. At the July 1 and 7, 2004 local hearings, three people provided testimony.

(5) On May 24, 2004, OCC filed a motion to dismiss the application on various legal grounds. By entry dated June 1, 2004, the examiner deferred a ruling on OCC's motion to dismiss, stating that all parties shall have the opportunity to argue the legality of AEP's proposal in post-hearing briefs.

(6) The evidentiary hearing began on June 8, 2004, and continued through June 14, 2004. AEP presented the testimony of five witnesses. The staff and OCC each presented the testimony of two witnesses. APAC, Lima/Allen Council on Community Affairs, and WSOS Community Action jointly sponsored the testimony of one witness and OEG presented the testimony of one witness.

(7) The parties filed post-hearing briefs on July 13 and 30, 2004.

(8) AEP's MDP will end on December 31, 2005.

(9) AEP's proposed elimination of the five percent residential discount in provision two is precluded by the ETP decision.

(10) OCC's motion to dismiss the application should be denied.

(11) We adopt all provisions of the proposed RSP with the exception of the:

(a) RSP's proposed elimination of the five percent residential discount in Provision Two,

(b) Proposed deferral of RTO administrative charges in Provisions One and Six,

(c) Proposed deferral of CWIP and in-service plant carrying charges in Provisions One and Six,

(d) Proposed review period associated with FERC-approved transmission rate changes in Provision Four, and

(e) Proposed treatment of the Columbus Southern shopping incentive in Provision Seven.

(12) Our adopted provisions of the proposed RSP, our decision to require AEP to allot $14 million for low-income customers and economic development, our decisions to require AEP to work with our Service Monitoring and Enforcement Department staff to work out the details for those dollars, and our decision to allow AEP to establish a POLR charge, taken together, appropriately balance three objectives: (a) rate certainty, (b) financial stability for AEP, and (c) the further development of the competitive electric market. Moreover, the combination of the approved components of the RSP, along with the additional conditions of our decision and continuation of the unaffected provisions of the ETP, will prompt the competitive market and continue to provide customers a reasonable means for customer participation in the electric competitive market.

ORDER

It is, therefore,

ORDERED, That OCC's motion to dismiss this application is denied. It is, further,

ORDERED, That AEP's application is approved, subject to the modifications set forth in this decision. It is, further,

ORDERED, That AEP work with our Service Monitoring and Enforcement staff to work out the details for the allotted low-income and economic development dollars. It is, further, ORDERED, That a copy of this opinion and order be served upon all 28 parties to this proceeding and any interested persons of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason

Clarence D. Rogers, Jr.

GLP;geb

Entered in the Journal

JAN 2 6 2005

Reneé J. Jenkins
Secretary

Summary of
Case No. 88-102-EL-EFC
Columbus Southern Power Company

In this proceeding, the Commission establishes a new electric fuel component (EFC) rate to be charged to Columbus Southern Power Company's EFC jurisdictional customers for the six-month period beginning December 1, 1988. The new rate established in this proceeding is 1.599888 cents/kWh. The new rate represents a 2% increase from the present rate of 1.568720 cents/kWh. The increase was the result of higher projected fuel costs.

This proceeding is the annual audit proceeding of Columbus Southern Power Company. The financial auditor found no exceptions to CSP's accounting procedures. A witness for the Office of the Consumers' Counsel questioned the accounting method used by CSP for system losses. The Commission found that CSP had correctly used the Commission's established method which method was more fair and consistent than the method proposed by OCC.

The management/performance auditor reported on CSP's high coal inventory levels and the efforts by CSP to reduce the coal in inventory. The auditor believed that CSP had acted reasonably to reduce its coal in inventory. The Commission found that CSP's coal inventory levels and efforts to reduce the levels should be reviewed again in the next audit proceeding. The Commission agreed to look at the effects of American Electric Power Company's new dispatch system and price policy for off-system sales to determine if these new factors are helping CSP to burn more coal. In another issue raised by the management/performance auditor, the Commission also ordered the company to provide a witness at the next EFC hearing to discuss the progress made by CSP in improving and standardizing its performance tests on equipment.

In another issue raised by OCC's witness, the Commission determined that CSP had acted reasonably in giving below-the-line treatment to the gain from the sale of depreciable assets of Simco, Inc., a subsidiary of CSP. The Commission did not believe that the EFC ratepayers had purchased an interest in the Simco assets and that the ratepayers had assumed the risks or benefits of ownership of the assets.

The Commission found that refunds received by CSP from Empire Coal Company as a result of black lung excise tax overpayments included in the cost of Empire's coal should be returned in the appropriate amount to CSP's EFC ratepayers. The refunds should be made through a Reconciliation Adjustment to the EFC rate.

This summary was prepared to provide a brief statement of the Commission's action. It is not a part of the Commission's decision and does not supersede the full text of the order.

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Columbus Southern Power Company and Related Matters.	)))))	Case No. 88-102-EL-EFC

OPINION AND ORDER

The Commission, coming now to consider the above-entitled matter and having reviewed the testimony and exhibits presented at the public hearing in this matter and all late-filed exhibits, hereby issues the following Opinion and Order.

APPEARANCES:

Messrs. Porter, Wright, Morris and Arthur, by Mr. Daniel R. Conway and Ms. Janet J. Henry, 41 South High Street, Columbus, Ohio 43215, and F. Mitchell Dutton, 215 North Front Street, Columbus, Ohio 43215, on behalf of Columbus Southern Power Company.

Mr. Anthony J. Celebrezze, Jr., Attorney General of Ohio, by Ms. Anne L. Hammerstein and Mr. William L. Wright, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43266-0573, on behalf of the staff of the Public Utilities Commission of Ohio.

Mr. William A. Spratley, Office of Consumers' Counsel, by Ms. Evelyn R. Robinson-McGriff and Ms. Loretta B. Looper, Associate Consumers' Counsel, 77 South High Street, Columbus, Ohio 43266-0550, on behalf of the residential consumers of Columbus Southern Power Company.

OPINION:

Columbus Southern Power Company (CSP, company) is an electric company within the meaning of Section 4905.03(A)(4), Revised Code, and is, therefore, a public utility subject to the jurisdiction and supervision of this Commission pursuant to Sections 4905.02, 4905.04, 4905.05, and 4905.06, Revised Code. CSP is also an electric utility within the meaning of Rule 4901:1-11-01(L), Ohio Administrative Code (O.A.C.).

Section 4905.301, Revised Code, requires the Commission to review each electric utility's electric fuel component (EFC) at a hearing once every six months. By Entry dated January 21, 1988, the Commission initiated this proceeding to review CSP's EFC and related matters.

In addition to the hearing requirements set forth in Section 4905.301, Revised Code, the Commission is required by Section 4905.66(B)(2), Revised Code, to conduct, or cause to be conducted, at least annually, an audit of the fuel-related policies and practices of each electric utility. Rule 4901:1-11-10, O.A.C., provides under Paragraph (A) that each electric utility shall be subject to a management/performance audit and a financial audit of its fuel-related policies and practices. Rule 4901:1-11-10(B)(1), O.A.C., requires the Commission to conduct the management/performance audit or cause this audit to be conducted by a qualified independent auditing firm selected by the Commission. Rule 4901:1-11-10(B)(2), O.A.C., requires the Commission to conduct the financial audit or cause this audit to be conducted by a qualified independent auditing firm selected by the electric utility. Rules 4901:1-11-10(B)(1) and 4901:1-11-10(B)(2), O.A.C., require the electric utility to bear the cost of the audits. Deloitte Haskins & Sells (DH&S) was chosen to perform the financial audit, and Arthur D. Little (ADL) was chosen to perform the management/performance audit. The scope of the audits was defined in Rule 4901:1-11-10(C), O.A.C., the Commission's directives in Case Nos. 87-102-EL-EFC and 88-02-EL-EFC, and the Entry dated January 21, 1988. DH&S and ADL submitted their reports on August 19, 1988, in accordance with Rule 4901:1-11-10(D), O.A.C.

Section 4909.191(A), Revised Code, requires each electric utility to file proof at the time of its semiannual EFC hearing that notice of the proceeding was published in accordance with that statute. Rule 4901:1-11-11(C), O.A.C., requires that the same hearing notice be additionally published once between fifteen and thirty days prior to the hearing date. CSP caused the required publications to be made (CSP Ex. 3A). In addition, the company included notice of the hearing in its July-August 1988 billings (CSP, Ex. 3C). Furthermore, audio tapes were produced and sent to all radio stations in the service area, in accordance with prior Commission directive (CSP Ex. 3B).

Section 4909.191(C), Revised Code, and Rule 4901:1-11-11(B), O.A.C., require each electric utility to demonstrate at its EFC hearing that its acquisition and delivery costs were fair, just, and reasonable. On August 5, 1988, CSP filed its annual summary report as required by Rule 4901:1-11-09(A), O.A.C. CSP filed its prehearing data on August 19, 1988, in accordance with Section 4909.191(B), Revised Code, and Rule 4901:1-11-11(D)(1), O.A.C. The direct testimony of the company's witnesses was filed on September 2, 1987.

On May 13, 1988, the Office of Consumers' Counsel, state of Ohio, (OCC) intervened in this proceeding on behalf of the residential consumers of CSP. On June 14, 1988, OCC's intervention in this proceeding was granted.

A public hearing in this matter was conducted at the offices of the Commission on September 19 and 20, 1988. At the hearing, Mr. Charles D. Muha testified on behalf of DH&S; Mr. Glenn G. Wattley testified on behalf of ADL; Messrs. Nicholas M. Champa, Martin L. Mearhoff, and Robert A. Taylor and Ms. Elizabeth Kavander testified on behalf of CSP. Mr. Gregory S. Campbell offered rebuttal testimony on behalf of CSP. Mr. Mark S. Erlitz testified on behalf of OCC.

The testimony of Mr. J. Craig Baker as presented in Ohio Power Company, Case No. 88-101-EL-EFC, was admitted into the record in this proceeding with some modification, and the testimony of Robert T. Evans of Clifton, Gunderson and Company on behalf of OCC also in Case No. 88-101-EL-EFC was admitted into the record in this proceeding. The testimony of Mr. Baker and of Mr. Evans concerned the system dispatch study of American Electric Power Service Corporation (AEPSC) and the experimental implementation of AEPSC's new policy for the pricing of off-system sales. American Electric Power is the parent company of both Ohio Power Company and CSP. The Commission's decision regarding approval or disapproval of the new dispatch system will not be discussed in this Opinion and Order but will be discussed in the Opinion and Order in Case No. 88-101-EL-EFC with the understanding that the findings of that Opinion and Order in regard to the system dispatch issue will apply to CSP as they do to Ohio Power Company. It is understood that should CSP need to appeal the Commission's decision, the appeal would be filed in this proceeding but be discussed in the Ohio Power Company rehearing entry.

Post-hearing briefs in this proceeding were submitted by all three parties on October 7, 1988. Reply briefs were filed by all three parties on October 14, 1988.

Section 4909.191(C), Revised Code, requires the Commission at each EFC hearing to consider, to the extent applicable, the efficiency of the electric utility's fuel procurement policies and practices, the results of financial and performance audits, and the electric utility's compliance with previous Commission performance recommendations. Rule 4901:1-11-11(B), O.A.C., additionally requires the Commission to determine the EFC rate to be charged by the electric utility during the next current period and to calculate the cost effectiveness measure for the electric utility pursuant to Appendix A of Chapter 4901:1-11, O.A.C.

THE FINANCIAL AUDIT

On August 19, 1988, DH&S, the financial auditor, filed with the Commission its report on CSP's EFC (Comm. Or. Ex. 1). The financial auditor reviewed CSP's approved EFC rate for the two six-month periods ending November 30, 1987 and May 31, 1988. In DH&S's opinion, CSP fairly determined the EFC rates for these two six-month periods in accordance with the financial procedural aspects of the EFC rule as set forth in Chapter 4901:1-11, O.A.C., and properly applied the EFC rates to customers' bills (Comm. Ord. Ex. 1, at 1). No exceptions to CSP's accounting procedures were identified by the financial auditor. Data projections by CSP were found to be reasonable. Coal inventory adjustments were found to have been made in accordance with Commission rules. No exceptions to the calculations of the reconciliation adjustment (RA) or system loss adjustment (SLA) were made by the financial auditor.

SLA calculation

However, OCC's witness Erlitz challenged the SLA calculation. According to Mr. Erlitz, under the present rule, all amounts of over-recovery by a utility of the incremental system loss costs are returned to customers. If there has been an over-recovery of system losses, according to Mr. Erlitz, the efficiency factor known as the Gccf, which would reduce the amount of credit due to ratepayers, is not applied. However, in the case of under-recovery by a utility in any month, the efficiency factor known as the Fcrf, which would reduce the recovery due the utility, is applied to determine how much of the under-recovered system loss costs may be recovered by the utility from ratepayers. Mr. Erlitz testified that in June and July 1987, the company under-recovered its system losses but did not properly factor in the Fcrf. Mr. Erlitz calculated that $281,760.16 should have been credited to customers rather than the $267,981.03, which the company calculated. This makes a difference of $13,779.13, which Mr. Erlitz believes the company should not be able to collect from ratepayers. The revision would reduce the company's proposed EFC rate by .000227 cents per kWh (OCC Ex. 1, at 8).

The company and the staff argued that CSP was calculating the SLA in accordance with Commission rules and orders. Both the company and staff asked that the Commission reject Mr. Erlitz's interpretation of the Commission's rules and orders regarding the calculation of the SLA.

The SLA of the EFC accounts for system losses that are either in addition to or less than the system losses provided for in the company's base rates. Therefore, the system losses dealt with in the EFC rate are incremental system losses. The Commission notes that the Commission's method of calculation of the SLA was partially developed in Ohio Edison Company, Case No. 82-164-EL-EFC, January 26, 1983. In that case, the Commission dealt with the circumstance that the application of the Gccf could result in an electric utility recovering through the SLA more than its actual system losses for the six-month period. This is because the Gccf, the factor applied when the company over-recovers the system losses already provided in base rates, will reduce the amount of the credit for the over-recovery to be applied to customers' bills. As a result, the electric utility will not have to return to customers the full amount of the over-recovery. The rationale for such a factor is that when an electric utility over-recovers system losses for EFC purposes, the company has had less system losses than expected as provided for in base rates. The Gccf incentive factor would reward the company for less losses, or for more efficiency, by reducing the amount of the over-recovery to be credited to ratepayers. Conversely, the efficiency factor applied when a company under-recovers its system losses, the Fcrf, will come into play when the company has more system losses than expected as provided for in base rates. In that case, the company would be less efficient and would be penalized by the Fcrf factor which reduces the amount of the under-recovery that the company can subsequently recover from EFC ratepayers.

In Ohio Edison, there were over-recoveries in some months and under-recoveries in other months, and the final result of the application of the factors was that Ohio Edison was going to recover more from ratepayers than its actual incremental system losses. The Commission balked at this result on the grounds that more recovery than the dollar amount of actual losses could not properly be considered costs for EFC purposes. Therefore, the Commission limited the application of the factors so that the utility would never recover through the SLA of the EFC rate more than the actual incremental system loss costs, which appeared in Column 10 of Form ER-16-S. Column 10 gives the actual incremental system loss costs before either the Fcrf or Gccf factor is applied. As a result of Ohio Edison, electric utilities were instructed to apply the Gccf factor in Column 13 in the event of an over-recovery for any given month or the Fcrf factor in Column 12 in the event of an under-recovery for any given month, and then to figure out what the SLA for the six-month period would be if the two factors were applied. However, if the end result was an

SLA that would recover from ratepayers more than actual incremental losses as shown in Column 10 in the event of an underrecovery or an SLA that would credit to ratepayers less than actual losses as shown in Column 10 in the event of an overrecovery, the utility was instructed to disregard the factors entirely and merely use the actual incremental loss figure of Column 10 for the SLA.

For the six-month period in question in this proceeding, CSP under-recovered system loss costs in June and July and figured out the amount that could be recovered from ratepayers using the Fcrf, which was a reduced amount from actual losses. In August, September, October, and November, CSP over-recovered system loss costs and figured out the reduced amount that would be credited to ratepayers using the Gccf. The end result of the application of the factors was that CSP would be crediting to its ratepayers less than CSP would have credited if the actual system losses were used. Therefore, under the Commission's orders and the new Rule 4901:1-11-07(C)(3), O.A.C., which adopts the Ohio Edison method, the actual losses were used, and the efficiency incentive factors were not applied for the purposes of the SLA for the six-month period.

Mr. Erlitz takes note of the Commission rule that all amounts of over-recovery are to be returned to ratepayers. This is true, and the Commission's method accomplishes this result. However, the Commission's method does not have to disregard the Gccf to the extent that Mr. Erlitz does. Although all amounts of over-recovery are to be returned to ratepayers, Rule 4901:1-11-07(C)(2), O.A.C., still requires that the calculations using both the Fcrf and the Gccf be made. In the initial stage of the calculation, the utility is to figure the reduction of the credit to be given customers as a result of over-recoveries and the reduction of the recovery to be given itself as a result of underrecoveries. The net amount of this calculation stands as a possible incremental system loss dollar amount. Then, in the Commission's method, when the system loss amount figured by using the two factors results in recovery of more than actual system losses or credit of less than actual losses, the actual system loss dollar amount is used.

Mr. Erlitz is correct to stress the purpose of the SLA to provide an incentive for efficiency, but his method would make the reward to the company merely the absence of penalties. Mr. Erlitz's method would simply require the elimination of the factor that rewards the utility, the Gccf, because the Gccf allows the utility to credit to ratepayers less than actual loss costs. Mr. Erlitz would keep the Fcrf because that factor penalizes the utility by reducing the amount of under-recovered losses that can be recovered through the EFC rate. However, it makes no sense to apply the Fcrf as a penalty to reduce the amount of under-recovered system losses that a company may recover in any given month and not to apply the Gccf to reward the company with a reduction of the credit to be given to customers in the event of over-recovery in any given month at this stage of the calculation. The Commission's method either uses both efficiency factors or neither efficiency factor. The Commission's method has accomplished the same goal as Mr. Erlitz's method but with a somewhat more consistent and fair methodology.

In sum, the Commission's method allows for the use of the Fcrf to reduce the recovery amount in months of under-recovery and also for the use of the Gccf to reduce the credit to customers in months of over-recovery. However, the Commission's method does not allow the factors to reduce the credit to ratepayers below or to increase the recovery from ratepayers above the dollar amount of actual incremental system losses. Under the Commission's method, the incentive factors are only an alternative that will be disregarded in order to assure that customers do not pay more than the actual dollar amount of incremental system loss costs for the six-month period. Therefore, the Commission believes that its method is appropriate.

Coal washing costs

The financial auditor determined that coal washing costs being charged EFC customers were in accordance with the contract between CSP and the Conesville Coal Preparation Company (CCPC). For the period June 1, 1987 through May 31, 1988, CCPC billed CSP $7,559,742 to recover for operation, maintenance, taxes, and return on working capital. The return earned by CSP on its investment in CCPC was $71,405 for the year ending May 31, 1988. This return was computed in accordance with Securities Exchange Commission authorization. The financial auditor reported that the return had been reduced by $770,547 because of the amortization of and an adjustment to the gain resulting from the sale/leaseback of the Conesville Coal Preparation Plant (CCPP), interest income of $20,593, and miscellaneous other income of $9,161 (Comm. Ord. Ex. 1, at 12).

MANAGEMENT/PERFORMANCE AUDIT

The management/performance audit, performed by ADL, covered the period from June 1, 1987 to May 31, 1988. The scope of the 1988 management/performance audit was restricted to follow-up issues of last year's audit. ADL reported on the off-system dispatch study conducted by AEPSC, CSP's coal inventory, CSP's coal mix strategy, the closing of the Poston Plant, the dissolution of the Simco-Peabody joint venture, the sale/leaseback of CCPP, unit test procedures, and availability monitoring.

Off-system sales

ADL reported that AEPSC recently completed a study of the effects of the pricing of electricity for off-system sales. AEPSC concluded that by pricing sales on a replacement cost basis, instead of the present method of weighted average cost of inventory, AEPSC might increase electric sales by being more competitive in the off-system sales market. The assumptions of the new pricing system are that contract and affiliate coal are for internal load, that spot coal is bought to supplement internal load and for off-system sales, that the replacement cost of fuel is equal to the price of spot coal, and that contract and affiliate coal has a zero marginal cost for dispatching purposes. With this reallocation of fuel costs, the actual EFC rate is expected to increase because of the greater allocation of affiliate and contract coal to EFC customers. However, during the verification period for the new system, AEPSC would recover fuel costs under an EFC rate based on the existing average cost methodology. After the verification period, AEPSC expects the EFC rate to reflect the new methodology but plans to adjust its base rates to credit the EFC customer for any increased profits from increased off-system sales. ADL believed that AEPSC's plan to implement the new methodology was reasonable (Comm. Ord. Ex. 2, at 12). The Commission's findings regarding the new dispatch system will be made in Case No. 88-101-EL-EFC. Reference to the new dispatch system in this proceeding will be made only to the extent that the new system is expected to affect other matters at issue in this proceeding relating to CSP.

Conesville Unit 4 outage

Company witness Kavander testified that Conesville Unit 4 was out of service for sixteen weeks in the audit period. A scheduled outage of the unit began on February 27, 1988 and was expected to last for ten weeks. Company witness Champa testified that when the Conesville Unit 4's generator stator was replaced as part of the scheduled outage, an inspection revealed unexpected extensive damage to the rotor. Additional inspections and replacement of parts continued the outage for another six weeks. The unit was returned to service on June 17, 1988. Mr. Champa stated that the damage was extensive enough to warrant a replacement rotor which will be installed in October 1989 at the time of another scheduled maintenance outage of the unit (CSP Ex. 4, at 2).

The staff requested that the company provide a witness to testify at the time of the fall 1989 EFC hearing as to whether or not the company is on schedule to complete the work. The company had no objection to the recommendation except that the scheduled outage is not scheduled until October 1989 which may be after the fall 1989 fuel hearing. The Commission agrees with the company that the scheduled outage will probably occur after CSP's fall 1989 hearing. Therefore, the Commission will make no orders regarding the Conesville Unit 4 repair at this time.

Inventory levels

The management/performance auditor reported on CSP's coal inventory. Over the past few years, CSP has had a high commitment to long-term contract coal which has caused an excessive inventory problem. ADL reported that CSP's commitment to contract coal has restricted its flexibility to manage inventory levels. In addition, the closing of the Poston plant and the extensive outage at Conesville Unit 4 contributed to inventory remaining at a high level.

ADL reported that by the end of January 1988, Conesville's inventory was approximately 15% above its target, and Picway's inventory was 162% above target. On the whole, CSP's inventory was approximately 24% above target. Since March 1988, inventory levels have come down slowly, but the outage at Conesville Unit 4 prevented quicker reductions. Control of inventory at Picway has been affected by the closing of the Poston Plant because coal that would have gone to Poston has been diverted to Picway.

Because of the high inventory levels, AEPSC's Fuel Supply Department (FSD) deferred some contract tonnage from early 1988 to the second half of 1988. In addition, the Peabody-Simco contract was renegotiated to defer tonnage to 1991. The Peabody-Sunnyhill contract was amended to reduce total tonnage in consideration for a 1.7 cents per MMBtu price increase. The N&W Sales contract was amended to reduce monthly shipments in return for a one-year extension of the contract. ADL concluded that FSD was acting reasonably to control CSP's inventory levels (Comm. Ord. Ex. 2, at 16).

Company witness Kavander stated that CSP has been attempting to reduce inventory levels without breaching its contracts with suppliers. As ADL described, CSP has attempted to adjust deliveries and to renegotiate contracts. Tentative agreements were reached for smaller deliveries as a result of the Conesville Unit 4 outage. A permanent tonnage reduction was achieved in the case of the Peabody-Sunnyhill contract renegotiation described above (CSP Ex. 5, at 9).

The staff agreed with ADL that CSP was acting reasonably to control its inventory levels. However, the staff requested that the Commission order the spring 1989 management/performance auditor to place particular emphasis on the Picway and Conesville inventory levels to determine if the levels are being decreased.

OCC concurred in the staff's recommendation. OCC believes that the company's efforts to reduce inventory have not been fruitful. OCC contended that the inventory at Picway was increasing from April through June 1988.

The Commission agrees with the staff and OCC that CSP's inventory levels remain high and that efforts to reduce the inventory levels have not been as productive as the efforts should be. Therefore, the Commission will request that the management/performance auditor in the upcoming spring audit review the inventory levels at all CSP's plants, with particular emphasis on the Picway and Conesville plants, to determine if the levels are being decreased. The auditor should also make recommendations regarding any additional measures the company could take to reduce the inventory levels.

Contract/spot coal mix

ADL reported that FSD has recognized a need to reduce CSP's contract coal commitment and to improve CSP's contract/spot coal mix. During the second half of 1987, CSP's coal supply mix was 100% contract coal and 0% spot coal. Beginning in January 1988, CSP renegotiated its contract with South-East Ohio Coal Company (South-East) and agreed to take 5,000 tons of coal per month from South-East at a spot market price if an agreement on the price could be reached. As a result, ADL considered that CSP's new mix was 98% contract and 2% spot.

OCC argued that CSP's coal supply mix remained simply 100% contract coal. According to OCC, the 2% spot coal figure was arrived at only by calling the 5,000 ton monthly purchases from the renegotiation of the South-East contract spot purchases. Under the renegotiated contract, South-East has the right to offer CSP these tons per month at spot prices. If CSP agrees to the price, CSP is obligated to purchase 60,000 tons per year on that basis. OCC argued that CSP has not diminished its contract responsibilities with this contract renegotiation. OCC contended that the price and the length of the commitment to purchase do not make the coal spot coal. OCC recommended that the Commission order the management/performance auditor to review CSP's designations of spot versus contract coal for the purposes of determining the contract/spot mix.

CSP argued that a spot purchase order is any purchase of coal with an initial duration of one year or less. Under the option rights of the South-East contract, South-East has the right to be offered and to accept spot coal supply purchase orders for 60,000 tons per year in 1988, 1989, 1990, and 144,000 tons in 1991. According to CSP, the agreements for these tonnages will be spot purchase orders for one-year periods if both parties can reach agreement on a spot market price. CSP believes that these option rights constitute spot purchases. CSP argued that in any event the company has obtained spot market prices for the coal and thereby lowered the cost of fuel.

The Commission finds that the designations of contract coal and spot coal are important and that an electric company's supply mix is a customary consideration in any management/performance audit. However, there will be circumstances such as the purchases involved in the South-East renegotiation where the line between what is contract and what is spot coal will be blurred. This is not disturbing as long as the Commission is informed about the purchases that do not fit neatly into one category or another. In this case, the evidence on record describes the exact nature of the purchases from South-East which the auditor and the company have designated as spot coal. The Commission needs to be aware of circumstances where certain purchases could be designated as either spot or contract coal. Because the Commission has been made aware of this circumstance through the management/performance audit and the company's testimony, there appears to be no need for corrective action. The denomination of the coal purchases as "contract" or "spot" is not the critical issue; the Commission's concern is whether the company has sufficient flexibility to make the most cost-effective purchases.

OCC noted that AEPSC's targeted overall system mix is 80-85% contract to 20-15% spot coal. OCC argued that CSP's commitment to contract coal has caused the excessive inventory problem and has resulted in higher coal costs because contract coal is higher priced. OCC suggested that it might be reasonable for CSP to evaluate the cost effectiveness of contract buyouts. OCC also recommended that the Commission review the effectiveness of CSP's efforts to increase its percentage of spot coal purchases in its overall system mix.

CSP responded that CSP's long-term contracts are at the low end of the range of coal prices and that the Commission has found that CSP's long-term contracts have not adversely affected the rates paid by EFC jurisdictional customers. CSP argued that there was no evidence that customers have been adversely affected by the contract/spot ratio. In addition, CSP argued that there are many benefits to the renegotiated coal contracts.

The staff argued that the company is making a reasonable effort to improve its overall contract/spot mix. The staff believes that CSP is well aware of the possibility of contract buyouts but that buyouts would be an expensive alternative at best. However, the staff agreed with OCC's recommendation that the next management/performance auditor should review the company's coal mix and determine what has been the impact of the steps already taken by the company to improve the mix.

The Commission notes that CSP's commitment to contract coal has contributed to CSP's inventory problems and the inability of CSP to increase its spot coal purchases. While CSP's commitment to contract coal has kept CSP's customers from enjoying the benefits of lower spot coal prices, the Commission continues to believe that CSP's long-term contract coal is not unfavorably priced. In addition, the Commission cannot see how CSP could purchase more spot coal given its inventory levels. Obviously, CSP needs to reduce its contract commitments before the company can purchase any significant amount of spot coal.

The Commission finds that FSD has been active in attempting to resolve CSP's problem of over-commitment to contract coal. However, the Commission will continue to monitor FSD's actions to reduce CSP's contract coal commitments. Therefore, the Commission will ask the next management/performance auditor in the spring 1989 audit to review the company's further efforts to reduce its contract commitments. In addition, the Commission will ask the auditor to suggest any additional measures the company might take to reduce its contract commitments.

<u>Effects of the new dispatch system</u>

ADL believed that if AEPSC's new system dispatch plan works well, an increase in burn should result. ADL believed that the increased burn would improve CSP's coal mix. ADL recommended that the Commission direct the next management/performance auditor to report on the effects of the new dispatch system on CSP's burn and contract/spot coal mix (Comm. Ord. Ex. 2, at 19).

The staff believed that the new dispatch system should improve CSP's inventory levels and contract/spot coal mix. Staff believed that the Commission should not take any specific actions regarding the company's supply mix and inventory levels until the effectiveness of the new dispatch system is gauged. The staff and OCC agreed with ADL that the upcoming spring 1989 management/performance audit should review the impact of the new dispatch system on the company's inventory and coal supply mix.

CSP was not opposed to a review of the effects of the new dispatch system but was concerned about the timing of the review. CSP stated that the dispatch plan, which was to be effective as of October 1988, will be delayed due to the necessity of FERC approval. CSP pointed out that CSP's next EFC proceeding is an audit proceeding. The work for the next audit will probably begin in December 1988. CSP argued that only a limited amount of preliminary data would be available for the auditor to review, and as a result the review would be useless. CSP believed that at least a year's worth of data would be necessary for a final assessment. Therefore, CSP recommended that the management/performance auditor not review the new dispatch system. The company offered simply to report on the status of the dispatch plan at the upcoming EFC hearing, and then the Commission could determine if the 1990 auditor should review the effects of the new dispatch system.

OCC quoted the management/performance auditor's comments that two months of data would show a start of some effect and that the issue should probably be reviewed throughout the verification period. OCC requested that the Commission order a review by the spring 1989 management/performance auditor of the impact of the new dispatch system on inventory levels and the supply mix.

The staff agreed with OCC that even a limited review of the impact of the new dispatch system would be within the normal scope of any management/performance audit in an EFC proceeding. Staff found it reasonable that the upcoming auditor would review whatever data was available although the staff cautioned against forming definitive conclusions in the absence of more data.

The Commission will order the management/performance auditor in the upcoming audit to report on whatever data is available on the effects, if any, of the new dispatch system, if the system is approved. The auditor may attempt to determine if the new dispatch system, if approved, has lowered CSP's coal inventory levels. However, the Commission recognizes that it would be far too early to make any conclusions about any effects of the dispatch system at the time of the next audit.

<u>The closing of the Poston plant</u>

ADL reported on the impact of the closing of the Poston Plant on fuel procurement. ADL reported that, pursuant to contract, coal which could not be delivered to Poston was delivered to Picway. ADL believed that, given CSP's contract commitments, FSD reasonably managed the impact of the Poston shutdown. According to ADL, increased burn from the new dispatch system should help to alleviate the problems caused by the Poston closing (Comm. Ord. Ex. 2, at 22).

Company witness Kavander testified that when Poston was retired, Poston's two contract suppliers objected to tonnage reductions. A settlement was reached with South-East as described above, but M&H Stage pursued arbitration. At this point, the arbitration has been discontinued pending efforts to reach a settlement. In the interim, a tonnage reduction has allowed CSP to reduce the Picway inventory. Ms. Kavander testified that inventory at Picway has decreased since December and should continue to decrease as a result of the tonnage reductions and settlements with the former Poston suppliers (CSP Ex. 5, at 6).

OCC pointed out that Picway's inventory was as much as 162% above target. As discussed above, OCC argued that the South-East agreement merely allowed CSP to refer to some of the South-East tons as spot purchases instead of contract purchases and that CSP's commitment to purchase the South-East coal that would have been delivered to Poston has not diminished. OCC complained that objections to questions regarding the M&H Stage arbitration had been sustained by the examiner at the hearing because CSP believed that disclosure of the negotiations might prejudice them. Ms. Kavander testified that the settlement might be finalized within a few weeks (Tr. II, at 7).

Therefore, OCC argued that the impact of the closing of Poston remains an open issue. OCC recommended that the Commission order the management/performance auditor in the upcoming audit to review again the impact of the closing of Poston on fuel procurement, inventory levels, and EFC ratepayers in general. OCC also requested that the Commission order CSP to provide a witness at the upcoming proceeding to testify regarding the impact of the closing of the Poston station on fuel procurement, inventory levels, and EFC ratepayers in general.

The Commission must agree with OCC that several issues with regard to the Poston closing remain open. Therefore, the management/performance auditor and the company's witness should again provide updated information on the impact of the closing of the Poston station.

<u>Simco's sale of depreciable assets to Peabody Coal Company</u>

The dissolution of the Simco-Peabody joint venture was another topic reviewed by ADL. In dissolving the Simco-Peabody joint venture, Simco, a wholly-owned subsidiary of CSP, sold to Peabody Coal Company the coal lands, which produced a $1.2 million net gain to Simco, and assets, which produced a $2.0 million net gain to Simco. According to ADL, AEPSC booked these gains below the line because the properties were never in CSP's rate base and the investment in those properties was at risk to Simco's one stockholder, CSP. ADL believed that because these were non-utility assets, the CSP/Simco stockholders correctly received the full benefit of the financial gain on the sales (Comm. Ord. Ex. 2, at 24). ADL agreed with CSP that the below-the-line treatment was in accordance with the FERC Chart of Accounts on the Gain on Disposition of Property. The staff supported the finding of the management/performance auditor and argued that no further review of the dissolution of the Simco-Peabody joint venture was necessary.

OCC's witness Erlitz disagreed with the management/performance auditor on CSP's treatment of the gain on the sale of the depreciable assets associated with the Simco-Peabody dissolution. In Mr. Erlitz's opinion, the ratepayers should have benefited from the gain on the sale of the depreciable assets. Mr. Erlitz stated that the charge per ton for Simco-Peabody coal included a component for equipment rental. The charge per ton was based in part upon the annual depreciation of the assets. According to Mr. Erlitz, the plant-in-service was $12,781,949, and the accumulated depreciation on that was $9,679,167 so that the ratepayers would have paid the $9,679,167 of the total $12,781,949 cost of the assets (Tr. II, 126-127). According to Mr. Erlitz, CSP's ratepayers had been purchasing an interest in these assets through the cost of coal and therefore should reap the benefit from the sale of the assets. Mr. Erlitz argued that it is irrelevant whether the assets were in rate base or whether the particular FERC account was used. He argued that the CCPP was not in rate base but that the ratepayers are receiving the benefit of the gain on the sale/leaseback of CCPP. Mr. Erlitz argued that the portion of the $2.0 million gain from the sale of Simco assets which is commensurate with CSP's ownership share in the Conesville power plant should be passed back to EFC ratepayers through an RA (OCC, Ex. 1, at 5).

In rebuttal, CSP's witness Mr. Campbell stated that the ratepayers never purchased an interest in the assets, never were the legal owners of the assets, and never were subject to the risks of ownership of the Simco assets. Mr. Campbell stated that the stockholders had the sole risk of ownership and should receive the gain from the sale. CSP disagreed with Mr. Erlitz's assertion that the EFC ratepayers paid rental rates sufficient to cover all of the depreciation charges of the assets. Mr. Campbell argued that the return to CSP on its affiliate operations had always been poor. Finally, Mr. Campbell stated that the treatment of the gain from the sale/leaseback of CCPP did not contradict the treatment of the gain on the sale of the Simco depreciable assets because CSP has a continuing relationship with the CCPP and CSP's customers are paying the lease costs through the cost of coal washing so that a gain on the sale/leaseback should be used to reduce the future coal cleaning costs. However, according to Mr. Campbell, Simco has no further direct involvement with the depreciable assets sold to Peabody, and Simco is out of the coal mining business.

The Commission believes that CSP's EFC ratepayers did not purchase an interest in the Simco equipment through the equipment rental component included in the cost of Simco-Peabody coal. The Commission does not find it appropriate to conclude that the actual nature of the rental component is similar to an installment sale. The inclusion of an equipment rental component in the cost of coal does not confer the benefits or the risks of ownership of the equipment on those who pay EFC rates which include the cost of the coal. Therefore, the Commission rejects OCC's argument that CSP should pass back to EFC ratepayers a portion of the gain on the sale of the Simco depreciable assets. The Commission agrees with the management/performance auditor and the company that the treatment of the gain on the sale of the Simco depreciable assets was appropriate.

The sale/leaseback of CCPP

CSP gained $1.9 million on the sale/leaseback of CCPP through the use of $4.4 million of deferred federal income tax and $3.3 million of deferred investment tax credit. CSP credited the gain to the cost of coal by amortizing the gain over the fifteen year life of the lease. The monthly credit for the amortization of the gain is $19,722. ADL reported that the ratepayers are receiving the full benefit of the gain associated with the CCPP sale/leaseback as a reduction in the cost of washing coal at CCPP (Comm. Ord. Ex. 2, at 26).

Completion of the component performance test procedures manual

ADL reported on AEPSC's unit test procedures manual. The 1987 audit had recommended that AEPSC prepare written procedures for component performance tests and that these procedures be consistent across units and between plants. ADL reported that the resulting manual appeared to be well written and complete as far as component testing procedures were concerned. However, ADL reported that some sections of the manual were missing and that AEPSC would not complete work on the manual until December 1988. In the audit report, ADL recommended that the manual's completion be verified by the management/performance auditor in the next audit proceeding (Comm. Ord. Ex. 2, at 28). OCC supported this recommendation.

The staff noted that the company revised the date for the completion of the manual to the second quarter of 1989 (Tr., I at 60). Therefore, the staff recommended that the Commission order the management/performance auditor of the 1990 audit to review the status of the completion of the manual.

Company witness Mearhoff testified that there is a performance test manual for each of the seven series of units and eight other unique unit types on the AEPSC system. Each of the fifteen manuals contains approximately 250 pages. Mr. Mearhoff testified that only one test procedure was omitted from the CSP test manuals and that that procedure will be included in the manuals when they are revised in the second quarter of 1989 (CSP

Ex. 6, at 6). Mr. Mearhoff also stated that other reference material will be included in the manuals when they are revised.

The company opposed the recommendation that the upcoming management/performance auditor review the completion of the manuals. CSP noted that ADL found the manuals to be substantially complete. CSP stated that the only additional progress anticipated by the next EFC hearing would be the collection of comments from engineers and plant management. The company proposed that the company simply report on the status of the performance manuals' revisions and completion at the upcoming EFC proceeding.

The Commission will ask the company to report on the status of the completion of the initial revisions to the performance manual at the time of the next EFC proceeding. The Commission recognizes that the manual will not be completely revised until the second quarter of 1989.

Periodic reviews of the performance manual

ADL also identified some inconsistencies in the manual as developed by AEPSC. None of these inconsistencies were major, but ADL believed that such inconsistencies should be resolved. AEPSC has already begun this process with the revisions discussed above. ADL recommended that AEPSC require plant performance engineers to suggest manual revisions in writing based on test experience and that AEPSC perform systematic review of the manual following revisions. ADL believed that identifying revisions is important to the usefulness of the manual. ADL recommended that technical reviews of the manual be performed to ensure that the manual is current. The staff and OCC supported the recommendation of the management/performance auditor that the company should review the manual periodically in order to assure that the manual is kept current. OCC recommended that the Commission order the management/performance auditor in the next audit proceeding to review whether updates were being made by AEPSC.

The company stated that inconsistencies such as those identified by ADL would be addressed at the time of the revisions. The company also stated that reviews of the manuals will be performed so that the manuals are kept up-to-date. The company pointed out that the first revision will not be complete until June 1989 and that OCC was premature to recommend that the next auditor review whether updates were made. CSP also argued that further review by the auditor would be unnecessary. CSP contended that it is aware of the need for periodic reviews when changes affect the manuals.

The Commission will not order the auditor in the upcoming audit to review revisions made to the manual because no such revisions will have been completed by the time of the audit. The company's witness at the next hearing on the status of the completion of the manual should be able to answer questions regarding subsequent revisions.

Specific revisions to the performance test manual

ADL suggested that the company issue a written policy statement that defines the purpose of the manual. However, Mr. Mearhoff suggested that such a policy statement had already been issued to address the frequency of performance tests and the purposes of a uniform performance test program (CSP Ex. 6, at 11). The company argued that further review of the need for a policy statement was not warranted. The staff noted that the auditor apparently had not reviewed the statement. The staff recommended that the next management/performance auditor be ordered to review the policy statement referred to by Mr. Mearhoff and to determine whether the statement comports with what the auditor believed should be contained in the policy statement. The Commission believes that the staff should address its questions regarding the policy statement to the company's witness at the next hearing.

ADL also recommended that AEPSC prepare specific written procedures and or policy guidelines for critical instrumentation and or equipment that has a direct impact on unit performance. The company agreed with this recommendation (CSP Ex. 6, at 11-12). Mr. Mearhoff stated that AEPSC is in the process of developing guidelines where they do not already exist. The staff agreed that the recommendation was reasonable and that the Commission should adopt it. OCC recommended that the Commission order the management/performance auditor in the next audit to review the guidelines which AEPSC is currently developing. The company proposed to report on the status of this project in the next EFC hearing and to have the Commission determine if the auditor should review the matter only after the company's report. The Commission agrees with the company that the company should provide a witness on the development of these guidelines at the next hearing.

ADL recommended that written quality assurance/quality control (QA/QC) procedures should be prepared for use with the manual because of the importance of accurate results from component performance tests (Comm. Ord. Ex. 2, at 30). The auditor recommended that the QA/QC procedures be incorporated in the manuals.

Mr. Mearhoff objected to ADL's suggested that written QA/QC checks be prepared. He stated that the current review process assures that there is more than adequate quality control and assurance for each performance test conducted. He stated that already test data is checked by three different groups. He believed that the position descriptions of engineers and managers define responsibilities for checking test data. In addition, Mr. Mearhoff contended that the time required to develop and implement further formalized procedures would not be beneficially spent because these formalized procedures would have no impact on the overall quality of the tests. CSP argued that to incorporate the company's QA/QC procedures into the manuals from the job descriptions was not needed.

The staff and OCC recommended the adoption of the auditor's recommendation that written QA/QC procedures be prepared for use with the manuals. The staff argued that the company would benefit from having the QA/QC procedures recorded in one definitive source. The staff quoted the management/performance auditor's testimony that CSP has already documented many other procedures and that a formal record of the QA/QC procedures would benefit CSP. The staff also believed that formal documentation would ensure that the QA/QC information was available to all appropriate personnel. The staff contended that, contrary to Mr. Mearhoff's testimony, a written QA/QC program is not currently in place. The staff did not believe that the position descriptions of managers were an adequate documentation. OCC also recommended that the Commission order the management/performance auditor at the time of the next audit to review the written QA/QC procedures.

The Commission agrees with the staff and OCC that the company should prepare written QA/QC procedures for use with the manuals. Therefore, the Commission will order the company to prepare such written procedures and to report on its progress at the time of the next EFC hearing.

ADL noted that AEPSC did not initially plan to include software with the manual. ADL believed that performance test software should be developed in a timely way and that plant engineers should be given access to it. ADL recommended that AEPSC prepare a software development timetable and that the next management/performance auditor review the software development schedule, the software developed, the accessibility of the mainframe to plant performance engineers, and the software documentation. OCC agreed with the auditor.

Mr. Mearhoff agreed that schedules should be prepared for the development of software for automatic calculation of performance test results. However, Mr. Mearhoff did not agree that the next management/performance auditor should review the software development schedule or its implementation because he believed that it was unreasonable to expect completion of the project before the next audit proceeding. The company contended that creating and documenting the software was contingent upon completing the first revisions to the manuals. The manuals themselves will not be revised until June 1989. Mr. Mearhoff preferred that CSP provide the Commission with the project completion schedule and a status report on the software development and documentation at the next EFC proceeding (CSP Ex. 6, at 14).

The staff recommended that the Commission adopt the company's suggestion and order the company to produce a witness to provide this information at the next EFC hearing. The Commission will adopt the company's suggestion that the company provide a witness on the software development at the next EFC proceeding.

Availability analysis

ADL reported on AEPSC's new Generating Availability Data System (GADS), which came on-line in January 1988. The purpose of this software is to accumulate, process, store, and retrieve information needed for evaluating and improving plant availability. Once on-line for a period of time, the system will provide a computerized database on outages. The system was developed primarily to meet maintenance planning requirements and to improve plant availability. ADL recommended that the 1989 management/performance auditor review the existing availability analysis program to ensure that GADS has been effectively integrated into it in order to maintain and to improve unit availability (Comm. Ord. Ex. 2, at 34). The staff supported the recommendation.

Mr. Mearhoff objected to the management/performance auditor's suggestion that AEPSC did not factor the old availability data system into the new automated system. He stated that under the new GADS system, AEPSC will simply be able to do in a more flexible manner the analyses which have always been done (Comm. Ord. Ex. 6, at 18). CSP argued that current availability information was being placed in the data base and that ten years of historical information was also available. CSP argued that the same information as to causation, megawatt-hours lost, and duration has been included and that the new GADS system is simply a better tool than that previously used to identify unit problems and plan maintenance. CSP argued that the auditor's recommendation was not necessary because there is no evidence that the new system is not effectively integrated into the availability analysis program.

The Commission finds that the company has explained that the systems are already integrated. The Commission finds that no further review of the management/performance auditor on this matter is necessary.

Peer unit comparisons

Mr. Mearhoff also objected to the management/performance auditor's recommendation that AEPSC should develop availability comparisons with non-AEPSC system units or should develop a cost-benefit analysis of developing regular non-system peer unit comparisons. AEPSC does not formally compare availability statistics between AEPSC units and units of other electric utilities. Mr. Mearhoff stated that availability data in the public domain does not provide the necessary level of detail to assist the AEPSC system plants in maintenance planning or problem identification. According to Mr. Mearhoff, the differences in equipment are so great and the interpretation of failure so elusive, that comparisons off-system are not cost effective. In addition, CSP argued that AEPSC is already comparing the forty-seven AEPSC owned fossil units. CSP opposed the recommendation that comparisons of non-system peer units be made and that a cost/benefit analysis of the development of non-system peer unit comparisons be performed.

The staff acknowledged that AEPSC would have to devote a great deal of time and money to implement the recommendation that non-system peer unit comparisons be made. CSP's arguments convinced the staff that such comparisons involve far more than the management/performance auditor had indicated, and the staff doubted the practicability and the value of the non-system peer unit comparisons. Therefore, the staff recommended against the auditor's recommendation. The Commission agrees with the company and the staff that non-system peer unit comparisons are not practical given their cost and dubious value.

REFUNDS FROM EMPIRE COAL COMPANY

OCC's witness Mr. Erlitz raised the issue of the Empire Coal Company (Empire) federal black lung excise tax refund. According to Mr. Erlitz, Empire was applying to the Internal Revenue Service for refunds for certain federal black lung excise taxes paid from 1985 through 1987. Mr. Erlitz understood that Empire intended to refund, plus interest, to CSP any refund that Empire received. According to Mr. Erlitz, Empire had included a cost component for federal black lung excise taxes in its cost of coal which CSP's EFC customers paid as part of the EFC rate. Because CSP's customers funded the payments, Mr. Erlitz believed that the customers should receive the full refunds. OCC recommended that CSP refund to EFC customers any excise tax refunds at the time the refunds are received. OCC also recommended that the financial auditor in the next financial audit report on what refunds were received and whether the refunds including the interest were properly passed back to EFC jurisdictional customers (OCC Ex. 1, at 6).

CSP's witness Kavander testified that CSP intends to return to its EFC ratepayers approximately $26,000 as a result of the refunds that CSP will receive from Empire (Tr. II, at 12). CSP's witness Taylor testified that the refunds would be viewed as an adjustment to the price of coal. As such, the refunds would merely be flowed back to consumers as a reduction in the price the company pays for coal. The company argued that its practice of flowing the effects of any adjustment to the price of coal through credits or debits to its fuel stock account conforms to the actual nature of the company's coal inventories. According to CSP, individual tons of coal cannot be traced after delivery from a specific supplier. As a result, CSP argued that individual dollars paid for specific tons of coal cannot be traced. Therefore, the company spreads the amount paid for the coal over all tons of coal in the coal pile. The company also argued that no review by the financial auditor was necessary.

The staff agreed that CSP should refund to its customers all amounts received from Empire as the amounts are received by CSP. However, the staff believed that the refund should be made through a reconciliation adjustment (RA) which would reflect amounts received by CSP during the applicable period rather than through an adjustment to the cost of coal. The staff believed that it would be easier to track and verify the refunds if the refunds were made through an RA to the EFC rate. The staff agreed with OCC that the financial auditor in the 1989 financial audit should review the refunds received and passed back to EFC ratepayers through an RA. OCC agreed with the staff that the refunds should be passed back to customers through an RA to the EFC rate.

CSP replied that it would be as easy to review the adjustment to the cost of coal as it would be to review the RA. In addition, CSP noted that for an RA, a specific allocation of the refund would have to be made to ensure that the company's EFC ratepayers receive only that portion of the adjustment attributable to the EFC jurisdiction while this allocation would be automatically accomplished under CSP's method. CSP argued that adjustments to the price of coal are frequently made and that treatment through an RA of such adjustments is not convenient. CSP also argued that the RA treatment would make the EFC rate more volatile.

The Commission believes that the appropriate refunds should be passed back to EFC ratepayers through an RA to the EFC rate. Treatment through an RA to the EFC rate is the customary method of such adjustments. Ohio Power Company, Case No. 87-101-EL-EFC, November 3, 1987, at 7. The Commission agrees that the amount of the refunds received from Empire will be subject to allocation of the jurisdictional amount before an RA to the EFC rate may be made. However, this allocation should not be difficult for the company to accomplish. The financial auditor in the upcoming audit should report on the receipt of the refunds and the corresponding RA.

ELECTRIC FUEL COMPONENT RATE

The EFC rate approved by the Commission in this proceeding will be derived from actual and projected data from the six-month base period of June 1, 1988 through November 30, 1988, and will be used by CSP to compute the fuel charges rendered to jurisdictional customers during the six-month current period of December 1, 1988 through May 31, 1989. The EFC rate will consist of a fuel component calculated pursuant to Rule 4901:1-11-04, O.A.C., an RA calculated pursuant to Rule 4901:1-11-06, O.A.C., and an SLA calculated pursuant to Rule 4901:1-11-07, O.A.C.

Based on actual and projected data, the company has calculated a fuel component of 1.654026 cents/kWh. In calculating this value, CSP divided includable fuel costs of $101,232,406.05 by includable kWhs of 6,120,362,927 (CSP Ex. 7, Attachment RT-1, at 4). None of the other parties to this proceeding have challenged this calculation or presented alternative computations. The Commission finds that 1.654026 cents/kWh should be adopted as the fuel component portion of the EFC rate.

With regard to the RA, the company proposes a rate of (0.045396) cents/kWh. This adjustment is necessary because actual includable fuel costs during the base period were less than calculated fuel component revenues collected through the EFC. In calculating this value, CSP divided over-recovered fuel costs of $(2,778,426.42) by includable kWhs of 6,120,362,927. The Commission finds that the company's RA calculation of (0.045396) cents/kWh is proper and should be used in the calculation of the EFC rate.

The company has calculated an SLA of (0.008742) cents/kWh. In calculating this value, CSP divided over-recovered system losses of $(535,050.97) by includable kWhs of 6,120,362,927. The average cost effectiveness measure used to calculate the SLA for the six-month period from December 1987 to May 1988 was 1.1204. We find that (0.008742) cents/kWh should be adopted as the system loss portion of the EFC rate.

Based upon these findings, the Commission concludes that the EFC rate should be 1.599888 cents/kWh. This rate represents a 2% increase from the present 1.568720 cents/kWh. This increase resulted from an increase in the fuel component because fuel costs are estimated to increase by 5.8%. The total dollar amount refunded through the RA and SLA increased which slightly offset the increase in projected fuel costs. CSP should file the EFC tariff rider setting forth this rate no later than November 30, 1988. The tariff rider should become effective on December 1, 1988 and should remain in effect until otherwise ordered by the Commission.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

1) CSP is an electric light company within the meaning of Section 4905.03(A)(4), Revised Code, and as such is a public utility subject to the jurisdiction and supervision of the Commission. CSP is also an electric utility within the meaning of Rule 4901:1-11-01(L), O.A.C.

2) Section 4905.301, Revised Code, requires the Commission to review each electric utility's electric fuel component at a hearing once every six months. By Entry dated January 21, 1988, the Commission initiated this proceeding to review CSP's EFC and related matters.

3) The public hearing was held on September 19 and 20, 1988. Notice of the hearing was published in accordance with the requirements of Section 4909.191(A), Revised Code, and Rule 4901:1-11-11(C), O.A.C.

4) The financial and management/performance audits were performed in compliance with Section 4905.66(B), Revised Code, and the provisions of Rule 4901:1-11-10, O.A.C.

5) The company has demonstrated that its acquisition and delivery costs were fair, just, and reasonable pursuant to Section 4909.191(C), Revised Code.

6) The financial auditor believed that costs charged to customers through the operation of the company's approved EFC rate were in accordance with Chapter 4901:1-11, O.A.C., during the six-month periods ending November 30, 1987 and May 31, 1988.

7) The financial auditor did not challenge the company's accounting procedures.

8) OCC challenged the system loss adjustment calculated by the company.

9) OCC recommended that $13,779.13 less in system losses be recovered by the company. The Commission found that CSP had correctly calculated the system loss adjustment according to Commission rules and orders.

10) ADL reported that during a verification period, AEPSC will recover fuel costs under an EFC rate based on the existing average cost methodology for off-system sales but after this period, the new methodology based on replacement cost will be used. AEPSC plans to offset higher EFC costs with adjustments to base rates that will credit the EFC customer for increased profits from off-system sales.

11) CSP was impeded in its efforts to reduce its high coal inventory by a sixteen week outage at Conesville Unit 4.

12) On the whole, by the end of January 1988, CSP's inventory was 24% above target.

13) Because of high inventory levels, CSP deferred some contract tonnage and attempted to renegotiate contracts to reduce tonnage levels.

14) During the second half of 1987, CSP's coal supply mix was 100% contract coal and 0% spot purchases.

15) When the Poston Plant was closed, coal suppliers were allowed by contract to divert the coal to Picway.

16) CSP booked the gains from the sale of property and assets of the Simco-Peabody joint venture below the line so that the shareholders of these two companies received the full benefit of the financial gain.

17) OCC's witness objected to CSP's treatment of the sale of depreciable assets of the Simco-Peabody joint venture. The Commission found CSP's treatment of the gains from the sale of the assets to be appropriate.

18) CSP argued that the EFC ratepayers never were legal owners of the depreciable assets and

never were at risk. The Commission agreed with CSP that EFC ratepayers never assumed the benefits or the risks of ownership of the assets.

19) The gain from the sale/leaseback of CCPP is being amortized over the life of the lease and credited to the cost of coal paid to serve EFC customers.

20) The management/performance auditor made several recommendations regarding the performance test procedures manual developed by AEPSC.

21) The company's witness questioned the need for further review of the performance test manual and the GADS system by the management/performance auditor.

22) OCC and the staff believed that CSP should refund to EFC ratepayers any refunds for federal black lung excise taxes refunded to CSP by Empire Coal Company through an RA to the EFC rate. The company did not object to returning the appropriate refunds but did object to RA treatment. The Commission agreed with the staff and OCC that the refunds should be made through an RA to the EFC rate.

23) The EFC rate for the period beginning December 1, 1988 should be 1.599888 cents/kWh.

It is, therefore,

ORDERED, That the management/performance auditor in the next management/performance audit report on FSD's attempts to reduce CSP's inventory levels and report on the inventory at all CSP's plants with special emphasis on inventory levels at Picway and Conesville to determine if the inventory levels are being reduced. The auditor should also make recommendations regarding any additional measures the company could take to reduce inventory levels. It is, further,

ORDERED, That the management/performance auditor in the company's upcoming audit review the company's efforts to reduce its contract coal commitments, and the auditor should make suggestions regarding what possible further actions could be taken to reduce CSP's contract commitments. It is, further, ORDERED, That the management/performance auditor report on the effect on CSP, if any at the time of the audit, of the new system dispatch and off-system sales pricing policies of AEPSC, if the policies are approved. It is, further,

ORDERED, That the management/performance auditor in the upcoming audit report on the current status of the impact of the closing of the Poston station. It is, further,

ORDERED, That CSP provide a witness at the time of the next EFC hearing to report to the Commission on the completion and revision of the various projects associated with and/or ordered to be completed in association with the performance test manuals. It is, further,

ORDERED, That the refunds received from Empire be passed back to EFC ratepayers in the appropriate jurisdictional amount through an RA to the EFC rate. It is, further,

ORDERED, That the financial auditor in the upcoming financial audit report on the refunds received from Empire and the appropriate RA amount. It is, further,

ORDERED, That CSP file its EFC tariff rider incorporating the new EFC rate of 1.599888 cents/kWh no later than November 30, 1988. It is, further,

ORDERED, That the EFC rider will become effective on December 1, 1988, and remain in effect until otherwise ordered by the Commission. It is, further,

ORDERED, That a copy of this Opinion and Order be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Thomas V. Chema

Thomas V. Chema, Chairman

Ashley C. Brown

Ashley C. Brown

Gloria L. Gaylord

Gloria L. Gaylord

Alan R. Schriber

Alan R. Schriber

Lenworth Smith, Jr.

Lenworth Smith, Jr.

CLM/vrt

Entered in the Journal

28 OCT 1988

A True Copy

Nancy L. Wolpe

Nancy L. Wolpe
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Columbus Southern Power Company and Related Matters.	)	Case No. 88-102-EL-EFC

ENTRY ON REHEARING

The Commission, coming now to consider the Opinion and Order issued in this proceeding on October 28, 1988, the applications for rehearing filed November 25 and 28, 1988, the replies to the applications filed December 5 and 8, 1988, and being fully advised, hereby issues its Entry on Rehearing.

1) The Opinion and Order in this proceeding was issued October 28, 1988. The Commission found, inter alia, that Columbus Southern Power (CSP) had correctly calculated the system loss adjustment (SLA) according to Commission rules and orders and that the Commission's method of calculation of the SLA was appropriate, that CSP's treatment of the gains from the sale of depreciable assets of the Simco-Peabody joint venture was appropriate, and that refunds received by CSP from Empire Coal Company as a result of federal black lung excise tax over-payments should be returned, in the appropriate jurisdictional amount, to EFC ratepayers through a Reconciliation Adjustment (RA) to the electric fuel component (EFC) rate.

2) On November 25, 1988, CSP filed an application for rehearing. CSP stated that the Commission erred by ordering an RA for the Empire Coal refunds as opposed to an adjustment to the acquisition cost of fuel recorded in Account 151, Fuel Stock. CSP argued that price adjustments in connection with coal previously purchased occur frequently. One example given by CSP was the bonus/penalty provision in coal contracts for the quality of coal supplied. According to CSP, bonus/penalty adjustments

are reflected through increases and decreases in the amounts previously booked for coal from suppliers in Account 151. CSP asserted that it would be extremely burdensome to reflect bonus/penalty adjustments through RA's. Another example given by CSP was a base price plus escalation contract which requires that tentative prices be paid for coal subject to later adjustments. These adjustments would also be credited or debited to Account 151. CSP found it difficult to see how the bonus/penalty and base price plus escalation adjustments differ from the Empire Coal refunds.

For support of its position, CSP cited Cleveland Electric Illuminating Company, (CEI) Case No. 88-08-EL-EFC, August 16, 1988, a case in which CEI had requested an RA to recover the difference between a final settlement amount and the amount originally booked. The Commission directed CEI to readjust the amount booked to inventory as a result of the final settlement because the inventory adjustment method had been used for the original amount. CSP argued that because the coal payments made to Empire Coal were initially booked to Account 151, the refund should be credited to Account 151. CSP also attempted to distinguish the case cited by the Commission when the Commission ordered the RA in this proceeding. CSP argued that the refund for mine health and safety fines refunded to EFC ratepayers through an RA in Ohio Power Company (Ohio Power) in Case No. 87-101-EL-EFC was distinguishable because Ohio Power had been ordered by the Commission not to include the fines in the EFC rate, but Ohio Power had continued to charge them to EFC ratepayers through a clerical error.

In the alternative, CSP argued that the Commission could grant rehearing for the purpose of considering further the proper accounting treatment of the Empire Coal refund. CSP suggested that the rehearing take place in the context of CSP's next EFC proceeding. CSP suggested that the financial auditor be directed to review the manner in which the refund should be accounted for under EFC rules. CSP argued that because CSP has not yet received the refund, the RA would not be included in any event in the EFC rate until the company's next EFC proceeding.

3) On November 28, 1988, the Office of the Consumers' Counsel (OCC) filed its application for rehearing. OCC argued first that the Commission erred by failing to find that CSP's calculation of the SLA for the period June through November 1987 was improper. OCC argued that the Commission's methodology negates any incentive for the company to operate its plants efficiently. According to OCC, under the Commission's methodology, the company will always recover the actual system loss dollar amount. OCC argued that when the company under-recovers for system losses, an incentive factor should be applied to reduce the amount the company may subsequently recover. When the company over-recovers for system losses, OCC argued, an incentive factor in the company's favor should not be applied, but the entire amount of the over-recovery should be returned to EFC ratepayers. OCC argued again that the Commission should order the $13,779.13 RA recommended by OCC for CSP's SLA calculation.

Second, OCC argued that the Commission erred by failing to find that the portion of the gain from the sale of Simco assets which is commensurate with CSP's ownership share of the Conesville Coal Preparation Plant (CCPP) should benefit CSP's EFC ratepayers. OCC argued that the Commission erred in finding that the inclusion of an equipment rental component in the cost of coal did not confer the benefits of ownership of the equipment on those who pay EFC rates which include the cost of coal. OCC argued that EFC ratepayers purchased an interest in the assets through their funding of the accumulated depreciation of the equipment. OCC believed that it was inconceivable that an asset for which ratepayers had paid approximately two-thirds of the cost should suddenly disappear. OCC contended that EFC ratepayers received benefits from the sale/leaseback of the CCPP and that there was no justification for a different treatment for the sale of depreciable assets of Simco and the sale/leaseback transactions. OCC requested that the Commission grant rehearing and order the company to pass back to EFC ratepayers the portion of the $2,045,301 gain from the sale of the assets which is commensurate with the company's ownership share of the CCPP. In the alternative, OCC argued that the Commission should amend its Opinion and Order and order the company to pass back to EFC ratepayers the portion of the gain on the sale which is proportionate to the amount of accumulated depreciation that the EFC ratepayers funded.

4) On December 5, 1988, OCC filed its memorandum contra to CSP's application for rehearing. OCC argued that there was no merit to CSP's assertion that the black lung excise tax refund should be treated as a credit to the cost of coal. OCC argued that a refund was not a cost of coal adjustment as provided for in a coal contract. OCC also asserted that an RA can be more easily traced and verified. OCC rejected CSP's suggestion that, in the alternative, the Commission could order that this issue be considered again in the next EFC hearing. OCC stated that there was no doubt that RA treatment for the Empire Coal refund was appropriate.

5) On December 8, 1988, CSP filed its memorandum contra to OCC's application for rehearing. CSP argued that OCC raised nothing new in its Application for Rehearing. CSP argued that under the Commission's SLA methodology, an electric utility will never over-recover for system losses.

CSP argued that CSP's ratepayers did not purchase an interest in the Simco depreciable assets. CSP also argued that CSP's continuing relationship with the CCPP distinguished that transaction from the sale of Simco's depreciable assets.

6) The Commission finds that CSP's application for rehearing should be denied. The Empire Coal refund does not represent a frequent, everyday adjustment to the cost of coal as

occurs with bonus/penalty provisions or base price plus escalation contracts. The Empire Coal refund is the result of a court decision that black lung excise taxes had been overstated in the cost of coal from 1985 through 1987. There is no indication that the refund will be a recurring process that will complicate the operation of the EFC if RA treatment is used. The RA is the mechanism to account for a refund such as the one CSP will receive from Empire Coal, and RA treatment of the refund does not in any way diverge from "traditional" EFC procedures.

In addition, CSP's reliance on the two prior Commission EFC cases is unwarranted. The Empire Coal refund is far more similar to the refund of Ohio Power mine fines than it is to the CEI inventory situation. In the CEI situation, there had been an original settlement for coal which had not been delivered and the Commission, in a prior case, had ordered that the settlement be accounted for as a reduction of inventory and the value of inventory. If an RA had been appropriate, the RA would have been in the customers' favor. Then, the final settlement resulted in less recovery for CEI than the original settlement. CEI proposed an RA in its favor to account for the difference. The Commission's decision was that because the original settlement had not been an RA in the customers' favor but an adjustment to inventory, it was inappropriate, at that point, to permit CEI to take an RA in its own favor to recoup the difference between the original claim and the settlement. It is clear that this need for consistency was the basis of the Commission's decision in CEI and that that situation is irrelevant here. CSP's attempt to distinguish the Ohio Power mine fine refund from the Empire Coal refund is also without merit. Even though the error resulting in the refund in this proceeding was not CSP's, the originally booked Empire Coal costs were in error; that is why there is going to be a refund. CSP argued that there was no record that the portion of CSP's payments to Empire Coal that corresponded to the excise taxes now expected to be refunded had actually been charged to EFC ratepayers; however, CSP also stated that the amounts paid to Empire Coal which corresponded to the expected excise tax refund were properly treated as "acquisition or delivery costs" of fuel when paid to Empire Coal and were properly included in Account 151. There is no doubt then that EFC ratepayers have been subject to the Empire Coal over-payments.

It is true that an appropriate jurisdictional amount must be ascertained and that the Commission has ordered that only the appropriate jurisdictional amount be refunded. However, the Commission remains convinced that the determination of the appropriate RA amount ought not to be difficult for CSP to determine. CSP has said nothing in its application for rehearing as to why CSP might be unable to determine the appropriate jurisdictional amount for the Empire Coal refund. CSP is correct that any RA regarding the Empire Coal refund will have to be approved in the company's next EFC proceeding. Therefore, the Commission will look at the company's proposed RA in the next proceeding and will determine if it is appropriate. However, the Commission will not grant rehearing in this proceeding on the issue of RA treatment for the Empire Coal refund because the Commission remains convinced that RA treatment is appropriate.

OCC's application for rehearing should also be denied. OCC is incorrect to assert that an electric company will always recover the actual system loss dollar amount. The Commission's statement that "when the system loss amount figured by using the two factors results in recovery of more than actual system losses or credit of less than actual losses, the actual system loss dollar amount is used" does not mean that all system losses are recovered. A recovery of more losses and a credit of less losses are not the only two possibilities. Instead, there remains the possibility that the company will recover less than actual system losses. Under the calculation, the dollar amount for actual incremental system losses for each month of the six-month period is determined. Then, the Fcrf will be applied to reduce the amount the company may recover in each month, and the Gccf will be applied for each month to increase the amount the company may recover. If the total for the six-month period ends in a recovery amount of more than actual losses, the company will recover only the actual losses. However, if the total for the six-month period ends in a recovery amount of less than actual losses, the company will recover the lesser amount.

The SLA calculation of Ohio Power in Case No. 87-101-EL-EFC demonstrates how the method works to reduce a recovery amount below the amount of actual losses. In Case No. 87-101-EL-EFC, Ohio Power figured out the dollar amount for actual incremental system losses at $762,429.09; Ohio Power then applied both the Fcrf and Gccf; the result of the application of the incentive factors was that Ohio Power would recover $714,063.57 using the factors, an amount less than the actual losses. Ohio Power's incremental system loss adjustment for the six-month period was $714,063.57, the lesser amount. Ohio Power did not recover for all actual system losses.

As the Commission explained in the Opinion and Order in this proceeding, whatever adjustment the Commission has done with the method has occurred because the Commission did not find it proper to allow a company to recover <u>more</u> than the dollar amount of actual losses through the EFC. However, the possibility still exists that the company will recover less than actual losses. The Commission's revisions have been solely to the benefit of EFC ratepayers.

OCC has repeated in its application for rehearing its argument that the EFC ratepayers should have benefited from the gain on the sale of Simco's equipment because the ratepayers were purchasing an interest in Simco's equipment by paying for coal, the cost of which contained a component for the rental of the equipment. OCC repeated its argument that the ratepayers assumed the risk of the ownership of the equipment because the Simco-Peabody contract was for the life of the reserves. OCC also repeated its belief that the ratepayers purchased an interest in the equipment because the rental component was based on the depreciation of the equipment. Finally, OCC returned to its argument that because the benefits of the sale/leaseback of the CCPP were allowed to flow to EFC ratepayers, the benefits of the sale of the Simco equipment ought to have benefited ratepayers as well.

The Commission notes that the management/performance auditor testified that in his opinion CSP was not compelled to allow the benefits of the sale/leaseback of CCPP to flow to ratepayers but that CSP did so because CSP interpreted the transactions differently. The Commission concurred in CSP's judgment that benefits from the sale/leaseback of CCPP should be flowed to EFC ratepayers, and the Commission has agreed that the EFC ratepayers had no ownership interest in the Simco equipment and that the sale of the Simco assets did not require that the gain be flowed to EFC ratepayers. If the equipment had been sold at a loss, would OCC now be supporting an RA in the company's favor to compensate the company for the loss? This Commission certainly would not agree to such an RA in the company's favor and therefore will not order an RA in the customers' favor for the gain on the sale of the assets which were owned by Simco. The Commission has no doubt that the ratepayers were not purchasing an ownership interest in the equipment through the rental component cost.

It is, therefore,

ORDERED, That CSP's application for rehearing is denied. It is, further,

ORDERED, That OCC's application for rehearing is denied. It is, further,

ORDERED, That a copy of this Entry on Rehearing be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Thomas V. Chema, Chairman

Ashley C. Brown

Gloria L. Gaylord

Alan R. Schriber

Lenworth Smith, Jr.

CLM/vrt

Entered in the Journal

DEC 20 1988

A True Copy

Gary E. Vigorito
Secretary

R.C. 4903.09 Written opinions filed by commission in all contested cases.

In all contested cases heard by the public utilities commission, a complete record of all of the proceedings shall be made, including a transcript of all testimony and of all exhibits, and the commission shall file, with the records of such cases, findings of fact and written opinions setting forth the reasons prompting the decisions arrived at, based upon said findings of fact.

Effective Date: 10-26-1953

R.C. 4928.143 Application for approval of electric security plan - testing.

(A) For the purpose of complying with section 4928.141 of the Revised Code, an electric distribution utility may file an application for public utilities commission approval of an electric security plan as prescribed under division (B) of this section. The utility may file that application prior to the effective date of any rules the commission may adopt for the purpose of this section, and, as the commission determines necessary, the utility immediately shall conform its filing to those rules upon their taking effect.

(B) Notwithstanding any other provision of Title XLIX of the Revised Code to the contrary except division (D) of this section, divisions (I), (J), and (K) of section 4928.20, division (E) of section 4928.64, and section 4928.69 of the Revised Code:

(1) An electric security plan shall include provisions relating to the supply and pricing of electric generation service. In addition, if the proposed electric security plan has a term longer than three years, it may include provisions in the plan to permit the commission to test the plan pursuant to division (E) of this section and any transitional conditions that should be adopted by the commission if the commission terminates the plan as authorized under that division.

(2) The plan may provide for or include, without limitation, any of the following:

(a) Automatic recovery of any of the following costs of the electric distribution utility, provided the cost is prudently incurred: the cost of fuel used to generate the electricity supplied under the offer; the cost of purchased power supplied under the offer, including the cost of energy and capacity, and including purchased power acquired from an affiliate; the cost of emission allowances; and the cost of federally mandated carbon or energy taxes;

(b) A reasonable allowance for construction work in progress for any of the electric distribution utility's cost of constructing an electric generating facility or for an environmental expenditure for any electric generating facility of the electric distribution utility, provided the cost is incurred or the expenditure occurs on or after January 1, 2009. Any such allowance shall be subject to the construction work in progress allowance limitations of division (A) of section 4909.15 of the Revised Code, except that the commission may authorize such an allowance upon the incurrence of the cost or occurrence of the expenditure. No such allowance for generating facility construction shall be authorized, however, unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Further, no such allowance shall be authorized unless the facility's construction was sourced through a competitive bid process, regarding which process the commission may adopt rules. An allowance approved under division (B)(2)(b) of this section shall be established as a nonbypassable surcharge for the life of the facility.

(c) The establishment of a nonbypassable surcharge for the life of an electric generating facility that is owned or operated by the electric distribution utility, was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and is newly used and useful on or after January 1, 2009, which surcharge shall cover all costs of the utility specified in the application, excluding costs recovered through a surcharge under division (B)(2)(b) of this section. However, no surcharge shall be authorized unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Additionally, if a surcharge is authorized for a facility pursuant to plan approval under division© of this section and as a condition of the continuation of the surcharge, the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate associated with the cost of that facility. Before the commission authorizes any surcharge pursuant to this division, it may consider, as applicable, the effects of any decommissioning, deratings, and retirements.

(d) Terms, conditions, or charges relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, as would have the effect of stabilizing or providing certainty regarding retail electric service;

(e) Automatic increases or decreases in any component of the standard service offer price;

(f) Consistent with sections 4928.23 to 4928.2318 of the Revised Code, both of the following:

(i) Provisions for the electric distribution utility to securitize any phase-in, inclusive of carrying charges, of the utility's standard service offer price, which phase-in is authorized in accordance with section 4928.144 of the Revised Code;

(ii) Provisions for the recovery of the utility's cost of securitization.

(g) Provisions relating to transmission, ancillary, congestion, or any related service required for the standard service offer, including provisions for the recovery of any cost of such service that the electric distribution utility incurs on or after that date pursuant to the standard service offer;

(h) Provisions regarding the utility's distribution service, including, without limitation and notwithstanding any provision of Title XLIX of the Revised Code to the contrary, provisions regarding single issue ratemaking, a revenue decoupling mechanism or any other incentive ratemaking, and provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include a long-term energy delivery infrastructure modernization plan for that utility or any plan providing for the utility's recovery of costs, including lost revenue, shared savings, and avoided costs, and a just and reasonable rate of return on such infrastructure modernization. As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

(i) Provisions under which the electric distribution utility may implement economic development, job retention, and energy efficiency programs, which provisions may allocate program costs across all classes of customers of the utility and those of electric distribution utilities in the same holding company system.

(C)(1) The burden of proof in the proceeding shall be on the electric distribution utility. The commission shall issue an order under this division for an initial application under this section not later than one hundred fifty days after the application's filing date and, for any subsequent application by the utility under this section, not later than two hundred seventy-five days after the application's filing date. Subject to division (D) of this section, the commission by order shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. Additionally, if the commission so approves an application that contains a surcharge under division (B)(2)(b) or© of this section, the commission shall ensure that the benefits derived for any purpose for which the surcharge is established are reserved and made available to those that bear the surcharge. Otherwise, the commission by order shall disapprove the application.

(2)(a) If the commission modifies and approves an application under division©(1) of this section, the electric distribution utility may withdraw the application, thereby terminating it, and may file a new standard service offer under this section or a standard service offer under section 4928.142 of the Revised Code.

(b) If the utility terminates an application pursuant to division©(2)(a) of this section or if the commission disapproves an application under division©(1) of this section, the commission shall issue such order as is necessary to continue the provisions, terms, and conditions of the utility's most recent standard service offer, along with any expected increases or decreases in fuel costs from those contained in that offer, until a subsequent offer is authorized pursuant to this section or section 4928.142 of the Revised Code, respectively.

(D) Regarding the rate plan requirement of division (A) of section 4928.141 of the Revised Code, if an electric distribution utility that has a rate plan that extends beyond December 31, 2008, files an application under this section for the purpose of its compliance with division (A) of section 4928.141 of the Revised Code, that rate plan and its terms and conditions are hereby incorporated into its proposed electric security plan and shall continue in effect until the date scheduled under the rate plan for its expiration, and that portion of the electric security plan shall not be subject to commission approval or disapproval under division© of this section, and the earnings test provided for in division (F) of this section shall not apply until after the expiration of the rate plan. However, that utility may include in its electric security plan under this section, and the commission may approve, modify and approve, or disapprove subject to division© of this section, provisions for the incremental recovery or the deferral of any costs that are not being recovered under the rate plan and that the utility incurs during that continuation period to comply with section 4928.141, division (B) of section 4928.64, or division (A) of section 4928.66 of the Revised Code.

(E) If an electric security plan approved under division© of this section, except one withdrawn by the utility as authorized under that division, has a term, exclusive of phase-ins or deferrals, that exceeds three years from the effective date of the plan, the commission shall test the plan in the fourth year, and if applicable, every fourth year thereafter, to determine whether the plan, including its then-existing pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, continues to be more favorable in the aggregate and during the remaining term of the plan as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. The commission shall also determine the prospective effect of the electric security plan to determine if that effect is substantially likely to provide the electric distribution utility with a return on common equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution utility. If the test results are in the negative or the commission finds that continuation of the electric security plan will result in a return on equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that will face comparable business and financial risk, with such adjustments for capital structure as may be appropriate, during the balance of the plan, the commission may terminate the electric security plan, but not until it shall have provided interested parties with notice and an opportunity to be heard. The commission may impose such conditions on the plan's termination as it considers reasonable and necessary to accommodate the transition from an approved plan to the more advantageous alternative. In the event of an electric security plan's termination pursuant to this division, the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan.

(F) 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. Consideration also shall be given to the capital requirements of future committed investments in this state. The burden of proof for demonstrating that significantly excessive earnings did not occur shall be on the electric distribution utility. If the commission finds that such adjustments, in the aggregate, 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; provided that, upon making such prospective adjustments, the electric distribution utility shall have the right to terminate the plan and immediately file an application pursuant to section 4928.142 of the Revised Code. Upon termination of a plan under this division, rates shall be set on the same basis as specified in division©(2)(b) of this section, and the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan. In making its determination of significantly excessive earnings under this division, the commission shall not consider, directly or indirectly, the revenue, expenses, or earnings of any affiliate or parent company.

Amended by 129th General Assembly File No. 61, HB 364, § 1, eff. 3/22/2012.

Effective Date: 2008 SB221 07-31-2008

This section is set out twice. See also §4928.1431, effective until 3/22/2012.

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

REBUTTAL TESTIMONY
OF
PHILIP J. NELSON
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

December 8, 2008

A. Yes. Based on data provided to the Staff in interrogatory 12-2, the historical cost data for OPCO is below the FAC rate identified by the Companies for every year from 2001 through 2007. For CSP, only one year, 2006, exceeded the FAC rate identified in current rates by the Companies. Below is a summary of historical FAC costs compared to the Companies' calculated current FAC rates and the Staff's recommended current FAC costs. I believe the following confirms that the Companies have not overstated the non-FAC rate component of the current SSO, by understating the FAC rate component.

2001-2007 FAC Costs Compared to
The Companies' and Staff's FAC Component of the Current SSO

YEAR		Cents/kwh Columbus Southern Power		Cents/kwh Ohio Power
2001		2.109		1.726
2002		2.133		1.347
2003		2.212		1.298
2004		2.281		1.381
2005		2.527		1.645
2006		2.707		1.732
2007		2.549		1.642
Company FAC Rate	Exhibit PJN-1 (REV)	2.562	Exhibit PJN-4 (REV)	1.780
Staff Propsal	Hess Workpaper	2.625	Hess Workpaper	1.757

<u>2001-2008 Environmental Carrying Costs</u>

Q. OCC witness Smith takes the position that the Commission should disallow the Carrying Charges on incremental 2001-2008 environmental capital investments made by the Companies. Do you agree with her recommendation?

A. No. Ms. Smith offers very little rationale or support for her position. She cites two bases for the disallowance: 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. She also

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

POST-HEARING BRIEF SUBMITTED ON BEHALF OF THE STAFF OF THE PUBLIC UTILITIES COMMISSION OF OHIO

RECEIVED-DOCKETING DIV
2008 DEC 30 PM 4:30
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1. Projected 2009 Costs

In 2009, the proposed FAC would reflect projected costs. The first step in determining the FAC is to establish a baseline. This is necessary to ensure that the FAC does not recover fuel costs already being recovered in rates. The difference between projected costs and the baseline would determine costs to be recovered through the FAC. The Companies proposed using 1999 rates, brought forward to 2005, and then escalated by 3% annually for CSP, and 7% for OPCO.

Staff believes that actual costs should be used for determining the baseline.[5] Staff witness Cahaan recommended using 2007 data since all of that information would be readily available and would be a reasonable proxy for the current year.[6] Using actual costs is appropriate since the Companies are obviously currently recovering all of their fuel-related costs. Significantly, Companies' witness Nelson testified that Staff's proposal produces a known result very close to the Companies' method that would not significantly change the results of the Companies' overall plan.[7]

2. Purchased Power Costs

The Companies propose to purchase incremental power on a "slice of the system basis" to serve the Companies' loads. The Companies propose to make purchases equal to 5% of each company's load in 2009, 10% in 2010, and 15% of load in 2011.[8]

Staff believes that the Companies should be permitted to purchase power sufficient to meet the additional load responsibilities that they assumed for Ormet and the former Mon Power

5 Direct Testimony of Richard Cahaan, Staff Ex. 10, at 3-4.

6 Tr. Vol. XII at 244.

7 Rebuttal Testimony of Philip J. Nelson, Companies Ex. 7B, at 4.

8 Application at 5.

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

LEE SMITH

ON BEHALF OF
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
10 West Broad Street, Suite 1800
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OCTOBER 31, 2008

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.

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

APPLICATION FOR REHEARING AND MEMORANDUM IN SUPPORT OF INDUSTRIAL ENERGY USERS-OHIO

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April 16, 2009

Attorneys for Industrial Energy Users-Ohio

that the subject matter should **not** be addressed on a case-by-case or utility-specific basis.[16] Heads, AEP-Ohio wins. Tails, consumers lose.

The Order rejected the use of 2008 actual fuel costs as a basis for setting a baseline to separate the FAC and non-FAC components of current rates. The recommendation to use the 2008 actual costs was designed to make sure that the FAC baseline value was not too low and the non-FAC rate set too high.[17] The Commission elected to not use actual 2008 costs, saying that actual costs were not known at the time of the hearing. Instead, it adopted a Staff-sponsored proxy for 2008 costs perhaps believing that a wrong number was close enough.

Regardless of what was known at the time of the hearing, the Commission could have nonetheless found in favor of the methodology that set the baseline based on 2008 actual costs and required AEP-Ohio to observe this requirement for purposes of developing rates.

Since 2008 actual fuel costs are now known, since they are significantly higher than the "proxy" adopted by the Commission, and since the "proxy" is, by definition, not the prudently incurred costs authorized in Section 4928.143(B)(2)(a), Revised Code, the Order results in the non-FAC portion of rates being too high and the risk of increases in the FAC portion as well as the amount of deferrals too great. In fact, in public presentations during 2008 and 2009, AEP indicated that its average price of coal delivered in 2007 was $36.58/ton, while its 2008 cost was reported to be $46.61/ton; a 27.4 percent increase over 2007. These data indicate that the Staff proxy for

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[16] *Id.* at 68.

[17] *Id.* at 19.

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post-Market Development Period Rate Stabilization Plan.	))))	Case No. 04-169-EL-UNC

ENTRY ON REHEARING

The Commission finds:

(1) On February 9, 2004, Columbus Southern Power Company and Ohio Power Company (collectively AEP) filed an application with the Commission for approval of a rate stabilization plan (RSP) to follow its competitive electric market development period (MDP). AEP proposed a plan to substitute for a post-MDP, market-based standard service offer (MBSSO) and to eliminate a competitive bidding process (CBP) from 2006 through 2008.

(2) On January 26, 2005, the Commission issued an opinion and order in this proceeding. The Commission approved in large part AEP's proposed RSP, but made several modifications. The Commission concluded that the generation rates being approved in the RSP constitute an appropriate market-based standard service offer, as required by Section 4928.14(A), Revised Code.

(3) Section 4903.10, Revised Code, allows parties who have entered an appearance in a proceeding to apply for rehearing within 30 days of any Commission determinations made in such proceeding.

(4) On February 24 and 25, 2005, 12 parties filed timely applications for rehearing. They are:

Appalachian People's Action Coalition[1]
Constellation NewEnergy Inc.[2]
Constellation Power Source Inc., now known as Constellation Energy Commodities Group Inc.
Industrial Energy Users-Ohio (IEU-Ohio)
Lima/Allen Council on Community Affairs
MidAmerican Energy Company
Ohio Consumers' Counsel (OCC)
Ohio Energy Group (OEG)[3]

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1 Appalachian People's Action Coalition, Lima/Allen Council on Community Affairs, Ohio Partners for Affordable Energy, and WSOS Community Action are collectively referenced in this decision as LIA, the low-income advocates.

2 Constellation NewEnergy Inc., MidAmerican Energy Company, and Strategic Energy LLC are collectively referenced in this decision as OMG, the Ohio Marketers Group.

Ohio Partners for Affordable Energy
PSEG Energy Resources and Trade LLC
Strategic Energy LLC
WSOS Community Action

They have asserted 32 assignments of error. On March 7, 2005, AEP filed a memorandum contra all applications for rehearing.

(5) To the extent that those assignments of error are similar or overlap, we will address them jointly. We will first address the more generic assignments of error and then turn to those addressing specific portions of our prior decision in this proceeding.

(6) In IEU-Ohio's fourth assignment of error, it argues that the AEP decision differs so dramatically from the Commission's other RSP decisions that it is unreasonable and unlawful. Specifically, IEU-Ohio contends that, unlike the other RSP decisions, this decision did not include some type of market test/analysis for developing market prices, did not reserve the opportunity to terminate the RSP, and did not subject rate increases to periodic Commission review. Additionally, IEU-Ohio alleges that, with this RSP, some of AEP's large customer rates will be higher than the comparable rates in other service areas in Ohio. Consequently, IEU-Ohio alleges that the Commission should grant rehearing and modify the decision to conform with the other RSP proceedings.

IEU-Ohio acknowledges that the other RSP cases involved proposed settlements. While the Commission evaluated those settlements and made modifications thereto, the fact is that many parties in those proceedings presented compromise positions on many issues. There was no proposed settlement in this proceeding and, thus, the Commission reached its conclusions here after considering all parties' litigation positions. The fact that the outcomes reached were not the same between procedurally different cases does not render the decision in this proceeding unreasonable or unlawful. Moreover, the competitive electric markets in those services areas are not the same as the markets in AEP's service areas. Plus, other underlying facts in the cases are not the same and, thus, the Commission's conclusions need not all be the same or conform with the other RSP decisions.

(7) In the fifth assignment of error, IEU-Ohio argues that the Commission failed to provide the reasons for its approval of the RSP, contrary to Section 4903.09, Revised Code. IEU-Ohio alleges that the Commission's conclusions were not based upon sufficient

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3 OEG is composed of AK Steel Corporation, BP Products North America Inc., The Procter and Gamble Co., Ford Motor Company, and International Steel Group Inc.

facts or proof. AEP disagrees with this argument, citing to several examples in which the Commission explained its conclusion.

Our 40-page decision is not void of analysis and rationale. In response to each portion of the proposed RSP, we summarized the evidence and positions of the parties, and set forth our evaluation and conclusion. We satisfied the requirements of Section 4903.09, Revised Code. This assignment of error is denied.

MBSSO and CBP

(8) Several applications for rehearing raised issues with this aspect of our earlier decision. OCC claims that the Commission ignored Section 4928.14, Revised Code. OCC reaches this conclusion because it claims the Commission did not find that the standard service offer was market-based (nor could it) and did not find that the market would provide the same result as a competitive bid. OCC believes that, to comply with this statute, the Commission should have established a MBSSO via a CBP along the lines of its proposal. OCC believes a workable auction would result.

Similarly, OMG, Constellation Energy Commodities Group Inc., and PSEG Energy Resources and Trade LLC (collectively Marketers/Suppliers) argue, in their first assignment of error, that the Commission erred in concluding that a CBP is not required or necessary. The Marketers/Suppliers believe that the Commission should test whether the RSP generation rates will be better than market rates because, otherwise, standard service offer customers are exposed to above-market rates during the RSP period. They also argue that the Commission should not assume that past market penetration is indicative of future bids participation or prices. They contend that the Commission should test the RSP prices before committing to them for the RSP period, particularly since the cost to conduct an auction is very modest.

AEP agrees with the Commission's conclusion to not require at this time that a CBP be held during the RSP period. AEP believes that, with the other CBP experiences, the Commission could reasonably conclude that a CBP was neither practical nor necessary.

We have the discretion to determine, under Section 4928.14(B), Revised Code, that a CBP is not necessary. Nothing in the rehearing applications on this point convinces us that we erred in deciding to not require, *at this time*, a CBP for the RSP period. Past competitive participation in AEP's territory and other auction activity in Ohio do not convince us that a CBP is worthwhile at this time. We have weighed the interests (costs, time, and benefits) on this issue and have decided to not require a CBP.

We also remain convinced that the generation rates we approved will constitute an appropriate MBSSO, as required by Section 4928.14(A), Revised Code. OCC's own witness stated that the Commission can establish a proxy for a MBSSO, given that both the retail electric choice market and the wholesale market have not sufficiently developed. We did not ignore Section 4928.14, Revised Code. We accepted evidence that was presented by our staff as to the nature of the proposed increased generation rates and concluded that they will be, for the RSP period, an appropriate MBSSO. We affirm that ruling.

(9) IEU-Ohio argues, in its second assignment of error, that the Commission failed to carry out its responsibilities because the decision does not properly balance the Commission's RSP objectives and the state's policy objectives in Section 4928.02, Revised Code, and does not include just and reasonable rates.[4] IEU-Ohio argues that evaluation of the proposed RSP required consideration and balancing of the costs to AEP customers. In particular, IEU-Ohio notes that a cost-based analysis would be relevant to adjust the level of transition costs during the RSP period, given the RSP's rate increases, or to analyze AEP's additional generation increases through the pooling arrangement.

We disagree. We did not reach the same conclusions as IEU-Ohio advocated, but we certainly evaluated our RSP objectives and the state's policy objectives in reaching our decision. As we just stated, we considered the proposed increased generation rates and concluded that they will be, for the RSP period, an appropriate MBSSO.

(10) In the Marketers/Suppliers' second assignment of error, they argue that the Commission should have retained the opportunity to call for a CBP during the RSP period. They characterize the Commission's decision not to require a CBP during the RSP period as an unlawful renunciation of that authority. Instead, they assert that the Commission must order a CBP immediately to test the RSP generation rates and, alternatively, retain its right to call for a CBP in 2007 and 2008, if conditions exist such that customers do not have access to competitively bid generation options.

We did not renounce our ability to conduct a CBP, despite the Marketers/Suppliers' statement. We have the authority, per

4 IEU-Ohio does agree that an RSP may substitute for the MBSSO and the CBP required by Section 4928.14, Revised Code. However, IEU-Ohio contends that the RSP must still be just, reasonable, properly balanced and responsive to Section 4928.02, Revised Code. AEP counters by stating that the just and reasonable standard is only for services declared competitive by the Commission, not for generation service, per Section 4928.06(B), Revised Code.

Section 4928.14(B), Revised Code, at any time to determine that a CBP is not required. In the event we change that determination, Section 4928.14(B), Revised Code, requires AEP to establish generation service prices through a CBP. Our RSP decision does not alter that statutory authority. We do not need to grant rehearing or affirmatively state our right to alter that determination and effectively call for a CBP, but we are not doing it at this time.

Generation Rate Increases (Automatic and Additional)

(11) OCC, LIA, OEG, and IEU-Ohio all take issue with the Commission's approval of the proposed automatic generation rate increases. OCC contends in its second assignment of error that the record does not support the Commission's conclusion that the increased generation rates are MBSSOs. OCC considers the higher generation rates to be arbitrary increases that will not necessarily stimulate the competitive market. Instead, OCC contends that the competitive market would be spurred if the Commission ordered a CBP. Similarly, LIA states that the only means of determining generation rates absent a CBP is through cost-of-service proceedings and, for that reason, the RSP process was improper. LIA states that the Commission was required to follow Section 4928.14, Revised Code, and must now reverse its approval of the automatic rate increases.

Moreover, OCC, OEG and IEU-Ohio contend that the Commission should not have ordered generation rate increases (on the basis of concern for AEP's financial stability) because AEP has had very healthy rates of return for some time. They believe that the generation rate increases will produce earnings far in excess of what is needed to ensure financial stability and will result in excessive retail rates. Further, they contend that cost of service must be a factor for consideration because it is a means for evaluating a fair rate of return. Further, OCC alleges that the Commission considered the basis for the automatic generation rate increases in isolation of AEP's total revenues and expenditures, which is improper single-issue ratemaking, ratemaking without consideration of attendant benefits, and ratemaking that should only be accomplished in the context of a rate proceeding (per Section 4909.18, Revised Code).

AEP considers these positions to be rather inconsistent. AEP contends that these parties claim to want competition to take hold, yet still want to cling to cost-of-service regulation. AEP notes that it has given up its statutory right to move to market rates at the end of the MDP in exchange for fixed rate increases. AEP considers this to be a balanced plan.

These same arguments were raised before, considered, and rejected. As we noted in our earlier decision (at page 18), company earnings levels do not come into play *for establishing its generation rates* under the statutory framework for competitive electric generation service and, thus, that earnings evidence did not convince us that we should reject the proposed fixed generation rate increases. We found that those fixed increases would spur the competitive market and, at the same time, protect customers from the anticipated dramatic or volatile generation price changes. We do not accept the rehearing arguments to the contrary.

(12) Next, IEU-Ohio and OEG take issue with the Commission's statement that the generation rate increases can be avoided. Neither group accepts that the generation rate increases will be avoidable because no real competitive market exists now in which customers can switch to other generation service providers. IEU-Ohio contends that the Commission could better serve customers by rejecting the generation rate increases, rather than increasing the generation rates under the theory that customers will, at some point, be able to switch to another provider and avoid them.

There was no error in our statement. These increases are completely avoidable if a competitor can beat AEP's price and customers shop. Contrary to the suggestion of IEU-Ohio and OEG, AEP's customers will switcch suppliers where market rates for generation fall below the RSP rates; if market rates remain above the RSP rates, customers will continue to benefit from the protection of this RSP. IEU-Ohio and OEG do not agree that the market will grow or that some lag will occur, during which customers cannot avoid the generation rate increases. Time will tell, but that criticism does not warrant rehearing.

(13) OEG and OCC also take issue with the Commission's approval of AEP's ability to seek additional generation rate increases up to four percent each year. OEG argues that the Commission should hold now that the additional generation rate increases will only be considered if the return on equity is not excessive and shall not include recovery of items already included in the automatic generation rate increases. OCC raises a different criticism. OCC argues that the additional increases will not result from changes in market conditions and, as a result, will not result in a MBSSO.

We do not agree with OEG or OCC. As we noted in our earlier decision (at page 22), we will evaluate any additional generation rate increase proposals when we receive them. We do not consider it appropriate to establish a rate-of-return threshold before which AEP can seek additional generation rate increases. Nor do we concur with OCC's allegation that additional increases cannot result in market-based generation rates during the RSP period.

Distribution Rates and Charges

(14) As to this area of the decision, OCC contends that it was improper for the Commission to approve two additional exceptions to the distribution rate freeze, beyond those already approved in the electric transition plan proceeding. OCC contends that this aspect of AEP's proposed RSP was a unilateral modification of the other proceeding's stipulation that the Commission should never have accepted. Plus, OCC argues that the two additional exceptions constitute single-issue ratemaking that fail to account for any decreases in expenses.

These are all arguments that OCC raised earlier in this proceeding. We considered them and were not persuaded by them. Nothing in this part of OCC's application for rehearing convinces us to alter our earlier ruling in relation to the distribution rates and charges.

(15) In its third assignment of error, OEG contends that the Commission should not have adopted the RSP's proposed distribution rate freeze. Instead, OEG states that the Commission should conduct a distribution rate case and consider cost allocation and rate design. AEP claims it is unclear how customers would benefit from the distribution rate proceeding OEG seeks.

We considered this very issue previously. We noted our appreciation for the concern raised, particularly since AEP's distribution rates have not been evaluated for some tine. When balancing that concern with our ultimate goals, we chose not to conduct a distribution rate proceeding during the RSP period. Nothing that OEG raises on rehearing convinces us that our prior conclusion on this point should be changed.

Regional Transmission Organization (RTO) Administrative Charges

(16) Marketers/Suppliers raise a concern in their third assignment of error and OEG and OCC echo that concern because the Commission did not accept a prior request for customer credits to those who shop after AEP joined the RTO PJM Interconnection L.L.C. (October 2004) until the end of the MDP. Specifically, the argument was that shopping customers will pay pre-2006 RTO administrative charges when receiving that generation supply and also pay those same charges a second time when AEP assessed its proposed deferral during the RSP. They believe that shopping customers after October 2004 should get a credit for the RTO administrative charges and net additional transmission charges

until the end of the MDP, plus interest if AEP is permitted to accrue interest on the deferred charges.

The Marketers/Suppliers, OEG and OCC seem to have overlooked the fact that we did not approve AEP's proposed deferral of RTO administrative charges (see, page 27 of our prior decision). Thus, AEP will not be recovering deferred RTO administrative charges during the RSP period. Because we rejected AEP's proposed deferral on this point, the potential duplicate charge to customers who shop between October 2004 and December 2005 was eliminated. Therefore, we made no error in not accepting that proposal in our earlier decision. Moreover, we point out that our decision established a POLR charge, which will be calculated in part based upon the RTO administrative charge amounts proposed for deferral. Establishment of the POLR charge, however, was not approval of the deferral or recovery of the proposed RTO administrative charges.

(17) LIA, OCC and OEG raise similar criticisms with the Commission's establishment of provider of last resort (POLR) charges. LIA and OCC contend that the Commission ignored the statutory requirements of Section 4928.14, Revised Code, by allowing AEP to collect costs incurred during the MDP through POLR charges in the RSP period. Both believe that the statutory framework does not include the POLR concept and the statutory framework prohibits imposition of MDP costs after the MDP. OCC considers a POLR service to be compensated by the generation charge itself and no additional or separate charge is permitted under Ohio law, particularly as part of distribution or transmission rates. Moreover, OCC contends that the Commission cannot simply rename the charge to recover the proposed deferral amount. OCC considers this to be single-issue ratemaking, which cannot occur and which was not justified by AEP's financial condition. OEG states that RTO administrative charges are not appropriate POLR charges because they are not costs that AEP must incur in order to welcome back a shopping customer. Instead, OEG states that the RTO administrative charges must be avoidable for shoppers; otherwise, customers will be convinced to stay with the default supplier.

AEP responds and points out that Sections 4928.35(C) and 4928.14, Revised Code, provide that the electric distribution companies shall provide customers all competitive retail electric services (including generation service) and that customers will default to the electric distribution company if the other supplier fails to deliver the generation service. Thus, AEP argues that the statutory framework recognizes the POLR concept and does not preclude the Commission from establishing a POLR charge.

Again, we reiterate that establishment of the POLR charge was not approval of the requested deferral or approval of the recovery of the proposed RTO administrative charges. We have established a new charge that is not intended to recover costs incurred during the MDP. We find nothing in the statutory framework that prohibits this aspect of our earlier decision. We are unconvinced by these rehearing arguments.

Construction Work in Progress and In-Service Plant Expenditures

(18) Similar to the assignments of error related to the RTO administrative charges, OCC and OEG contend that the Commission approved AEP's proposed deferral of construction work in progress and in-service plant expenditures (to be recovered as part of the POLR charge). OCC reiterates the same arguments noted in findings 16 and 17 with regard to the recovery of RTO administrative charges as part of the POLR charge. In addition, OCC and OEG argue that this part of the prior decision violates the electric transition plan decision and the distribution rate freeze. Moreover, they state that there is no basis to recover these generation-related deferrals through any of the specified exceptions to the distribution rate freeze.

Once again, there is a misunderstanding as to the nature of the POLR charge we established. Our establishment of the POLR charge was not approval of the requested deferral or recovery of the proposed construction work in progress and in-service plant expenditures. We have established a new charge that is not intended to recover costs incurred during the MDP.

Consumer Education, Customer Choice Implementation, Transition Plan Filing Costs, and all RSP Filing Costs

(19) OCC claims that the Commission erred in allowing AEP to defer the RSP filing costs for recovery after the RSP period and further defer the other identified costs. OCC points out that the RSP filing costs are costs incurred during the MDP and deferral of those costs after the MDP violates Section 4928.34(A)(6), Revised Code, and Commission precedent.[5] As for further deferral of the other costs, OCC argues that no further authorization was necessary and, thus, it was wrong of the Commission to do otherwise.

AEP responds to this claim, arguing that the Commission rejected OCC's position last month in another matter in relation to a rider

5 OCC cited to *In the Matter of the Application of The Cincinnati Gas & Electric Company to Modify its Nonresidential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish an Alternative Competitive-Bid Service Rate Option Subsequent to the Market Development Period*, Case No. 03-93-EL-ATA, (September 29, 2004).

for billing modification expenses. *Dominion Retail Inc. v. The Dayton Power and Light Company,* Case No. 03-2405-EL-UNC, (February 2, 2005). AEP explains that, despite a deferral of the RSP filing costs, the distribution rates remain the same for the statutorily required period (the MDP) and, therefore, there is no violation of Section 4928.34(A)(6), Revised Code.

OCC made these same arguments and statements previously in this case. We see no error in granting further deferral of the costs previously deferred in the electric transition plan proceeding. This was effectively affirming the previous deferral. Moreover, as part of the RSP package, we remain willing to accept the deferral of all RSP filing costs. We find nothing in this aspect of OCC's application for rehearing that warrants a change in our prior decision.

Transmission Rates and Charges

(20) In its sixth assignment of error, OEG takes issue with part of our decision on the subject of transmission rates and charges. Specifically, OEG believes that the pass-through of RTO transmission charges[6] should be offset by any revenues and savings generated by AEP's recent membership with PJM. OEG states that it is only fair and logical that additional costs be "netted out" against the benefits because customers should not pay the costs of PJM membership while AEP enjoys the resultant revenues and savings.

We see no error in accepting this part of the proposed RSP. We will evaluate each proposed "pass through". With the process we established, interested parties will have the opportunity to participate. Thus, at the time of a proposed pass through, parties who have concerns can raise them and we will be able to consider them. For purposes of considering an RSP, we do not need to require an offsetting of transmission charges and benefits.

Unused Columbus Southern Shopping Incentive and Low-Income Funding

(21) In relation to this aspect of the RSP decision, OCC and LIA allege some errors. OCC asserts that the Commission should not have changed the manner in which the Columbus Southern unused shopping incentive would benefit customers. OCC points out that the anticipated use of those funds was negotiated and approved in the electric transition plan proceeding. Next, OCC argues that,

6 These transmission charges are separate from the RTO administrative charges discussed earlier in this decision.

because the unused Columbus Southern shopping incentive amount could be more than $14 million, the Commission should have allotted all of the unused Columbus Southern shopping incentive monies (not a flat dollar figure) for low-income customers and economic development. LIA too believes the Commission erred in not specifying the amount required, but LIA states the Commission should require $1.5 million annually, as LIA previously requested. Similarly, OCC contends that AEP should directly fund the targeted energy efficiency program (not through the use of unused shopping incentive dollars) in the amount of $1.5 million per year. OCC further argues that the Commission should have adopted LIA's percentage of income payment plan arrearage forgiveness proposal. Finally, OCC contends that the Commission should require a report of the actual unused shopping incentive amount as of December 31, 2005, a full accounting and annual reports of fund expenditures for the programs.

AEP believes the Commission's decision on this point was adequately clear and that a definitive $14 million amount was appropriate since it is not known what the unused amount of the Columbus Southern shopping incentive will be.

We are satisfied with our determination to redirect the unused Columbus Southern shopping incentive monies and to declare that $14 million must be used for low-income AEP customers and economic development. OCC raised many of these same arguments earlier (in relation to AEP's proposed redirection of the unused Columbus Southern shopping incentive monies) and we were unconvinced. Moreover, we believe $14 million is an appropriate amount. Nor do we believe that rehearing should be granted now in order to mandate a specific dollar amount or another source for those dollars. Plus, a definitive dollar amount will allow the Service Monitoring and Enforcement Department staff and AEP to plan quicker for the use of the monies and possibly provide benefits to customers sooner.

We were not convinced to adopt LIA's $1.5 million annual funding recommendation, the forgiveness proposal or the resurrection of the targeted energy efficiency program as part of our decision in this case. We chose to allow AEP and our staff (in consultation with the Ohio Department of Development) to work out the details for both low-income benefits and economic development endeavors. We are comfortable allowing the staff and AEP the opportunity to discuss the amount and use of low-income funding, as well as use of the remaining funds for economic development. Nothing stated on rehearing justifies a change in those conclusions. Finally, we do not need today to establish reporting and/or accounting requirements. In the course of the discussions between our Service Monitoring and Enforcement Department staff and AEP, those details can be worked out.

Corporate Separation

(22) OCC next argues that the approved RSP does not comply with Sections 4928.17 and 4928.02, Revised Code, because the RSP will extend unlawful advantages to AEP's competitive generation business. OCC considers such unlawful advantages to be: requiring the distribution ratepayers to pay charges associated with competitive generation service and requiring all customers to pay AEP generation- and transmission-related costs in addition to those of their supplier.

AEP points out that OCC's arguments on rehearing are the same as those raised previously and rejected by the Commission. Moreover, AEP argues that its statutory obligation to sell generation service as part of its distribution function (as POLR) cannot be considered to be engaging in the competitive retail generation business for purposes of Section 4928.17, Revised Code. Thus, AEP contends there is no undue competitive advantage created.

We are unconvinced by OCC's argument on rehearing about our conclusion to allow functional separation through the RSP period. We do not believe the RSP will extend unlawful advantages to AEP's competitive generation business. Furthermore, AEP has not been able to structurally separate because it does not have the necessary federal authority to do so. OCC has overlooked the fact that other approvals are needed and have not been forthcoming. Allowing AEP to functionally separate over the short three-year term of the RSP is acceptable and consistent with Section 4928.17, Revised Code.

Minimum Stay Provisions

(23) Marketers/Suppliers and OCC argue that the Commission erred in accepting the RSP's proposed minimum stay requirements. OCC contends that there is no support in the record for the Commission's conclusion. Marketers/Suppliers believe a mandatory 12-month stay is a harsh barrier to shopping, particularly for large commercial and industrial customers (GS-4 customers). Both Marketers/Suppliers and OCC ask that the Commission retain, for the RSP period, the current practice of allowing shopping customers to return to the standard service offer three times before the minimum stay is triggered. In the alternative, Marketers/Suppliers ask that the Commission require development of explicit details, costs and conditions to the

alternative mentioned in AEP's open access distribution service tariffs. They assert that such alternative should contain an exit fee and be implemented by January 1, 2006.

AEP supports the Commission's minimum stay ruling and agrees that, for the three-year period of the RSP, implementation of AEP's minimum stay provisions will allow the Commission to evaluate the effects, rather than continue the theoretical debate that has gone on for several years.

We weighed this issue before. The minimum stay issue has been a lingering debate at the Commission (beyond this RSP proceeding), with negatives and positives presented on both sides of the issue. We chose to accept this part of the proposed RSP and essentially test the debate that has been ongoing. It was not error for us to reach this conclusion for the three-year RSP period.

OEG's Proposed RSP

(24) OEG asserts in its final assignment of error that the Commission should have adopted OEG's proposed RSP. OEG characterizes its plan as moderate and sensible because it recognizes the electric transition plan bargains and provides AEP the opportunity to recover verified costs.

This issue was expressly raised earlier in this proceeding and we did not accept it. Nothing that OEG states in its application for rehearing convinces us that we should dramatically modify our earlier decision and accept OEG's proposed RSP.

OCC's Motion to Dismiss

(25) OCC again claims that the RSP application should have been dismissed for the reasons set forth in its motion to dismiss.

We fully evaluated the arguments contained in OCC's motion to dismiss in our earlier decision. In that pleading, OCC raised many legal arguments with respect to many provisions of the proposed RSP. Today, we are not changing our conclusions on the various components of the RSP and see no reason to reach different conclusions with regard to OCC's motion to dismiss. We affirm our prior denial of the OCC's motion to dismiss.

Integrated Gasification Combined-Cycle (IGCC) Facility

(26) IEU-Ohio and LIA have raised assignments of error in relation to the last portion of our decision. IEU-Ohio argues last that the Commission may have been improperly influenced by matters

outside the record in this proceeding because of the Commission's mention (in a few sentences at the end of the decision) of AEP's plan to construct an IGCC facility. IEU-Ohio urges the Commission to not make funding commitments for such a facility. Similarly, LIA contends that the decision was unreasonable and unlawful because it implied that AEP could recover construction costs for this facility.

AEP characterizes the statements made by IEU-Ohio and LIA as chastising the Commission for "looking forward for solutions to problems that face Ohio's electric industry, including the customers of Ohio's electric utilities", while at the same time complaining that the Commission is not doing enough to protect customers from market deficiencies. AEP agrees that it is important to consider the manner in which electric generation service should be provided to customers after the RSP period and the Commission appropriately touched upon the subject.

IEU-Ohio's and LIA's criticisms in this regard are premature and speculative. AEP recently filed an application (Case No. 05-376-EL-UNC) to advance its proposal for construction of an IGCC plant in Ohio. The issues raised in AEP's IGCC proposal are unresolved and will be decided in due course as part of Case No. 05-376-EL-UNC. In the context of approving this RSP, however, the Commission does note that AEP's IGCC application makes a commitment that any IGCC-related revenue collected during the RSP period will offset the amounts of additional distribution rate increases (i.e., additional increases beyond fixed increases) that could otherwise be requested under the RSP.

(27) IEU-Ohio's application for rehearing also contained a 14-page introduction, which included many statements contrary to the Commission's decision in this proceeding. These arguments were not identified as assignments of error or specific grounds for rehearing, as required by Section 4903.10(B), Revised Code. However, to the extent IEU-Ohio is attempting to raise them as assignments of error, we expressly deny them. IEU-Ohio claims that the Commission did not base its conclusion in several areas upon credible evidence, the Commission improperly rejected or weighed certain evidence, and the Commission did not consider certain evidence presented. We do not agree with these statements and IEU-Ohio is simply arguing that we should have considered the evidence and reached the conclusions that it advocated. Nothing contained in the introductory portion of IEU-Ohio's application for rehearing convinces us that we made any errors in our decision or that rehearing is warranted.

(28) Lastly, we note that AEP will need to file revised tariff provisions in order to implement the RSP that we have approved. We encourage AEP to file proposed tariff revisions well in advance of the start of the RSP period so that we may have ample time to review those proposed revisions and approve appropriate revisions.

It is, therefore,

ORDERED, That the applications for rehearing filed by IEU-Ohio, LIA, OCC, OEG, and Marketers/Suppliers are denied. It is, further,

ORDERED, That a copy of this entry on rehearing be served upon all parties to this proceeding and any interested persons of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason

Clarence D. Rogers, Jr.

GLP;geb

Entered in the Journal

MAR 2 3 2005

Reneé J. Jenkins
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of an 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

ENTRY ON REHEARING

The Commission finds:

(1) On July 31, 2008, The Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio or the Companies) filed an application for a standard service offer (SSO) pursuant to Section 4928.141, Revised Code. The application is for an electric security plan (ESP) in accordance with Section 4928.143, Revised Code.

(2) On March 18, 2009, the Commission issued its opinion and order (Order) in these matters approving, with modifications, AEP-Ohio's proposed ESP. On March 30, 2009, the Commission amended, nunc pro tunc, its Order.

(3) Section 4903.10, Revised Code, states that any party to a Commission proceeding may apply for rehearing with respect to any matters determined by the Commission, within 30 days of the entry of the order upon the Commission's journal.

(4) On April 16, 2009, Ohio Energy Group (OEG) and Industrial Energy Users-Ohio (IEU) each filed applications for rehearing. Applications for rehearing were also filed by the Office of the Ohio Consumers' Counsel (OCC); Ohio Association of School Business Officials, Ohio School Boards Association, and Buckeye Association of School Administrators (collectively, Schools); Ohio Hospital Association (OHA); Ohio

Manufacturers' Association (OMA); Kroger Company (Kroger); and AEP-Ohio on April 17, 2009. Memoranda contra the various applications for rehearing were filed by Kroger, OCC, AEP-Ohio, IEU, OEG, Integrys Energy Service, Inc. (Integrys), and Ohio Partners for Affordable Energy (OPAE). In their applications for rehearing, the various intervenors raised a number of assignments of error, alleging that the Order is unreasonable and unlawful.

(5) By entry dated May 13, 2009, the Commission granted rehearing for further consideration of the matters specified in the applications for rehearing. In this entry, the Commission will address the assignments of error by subject matter as set forth below.

(6) The Commission has reviewed and considered all of the arguments on rehearing. Any arguments on rehearing not specifically discussed herein have been thoroughly and adequately considered by the Commission and are being denied.

(7) IEU filed a motion for immediate relief from electric rate increases on April 20, 2009, and AEP-Ohio filed a memorandum contra on April 23, 2009. IEU filed a reply on April 24, 2009. Further, on June 5, 2009, OCC, OMA, Kroger, and OEG filed a motion for a refund to AEP-Ohio's customers and a motion for AEP-Ohio to cease and desist future collections related to its arrangement with Ormet Primary Aluminum Corporation (Ormet) from its customers. AEP-Ohio and Ormet filed memoranda contra the motions on June 12, 2009, and June 23, 2009, respectively, and the movants replied on June 17, 2009, and June 30, 2009. OCC also indicates in its application for rehearing that it is seeking rehearing on the two March 30, 2009, orders issued by the Commission, which includes the Entry Nunc Pro Tunc that amended the Order in this proceeding, as well as the order issued denying a motion for a stay. The Commission will address the substance of all of the motions, and all responsive pleadings, within our discussion of and decision on the merits of the applications for rehearing as set forth below. Accordingly, with the consideration herein of the issues raised in the motions, the motions are granted or denied as discussed herein.

I. GENERATION

A. Fuel Adjustment Clause (FAC)

(8) AEP-Ohio asserts that limiting the FAC to only three years (the term of the ESP) is unreasonably restrictive (Cos. App. at 37-38). AEP-Ohio argues that it is unreasonable to allow the FAC to expire given that a FAC may be required in a future SSO established in accordance with Section 4928.141, Revised Code.

(9) IEU and OCC disagree with AEP-Ohio and submit that there is no valid reason for the FAC mechanism to extend beyond the life of the ESP (IEU Memo Contra at 13; OCC Memo Contra at 6-7).

(10) The Commission finds that AEP-Ohio's argument lacks merit, and therefore AEP-Ohio's rehearing request on this ground should be denied. The Commission limited the authorized FAC mechanism, established as part of the proposed ESP, to the term of the ESP approved by the Commission. If a FAC mechanism is proposed in a subsequent SSO application filed pursuant to Section 4928.141, Revised Code, the Commission will determine the appropriateness of the SSO proposal, including all of its terms, at that time. It is unnecessary, at this time, to extend this provision of the ESP beyond the term of the approved ESP.

1. FAC Costs

(a) Off-System Sales (OSS)

(11) OCC contends that the Commission erred by not crediting customers for revenues from OSS and for not following its own precedent (OCC App. at 16). OCC relies on past Commission decisions concerning electric fuel clause (EFC) proceedings.

(12) IEU also disagrees with the exclusion of an offset to the FAC costs for revenues associated with OSS, claiming that the Commission did not explain the basis for its decision (IEU App. at 11).

(13) AEP-Ohio notes that OCC's arguments were already rejected by the Commission in its Order, and that the Commission's decision is not inconsistent with any of its precedents regarding the sharing of profits from OSS between a utility and its customers (Cos. Memo Contra at 40). AEP-Ohio distinguishes previous EFC proceedings from proceedings filed pursuant to SB 221.

(14) The Commission first explains that this is not an EFC proceeding. While some aspects of the automatic recovery mechanism contained in Section 4928.143(B)(2)(a), Revised Code, may be analogous to the EFC mechanism, the statutory provisions regarding the EFC were repealed many years ago. Thus, OCC's cited precedent is irrelevant to our ruling in this case with respect to the OSS. Secondly, contrary to IEU's assertion, the Commission has already fully considered and addressed, in the Order at pages 16-17, all of the arguments raised on rehearing by OCC, as well as those raised by other intervenors in the proceeding. The Commission explained that Section 4928.143(B)(2)(a), Revised Code, specifically provides for the automatic recovery, without limitation, of certain prudently incurred costs: the cost of fuel used to generate the electricity supplied under the SSO; the cost of purchased power supplied under the SSO, including the cost of energy and capacity and power acquired from an affiliate; the cost of emission allowances; and the cost of federally mandated carbon or energy taxes. Given that OCC and IEU have failed to raise any new arguments regarding this issue, rehearing on these grounds should be denied. However, we emphasize that FAC costs are to continue to be allocated on a least cost basis to POLR customers and then to other types of sale customers. Allocating the lowest fuel cost to POLR service customers is consistent with the electric utilities' obligation to POLR customers and will minimize the burden on most ratepayers.

2. <u>FAC Baseline</u>

(15) OCC's first assignment of error is that the Commission's adoption of the FAC baseline was not based on actual data in the record, and that the Company bears the burden of creating such a record in order to collect fuel costs pursuant to Section 4928.143(B)(2)(a), Revised Code (OCC App. at 12). OCC

recognizes that an ESP may recover the costs of fuel, but argues that these costs must be "prudently incurred" (Id.). OCC adds that "[t]he clear language [of SB 221] must be read to include recovery of only actual costs as anything more would not be prudent to recover from customers" (Id.). Nonetheless, OCC then admits that the actual 2008 fuel costs were not known at the time of the hearing,[1] but requests that the Commission order the Companies to produce actual fuel costs for 2008, after the record of the case has been closed, for purposes of establishing the baseline. Thus, OCC would have the Commission do exactly what its first assignment of error is criticizing the Commission's order for doing, which is use data that is not in the record.

(16) Similarly, IEU argues that, based on information and reports that have been subsequently developed and filed in other jurisdictions, Staff's methodology was incorrect. Therefore, IEU requests that the Commission adopt a methodology that sets the baseline based on 2008 actual costs (IEU App. at 12-13).

(17) AEP-Ohio responds that the Commission's decision must be based on the record before it and it is not feasible to do what OCC and IEU request (Cos. Memo Contra at 39). Nonetheless, AEP-Ohio states that, even if the 2008 data was available in the record, it would be inappropriate to use absent substantial adjustments due to the volatility of fuel costs in 2008 and the extraordinary procurement activities that occurred (Id., citing Cos. Ex. 7B at 2-3; Tr. XIV at 74-75).

AEP-Ohio further argues that the Commission's modification of the Companies' baseline contained in its proposed ESP was unreasonable. AEP-Ohio argues that its methodology was the appropriate methodology because its methodology identifies the portion of the 2008 SSO rate that correlates to the new FAC rate, and is not a proxy for 2008 fuel costs (Cos. App. at 38-39). OCC disagrees and urges the Commission to reject AEP-Ohio's methodology, as well as Staff's, and adopt the actual 2008 fuel costs (OCC Memo Contra at 8).

1 We will assume that OCC's reference to 2009 actual data was a typographical error and the reference should be to 2008 (see OCC App. at 13).

(18) As explained in the Order, the actual 2008 fuel costs were not known at the time of the hearing (Order at 19, citing OCC Ex. 10 at 14). Therefore, based on the evidence presented in the record, the Commission determined that a proxy should be used to calculate the appropriate baseline. After making this determination, the Commission reviewed all evidence in the record and all parties' arguments, and adopted Staff's methodology and resulting value as the appropriate FAC baseline. AEP-Ohio, OCC, and IEU have raised no new arguments regarding this issue. Accordingly, rehearing on this ground is denied.

3. FAC Deferrals

(19) OCC argues that the Commission erred by not requiring deferrals and carrying costs to be calculated on a net-of-tax basis, and the Commission's reliance on Section 4928.144, Revised Code, was misplaced because the FAC deferral approved by the Commission is not a phase-in of rates authorized by SB 221 (OCC App. at 14). The Schools, however, conclude that the Commission exercised its authority pursuant to Section 4928.144, Revised Code, when it found that AEP-Ohio should phase-in any authorized increases, and that those amounts over the allowable increase percentage levels would be deferred pursuant to Section 4928.144, Revised Code, with carrying costs (Schools App. at 4). Notwithstanding the Commission's statutory authority to phase-in increases through deferrals, the Schools assert that School Pool participants who buy generation service from competitive retail electric service (CRES) providers should receive a credit on their bills during the ESP equal to the fuel that is being deferred (even though FAC deferrals will not be recovered via an unavoidable surcharge until 2012, if necessary) (Id. at 5). The Schools rationalize that any other outcome would violate the policy of the state, specifically Section 4928.02(H), Revised Code (Id. at 6).

(20) OCC also argues that the Commission failed to follow its own precedent and that deferrals are incompatible with Section 4928.143(B)(2)(d), Revised Code, inasmuch as the deferrals destabilize customer prices, introduce uncertainty, and are unfair and unreasonable (OCC App. at 14, 42-44). OCC recognizes that SB 221 allows deferrals under an ESP, but states

that those deferrals are limited to those that stabilize or provide certainty (Id. at 42). OCC explains that deferrals will cause future rate increases and add carrying costs to the total amount that customers will pay. OCC adds that the record is void of any projection that electric rates will decrease following the ESP period, and, therefore, concludes that the deferrals will have a de-stabilizing effect on customers' electric bills beginning in 2012 (Id. at 42-43). The Commission notes that based on its analysis of the Companies' ESP, as approved in the Order and modified in this entry on rehearing, our projections indicate that deferred fuel cost will likely be fully amortized by the end of this ESP for CSP and within two to three years after the end of this ESP for OP.

(21) OCC further contends that the use of a weighted average cost of capital (WACC) to calculate the carrying costs associated with the FAC deferrals is unreasonable and will result in excessive payments by customers. OCC asserts that the carrying charges should instead be based on the actual financing required to carry the deferrals during the short-term period (Id. at 45).

(22) IEU submits that the Commission failed to require AEP-Ohio to limit the total bill increases to the percentage amounts specified in the Order (IEU App. at 40).

(23) AEP-Ohio supports the Commission's decision authorizing FAC deferrals, with carrying costs, and contends that the authorized phase-in of rate increases, and associated FAC deferrals, comply with Section 4928.144, Revised Code, and are compatible with Section 4928.143(B)(2)(d), Revised Code (Cos. Memo Contra at 42). AEP-Ohio also supports the use of WACC, rather than a short-term debt interest rate, given that the period of cost deferrals and their subsequent recovery will take place over the next ten years (Id. at 43).

(24) AEP-Ohio, however, argues that the Commission's adjustment to its phase-in proposal and 15 percent cap on the ESP rate increases were unreasonable, disrupting the balance between up-front revenue recovery and subsequent recovery of deferrals (Cos. App. at 12). To this end, AEP-Ohio contends that the Commission's authority under Section 4928.144, Revised Code, "must be exercised in the total context of Chapter 4928, Ohio

Rev. Code, particularly in the context of the standard for approval of an ESP without modification" (Id., n.6). AEP-Ohio adds that the Commission's modification of its 15 percent cap was "too severe," and requests that the Commission rebalance the amount of the authorized increases and the size of the deferrals to reflect, at a minimum, annual 10 percent increases during the ESP term (Id. at 12-13). While agreeing with AEP-Ohio that the Order is unjust and unreasonable, IEU disagrees that the balance favors customers. IEU argues that the Commission's imposition of limits on the total percentage increases on customers' bills has not been followed (IEU Memo Contra at 8-9).

(25) Furthermore, AEP-Ohio requests that, if the Commission does not modify the total percentage increases allowed, the Commission should clarify the intended scope of the limitations that it has imposed, and specify that the 15 percent cap does not include revenue increases associated with a distribution base rate case or the revenues associated with the Energy Efficiency and Peak Demand Reduction Cost Recovery (EE/PDR) Rider (Cos. App. at 13). OEG supports AEP-Ohio's clarification, while IEU urges the Commission to reject AEP-Ohio's requested clarification, and find that the limitations on the percentage increases imposed by the Commission in the Order apply on a total bill basis (OEG Memo Contra at 3; IEU Memo Contra at 9).

(26) Section 4928.144, Revised Code, authorizes the Commission to order any just and reasonable phase-in of any electric utility rate or price established pursuant to an ESP, with carrying charges, and requires that any deferrals associated with the authorized phase-in be collected through an unavoidable surcharge. The Commission continues to believe that a phase-in of the ESP increases, as authorized by Section 4928.144, Revised Code, is necessary to ensure rate or price stability and to mitigate the impact on customers. We further believe that our established limits on the total percentage increases on customers' bills in each year were just and reasonable and remain appropriate. Nonetheless, upon further review of the workpapers filed with the tariffs and the comments received from parties concerning the practical application of the total percentage increases on customers' bills, it has come to the Commission's attention that the Companies included in the total allowable revenue increase

an amount that equals the revenue shortfall associated with their joint service territory customer, Ormet. In their calculation, the Companies assumed that the joint service territory customer would continue paying the amount that it was paying on December 31, 2008 (established pursuant to a prior settlement), which was above the approved tariff rate for that rate schedule. Instead, the Companies should have calculated the allowable total revenue increase based on that customer paying the December 31, 2008, approved tariff rate for its rate schedule. Additionally, the Companies' calculation should have been levelized and not reflected any variations in customers' bills for tariff/voltage adjustments. Accordingly, we direct the Companies to recalculate the total allowable revenue increase approved by our Order issued on March 18, 2009, as clarified by the Entry Nunc Pro Tunc issued on March 30, 2009, and as modified herein, and file revised tariffs consistent with such calculation.

(27) Additionally, the Commission clarifies that the Transmission Cost Recovery (TCR) rider should not impact the allowable total percentage increase. As approved in the Order, the TCR rider will continue to be a pass-through of actual transmission costs incurred by the Companies that is reconciled quarterly. Similarly, any future adjustments to the EE/PDR Rider are excluded from the allowable total percentage increases. As explained in the Order, the EE/PDR Rider was designed to recover costs associated with the Companies' implementation of energy efficiency programs that will achieve energy savings and peak demand programs designed to reduce the Companies' peak demand pursuant to Section 4928.66, Revised Code (Order at 41). The costs included in the EE/PDR Rider will be trued-up annually to reflect actual costs.

(28) We further clarify that the phase-in/deferral structure does not include revenue increases associated with any distribution base rate case that may occur in the future. Any distribution rates established pursuant to a separate proceeding, outside of an SSO proceeding, will be considered separately. Section 4928.144, Revised Code, authorizes phase-in of rates or prices established pursuant to Sections 4928.141 to 4928.143, Revised Code, not distribution rates established pursuant to Section 4909.18, Revised Code.

(29) With respect to OCC's and the Schools' issues regarding the FAC deferrals and carrying charges, we find that those issues were thoroughly addressed in our Order at pages 20-24, and that the parties have raised no new arguments regarding those issues. Accordingly, the Commission finds that rehearing on those assignments of error are denied.

(30) Similarly, the Commission finds that AEP-Ohio's arguments regarding its proposed 15 percent cap were fully addressed in our Order, and AEP-Ohio has raised no new arguments to support its position. Additionally, AEP-Ohio's alternative proposal of an annual 10 percent cap fails on similar grounds. The Companies have offered no justification or support for its adjusted proposal. As such, the Commission finds that rehearing on this ground is denied.

(31) With respect to the other assignments of error raised, the Commission emphasizes that it was the intent of our Order to phase-in the authorized increases and to limit the total percentage increases on customers' bills to an increase of 7 percent for CSP and 8 percent for OP for 2009, an increase of 6 percent for CSP and 7 percent for OP for 2010, and an increase of 6 percent for CSP and 8 percent for OP for 2011, as explained herein. To the extent that the Commission's intent was not memorialized in the Companies' tariffs, or the application of those tariffs, we grant rehearing to correct the errors or clarify our Order as delineated above.

B. Incremental Carrying Cost for 2001-2008 Environmental Investment and the Carrying Cost Rate

(32) In the Order, the Commission concluded that AEP-Ohio should be allowed to recover the incremental capital carrying costs that will be incurred after January 1, 2009, on past environmental investments (2001-2008) that are not presently reflected in the Companies' existing rates, as contemplated in AEP-Ohio's RSP Case. Further, the Commission found that the recovery of continuing carrying costs on environmental investments, based

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FILE

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

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

PREPARED TESTIMONY

Of

RAYMOND W. STROM
FACILITIES, SITING AND ENVIRONMENTAL ANALYSIS DIVISION
OF THE ENERGY AND ENVIRONMENT DEPARTMENT

STAFF EXHIBIT___

November 7, 2008

auditing the companies fuel procurement and fuel related activities under the FAC.

9. Q. Do you agree that these costs are appropriate to include in the FAC?

A. Yes, I do. Although many of the costs included in the FAC rate are not traditional EFC costs, their inclusion together in a single rate does make logical sense. During the implementation of the EFC, there were times when the issue of adverse incentives arose. For example, a company could have to make a decision to purchase lower cost high sulfur coal, and incur higher scrubbing costs, versus higher cost low sulfur coal and lower scrubbing costs. If coal costs are directly recoverable, while the cost of lime and scrubber sludge disposal are not, this can provide an incentive to a company to make a decision that does not minimize overall cost. Including all of these components in the same rate mechanism removes such incentives.

It is important to note that inclusion of costs in the FAC rate should occur only if those same costs are not included in other rate components of the ESP. The companies recognize this principle through their recommendation for constructing a baseline FAC component, as presented in Mr. Nelson's testimony. Staff witness Cahaan presents the Staff's recommendation on development of the baseline FAC and avoidance of the potential for double counting costs.

10. Q. How do you anticipate the FAC process will be implemented?

A. I expect that the first quarterly FAC rider will become effective with the first billing cycle of January, 2009, based on the FAC rate process determined through this ESP proceeding. Subsequent FAC riders should become effective with the first billing cycle of April, July, and October. This quarterly cycle would continue throughout the ESP period. If the Commission adopts Staff's recommendation regarding deferrals, as presented by Staff witness Cahaan, each quarterly filing should be updated with the most current fuel cost information in order to minimize potential over- or under-recovery of the quarterly fuel costs. Proposed FAC rider rates, along with all necessary information to show the development of the rates, should be provided to Staff for review by the first day of the month prior to their effective dates. Reconciliation amounts should be included in the first quarterly filing for which actual costs and actual revenues are available, which I anticipate to be the third quarter of 2009, and in each quarterly filing thereafter.

A review of the appropriateness of the accounting of FAC costs, and the prudence of decisions made relative to the components of the FAC, should be conducted annually. I would expect the audit activities associated with these reviews to begin shortly before the end of each calendar year, and be concluded with an audit report to be filed by early March. The auditor selection process, and the procedural schedule for conducting the audit and hearing related activities, should be established by the Commission.

11. Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE

The undersigned counsel certifies that Ohio Power Company's Appendix to Merit Brief was served by First-Class U.S. Mail upon the following counsel of record this 13th day of November, 2012.

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