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REPORT OF THE MANAGEMENT/PERFORMANCE AND FINANCIAL AUDITS OF THE FAC OF THE COLUMBUS SOUTHERN POWER COMPANY AND THE OHIO POWER COMPANY

Case No. 10-268-EL-FAC
Case No. 10-269-EL-FAC
Case No. 10-870-EL-FAC
Case No. 10-871-EL-FAC
Case No. 10-1286-EL-FAC
Case No. 10-~~1287~~ 1288-EL-FAC

May 26, 2011

Prepared for:
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1 INTRODUCTION

Under Senate Bill 221, the Columbus Southern Power Company ("CSP") and the Ohio Power Company ("OPCO") (jointly "AEP Ohio" or the "Companies") filed applications for approval of an electric security plan ("ESP") which includes a fuel adjustment clause ("FAC") mechanism under which the Companies can 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. Pursuant to Senate Bill 221, CSP and OPCO filed applications with the Public Utilities Commission of Ohio ("PUCO") for approval of ESP's on July 31, 2008 (Case Nos. 08-917/918-EL-SSO). The PUCO approved the establishment of fuel adjustment clauses ("FAC") for CSP and OPCO in its Opinion and Order dated March 18, 2009 and affirmed in its Entry on Rehearing dated July 23, 2009.

The PUCO established an annual audit to approve appropriateness of the accounting of the FAC costs and the prudency of decisions made. Energy Ventures Analysis, Inc. ("EVA") and its subcontractor, Larkin & Associates PLLC ("Larkin"), were selected by the PUCO to perform the management/performance and financial[1] audits, respectively for up to three years. The report covering the initial audit period January through December 2009 period was filed May 14, 2010. This second audit covers the period January through December 2010; a third audit will cover the period January through December 2011.

Background On The FAC

The FAC is the Fuel Adjustment Clause, and is the mechanism that is being used to recover prudently incurred fuel, purchased power, and other miscellaneous expenses. The FAC includes the following:

- Account 501 (Fuel) – the cost of fuel and transportation for generating electricity.
- Account 502 (Steam Expenses) – the cost of material and expenses used in the production of steam including the cost of chemicals used in environmental controls.
- Account 509 (Allowances) – the cost of emission allowances related to emissions of sulfur dioxide (SO_2) and nitrous oxide (NOx)
- Account 518 (Nuclear Fuel Expense) – the amortized cost of the nuclear fuel assemblies which is not relevant at this time for CSP or OP.

[1] This part of the review has in prior reports been referred to as the "Financial Audit", a term which could be misleading because the work does not involve an audit of financial statements, but rather is an attestation engagement involving verification of AEP-Ohio's FAC filings that is conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants, and using guidance set forth in former Chapter 4901:1-11 and related appendices of the Ohio Administrative Code relating to "Uniform Financial Audit Program Standards and Specifications for the Electric Fuel Component"

- Account 547 (Non-Steam Fuel) – the cost of fuel used in non-steam applications such as simple cycle gas peaking plants.
- Account 555 (Purchased Power) – the cost of purchased electricity including both energy and demand or capacity charges.
- Account 507 (Rents) – the costs associated with purchase contracts or unit power sales that have to be recorded as a lease per accounting rules.
- Account 557 (Other Expenses) – the cost of renewable energy credits (REC's) to meet the renewable requirements of S.B. 221.
- Accounts 411.8 and 411.9 (Gains and Losses from Disposition of Allowance) – the gains or losses from the sale of allowances.
- Other Accounts – the costs associated with items allowed to be recovered under the FAC not included in the above.

In its initial application for an ESP, AEP Ohio proposed mitigating the rate impact of any FAC increases on its customers by phasing in the new ESP rates by deferring a portion of the annual incremental FAC costs during the three-year ESP period ending December 31, 2011.

Specifically, AEP Ohio proposed that the amount of incremental FAC costs to be recovered from customers would be such that total bill increases would not be more than 15 percent during each year of the ESP. However, in its Opinion and Order dated March 18, 2009, the PUCO modified AEP Ohio's proposal to mitigate the rate impact on customers by limiting the phase-in of any FAC cost increases on a total bill basis by the percentages shown in Exhibit 1-1.

Exhibit 1-1
Annual Percentage Increase Caps On FAC Costs

Company	2009	2010	2011
CSP	7	6	6
OPCO	8	7	8

CSP has 17 different FAC rates and OPCO has 23 different FAC rates. The PUCO stated that the collection of any deferrals, including carrying costs that are remaining at the end of the ESP "shall occur from 2012 through 2018 as necessary to recover the actual fuel expenses incurred plus carrying costs."[2]

Audit Of The FAC

This audit direction was to follow the general guidance provided for this work in former Appendix D and Appendix E to Chapter 4901:1-11, Ohio Administrative Code (O.A.C.). In addition, the initial audit should include the actual cost for the Rider FAC for the months January 1, 2009 through December 31, 2009. Such audit should follow the guidelines in Section L of Appendix D and Section M of Appendix E to former Chapter 4901:1-11, O.A.C.

[2] See PUCO's Opinion and Order dated March 18, 2009 at page 23.

Audit Approach

EVA and Larkin conducted this audit through a combination of document review, interrogatories, site visits and interviews. EVA and Larkin visited the Gavin station on March9, 2011. EVA and/or Larkin conducted interviews with the individuals in the positions listed in Exhibit 1-2 mostly during the week of March 7, 2011.

Exhibit 1-2
List Of Interviews

Topic	Department	Participants
Coal Procurement	Coal Procurement	Jason Rusk, Director- Coal Procurement; Kim Chilcote, Manager- Coal Procurement; Clint Stutler- Coal Buyer; Stephen "Mike" Debord, Vice President - Fuel Procurement; Jim Sorrrels, Manager- Fuel Cost Recovery; Jeff Dial, Manager- Transportation; Shelli Sloan, Regulatory Consultant- Fuel Cost Recovery
Natural Gas Procurement	Natural Gas Procurement	Ken Howsen, Director - Gas & Oil Procurement; Anita Spracklen, Gas & Oil Procurement; Shelli Sloan; Jim Sorrels
Consumables Procurement	Consumables	Darryl Scott, Manager- Reagents & Coal Combustion Products; Reggie Pratt, Reagents Buyer; Ben Duckworth, Reagents Buyer; Shelli Sloan
Biofuels; Gas Conversion; Special Projects	Biofuels	Ashley Weaver, Manager- Alternative Fuels
Fuel Accounting	Accounting	Tim Dooley, Director- Energy Accounting; Brian Frantz, Supervisor Fuel & Contract Accounting; Glenn Gaffney, Manager- Fuel Accounting; Shelli Sloan
Ohio Regulatory/FAC Reporting	Accounting/ Regulatory	Andrea Moore, Manager- Regulatory Pricing & Analysis AEP Ohio; John Pulsinelli, Regulatory Consultant- Regulatory Pricing and Analysis AEP Ohio; Tim Dooley; Pat Lawrence, Case Manager- Regulatory Services
Purchased Power	Commodity Accounting	Mark Leskowitz, Director Commodity Accounting; Craig Adelman, Manager- East Power Accounting; Tim Dooley
CCPC Accounting	Regulated Accounting Group	Frederick "Scott" Travis, Director- Regulated Accounting; Dorra Campbell, Manager- Regulated Accounting
Coal Contracts Follow Up	Regulatory	Pat Lawrence
Internal Audits	Internal Audits	Rod Burnham, Director- Audit Services; Tim Dooley; Pat Lawrence; Rich Mueller, Vice President- Audit Services

Environmental Compliance	Environmental	John McManus, Vice President- Environmental Services; Tim Dooley; Pat Lawrence; Ed Locigno, Regulatory Consultant- Generation Regulatory Support
Ormet Agreement Follow Up	Regulatory, Accounting	Rod Burnham, Andrea Moore, Tim Dooley
Renewables	Renewable Energy	Jay Godfrey, Managing Director Renewable Energy; Peggy Simmons, Manager Renewable Energy; Mike Giardina, Manager- Generation Reporting; Pat Lawrence; Alex Vaughan, Regulatory Analyst- Commercial Operations Regulatory Support; Matt Nollenberger, Manager- Commercial Operations Regulatory Support; Tim Dooley
Gavin Plant Station Visit	Generation/ Regulatory	Andrea Knopp, Chief Chemist; Randy Sheidler, Process Supv II - Preventive Maintenance/PRO (Plant Reliability Optimization) specialist; Mark Hall, Energy Production Supt I; Tim Jenkins, Maintenance Supt I; Don Martin, Process Supv II - Coal yard process owner; Charlene Hemphill, Administrative Supt; Ashley Smith, Administrative Associate II (enters into Comtrac the coal yard barges/inventory); Brandon Winland, Administrative Support; Jeff White, Manager- Generation Regulatory Support; Shelli Sloan
Quality of Coal Samples	Quality	Jason Echelbarger, Coal Quality Engineer
AEP River Operations	River Transportation Division; AEP Corporate Accounting	Tom Palumbo, AEP River Operations- Director, Accounting and Finance; Darlene Norris, AEP River Operations- Manager, Planning, Budgeting & Costing; Carolyn Minkler, AEP River Operations- Senior Cost Analyst; Christine Dyroff, AEP River Operations- Manager Accounting Operations; Brad Funk, Manager, Regulated Accounting; Tim Dooley; Jim Sorrels; Shelli Sloan

2009 Audit Recommendations

A number of recommendations were made in the first audit cycle. There was agreement on most of the issues. A hearing was held in August 2010, the primary focus of which was the disputed matters. To date, the PUCO has not issued an Opinion and Order in that case.

Major Management Audit Findings- 2010

1. Overall, AEP Ohio's fuel costs declined in 2010, primarily as result of the expiration of the contract premium AEP had paid to its largest supplier in 2009. The ability to terminate the premium is an affirmation of the success of the AEP strategy vis-à-vis bolstering this critical supplier during a difficult market period in exchange for continued contract performance.

2. AEP Ohio coal burn did not rebound in 2010 as hoped. The primary factors were the lingering effects of the economic recession, low natural gas prices, and residual effects from the scrubber's unexpected operating results at Conesville 4. In addition, a number of AEP Ohio's units were put on "extended startup" status which reduced their utilization. As a consequence, AEP Ohio's inventory levels remained high throughout the audit period despite negotiated shipment deferrals under several contracts and the early termination of another contract.

3. At the end of the second year of the FAC, there continues to be a large under-recovery. The under-recovery amounts (subject to adjustment) total $14.2 million for CSP and $451.2 million for OPCO. The lower fuel costs in 2010 reduced but by no means eliminated the annual under-recovery for OPCO.

4. AEPSC's fuel procurement activities underwent a number of changes in 2010. The previous and long-term manager of the department moved to a different role and the department was realigned. The team is still transitioning to their new roles. In addition, AEPSC switched over to a new fuel accounting system, [redacted], which has limited report-writing capability. The latter posed significant problems to the performance of the management/performance audit as desired output reports were not able to be produced in a format that facilitated analysis by the Auditor.

5. AEP announced that its current Integrated Resource Plan assumes the retirement of over 5,900 MW of coal-fired capacity from its eastern fleet by 2020, over half of which is operated by AEP Ohio. The schedule for the retirements has not yet been finalized except with respect to the units for which dates were established under the Consent Decree related to New Source Review. Muskingum 5 is on this list although it technically does not fall into the "fully-exposed" category. A final decision must be made with respect to Muskingum 5 by the end of the 2011 because of the lead time required to complete the scrubber retrofit required under the Consent Decree by the end of 2015. The loss of this coal-fired capacity will affect AEP Ohio's coal requirements.

6. AEPSC completed the revision to its Procurement Policy. The revised manual is very general and provides little of the guidance typically provided by such manuals.

7. AEPSC indicated that Black & Veatch agreed to live up to its warranty with respect to the design deficiencies on the Conesville 4 and Cardinal 1 scrubbers. AEPSC, however, is receiving no compensation from Black & Veatch for any incremental operating costs associated with the repairs at Conesville 4.

8. AEPSC entered into two new coal supply contracts as well as a number of one year and less purchase orders. In addition, AEPSC substantively amended a number of other agreements. The two new contracts were the product of competitive solicitations and supported AEPSC's portfolio strategy. The amendments were largely tied to a desire to realign purchase commitments with demand.

9. In several amendments and price renegotiations, AEPSC relied heavily on non-liquid forward price curves to determine market pricing.

10. AEPSC completed its study of the Conesville Coal Preparation Plant and concluded that it was not economic to continue to operate the plant past the [redacted] of [redacted] with a caveat regarding the new hazardous air pollution regulations. AEPSC revised its Asset Retirement

Obligation and has increased its monthly charge to the Conesville Coal Preparation Plant in anticipation of a [redacted] closing.

11. CSP and OPCO filed timely Alternative Energy Compliance reports and AEP Ohio filed a timely Alternative Energy Portfolio Compliance Plan. CSP and OPCO were able to meet their solar requirements in 2010 although there is some question as to how the 2009 solar shortfalls were handled.

12. AEP would not disclose to the auditors information on the wind contract entered into in 2010 because it has not yet received regulatory approval.

Management Audit Recommendations

13. EVA recommends that AEP Ohio needs to develop and implement a strategy to reduce the inventory at [redacted] AEP Ohio should consider shifting some of the [redacted] coal supplies to other AEP Ohio plants, consignment of [redacted] coal to affiliate power plants, and/or the sale of some excess volumes to third parties.

14. EVA recommends that AEPSC should revise its approach to coal contracting for AEP Ohio in order to reduce the likelihood of being over-contracted. The strategy should be available for review in the next audit cycle.

15. EVA recommends that AEPSC improve its approach to determining the market values by which it makes procurement decisions. The revised approach should be available for review in the next audit cycle.

16. EVA recommends that AEPSC expand upon its policies and procedures in its revised policy manual so that they provide true guidance and a yardstick against which to measure performance.

17. EVA recommends that AEPSC insist upon compliance with coal quality specifications in its coal supply agreements. AEPSC should document these efforts for review in the next audit cycle.

18. EVA recommends that AEPSC work to minimize the costs associated with the closure of the Conesville Coal Preparation Plant. EVA recommends that AEPSC provide its plan for accounting for the closure costs to the auditor for review in the next audit cycle.

19. EVA recommends that the PUCO direct AEPSC to provide all requested documents to the auditor related to the wind purchases and not agree to provide CSP and OPCO recovery of any wind contract costs until they have been reviewed.

20. EVA recommends that AEPSC in its next CSP and OPCO Compliance Status Reports correct the allocation of the 2010 solar obligations so that it is clear that should any future force majeure situations occur the accounting procedures are clear.

Financial Audit Findings

1. CSP's FAC filing for the first quarter of 2010 dated December 1, 2009shows the wholesale (Westerville) sales forecast going from over 49 million Kwh in January 2010 to zero in February 2010 and subsequent months. The wholesale contract with Westerville ended in

December of 2009. The forecasted amount for January 2010 should have been zero as it was for February 2010 and subsequent months. The forecasted amount for January 2010 was entered in error. CSP indicated in its April 1, 2011 response to an informal inquiry that this was an error in the forecasted amount for January 2010, and there was no impact to the FAC due to this entry.

2. CSP's FAC filing dated March 8, 2010, at Schedule 3, page 2 of 3 showed amounts for the wholesale (Westerville) sales forecast for each month April, May and June 2010, erroneously. Those errors caused the Retail Jurisdictional Ratios on Schedule 2, line 8 to be less than 1.00000. These Company errors thus caused the FAC for Retail Load Before Renewables on Schedule 2, line 9, to be understated. The wholesale contract with Westerville ended in December of 2009. The forecasted sales amounts for wholesale for the months of April through June 2010 on Schedule 3, page 2 of 3 should have been zero as it was for February and March 2010 and for months subsequent to June 2010. The forecasted wholesale kWh sales amounts for the months of April through June 2010 on Schedule 3, page 2 of 3, were entered in error. CSP acknowledged this error in an April 1, 2011 response to an informal inquiry. Because CSP's FAC filings have appropriately reflected the termination of the Westerville wholesale contract in December 2009 in computing the RA adjustments, the errors in CSP's FAC forecast for the months in 2010 when CSP understated the amounts for FAC for Retail Load Before Renewables on Schedule 2, line 9, are being corrected via the application of the RA adjustments. After the application of the RA adjustments for the months of April, May and June 2010, for which CSP showed zero wholesale kWh, there should no net impact to the FAC due to the aforementioned CSP forecast errors which had affected the forecast retail jurisdictional allocation ratios for the April through June 2010 period.

3. CSP had a 2010 fuel cost over-recovery of $23,228,616. This amount was netted against CSP's under-recovery of $36,028,133 at December 31, 2009 as well as an additional item which the Company described as a "December balance sheet entry to accrue for FAC effect after pre-tax income was closed" in the amount of $1,436,284. The netting of these items resulted in an under-recovery for CSP at December 31, 2010 in Account No. 1823227 of $14,235,801.

4. On September 1, 2010, AEP Ohio filed an application for a Significant Excessive Earnings Test ("SEET"), which utilities are required to file annually at the PUCO in order to demonstrate whether significantly excessive earnings were made. In its Opinion and Order dated January 11, 2011, the PUCO determined that CSP generated $42.6 million in significantly excessive earnings in 2009, which the Commission ordered be refunded to customers through bill credits and the elimination of any deferrals. Schedule 3, page 1, line 8 of CSP's March 1, 2011 quarterly FAC filing reflects a line item called "SEET Refund" which removes the entire CSP FAC under-recovered balance, which is shown at that time to be $18,717,599.

5. OPCo showed an FAC under-recovery of $153,642,822 for 2010, which when added to OPCo's December 31, 2009 under-recovery of $297,570,318, results in an under-recovery of $451,213,140 at December 31, 2010 recorded in Account No. 1823144.

6. Concerning fuel amounts being deferred that affected the review period, as of December 31, 2010, OPCO had a deferred credit balance of $276,693.59 recorded in Account 253 that was

related to the remaining unrecognized fuel credit associated with the 2008 [redacted]. In addition, $5,726,511.61 of the related deferred credit was credited to OPCO's fuel inventory during 2010 as deliveries were made by the supplier. The remaining December 31, 2010 balance was credited to fuel inventory with the deliveries made in January 2011.

7. REC expense for 2010 was [redacted] for CSP and [redacted] for OPCO and is recorded in Account 5570009. In addition, ending solar REC book inventory in the amounts of [redacted] and [redacted] for CSP and OPCO, respectively, were recorded in Account 1740036.

8. AEP Ohio reflects renewables costs in its FAC under an assumption that the first dollars of FAC revenue are applied to recover such costs. Under this assumption the renewables cost, which are required to be bypassable, do not contribute to the FAC deferrals, that, if existing at the end of the ESP period, would be recoverable in a non-bypassable charge.

9. Larkin attempted to verify that the [redacted] and [redacted] identified in the response to LA-2010-62, reflected the total REC expense in CSP's and OPCO's FAC workbooks (provided in LA-2010-43) for the review period of January through December 2010. However, the REC expense for CSP in the FAC workbooks totaled [redacted] or $1,407 less than the [redacted] indicated above. The REC expense for OPCO in the FAC workbooks totaled [redacted] or $1,638 less than the [redacted] indicated above. Upon our inquiry, AEP Ohio stated the following with respect to CSP:

   The CSP variance of $1,407 represented an expense recorded to the December 2009 general ledger relating to Wholesale RECs which are not recoverable through the FAC. The expense was mistakenly added to the December 2009 FAC calculation. This mistake was corrected in February 2010's FAC workbook by deducting it. Thus the FAC workbooks provided in LA-2010-43 were $1,407 less than the REC expense provided by LA-2010-62, which used the 2010 general ledger as its source. Note that in February 2010, we established a new account in the general ledger to record retail REC activity separate from wholesale REC activity to avoid such mistakes as this $1,407.

   AEP Ohio provided a similar explanation for the $1,638 variance associated with OPCO's 2010 REC expense.

10. The zero value AEP has assigned to its non-Ohio non-solar REC inventory is questionable. A reasonable value for the REC should be assigned. The market information provided would appear to support a nominal value of $1.00 per REC in 2010, if not more. Because AEP Ohio failed to assign any valued to such REC inventory, its fuel costs for 2010 would be overstated by the amount of REC inventory value. Based on the information provided in response to LA-2010-2-97 and LA-2010-2-104, the difference between assigning a zero value and a $1.00 value to the non-Ohio, non-solar REC inventory for 2010 is approximately [redacted] for CSP and [redacted] for OPCo.

11. In Commission Case Nos. 08-917 and 08-918, originally in the March 18, 2009 Opinion and Order at page 23, and subsequent on rehearing, the Commission authorized AEP Ohio to apply a gross-of-tax WACC based on debt and common equity financing to the under-recovered FAC balances. Larkin examined those orders and various filings from those proceedings which were provided to us by AEP Ohio and Staff. Those Commission Orders would appear to allow AEP Ohio to apply the gross-of-tax WACC to the under-recovered FAC balances without any recognition of, or offset for, the related non-investor supplied

financing in the form of Accumulated Deferred Income Taxes (ADIT) that is recorded in Account 283, ADIT-Other, for the tax savings that are directly related to the under-recovered FAC balances. However, upon our review, it appears there is a mis-match between the authorization of a gross-of-tax WACC based on debt and equity capital, and the application of such a rate to deferred fuel under-recovery balances that were/are financed in part with non-investor supplied capital in the form of directly related credit-balance ADIT.

12. AEP Ohio is applying the monthly debt and pre-tax equity cost rates to under-recovered fuel balances in Account 1823144 without any offset for related credit-balance ADIT it has recorded in Account 283, ADIT-Other. There would typically be credit-balance ADIT related to the fuel under-recoveries. Assuming that the Company's fuel costs are deducted currently for income tax purposes, the deferral of the under-recovery for regulatory accounting would create a temporary difference and a credit-balance ADIT would be recorded. The related tax deduction would essentially provide cost-free financing for a portion of the fuel cost under-recovery. The ADIT is a source of non-investor supplied cost-free capital. Such ADIT is not being deducted from the under-recovered fuel balances in Account 1823144 in AEP Ohio's carrying cost calculations. If the ADIT balance related to the Company's FAC under-recovery balances is not considered, or deducted somewhere else, such as in rate base, ratepayers would be over-paying carrying costs by paying for carrying costs on the portion of the Deferred Fuel balance that has been financed by tax savings, i.e., on the portion not financed with investor-supplied capital.

13. AEP Ohio believes its carrying cost calculations to apply the gross-of-tax WACC to the under-recovered FAC balances in Account 1823144 (without any recognition of the fact that financing for a portion of the Deferred Fuel balances has provided by income tax savings reflected in the related credit-balance ADIT, Account 283) have been fully consistent with the Company's presentation and the authorization received from the Commission in Case Nos. 08-917 and 08-918, originally in the March 18, 2009 Opinion and Order at page 23, and subsequent on rehearing.

14. Larkin reviewed AEP Ohio's calculations of the carrying charges on the Deferred Fuel balance and found them to be consistent with AEP Ohio's understanding of the authorization it received from the Commission in Case Nos. 08-917 and 08-918. Larkin also selectively verified the postings of the calculated carrying charge amounts for debt and equity to the deferral account for CSP and OP. No exceptions were noted.

Financial Audit Recommendations

15. AEP should review and update the "Instructions" tab in its monthly FAC support Excel files at least annually.

16. AEP should identify and separate the renewable energy credits (RECs) value from the energy and capacity value of its renewable energy purchases.

17. AEP should show in detail how REC costs incurred by CSP and OP in 2010 have been separately identified and excluded from the 12/31/2010 FAC deferral for each company, CSP and OPCo.

18. AEP should be assigning appropriate values to its Renewables inventory, including its non-Ohio, non solar REC inventory.
19. AEP should be required to analyze the receipt of revenue and the payment of cash expenses for RTD captive operations, similar to a lead-lag study, and to present such information to support its assumption that RTD has a significant Cash Working Capital requirement. If adequate supporting information is not provided to substantiate that RTD has a significant Cash Working Capital requirement and the amount of that requirement using lead-lag study analysis of cash receipts and cash payments, the RTD Working Capital component of the RTD investment base should be removed from the cost charged by RTD to OPCo from January 1, 2011 forward.
20. AEP should address why an ROE that has been set in a FERC order or by a state commission (such as Indiana) for a utility would be appropriate for RTD, when RTD is functioning as a fully cost reimbursed operation with annual true-ups and with not competition serving captive affiliated clients, and, consequently, the level of risk to RTD and the related return required by investors would seem to be lower than for other utility operations.
21. AEP Ohio and the other parties to the case should re-examine whether the Commission-authorized gross-of-tax WACC for debt and common equity capital should be applied to what such investors are actually financing of the fuel cost under-recovery balances, which would appear to be the Deferred Fuel amounts recorded in Account 1823144 less the directly related credit-balance ADIT-Other for Deferred Fuel recorded in Account 283.
22. The Company should address the income tax savings it was/is recording related to the under-recovered FAC balances, and how those provide non-investor supplied capital that is financing a portion of the Deferred Fuel balances that have been recorded in Account 1823144. The Company should specifically address the related credit-balance ADIT that is recorded in Account 283, ADIT-Other, for the tax savings-based financing that appears to be directly related to the under-recovered FAC balances.

Audit Outline

The outline of the remainder of this report is as follows:

- Section 2 AEP Ohio Background
- Section 3 Fuel Procurement Audit
- Section 4 Conesville Coal Preparation Plant Audit
- Section 5 Environmental Audit/Alternative Energy Standards Audit
- Section 6 Performance Audit
- Section 7 Financial Audit

2 AEP OHIO BACKGROUND

Background On Columbus Southern Power And Ohio Power

Columbus Southern Power and Ohio Power are both wholly-owned subsidiaries of American Electric Power (AEP).[3] Fuel procurement for both companies is handled by American Electric Power Service Corporation (AEPSC). AEPSC is also responsible for fuel procurement for AEP's other utility subsidiaries and is agent for Ohio Valley Electric Corporation in which AEP owns the largest share and Cardinal Operating Company in which Ohio Power owns Unit 1. AEP's adoption of centralized fuel procurement was designed to minimize system-wide fuel procurement costs.

The plants operated by CSP and OPCO are listed in Exhibit 2-1. With the exception of Conesville 4, these plants are owned in their entirety by their respective companies. Conesville 4 is one of four CCD[4] plants in which CSP has an ownership position. The other three plants which CSP does not operate are Zimmer (operated by Duke Energy Ohio), Beckjord Unit 6 (operated by Duke Energy Ohio), and Stuart Plant (operated by Dayton Power & Light).

CSP recovers through the FAC its allowed costs associated with its ownership share of all four plants. CSP also recovers its purchased power costs for the Lawrenceburg plant which is owned by an affiliate, AEP Generating Co. ("AEG"). In March 2007, CSP and AEG entered into a 10-year agreement for the entire output of Lawrenceburg and pays for capacity, depreciation, fuel, and other operating costs. AEPSC buys the fuel for Lawrenceburg.

Exhibit 2-1
Columbus Southern Power And Ohio Power Plants

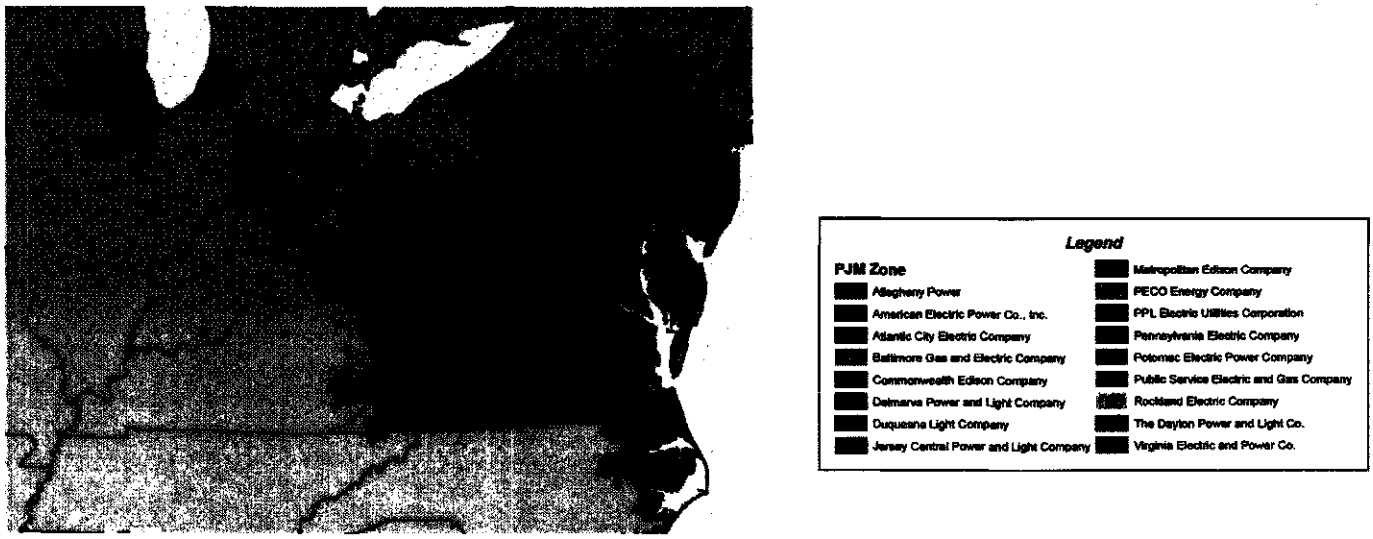
Utility Plant	State	Fuel	Year First in Service	FGD	MW
Conesville	OH	Coal	1973	4,5,6	1,745
Picway	OH	Coal	1955	No	100
Darby	OH	NG	2002		507
Waterford Energy Facility	OH	NG	2002		840
Gen J M Gavin	OH	Coal	1974	Yes	2,640
Muskingum River	OH	Coal	1953	No	1,440
Kammer	WV	Coal	1958	No	630
Mitchell	WV	Coal	1971	Yes	1,560
Cardinal	OH	Coal	1967	Yes	595
Sporn	WV	Coal	1980	No	750
Racine	OH	Water	1982		26

[3] AEP has proposed a merger of CSP and OPCO.
[4] CCD refers to Cincinnati Gas & Electric, Columbus Southern Power, and Dayton Power & Light.

OPCO owns Cardinal Unit #1 in its entirety (which along with Cardinal Unit #2 and Unit #3 is operated by Cardinal Operating Company) and owns a share of Amos Unit #3 and Sporn Units# 2, #4, and #5. OPCO recovers through the FAC its fuel costs associated with its ownership share of these plants.

AEP belongs to the regional transmission organization PJM Interconnection (PJM) which is part of the Eastern Interconnection grid operating an electric transmission system serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Among the primary purposes of PJM are to dispatch electric generating plants on a lowest cost basis, thereby reducing the electric costs for all members of the pool, to coordinate regional planning to ensure reliability to the region in which it operates, and to operate markets for capacity, energy, demand response products and ancillary services. Exhibit 2-2 provides a map of PJM.

Exhibit 2-2
PJM Interconnection Zones



AEP Ohio's share of generation by plant in 2010 is summarized in Exhibit 2-3. Over 90 percent of AEP Ohio's electricity generation is from coal, almost 75 percent of which is operated by AEP Ohio.

Exhibit 2-3
Generation by Plant, 2010 (MWH)

	Coal	Gas	Oil	Water	Total
John E. Amos	4,599,328				4,599,328
Philip Sporn	1,763,227				1,763,227
Cardinal	3,240,567				3,240,567
Conesville	4,836,156				4,836,156
Darby		38,093			38,093
Picway	65,072				65,072
Waterford Energy Facility		1,220,979			1,220,979
J.M. Stuart	3,499,668				3,499,668
J.M. Stuart IC			54		54
W.H. Zimmer	2,463,902				2,463,902
Walter C Beckjord	176,544				176,544
Gen J M Gavin	18,885,659				18,885,659
Kammer	1,498,424				1,498,424
Mitchell (WV)	10,242,061				10,242,061
Muskingum River	6,701,885				6,701,885
Racine				137,165	137,165

During 2010, AEP made some operating changes that affected the utilization of a number of AEP Ohio units. AEP instituted a plan that placed 10 units, representing 1,925 MW, into "extended startup" status for nine non-peak months of the year.[5] AEP determined it could reduce its operating costs by having a four-day window in which to return a plant to service. The plan, which took effect June 1, affected the units in Exhibit 2-4. In addition, Kammer is operating in a "substitute operation" mode, in which only two units are operated at one time.

Exhibit 2-4
Extended Start-Up Units

Operating Utility	Plant/Unit	MW
Appalachian Power	Clinch River 3	235
Appalachian Power	Glen Lyn 5&6	335
Appalachian Power	Sporn 3	150
Columbus Southern Power	Picway 5	95
Indiana Michigan	Tanners Creek 1&2	290
Ohio Power	Muskingum River 4	215
Ohio Power	Sporn 4&5	600
Total		**1920**

[5]The peak months are January, July, and August; Sporn 5 will operate in the extended start-up mode for the entire year.

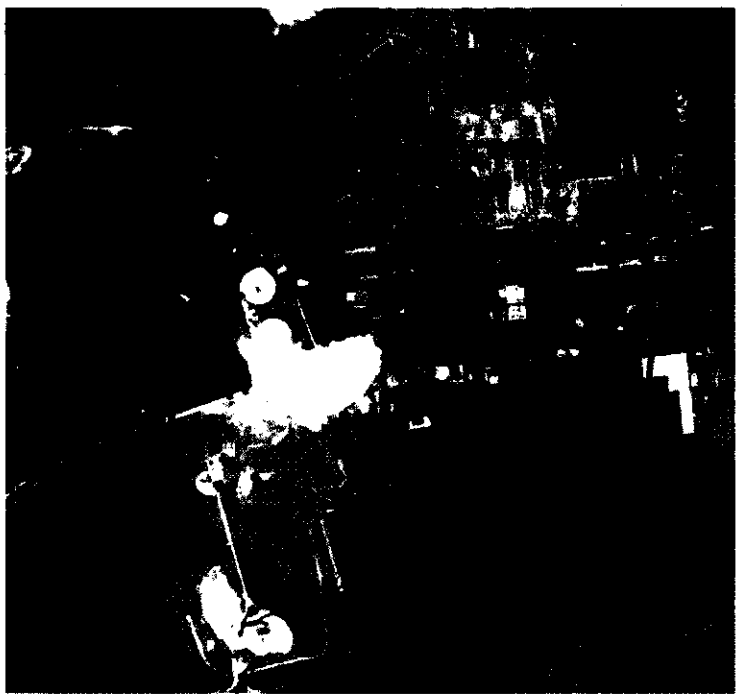
Coal Plants

This section provides background information on the six coal plants operated by AEP Ohio plus Cardinal, starting with the CSP plants.

Conesville (CSP)

The Conesville station consists of four units with a total generating capacity of 1,745 MW. Units 1 & 2 were retired in 2005. Conesville 3 has not been and will not be retrofitted with a scrubber. Conesville 4's retrofit was completed in 2009 but this was one of the retrofits that encountered unexpected operating results. Conesville 5 and 6 were built with scrubbers and these scrubbers were upgraded in 2009 to comply with the New Source Review settlement. As can be seen in Exhibit 2-5, Conesville 5 &6 share a stack. Coal to this station is delivered by truck, conveyor and rail.

Exhibit 2-5
Aerial View of Conesville Plant



Recent plant operating statistics are provided in Exhibit 2-6. Generation in 2009 and 2010 was depressed due to the tie-in outage and subsequent unexpected operating results with the scrubber retrofit on Conesville 4.

Exhibit 2-6
Conesville Operating Statistics[6]

Utility	Plant	Units	Location	Ownership %	Total MW	Utility Share
Columbus Southern	Conesville	3-6	Conesville, OH	74.61	1745	1302
		2010	**2009**	**2008**	**2007**	**2006**
Coal		3,027,261	2,817,418	4,169,889	4,627,705	3,914,831
Oil		24,722	18,923	21,401	20,043	23,340

Picway (CSP)

Picway is AEP Ohio's smallest coal plant. (Exhibit 2-7)Coal is delivered to this station by rail or truck.

Exhibit 2-7
Aerial View of Picway Plant

Recent plant operating statistics are provided in Exhibit 2-8. Generation in 2010 was under 10 percent. AEP has had some success with biodiesel at Picway.

[6] Operating Statistics for Conesville and the other plants are derived from SNL Coal database. AEPSC notes that in some cases its data differ from the data reported herein.

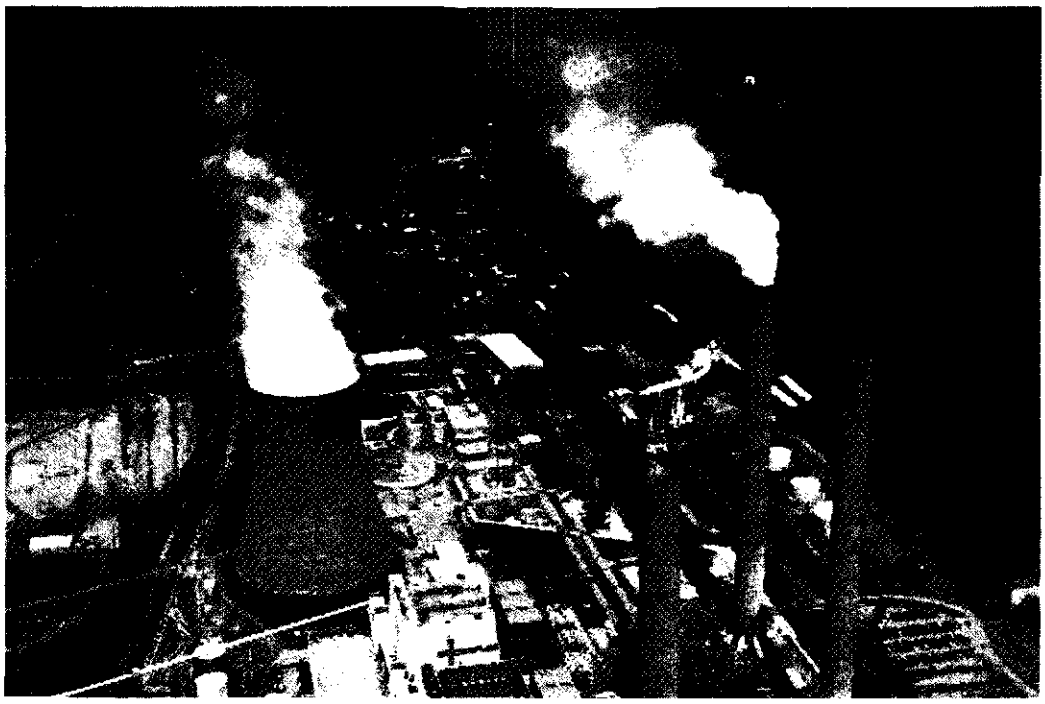
Exhibit 2-8
Picway Operating Statistics

Utility	Plant	Units	Location	Ownership %	Total MW	Utility Share
Columbus Southern	Picway	5	Lockbourne, OH	100	100	100
		2010	2009	2008	2007	2006
Coal		36,965	61,270	172,584	184,197	132,440
Oil		1,382	2,490	5,671	4,990	3,339

Gavin (OPCO)

The Gavin station consists of two units with a total generating capacity of 2,640 MW. These units were retrofit with flue gas desulfurization units in the early 1990's as part of AEP's acid rain compliance plan. All coal to this station (Exhibit 2-9) is currently delivered by barge.

Exhibit 2-9
Aerial View of the Gavin Plant



Recent plant operating statistics are provided in Exhibit 2-10. Generation in 2010 was strong, although not as strong as in 2009. This is OPCO's largest station, consistently burning more than seven million tons per year.

Exhibit 2-10
Gavin Operating Statistics

Utility	Plant	Units	Location	Ownership %	Total MW	Utility Share
Ohio Power	Gavin	1-2	Cheshire, OH	100	2640	2640
		2010	**2009**	**2008**	**2007**	**2006**
Coal		8,125,893	7,984,101	8,503,170	7,348,095	6,586,295
Oil		48,111	31,047	40,380	55,505	66,396

Kammer (OPCO)

The Kammer station consists of three 210 MW coal-fired power plants. The Kammer boilers are cyclones and as such require a lower fusion coal, consistent with the high sulfur coal they were designed to burn. Compliance with clean air regulations have been a challenge for Kammer because low sulfur bituminous coals typically have a high ash fusion temperature. AEP planned to switch to a blend of 80/20 Powder River Basin/eastern bituminous coals but abandoned this plan for several reasons including concerns about selenium in the ash. An aerial view of the plant is provided in Exhibit 2-11.

Exhibit 2-11
Aerial View of Kammer Plant

Recent plant operating statistics are provided in Exhibit 2-12. Utilization of this plant has declined significantly in the last two years. Coal burn fell below 800,000 tons in 2010 in part due to the substitute operation plan that limits operations at Kammer to no more than two units at any one time. It is EVA's understanding that continued operation of Kammer is required for Ormet.

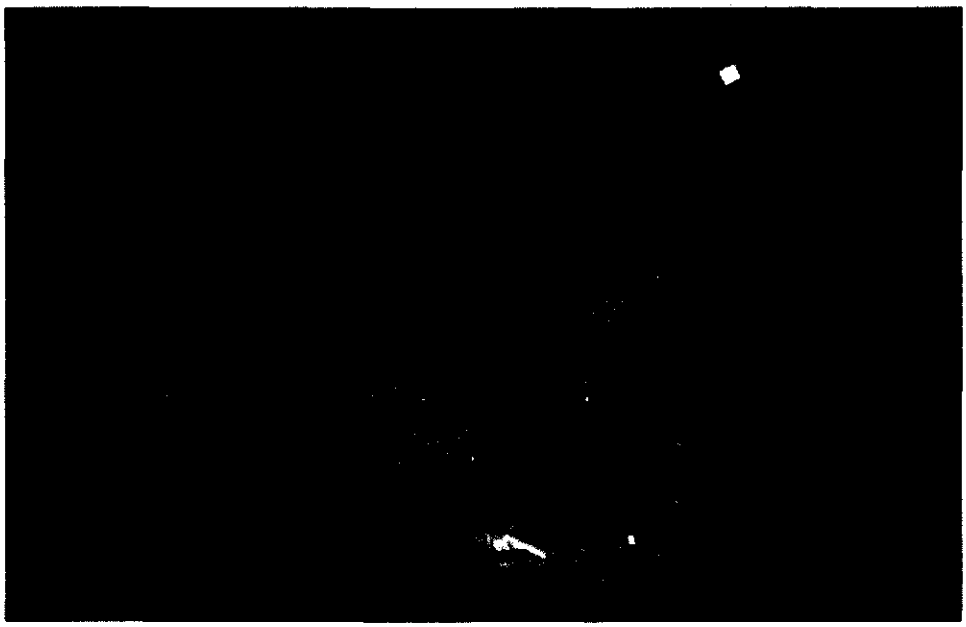
Exhibit 2-12
Historical Operational Statistics for Kammer

Utility	Plant	Units	Location	Ownership %	Total MW	Utility Share
Ohio Power	Kammer	1-3	Moundsville, WV	100	630	630
		2010	**2009**	**2008**	**2007**	**2006**
Coal		760,947	852,381	1,402,967	1,680,947	1,347,661
Oil		8,161	8,199	8,526	8,070	5,097

Mitchell (OPCO)

The Mitchell plant is located adjacent to Kammer in Moundsville. Mitchell consists of two units. An aerial view is provided in Exhibit 2-13. This plant receives coal by belt, rail and barge. The plant was retrofitted with scrubbers and SCRs in 2007.

Exhibit 2-13
Mitchell Plant



Recent plant operating statistics are provided in Exhibit 2-14. The plant's utilization has increased since the retrofit of scrubbers, causing an increase in coal burn.

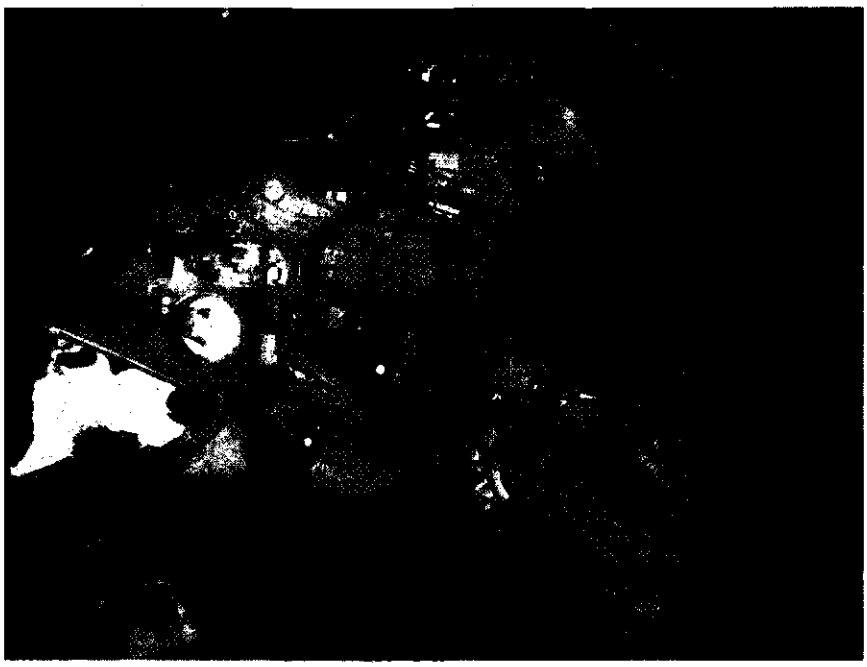
Exhibit 2-14
Historical Operating Statistics at Mitchell

Utility	Plant	Units	Location	Ownership %	Total MW	Utility Share
Ohio Power	Mitchell	1-2	Moundsville, WV	100	1560	1560
		2010	2009	2008	2007	2006
Coal		4,033,432	3,678,634	4,173,111	3,284,999	2,973,951
Oil		37,569	29,883	32,044	33,061	54,172

Muskingum River (OPCO)

The Muskingum River plant is located in Beverly, Ohio. Muskingum River consists of five units. The four smallest units are wet bottom boilers which require a lower fusion coal. Unit 5, the newest and largest boiler, is a dry bottom supercritical unit which can burn high fusion coals. An aerial view is provided in Exhibit 2-15. This plant receives coal by rail, as the Muskingum River is not navigable for barge deliveries. None of the units has been retrofit with scrubbers; Unit 5 has an SCR

Exhibit 2-15
Muskingum River Plant



Recent plant operating statistics are provided in Exhibit 2-16. The plant's utilization has been relatively low in the last two years. Coal burn has fallen to 2.7 million tons.

Exhibit 2-16
Historical Operating Statistics at Muskingum River

Utility	Plant	Units	Location	Ownership %	Total MW	Utility Share
Ohio Power	Muskingum Rv	1-5	Beverly, OH	100	1440	1440
		2010	2009	2008	2007	2006
Coal		2,723,728	2,869,762	3,528,464	3,249,850	2,797,865
Oil		30,854	34,094	31,985	38,095	41,115

Cardinal (Cardinal Operating)

The Cardinal plant is located on the Ohio River, mile marker 76.6. Cardinal consists of three units. Unit 1 is owned by Ohio Power. Units 2 and 3 are owned by Buckeye Power. Unit 1 was retrofit with a scrubber in 2008; unit 2 was retrofit with a scrubber in 2007. The Cardinal 1 scrubber was one of the scrubbers that did not perform as planned. An aerial view is provided in Exhibit 2-17. AEPSC buys coal for the entire station. This plant receives coal by barge and rail.

Exhibit 2-17
Cardinal Plant

Recent plant operating statistics for Cardinal 1are provided in Exhibit 2-18. Cardinal 1 consistently operates above a 60 percent capacity factor and burns 1.3 million tons of coal or more annually.

Exhibit 2-18
Historical Operating Statistics at Cardinal 1

Utility	Plant	Units	Location	Ownership %	Total MW	Utility Share
Ohio Power	Cardinal	1	Brilliant, OH	100	1820	595
		2010	**2009**	**2008**	**2007**	**2006**
Coal		1,344,156	1,442,748	1,361,428	1,440,158	1,506,399
Oil		18,620	21,403	28,838	16,538	20,356

Integrated Resource Plan

During the 2010 Integrated Resource Planning (IRP) cycle, an AEP-East unit disposition study was undertaken by a specially-formed IRP Unit Disposition evaluation team, which consisted of representatives from engineering, operations, fuels, environmental and commercial operations. The predominant focus was on what AEP refers to as the "Fully-Exposed" coal units which consist of approximately 5,300 MW of older-vintage, less-efficient plants that have not been retrofit with environmental controls. The list, shown in Exhibit 2-19, consists of several AEP Ohio units. The IRP assumes retirements of these units over its 10 year planning horizon but notes that final decisions as to timing have not yet been made except with respect to the schedule established in the Consent Decree from the New Source Review litigation.

Exhibit 2-19
AEP East – Fully Exposed Units

Operating Utility	Plant	Unit	MW	NSR R/R/R Date*
Appalachian Power	Clinch River	1-3	705	Possibly 12/31/2018
Appalachian Power	Glen Lyn	5	95	
Appalachian Power	Glen Lyn	6	240	
Appalachian Power	Kanawha River	1&2	400	
Appalachian Power	Sporn	1&3	300	Possibly 12/31/2018
Ohio Power	Sporn	2&4	300	Possibly 12/31/2018
Ohio Power	Sporn	5	450	12/31/2013
Columbus Southern Power	Conesville	3	165	12/31/2012
Columbus Southern Power	Picway	5	100	
Indiana Michigan	Tanners Creek	1-4	995	Possibly 12/31/2018
Kentucky Power	Big Sandy	1	278	
Ohio Power	Kammer	1-3	630	Possibly 12/31/2018
Ohio Power	Muskingum River	1&3	420	12/31/2015
Ohio Power	Muskingum River	2&4	420	12/31/2015
TOTAL			**5498**	
Columbus Southern Power	***Total***		**265**	
Ohio Power	**Total**		**2220**	

* Date by which unit must be retired, repowered or retrofit (R/R/R); also consent decree requires R/R/R to another 600 MW from choice of Clinch River 1-3, Sporn 1-4, Tanners Creek 1-3, and/or Kammer 1-3 by 12/31/2018.

The IRP Unit Disposition evaluation team also reviewed certain supercritical coal units that were determined to be "Partially Exposed". These units, listed in Exhibit 2-20, also include AEP Ohio units. The only supercritical plant assumed to be retired in the IRP is Muskingum River 5. Absent a change to the Consent Decree, a final decision vis-à-vis Muskingum River 5 must be made by the end of 2011 because of the lead time required to complete the scrubber retrofit.

Exhibit 2-20
AEP East – Partially Exposed Units

Operating Utility	Plant/Unit	Reason
Columbus Southern Power	Conesville 5&6	SCR needed by 2019
Indiana Michigan	Rockport 1/2	FGD/SCR by 2017/2019
Kentucky Power	Big Sandy 2	FGD by 2015
Ohio Power	Muskingum Rv 5	FGD by 2015

3 FUEL PROCUREMENT AUDIT

The fuel supply arrangements for CSP and OPCO consist of commercial purchases comprised of long-term, short-term, and spot purchases. CSP owns and operates the Conesville Coal Preparation Plant ("CCPP") which is owned and operated by Conesville Coal Preparation Company, a wholly-owned subsidiary. The CCPP was built in the mid1980s to provide more flexibility to AEPSC in its coal procurement for the Conesville station.

Coal procurement performance during the audit period is summarized on Exhibit 3-1.[7] In 2010, AEP Ohio had a high level of contract purchases. Most spot purchases were for low sulfur coal.

Exhibit 3-1
AEP Ohio Coal Purchases, 2010

		Contract					Spot					Total				
		Tons	Btu/lb	S (%)	$/Ton	$/MMBtu	Tons	Btu/lb	S (%)	$/Ton	$/MMBtu	Tons	Btu/lb	S (%)	$/Ton	$/MMBtu
CSP	Conesville	3,215	11,255	3.21	50.91	2.26	-	-	-	-	-	3,215	11,255	3.21	50.91	2.26
OPCO	Cardinal	3,744	12,017	2.38	41.56	1.73	121	9,738	0.43	43.51	2.23	3,865	11,945	2.32	41.62	1.74
	Gen J M Gavin	6,917	11,954	3.52	43.51	1.82	880	8,732	0.20	27.82	1.59	7,797	11,591	3.14	41.74	1.80
	Kammer	683	11,530	1.18	60.41	2.62	8	8,699	0.21	28.06	1.61	691	11,496	1.17	60.03	2.61
	Mitchell (WV)	3,578	12,499	2.25	55.97	2.24	577	12,150	0.93	69.83	2.87	4,155	12,451	2.07	57.90	2.32
	Muskingum River	2,550	12,384	2.03	57.02	2.30	335	12,597	1.60	55.15	2.19	2,886	12,409	1.98	56.81	2.29
	Total	17,473	12,125	2.70	48.28	1.99	1,922	10,496	0.68	46.20	2.20	19,394	11,964	2.50	48.07	2.01
Total		**20,688**	**11,990**	**2.78**	**48.68**	**2.03**	**1,922**	**10,496**	**0.68**	**46.20**	**2.20**	**22,609**	**11,863**	**2.60**	**48.47**	**2.04**

Source: EIA Form 923

AEP Ohio's coal costs compare favorably with the coal purchase expenses of other Ohio utilities as shown in Exhibit 3-2[8]. OPCO had the lowest delivered costs in 2010 which affirms the decision to support its suppliers during the 2008 and 2009 period, thereby avoiding bankruptcies and ultimately higher costs. CSP is in the middle of the pack.[9]This comparison is not dispositive with regard to performance as the utilities vary with respect to quality requirements and transportation.[10]

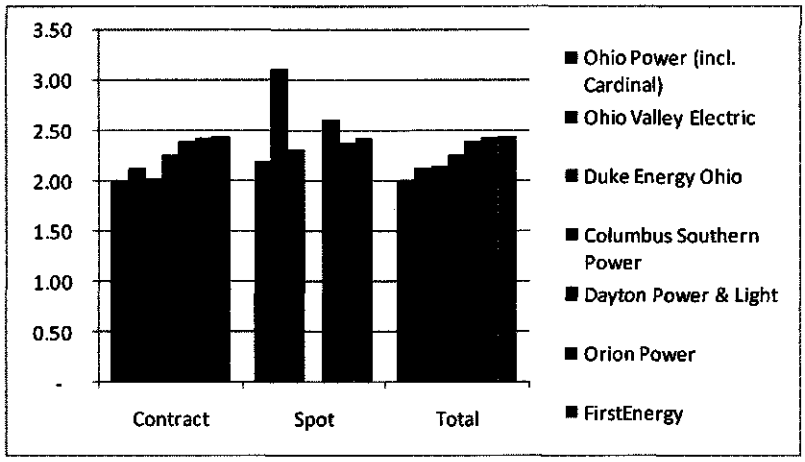
[7] This chart is not comparable to the chart in last year's report because (1) it does not include the Conesville Coal Preparation Costs and (2) it includes all of Cardinal, not just unit 1. AEP's new fuel accounting system does not yet have the report-writing capability to provide the desired information in a format conducive to analysis.

[8] The data come from the utility's Form 923 filings to the Energy Information Administration (EIA). EIA defines contract as purchases for one year or more and spot as everything else.

[9] As noted above, the purchase expenses do not reflect the Conesville Coal Preparation Plant costs. Given the margin between CSP and DP&L, the inclusion of these costs is unlikely to affect the rankings.

[10] The chart reflects purchase expense. Fuel expenses may be different because of credits or charges to the fuel accounts.

Exhibit 3-2
Average Price of Coal Purchases, 2010 ($/MMBtu)

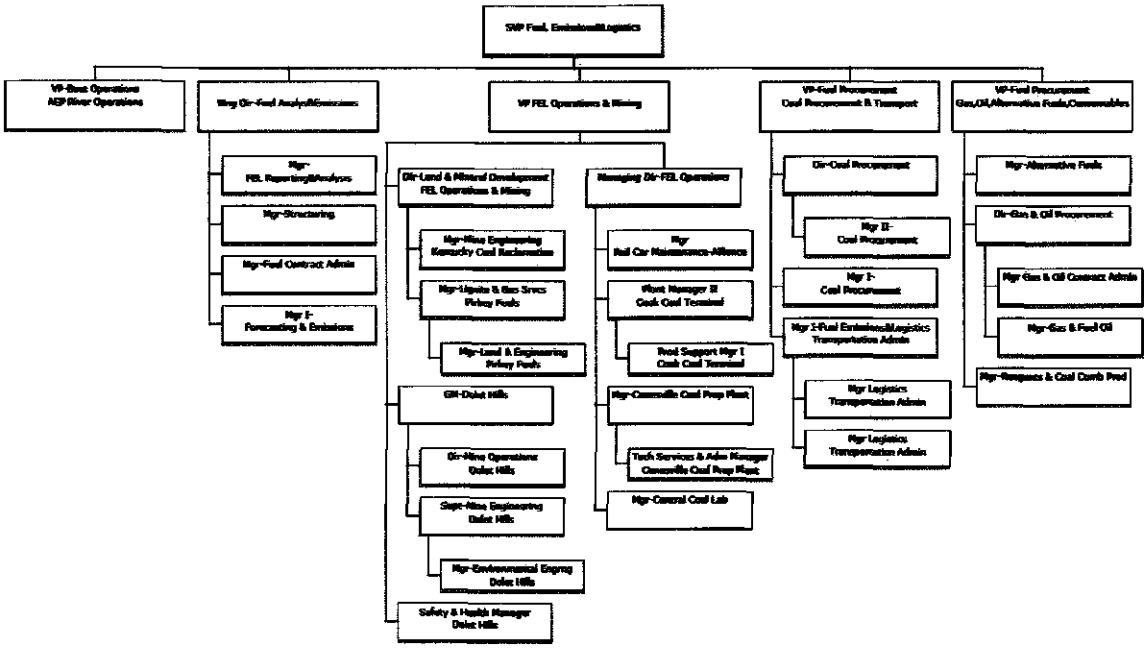


Source: EIA Form 923

Management And Organization

Responsibility for fuel and emission allowance procurement lies with the Senior Vice President Fuel Emissions and Logistics ("FEL"). As shown in Exhibit 3-3, the Senior Vice President has five direct reports, several of which have some involvement in fuel procurement issues for AEP Ohio. The individual most responsible for AEP Ohio coal procurement is the Vice President Fuel Procurement. FEL personnel interact with other AEP personnel on a routine basis.

Exhibit 3-3
Organization Chart For Fuel, Emissions And Logistics



Source: EVA-2010-1-47

FEL was reorganized during the audit period. The former individual with primary responsibility for AEP Ohio fuel procurement became Vice President FEL Operations and Mining. The new Vice President Fuel Procurement was an individual with considerable tenure in the fuel procurement area.

Policies And Procedures

AEPSC updated its Fuel, Emissions & Logistics Procurement Policy in February 2011. The basic policy is "to assure secure, flexible and competitively priced fuel supplies and transportation to meet generation requirements, recognizing the dynamic nature of fuel markets, environmental standards and regulatory requirements."

The organization of the manual (which has a total of 12 pages with text) is as follows:

1. The FEL Organization
   1.1. Roles and Responsibilities of the FEL Organization
   1.2. Organizational Structure of FEL
   1.3. Procurement Responsibilities
   1.4. General Administrative Duties
2. FEL Procurement Policy and Implementations
   2.1. Business Ethics and Corporate Compliances
   2.2. Procurement Considerations
   2.3. Proper Inventory Levels
3. Procurement Methods and Documentation
   3.1. Requests for Proposal
   3.2. Other Offer Evaluation
   3.3. Emergency Procurement
   3.4. Negotiating Responsibility
   3.5. Enforcement of Agreements
4. Hedging Policy
   4.1. Hedging Definition
   4.2. Hedging Strategy
5. Contract Administration
   5.1. Overviews and Responsibilities

The revised manual is very general and provides little of the guidance typically provided by such manuals. For example, the section on inventory levels states an objective to have adequate inventories, a policy to set target inventory levels, and the need to act if inventory levels diverge from target. No target levels are provided. No triggers are identified as to when actions should be taken. The types of actions that should be considered are not listed. Other sections are similarly inadequate.

Inventory Management

The Procurement Policy states that the "primary objective of FEL shall be to ensure the availability of an adequate reliable supply of fuel and reagents for the generation of electricity." Specific "solid fuel inventory target levels shall be recommended by the Fuel Supply Task Group

and subject to the approval of senior management." With respect to the actions that should be taken if the actual inventory levels diverge from targets, the Policy states simply "an appropriate course of action shall be implemented."

In last year's audit, AEPSC provided 2009 targets which are summarized in Exhibit 3-4. The target inventories range between 25 and 35 days of burn on a full load basis. The target winter inventories are generally (but not always) five days higher. EVA was informed that the inventory targets for 2010 had not changed.

Exhibit 3-4
2009 Inventory Targets

			Target Inventory		Winter Inventory	
Plant	Unit(s)	Tons/Day Full Load	Days	Tons	Days	Tons
[redacted]						

In 2009, stocks at the AEP Ohio plants increased substantially and exceeded target levels at all plants. EVA was sympathetic to the inflated inventory levels given the large decline in coal burn due to the global financial crisis. During 2010, as shown on Exhibit 3-5, AEP Ohio continued to struggle with its inventory levels and achieved some success at all plants except [redacted]. It is appropriate for AEPSC to develop and implement an inventory reduction program at [redacted] in 2011.

Exhibit 3-5
Inventory Levels At AEP Ohio Plants (Tons)

[*BEGIN CONFIDENTIAL*]

[redacted]

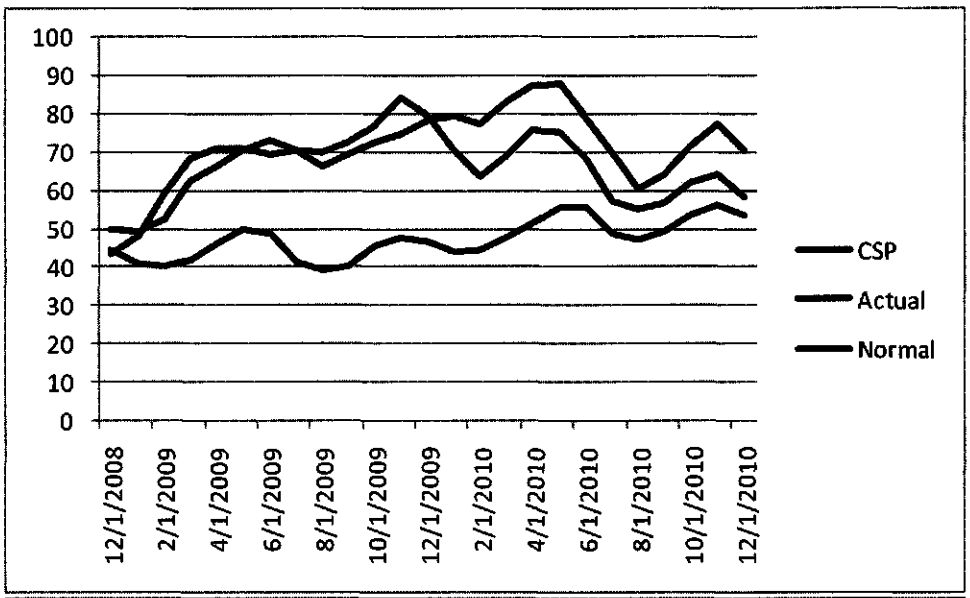
[redacted]

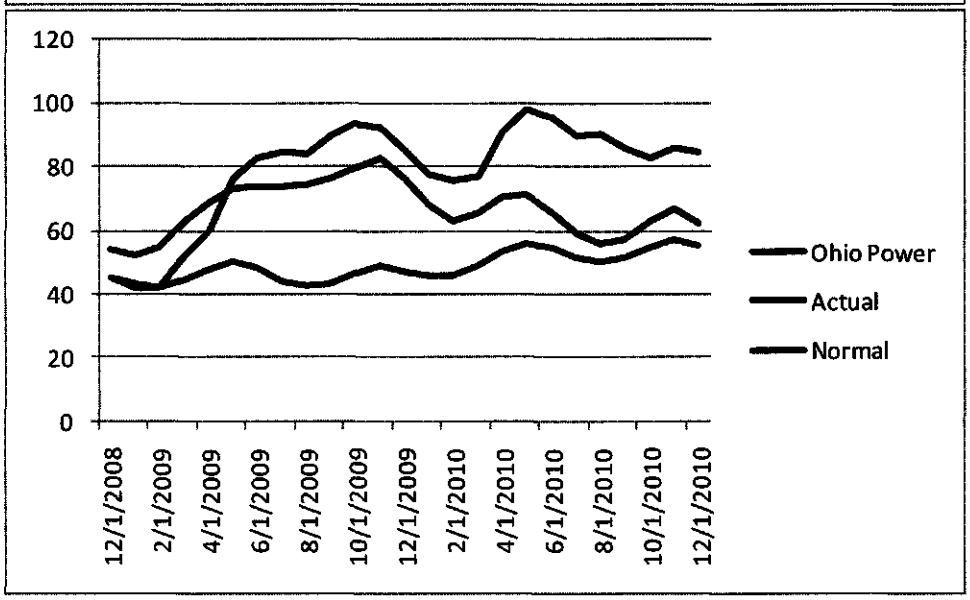
[*END CONFIDENTIAL*]

In Exhibit 3-6, CSP and OPCO inventory levels are compared, respectively, to actual and normal industry levels based upon EVA's proprietary stockpile report.[11] The CSP inventories are compared to just Northern Appalachian inventories as all the coal purchased for CSP is from Northern Appalachia. The OPCO inventories are compared to eastern utility inventories which consist of multiple coal types. Both CSP and OPCO did poorly with respect to inventory management compared to other utilities purchasing similar quality coals. OPCO's poor performance is driven by the inflated inventory levels at [redacted], which as noted above need to be addressed.

[11] EVA publishes the COALCAST Stockpile Data Report on a monthly basis which provides indicative utility inventory levels by coal type on a real time basis.

Exhibit 3-6
CSP And OPCO Inventory Days Versus Industry





Physical Inventory

During the era of full regulation, the PUCO mandated semi-annual physical inventory surveys and only allowed book adjustments if the surveys produced sequential errors in the same direction. Further, the adjustments were limited to 50 percent of the difference up to six percent. AEP now conducts its physical inventory survey and adjustments according to AEP System Accounting Bulletin No. 4 which provides for full adjustments to be made following each survey. The AEP System Accounting Bulletin No. 4 also requires that a variance of plus or

minus two percent be investigated. An annual audit of the coal pile inventories is conducted by Internal Audit.[12]

The physical inventory survey adjustments at AEP Ohio-operated plants are summarized in Exhibit 3-7. The adjustments are compared to the end of month inventory at the plant. Where the physical inventories were provided by unit, they were aggregated for this table. The shaded lines indicate a variance of more than two percent from the pile. The adjustments are also shown as a percent of burn. While the two percent threshold may be too low, several of the adjustments are much higher.

Exhibit 3-7
Physical Inventory Survey Adjustments

Plant	Date	EOM Inventory	Tonnage Adjustment	Adjustment as % of Inventory	2010 Burn	Adjustment as % of Burn
[redacted]						

Internal Audits

AEPSC has an active internal audit function which regularly audits components of fuel procurement. According to the internal auditors, each year they take the entire universe of audit areas and rank them based upon several factors such as dollar value, history of prior problems, and when the last audit was conducted. The internal auditors indicate they conduct approximately [redacted] audits per year, most of which are financial audits. Audits findings are ranked by risk. Anything determined to be medium or high risk requires follow-up.

The internal audits conducted in the fuel area are summarized in Section 7.

Coal Procurement

AEPSC annually purchases about 75 million tons of coal on behalf of AEP Ohio, Appalachian Power, Indiana Michigan Power, Kentucky Power, Public Service of Oklahoma and

[12] Internal Audit conducts the annual review to reduce the workload of the outside auditors. The annual review is conducted per agreed upon procedures.

Southwestern Electric Power and the utilities it is agent for: Ohio Valley Electric and Cardinal Operating.[13] Coal is purchased from virtually every coal supply region and under multiple types of arrangements. AEP has been in and out of the coal business several times. Currently, its mining activities are limited to lignite operations in Texas. AEP still operates the Conesville Coal Preparation Plant in Ohio.

Coal Procurement Strategy

AEPSC's strategy is to layer in coal commitments to minimize market exposure at any one time. While not stated in its procurement policy, [redacted] This has caused problems in recent years due to the volatility of burn levels. Going forward, AEPSC needs to consider a more flexible approach to procurement so as to avoid being over committed.

Coal Solicitation

AEPSC monitors its coal position overall and by plant and supplier through an internally developed model which monitors actual and target inventory levels, actual and projected burn, and spot and contract commitments. This tool helps determine when coal purchases should be made. When a need is identified, AEPSC typically buys through a formal solicitation. A request-for-proposal ("RFP") is issued, generally by AEPSC without naming which plants require coals. The RFP requests bids for a wide range of coals and give bidders the option to bid for spot and/or multi-year contract business. The results from the RFP process help to determine whether to buy coal on a spot or contract basis and for what term.

AEPSC also buys coal through direct negotiation with suppliers, telephone solicitations, and over-the-counter. Telephone solicitations are conducted when there is an immediate and generally unexpected need. Over-the-counter is used for spot coal commodity type purchases, e.g., 8,800 Btu per pound Powder River Basin coal.

AEPSC conducted three broad coal solicitations in 2010. The results of the solicitations are summarized in Exhibit 3-8. As shown, AEPSC entered into a number of agreements based upon the forecast of its open position.

Exhibit 3-8
2010 Coal RFP Results

[redacted]

[13] Purchases were lower in 2009 and 2010 due to reduced demand.

Regardless of the manner in which coal is procured, a written justification is prepared for every transaction. The justification includes why the procurement is being made (generally one or more screens from the model described above), how the specific procurement came about, and the economic justification for the decision. These memos are well written, comprehensive documents that provide good contemporaneous support for the procurement even though most are dated subsequent to the actual transaction.

Without there being a specific portfolio target identified, there appears to be a general desire to have a portfolio of procurements such that market exposure at any one time is limited and there is a diversification of supply and suppliers.

Procurement Administration

AEP Ohio switched from its [redacted] system to the [redacted] in May 2009. Plant personnel enter the fuel receipts information into [redacted] which contains the terms and conditions associated with fuel contracts. The system monitors contract performance and creates payment requests based upon the quantity and quality of coal received and the contract terms and conditions. The payment requests are then run through the [redacted] system.

For the 2009 audit period, AEP ran both systems in tandem and was able to produce information requested by the auditors from the [redacted] system. For 2010, only [redacted] was available and reports needed for the management/performance audit could not be produced. This lack of access to data created significant auditing problems as it was difficult to confirm purchases, quality, and in the case of coal delivered from the Conesville Preparation Plant, delivered prices. Further, EVA discovered at least one limitation in the [redacted] form which resulted in an incorrect price being printed on the form.[14] EVA recommends that the situation be remedied by the end of the next audit period by making it a high priority to develop reports that provide the information necessary to evaluate purchase costs and supplier performance.

Spot Coal Procurements

AEP Ohio purchased coal for OPCO under a number of agreements which it classifies as spot. Generally, the spot coal agreements have a term of one year or less. Spot coal agreements are good vehicles for matching supply and demand particularly during periods of uncertainty regarding burn levels.

The agreements are listed by supplier in Exhibit 3-9. Most of the spot agreements were for low sulfur coal for Mitchell.

[14] The invoice in this particular case was correct.

Exhibit 3-9
Spot Coal Agreements

Supplier	Contract ID	Effective Date	Delivery Period Start	Delivery Period End	Plant(s)	2010 Tonnage	Specificatons Btu/lb	Specificatons lb SO2/MMBtu
[redacted]								

[redacted][15]

The other transaction of note was the spot purchase from [redacted] It is always better to be transparent to the auditor in these types of transaction.

Contract Procurements

AEPSC entered into two new multi-year contracts for OPCO in 2010 in addition to several purchase orders for 2011 shipments. The basic terms of the new [redacted] agreements are summarized in Exhibits 3-10 and 3-11, respectively. The [redacted] contract was the result of the July 2010 RFP; the [redacted] contract was the result of the October 2010 RFP. Shipments under this contract do not begin until 2011. EVA reviewed both solicitations and concurs with AEPSC's decision to enter into both contracts.

[15] [redacted]

Exhibit 3-10

[redacted]

Exhibit 3-11

[redacted]

Contract Review

AEPSC is a party to a number of long-term coal supply agreements. During 2010, AEP Ohio received coal under 19 contracts although shipments under three of the contracts were carry-over tons from a prior period. Shipments by contract and supplier are listed in Exhibit 3-12.[16]

[16] The exhibit does not include in-transit shipments including PRB coal at the Cook Coal Terminal

Exhibit 3-12
AEP Ohio Contract Purchases, 2010

	Cardinal	CCPP	Conesville	CV5/6 Storage	Gavin	Kammer	Mitchell	Muskingum	TOTAL
[redacted]									

Several suppliers have multiple contracts. The two largest suppliers in 2010 were [redacted]l and [redacted] Combined [redacted] and [redacted] accounted for more than [redacted] percent of AEP Ohio's 2010contract purchases, as shown in Exhibit 3-13. [redacted]

Exhibit 3-13
AEP Ohio Contract Supplier Volume And Contract Market Share, 2010

Supplier	Tons	Market Share	Cumulative Market Share
[redacted]			

The key provisions of the 16 agreements are summarized in Exhibit 3-14.

Exhibit 3-14
AEP Ohio Long-Term Coal Supply Agreements

Supplier	Contract ID	Effective Date	Delivery Period Start	Delivery Period End	Plant(s)	2010 Tonnage	Type	Specificatons Btu/lb	Specificatons lb SO2/MMBtu
[redacted]									

Performance in 2010 under each of the long-term supply agreements is described below along with a summary of monthly shipments by plant. On the shipment tables, a shaded square indicates if the ash, SO_2/MMBtu, or Btu/lb are not compliant with the contracted half-monthly or monthly specifications for Btu, SO_2 and/or ash.

[redacted]

In [redacted] AEPSC identified a large open coal position at [redacted] and [redacted]. Given these units were either scrubbed or being retrofit with scrubbers, they could accept higher sulfur coals. At the time, AEPSC had only two term contracts for high sulfur coal: one with [redacted] and the other with [redacted], an affiliate of [redacted]. [redacted] was selected following an RFP process in March [redacted]

The [redacted] contract is for [redacted] years. The first two years are at an annual rate of [redacted]; the rest is at the annual rate of [redacted] tons. AEPSC also has a [redacted] and the [redacted].

In [redacted], AEPSC provided additional financial support to [redacted] due to concerns about its viability during the market run up. That support included a [redacted] on all shipments in [redacted]. The decision to continue the [redacted] was at AEPSC's sole election. [redacted] underwent a recapitalization in 2009 which improved its financial situation. AEPSC did not continue [redacted]. The [redacted] contract was amended three times in 2010, all of which were price-related adjustments.

Shipments under the [redacted] in 2010 are summarized in Exhibit 3-15. In all but two months, the average Btu content was below the contract specification.

Exhibit 3-15
Shipments Under [redacted]

Month	Plant	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	Cents/ MMBtu	$/Ton
[redacted]							

In [redacted] following the successful scrubber retrofits of the [redacted] stations, AEPSC determined the optimal coal blend for this station. To implement its strategy, AEPSC entered into several coal supply agreements in [redacted] including the one with [redacted] for lower sulfur coal. The agreement is for [redacted] starting in [redacted] for [redacted] tons per year. The contract was amended in 2010 to add an additional mine source.

Shipments under the [redacted] in 2010 are summarized in Exhibit 3-16. The Agreement provides for [redacted] with pricing based on the mode of transportation. Performance was mixed in 2010 with several instances of non-compliance with Btu, SO_2 and ash half-month specifications.

Exhibit 3-16
Shipments Under [redacted]

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	Cents/ MMBtu	$/Ton
[redacted]								

[redacted]

The initial [redacted] contract was signed in [redacted] for [redacted] tons per month of [redacted] coal for Conesville that would be washed in the Conesville Coal Preparation Plant. The initial contract ran through [redacted]. Subsequent amendments increased the volume to [redacted] tons per month and extended the contract, such that its current expiration date is [redacted]. In addition, [redacted] once its [redacted] is fully operational. However, at Buyer's option and if for at least a six month period, AEPSC can request only [redacted]0 tons of [redacted] coal and the balance [redacted].

Shipments under the [redacted] in 2010 are summarized in Exhibit 3-17. The shipments were [redacted] and [redacted] coal. In many months, the [redacted] coal did not meet the contracted quality specifications. In all but one month, the [redacted] coal did not meet the Btu specifications. This is disappointing given the [redacted] coal.

Exhibit 3-17
Shipments Under [redacted], 2010

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	Cents/ MMBtu	$/Ton

The [redacted] agreement was amended [redacted] times in 2010. Four of the amendments dealt with price adjustment-related issues. Amendment [redacted] provided [redacted] in 2010 and 2011 in exchange for a price [redacted] of [redacted] per ton for shipments in the fourth quarter. AEPSC's economic analysis showed the additional payment was less than the cost of outside storage which AEPSC estimated to be [redacted] per ton.

EVA has several concerns with this amendment. First, AEPSC notes that the payment is in part justified to [redacted] which is a major concern for [redacted]. Second, AEPSC could in fact have managed the additional inventory at [redacted] according to its own records, thereby reducing its avoided costs. Third, AEPSC does not tie the [redacted].[17] Given the excessive inventory at [redacted], any additional requirements at [redacted] would have been better met by diversion of existing purchase commitments, which may have been achieved at a lower cost.

[redacted]

In [redacted], AEPSC determined a need for coal for [redacted]. The operating and environmental requirements dictate a mid sulfur, low ash fusion coal. The contract with [redacted] is one of [redacted] contracts for this product. The contract is for [redacted] years at [redacted] tons per year. The coal under this contract is shipped from the [redacted] which [redacted]. The contract was not [redacted] retained the obligation to perform. The contract was extended to allow for full contract shipments.

Shipments under this [redacted] contract are listed in Exhibit 3-18. The average SO_2 level was above the contracted half-month quality in most months.

Exhibit 3-18
Shipments Under [redacted] Agreement, 2010

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	Cents/ MMBtu	$/Ton
[redacted]								

[17] [redacted]

The new agreement provided for firm tons and prices for 2009 and 2010 and provided a unilateral option for OPCO tons in 2011 at a predetermined price. The agreement also imposed some good faith obligations for the parties to negotiate for tons in .

In August 2010, the parties amended the agreement taking into account the contract obligations. The amendment provided a commitment for the tons plus another tons with firm pricing, as shown in Exhibit 3-19. The final million tons for delivery is subject to agreement on price. AEPSC appeared to rely EVA agrees the forward prices provide useful information but they should not be considered the definitive guide with respect to future pricing. Given the volume of tons, an RFP would have provided

Exhibit 3-19
Summary of Tons and Price Under Amendment 2010-1

	Oringal Contract	Amendment 2010-1

The amendment also provided for some adjustments to the quality and suspension rights for shipments in 2011 and beyond. AEPSC agreed to increase the

Shipments under the Agreement are summarized in Exhibit 3-20. shipped the full contract tonnage. However, most of the coal went to the station, not . In no months was the coal quality consistent with the contracted Btu. Even with the would be non-compliant in all but two months.

Exhibit 3-20
Shipments Under [redacted] Agreement, 2010

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	Cents/ MMBtu	$/Ton
[redacted]								

[redacted]

AEPSC entered into an agreement with [redacted] for Powder River Basin coal given an expectation that by 2010 [redacted] would burn a [redacted] with [redacted] coal/[redacted] coal. AEPSC subsequently determined that such high usage of Powder River Basin coal would likely result in violations of the [redacted], where the [redacted] ash is disposed. As a result, AEPSC is limited to [redacted] Powder River Basin coal in its [redacted] AESPC informed [redacted] that AEPSC had the right to suspend performance and, as a result, that the [redacted] tonnage of [redacted] tons per year needed to be reduced by [redacted] percent. After review, [redacted] agreed. AEPSC also informed [redacted] of the [redacted] at [redacted].

Pursuant to these discussions, the parties agreed to revise their respective obligations. The annual tonnage was [redacted] and the term was extended.[18]The amended agreement provides for delivery to [redacted]. AEPSC evaluation of the amendment yielded a [redacted]. EVA believes that AEPSC under-valued this amendment by not including any [redacted][19]

In August 2010, AEPSC determined that due to the [redacted] at [redacted] it was still over-committed with respect to Powder River Basin coal. AEPSC determined that it would save money if it were to sell its excess tons [redacted] rather than pay for off-site storage and handling costs. EVA concurs with this decision.

Shipments under this agreement in 2010 are summarized in Exhibit 3-21. The coal is shipped via the Cook Coal Terminal. The summary shows only the receipts at OPCO plants. The delivered Btu content of the coal is consistently below the contracted specification.

[18] [redacted]

[19] The standard industry tool to evaluate an option is the Black-Scholes model.

Exhibit 3-21
Shipments Under [redacted] 2010

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	Cents/ MMBtu	$/Ton
[redacted]								

[redacted]

In [redacted], AEPSC entered into a two year agreement with [redacted] for Powder River Basin coal given an expectation that [redacted] would burn a [redacted] with [redacted] Powder River Basin

coal. AEPSC subsequently decided that the required investment to achieve the [redacted] was not appropriate at this time given the uncertainty regarding new air regulations and the [redacted] The current plan is to burn [redacted] with [redacted] Powder River Basin coal. As a result, AEPSC has excess Powder River Basin coal under contract. The excess coal is being diverted to [redacted].

Shipments under this [redacted] agreement in 2010 are summarized in Exhibit 3-22. The coal is shipped via the Cook Coal Terminal. The summary shows only the receipts at OPCO plants.

Exhibit 3-22
Shipments Under [redacted] Agreement, 2010

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	Cents/ MMBtu	$/Ton
[redacted]								

In , AEPSC and entered into a complex contract for high volumes of sulfur coal for an extended period. The contract is complex in part because of its sourcing/quality and in part because of its pricing. The coal is supposed to be from mines. There are multiple quality specifications, some of which vary by year. Part of the coal comprises the sulfur portion of the coal blend and is delivered by . The pricing is complex because which also affect annual . In addition to the five plus pages of the contract devoted to the and , the contract also includes by reference an which is provided on .

The contract requires that the parties establish pricing for a total of in 2010 for delivery in . Negotiations yielded agreements on prices. AEPSC indicated that the negotiated prices compared favorably to both and . AEPSC also compared the price to the NYMEX price.

In theory, forward price curves represent the price at which willing sellers and buyers are willing to transact at for some future period. Some commodities, such as NYMEX coal, are actually traded in this manner, thereby allowing both physical and financial transactions to occur. sulfur coal, however, is not traded in this manner. There is no liquid index for these products. forward price curve simply reflects is similar. As a result, the forward price curves published by and are interesting but not definitive with respect to pricing and should not be used in this manner. NYMEX, on the other hand, is traded both physically and financially. However, NYMEX coal is very different than coal, both in respect to quality and price movements, and is not an appropriate metric for determining coal prices. AEPSC has many more years in this contract and needs to develop a better approach for determining market prices for future redeterminations.

Shipments in 2010 under the Agreement are summarized in Exhibit 3-23. The quality specifications, except with respect to are based upon coal origin. As a result, only the Btu non-compliance is shown.

Exhibit 3-23
Shipments Under [redacted] Agreement, 2010

Month	Plant	Product	Tons	Btu/lb	SO2	Ash	Cents/	$/Ton
[redacted]								

As noted above, in , AEPSC determined a need for coal for Given the boiler design and air emission limits, a coal is needed. The contract for coal was one of .

Shipments under the agreement in 2010 are summarized in Exhibit 3-24. In mid-2009 when it became clear that the projected burn would not materialize, AEPSC amended the contract to defer tons of deliveries until the d and quarter of at the and under the . With the exception of ash, the coal quality was in compliance with the contract specifications.

Exhibit 3-24
Shipments Under Agreement, 2010

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	$/ MMBtu	$/Ton

In following the successful of the stations, AEPSC determined the for this . To implement its strategy, AEPSC entered into several coal supply agreements in including the one with for sulfur coal. The agreement is for years, starting in . The years are at tons per year; the at tons. There were no amendments to the contract during the audit period.

Shipments under the Contract in 2010 are summarized in Exhibit 3-25 delivered the contract tons and met the SO_2 limits in each month. was slightly non-compliant with the monthly guaranteed Btu in two months.

Exhibit 3-25
Shipments Under [redacted] Agreement, 2010

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	$/ MMBtu	$/Ton
[redacted]								

[redacted]

In [redacted], [redacted] and [redacted] entered into a [redacted]-year agreement for the supply of [redacted] tons per year to the [redacted] plant. In addition, the agreement gives [redacted] the [redacted] on any tonnage sold from the [redacted] and an [redacted] tons each year provide such option is exercised no later than six months prior to the commencement of the next year. The mine is located on reserves [redacted]. The contract was amended three times in 2010, all of which were price adjustment-related, based on the [redacted] outlined in the terms and conditions of the contract.

Shipments in 2010 under the [redacted] are summarized in Exhibit 3-26. [redacted] was in compliance with all of the quality specifications on a monthly basis.

Exhibit 3-26
Shipments Under [redacted] Agreement, 2010

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	$/ MMBtu	$/Ton
[redacted]								

AEPSC did not exercise its option for [redacted] in2011.

[redacted]

The initial contract with [redacted] was signed in [redacted] and provided for [redacted] tons of [redacted] coal and [redacted] tons per year of [redacted] coal through [redacted] with [redacted] one-year extension options for AEPSC. With [redacted] months notice, AEPSC could elect to require [redacted] and deliver [redacted] tons per year of [redacted] in lieu of Specification A coal. The specifications are described in Exhibit 3-27.

Exhibit 3-27
Quality Specifications In [redacted] Mining Agreement

	A	B	C
[redacted]			

Subsequent amendments [redacted]. In [redacted], AEPSC amended the contract to increase volumes to [redacted] tons per year in [redacted] with an option to extend to [redacted]. As explained above, under the amended agreement, the option now runs to [redacted] with pricing in [redacted]nd later at the agreed upon [redacted].

In 2010, AEPSC recognized it could not purchase the entire 2010 [redacted] volumes due to [redacted] at [redacted]. AEPSC negotiated a revised shipment schedule with some [redacted] in order to accommodate the deferrals. In

addition, AEPSC agreed to purchase [redacted]

Shipments under the [redacted] are summarized in Exhibit 3-28. The coal moving to [redacted] was consistently higher in ash and lower in Btu than contracted.

Exhibit 3-28
Shipments Under [redacted] Mining Agreement, 2010

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	$/ MMBtu	$/Ton
[redacted]								

[redacted]

[redacted] approached AEPSC in January [redacted] about using [redacted] coal at several of its scrubbed plants traditionally supplied by [redacted] coal. The timing was good as prices for [redacted] coals had risen to all time highs. A technical review approved the coal for testing. Given expected open [redacted] sulfur coal positions at [redacted], AEPSC decided to proceed. AEPSC negotiated about a [redacted] year contract for [redacted] given the tight market at that time. As appropriate for a new source, the contract provided an out for AEPSC if it determined "in its sole discretion" that the [redacted] coal was not suitable. AEPSC made no such determination. According to [redacted], the [redacted] coal was never [redacted]. Given the relatively small size of the purchase, the coal "blended" into the [redacted] stockpile without incident.

The parties agreed to terminate the contract at [redacted]. According to AEPSC, [redacted] encountered [redacted]. [redacted] and the coal was not needed [redacted]

Shipments under the [redacted] contract in 2010 are summarized in Exhibit 3-29. The SO2 content was not in compliance with the half month specification during several months.

Exhibit 3-29
Shipments Under The [redacted] Contract, 2010

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	$/ MMBtu	$/Ton
[redacted]								

[redacted]

A long time source of supply to [redacted] has been the [redacted] mine.[20] [redacted]. In [redacted], the mine was sold to [redacted] and became part of a company currently known as [redacted]. The [redacted] contract is effectively a contract which is [redacted] the

[20] The mine has been operated by different owners and under different names.

coal to . At the end of closed on its purchase of which included

While is the named buyer, none of the coal as shown in Exhibit 3-30 moved to in 2010 as receives adequate supply from and . All shipments have been non-compliant with respect to .

Exhibit 3-30
Shipments Under Agreement, 2010

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	$/ MMBtu	$/Ton

The contract provided for the tons to for . According to AEPSC, the parties were not able to agree on a price going forward and the contract terminated on its own terms. The termination was appropriate given AEP Ohio's .

In , AEPSC entered into a year agreement with with shipments beginning in . The contract was signed during a period in which there were concerns about supply due to the tight market. AEPSC estimated a sulfur coal requirement for period, with an open position of tons. The commitment to of tons in and tons each , increased the contract commitment to . The commitment was entered into when a stable burn at these plants was a reasonable assumption. In hindsight, this did not turn out to be the case.

Shipments under this contract in 2010 are shown in Exhibit 3-31. Almost all of the shipments under this contract have been non-compliant with the Btu specifications. In several months, the AEPSC would have been able to . Given the and , AEPSC should be strictly enforcing performance.

Exhibit 3-31
Shipments Under [redacted] Agreement, 2010

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	$/ MMBtu	$/Ton
[redacted]								

[redacted]

The current [redacted] contract was entered into in late [redacted] Contract volume for [redacted] was [redacted] and the term [redacted] with the [redacted] tons. This coal was purchased for [redacted]. Subsequent to the purchase, [redacted] became a [redacted] making requirements both variable and uncertain.

This agreement was amended twice in 2010. The first amendment provided for a [redacted] to [redacted], along with some [redacted] to allow [redacted] to recover the [redacted]. The second amendment reduced [redacted] and [redacted] tons with a [redacted] in the [redacted] price. The changes are summarized in Exhibit 3-32.

Exhibit 3-32
2010 Amendments to the [redacted] Contract

	Base Contract	Amendment 2010-1
[redacted]		
	Base Contract	**Amendment 2010-2**
[redacted]		

AEPSC's analysis of the [redacted] amendment showed the first amendment to be effectively neutral to AEPSC. The analysis of the second amendment showed a significant present value driven primarily by the savings associated with not [redacted]. EVA believes that AEPSC over-stated the savings significantly by including in the saving the [redacted].[21] The true savings to AEPSC relate to the [redacted] Further, AEPSC should have estimated the cost associated with [redacted] this coal in [redacted] and [redacted].

[redacted] shipments during 2010 are shown in Exhibit 3-33. In five out of the last six months of the year, [redacted] was non-compliant with the Btu specifications.

Exhibit 3-33
Shipments Under [redacted] Company Contract

Month	Plant	Product	Tons	Btu/lb	SO2 (lb/MMBtu)	Ash (%)	$/ MMBtu	$/Ton
[redacted]								

The [redacted] coal met the SO_2 contract requirements on a regular basis. [redacted] missed the guaranteed monthly Btu specification in five out of the 12 months, although it was always above the [redacted] suspension limit. The ash maximum was exceeded during one month.

Transportation Review

Coal is generally offered to AEPSC FOB barge or FOB railcar and it is the responsibility of AEPSC to arrange for transportation. The only exception is truck coal which is sold FOB plant. Barge transportation is exclusively handled by AEP River Operations. River Operations is a wholly-owned affiliate operating within FEL. AEPSC is a party to multiple rail contracts under which the rail coal is delivered.

[21] [redacted] demonstrate the change in the coal market in the second half of 2010.

During the tight period in the market, AEPSC believes that its customers received extraordinary benefits from River Operations as the railroads were more focused on export business. AEPSC believes that a major reason it was able to maintain sufficient shipments to its plants was that it switched some rail movements to barge. The rates charged by River Operations are based upon costs and the returns and the allowed returns. The Financial Audit provides a full discussion of the associated accounting.

The rail contracts are summarized on Exhibit 3-34. AEPSC owns 1500 railcars and leases another 7500 which it uses as appropriate. Very little of the [redacted] movements use railroad owned cars.

Exhibit 3-34
Rail Contracts

Carrier	Agreement No.	Plants	Expiration
[redacted]			

There were no major issues with the railroads during 2010. AEPSC, along with most other western coal shippers, are working to determine how to address dust controls on trains moving on the Joint Line out of the Powder River Basin following the ruling by the Surface Transportation Board.

Other Fuel Procurement

AEPSC also acquires natural gas for CSP. The gas is for Darby and Waterford. Gas purchases in 2010 are summarized by month on Exhibit 3-35 and compared to 2009. [redacted]. AEPSC indicated that one of the reasons for the increase is the extended start on coal units. Current strategy has been to buy gas [redacted]. AEPSC has multiple NAESB[22] agreements in place which serve as the basis for the purchases. If capacity factors [redacted] AEPSC's strategy [redacted].

[22] North American Energy Standards Board

Exhibit 3-35
Natural Gas Purchases

	Tier Price (Wtd Avg)	Gross MMBtu's	Net MMBtu's
[redacted]			

AEPSC also purchases fuel oil. A competitive bid for oil was conducted. Purchases are relatively low and the agreement is for requirements.

4 CONESVILLE COAL PREPARATION PLANT

Plant Description and Operation

The Conesville Coal Preparation Plant (CCPP) was built in the early 1980's to wash local, high-sulfur, raw coal for Conesville Units 1-4 which at that time was subject to a 5.66 pound SO_2 per MMBtu emission limit. Since that time, Units 1 and 2 have been retired, and Unit 4 has been retrofit with a scrubber.

CCPP has a rated capacity to wash 1,000 raw tons of coal per hour, but typically runs around 850 raw tons per hour. The preparation plant consists of three primary washing circuits, each set up to wash a certain size material:

1. The **jig circuit** washes the 6" by 3/8" raw coal and is operated to work at an effective specific gravity of 1.6-1.65. The typical quality of the refuse from the jig circuit is 83 percent ash and 1,174 Btu/lb. The jig circuit produces about 55 percent of the clean coal.
2. The **heavy media cyclone circuit** washes the 3/8" by 28 mesh raw coal with two 26" heavy media cyclones operating at 1.47-1.48 specific gravity. The typical quality of the refuse from the heavy media cyclone is 76-77 percent ash and 1,088 Btu/lb. The heavy media cyclone circuit produces about 40 percent of the clean coal.
3. The **flotation cells** wash the minus 28 mesh raw coal, but this circuit has been idled for years. The plant is currently screening the minus 28 mesh material at 100 mesh. The 28 to 100 mesh material is dried with centrifuges and sent to the clean coal conveyor. The minus 100 mesh material is dried with filter presses and sent to the refuse pile. The 28 to 100 mesh material produces about five percent of the clean coal.

The raw coal handling facilities at the preparation plant site includes a truck dump, primary crusher to minus 6", raw coal pile with the ability to keep the two coals separate with a radial stacker, and an underground reclaim belt capable of blending the different raw coals. The clean coal handling facilities include a radial stacker with an underground reclaim conveyor that ships the coal directly to the Conesville power plant. A picture of the coal handling facilities at CCPP is shown in Exhibit 4-1. The picture was taken from the top of the preparation plant.

Exhibit 4-1
Coal Handling Facilities At CCPP

The refuse from CCPP is all dry refuse, i.e., no slurry ponds are used for the fine coal refuse. The fine refuse is dried with filter presses that reduce the moisture content of the fine refuse to about 30 percent. The fine refuse is blended with the coarse refuse and trucked to the refuse disposal area. The company reports it has sufficient permitted refuse area to last for [redacted] years at current operating rates.

CCPP currently washes raw coals from [redacted] suppliers. As shown in Exhibit 4-2, in 2010 [redacted] supplied about two-thirds of the raw coal. Average quality was about [redacted] percent ash and [redacted] percent sulfur. [redacted] supplies the balance. The ash was similar to [redacted] but the sulfur was much higher. The [redacted] coal is also higher in sulfur.

Exhibit 4-2
Raw Coal Shipped to CCPP, 2010

Supplier	Tons	M(%)	A(%)	S(%)	Btu/lb
[redacted]					

Operating Performance

The operating performance of the CCPP from 2006 to 2010 is shown in Exhibit 4-3. The utilization of the CCPP was [redacted] because of reduced demand for coal from Conesville and the delivery of almost [redacted] tons of [redacted] coal directly to the power plant. Yield in 2010 was the [redacted] of the last five years and Btu per pound was [redacted].

Exhibit 4-3
CCPP Operating Performance From 2006 To 2010

	2006	2007	2008	2009	2010
[redacted]					

Operating Cost

The operating costs of the CCPP [redacted] 2006 to 2010 are shown respectively in Exhibits 4-4 and 4-5. Clean coal production [redacted] in 2010 as compared to 2009 and almost half as compared to 2008. This drove up the benefit, maintenance, power, and other costs that are largely fixed on a total dollar basis. Costs per ton went up [redacted] percent year-on-year and [redacted] percent compared to [redacted]

Exhibit 4-4
CCPP Clean Coal Operating Costs, 2006 to 2010

Clean Costs ($/Ton)	2006	2007	2008	2009	2010
[redacted]					

Exhibit 4-5
CCPP Raw Coal Operating Costs, 2006 To 2010

Raw Coal ($/Ton)	2006	2007	2008	2009	2010
[redacted]					

Closure Study

EVA recommended in last year's report of the management/performance audit that AEPSC should undertake a study to determine whether there is an economic justification for continuing to operate the Conesville Coal Preparation Plant given the renegotiation of the [redacted] coal to washed coal combined with a [redacted] in overall Conesville coal demand. AEPSC agreed to perform the study. The study, which is not dated, was provided to the auditors on April 21st after repeated requests, starting in December 2010.[23] Responses to a follow-up data request related to the study were provided during the second week of May.

[23] It is clear from the report that AEPSC completed the study prior to March 16, 2011 when the EPA issued its proposed HAPs rule. ("The analysis for the CCPCO facility study was performed prior to the March 16, 2011 issuance of the proposed EPA Hazardous Air Pollutants (HAPs) rule.") It is not clear to the auditors why the study was not released for review sooner.

AEPSC narrowly designed the study. AEPSC evaluated four scenarios. The Base Case assumes the plant is closed in the [redacted] quarter of [redacted]; Scenarios II and III defer the closure by one year, varying only with respect to what quality of coal is delivered in [redacted]. Scenario III is the only scenario in which the plant is assumed to stay open through [redacted] and assumed an adjustment to generation given higher fuel costs. The Base Case is substantially [redacted] than the other scenarios. Scenario III costs are over [redacted] more than the Base Case costs on a net present value basis. AEPSC, therefore, concluded that "the best economic decision for closure would be during the [redacted] of [redacted]."

EVA identified several flaws[24] with AEPSC's study but agrees with its conclusions that continued operation of the preparation plant is not economic. That being said, EVA does not believe AEPSC has appropriately considered the timing of the plant closure as closure [redacted] may be more appropriate.

In an apparent addendum to the report, AEPSC noted it believes its conclusion regarding plant closure may be premature in the context of EPA's proposal regarding EPA's March 16th, 2011 proposal regarding regulation of Hazardous Air Pollutants. Specifically, AEPSC indicated it is concerned that it cannot comply with the new HAPS rule for mercury at [redacted] without burning a washed coal, although AEPSC provided nothing in the report to demonstrate specifically why this would be the case in the context of the proposed rule, its coal contract obligations, and its plans to retrofit SCR's on these units.

EVA disagrees with AEPSC's addendum for the following two reasons:

- AEPSC is not obligated to purchase a specific coal beyond [redacted]. If AEPSC determines it can only comply with the new HAPS rule by burning a washed coal, it is can purchase washed coal.

- Compliance with the new HAPS rules is unlikely to be required until November 2014. Therefore, continuing operation of CCCP in a non-economic manner would be imprudent.

Given AEPSC's findings that the closure of the plant is economic, EVA recommends the following:

- AEPSC immediately evaluate whether an earlier closure could be accommodated in the context of its existing coal supply agreements.

- AEPSC should offer to sell the plant (as is or in pieces) to third parties in order to minimize closure costs.[25]

[24] The flaws include the presumption that [redacted] coal would continue to be used post [redacted]; the earliest the plant could be closed was the [redacted] of [redacted]; and the lack of need for washed coal in [redacted] given the timing of a new HAPs regulation.

[25] A sale should not include a buy back obligation until it clear washed coal is required for [redacted] and unless it is the lowest cost option for CSP customers all things considered.

AEPSC provided its estimates of closure costs as of several closure dates. The net present values of the closure costs are summarized in Tab A to the closure study and provided in Exhibit 4-6.

Exhibit 4-6
Conesville Preparation Plant – Estimation of Closure Costs

[redacted]

The [redacted] costs and [redacted] costs are lower on a net present value basis if the plant closure is deferred simply because of the discounting factor. [redacted], on the other hand, [redacted] with the deferred closing because the expected increases in these costs ([redacted]) exceed the discounting factors.

AEPSC has already restated its Asset Retirement Obligation to reflect plant closure in [redacted].

AEPSC indicates that how the other costs are recovered is not clear as after the plant is closed as these costs are appropriately charged to FERC Account 506, which is not recovered through the FAC.[26] EVA recommends that AEPSC develop a proposal for the accounting of these costs for review in the next audit cycle. The proposal should reflect the fact that a substantial portion of

[26] AEPSC indicates it would require PUCO authorization to be recoverable.

these costs (1) should be paid by CSP's [redacted] in [redacted] and (2) these costs are tied to coal delivery in prior periods.

5 ENVIRONMENTAL AND ALTERNATIVE ENERGY SOURCES

Environmental Requirements

AEP Ohio coal plants are subject to air emission regulations through both state and federal programs. The only units equipped with flue gas desulfurization equipment when built were the Conesville 5 & 6 units. Since then Gavin, Mitchell, Cardinal 1 and Conesville 4 have been retrofitted with scrubbers.[27] As shown in Exhibit 5-1, the only remaining unit for which a scrubber is planned is Muskingum 5 in 2015. As discussed in Section 1, the current IRP assumes Muskingum 5 will be retired rather than retrofit. A final decision needs to be made by the end of the year given AEP's 2015 deadline under the Consent Decree for this unit.

Exhibit 5-1
Status Of Environmental Retrofits On AEP Ohio Units

	Cardinal	Conesville				Gavin		Kammer			Mitchell		Muskingum River					Picway
	1	3	4	5	6	1	2	1	2	3	1	2	1	2	3	4	5	5
SCR	X		X	2015	2015	X	X				X	X					X	
FGD	X		X	X	X	X	X				X	X					2015	

Note: X means installed; shading means not planned

The technology AEP chose for the scrubber retrofit on Cardinal 1and Conesville 4 (as well as other non-AEP Ohio plants) utilizes the jet bubbling reactor technology. AEP has encountered unexpected operating results with this technology which it has determined are a result of fundamental design deficiencies and that "inferior and/or inappropriate materials were selected for the internal fiberglass components." AEP and Black & Veatch developed a corrective action plan which AEPSC believes resulted in an immaterial increase in the capitalized costs of the projects for the modification of the scope of the contracts.

With the exception of Conesville 5&6, all of the scrubbed units and Muskingum 5 are equipped with selective catalytic reduction (SCR) for NOx control. AEP Ohio plans to retrofit Conesville 5&6 with SCRs in 2015. There are currently no plans to scrub or retrofit SCRs on Conesville 3, Kammer, Muskingum 1-4, and Picway. These units are what AEP calls "fully exposed". The current IRP assumes these units are retired by 2020. (See discussion in Section 1)

Under Title IV, AEP must forfeit an SO_2, seasonal NOx, and annual NOx emission allowance for each ton of SO_2, seasonal NOx, and annual NOx its units emit. The prices of emission allowances have been very volatile. As a result of significant technology retrofits, uncertainty regarding future emission allowance markets and reduced generation, allowance prices have fallen considerably.

[27] The scrubber retrofit on Cardinal 1

AEP has a stated policy with respect to emission allowance management. The policy acknowledges AEP's responsibility to have sufficient allowances to support generation. Only if it is determined that AEP has surplus allowances will the disposition of allowances be considered. AEP Ohio is a party to the Interim Allowance Agreement which provides the framework for the allocation of SO_2 purchases and sales among the AEP companies. Seasonal and Annual NOx allowances are managed separately for CSP and OPCO Emission Banks

The emission banks for AEP Ohio as of the start and end of the audit period are summarized in Exhibit 5-2. With the uncertainty over future value and the large drop in emissions in 2010, the market for allowances is still soft. CSP and OPCO had relatively little activity during 2010. The transactions were related to the March auction of allowances[28], some true ups/power sales-related, and emission re-allocations pursuant to the Interim Allowance Agreement and the Gavin reallocation.

Exhibit 5-2
Status Of Emission Allowance Banks

	Columbus Southern Power		Ohio Power	
	Balance as of 12/31/2009	Balance as of 12/31/2010	Balance as of 12/31/2009	Balance as of 12/31/2010
[redacted]				

AEP Ohio's consumption of emission allowances in 2010 is summarized in Exhibit 5-3 based upon ownership shares. Muskingum River was by far the largest emitter of SO_2, accounting for well over half of SO_2 emissions. Muskingum River was also the largest emitter of seasonal and annual NOx reflecting the lack of SCRs. Conesville was also a large emitter of NOx, also due to the lack of SCRs on Units 5&6.

[28] The EPA withholds 2.8 percent of the emission allocations each year and sells them in an auction. Auction proceeds are then distributed to the utilities.

Exhibit 5-3
Allowance Consumption During Audit Period(Tons)

	SO2	Seasonal NOx	Annual NOx
CSP			
Beckjord 6	5,098	258	523
Conesville	15,460	3,492	7,307
Picway	1,152	166	200
Stuart	2,609	910	2,971
Zimmer	5,119	781	2,061
OPCO			
Amos 3	2,011	659	1,632
Cardinal 1	3,805	321	654
Gavin	25,327	2,705	6,720
Kammer	14,111	1,177	3,050
Mitchell	4,447	1,277	2,714
Muskingum River	98,413	4,438	8,913
Sporn 2, 4, 5	9,023	849	1,906

Forecast Of Consumption Of Emission Allowances

AEP's current forecast of SO_2 emission allowance consumption through 2014 is summarized on Exhibit 5-4. Beginning in 2012, AEP assumes that two allowances must be forfeited for each ton of SO_2 emitted. The forecast is compared to 2009 emissions.

The biggest change from 2009 is with respect to Stuart because of the scrubber retrofit. There was also a drop due to reduced generation at Conesville and Kammer. Assuming the forfeiture policy remains the same, AEP Ohio has adequate SO_2 allowances in its bank for 30 years (assuming the scrubber retrofit of Muskingum River 5 proceeds as planned). While AEPSC is not actively marketing SO_2 allowances, it indicated that it would consider a sale if there was market interest.

AEP's current forecast of seasonal and annual NOx emissions is provided on Exhibit 5-5. As with SO_2, emissions vary with technology and plant utilization.

AEP Ohio also has a surplus of NOx emission allowances. AEPSC indicated that it did not believe the surplus will ever be utilized for compliance and that it was looking to monetize the surplus. AEPSC uses a variety of brokers (e.g., Climate Futures Exchange, ICAP, and Evolution Markets) for the sale.

Exhibit 5-4
Forecast Of SO2 Emission Allowance Consumption(1,000 Allowances)

2011	2012	2013	2014	2015

Exhibit 5-5
Forecasted Seasonal And Annual NOx Emission Allowance Consumption(1,000 Tons)

Seasonal					Annual				
2011	2012	2013	2014	2015	2011	2012	2013	2014	2015

Future Environmental Requirements

Several proposed environmental regulations that could directly affect utility coal consumption have been or are expected to be announced shortly.[29] In July 2010, EPA proposed the Clean Air Transport Rule (CATR), which is replacing the Clean Air Interstate Rule, to regulate fine particulates and ozone. In March 2011, EPA proposed new standards for hazardous air pollutants which will require the use of Maximum Achievable Control Technology (MACT) by 2015. EPA is required to finalize the Utility MACT by November 16, 2011. Compliance would be required within three years of the rule. Other new rules that could affect coal use relate to ash disposal points and once through cooling water.

AEP is actively evaluating the consequences of each new regulation individually and collectively on its units. As noted in Section 1, there is general consensus that the "fully exposed" units will be retired by 2020. Compliance strategies for the remaining units are being evaluated. With respect to AEP Ohio, the most imminent decision is whether to scrub Muskingum 5.

In addition to the regulations noted above, there continues to be uncertainty related to the utility consequences of the December 2009 EPA finding that atmospheric concentrations of greenhouse gases endanger public health and welfare within the meaning of the Clean Air Act. In May 2010, the EPA published final greenhouse gas emission standards for new motor vehicles pursuant to the Clean Air Act. Both the endangerment finding and motor vehicle standards are the subject of litigation.

In December 2010, EPA announced a settlement with states and environmental groups that had filed litigation challenges to EPA's decisions not to establish greenhouse gas emission standards for fossil fuel-fired power plants and for petroleum refineries under section 111 of the Clean Air Act. In the settlement, the EPA agreed: (1) to sign proposed new source performance standards for new and modified electric utility steam generating units under section 111(b), as well as proposed guidelines for states' development of emission standards for existing electric utility steam generating units under section 111(d), by July 26, 2011; and (2) to take final action on the proposed section 111(b) standards and section 111(d) guidelines by May 26, 2012. Whatever the EPA determines the new source performance standards to be, this will then be the minimum requirement for best available control technology requirements under the prevention of significant deterioration program. Absent new legislation, which in the current climate of partisanship is unlikely, the EPA is required to continue moving forward on greenhouse gas regulations.

AEP is developing strategies to reduce greenhouse gas emissions which are incorporated into American Electric Power's Corporate Sustainability Report.[30] The strategy incorporates the following components:

- Active participation in discussions around federal climate policy,
- Active participation in the Chicago Climate Exchange and the International Emissions Trading Association,

[29] There are a multitude of new regulations that are expected to be announced that could affect coal production as well.

[30] www.aepsustainability.com/ourissues/climate/

- Compliance with renewable energy and efficiency targets included in S.B. 221,
- Consideration of efficiency improvements in its generating fleet which will reduce CO2 emissions,
- Exploration of carbon capture and storage options for possible application to AEP Ohio plants,
- Exploration of lower CO2 emitting generating sources, and
- Investigation of emission offset credits as a compliance option.

Environmental Reagent Costs

The cost of environmental reagents is recovered in the FAC. Reagent costs have increased with the addition of scrubbers at Cardinal, Conesville, and Mitchell and SCRs. . A schedule of reagent requirements by plant is provided in Exhibit 5-6.

Exhibit 5-6
Reagent Requirements By Plant

	Lime	Limestone	Hydrated Lime	Trona	Urea
Conesville 4		X	X	X	X
Conesville 5/6	X				X
Cardinal		X	X	X	X
Mitchell		X	X	X	X
Gavin	X			X	X
Muskingum River					X

The Gavin and Conesville 5&6 scrubbers use lime: the other (newer) scrubbers use limestone. The use of limestone scrubbers has reduced the relative cost of scrubbing as limestone is significantly lower in cost than lime. There are multiple suppliers of limestone and good long-term availability. AEPSC uses hydrated lime for water treatment with the limestone scrubbers. Lime availability for the lime scrubbers is a concern.

The trona is used for SO3 mitigation. The largest trona deposit is in the Green River Basin in Wyoming. The trona is difficult and expensive to transport because it must be kept dry and away from heat.

Urea is required by the SCRs. The urea is imported from Qatar. Pricing is based upon the world market price for this commodity. The material is delivered by vessel to New Orleans and moved in covered barges to Ohio.

AEPSC had multiple consumable contracts in place during 2010. AEPSC has been actively working to develop multiple sources of supply for each consumable, thereby creating competition for the business and greater certainty of supply. To that end, AEPSC now has at least two sources of supply for each product. EVA agrees with this strategy.

Alternative Energy Portfolio Requirements

S.B. 221 included an Alternative Energy Portfolio Standard (O.R.C. 4928.64-65) which requires 25 percent of all kilowatt hours of electricity sold by electric distribution utilities and electric services companies to retail electric consumers under their standard service offers to be obtained by "alternative energy sources" by 2025. Alternative energy sources are defined as "advanced energy resources" and "renewable energy resources" that satisfy the applicable placed in-service requirement. Alternative energy sources can also include new and existing customer-sited advanced and renewable energy resources that the customer commits to integrate into the utility's demand-response, energy efficiency, or peak demand reduction programs. Examples include a resource that has the effect of improving the relationship between real and reactive power; a resource that makes efficient use of waste heat; storage technology that allows customers to modify their demand or load and usage characteristics; and any advanced renewable energy resource that can be utilized effectively. The final rules implementing the Alternative Energy Portfolio Standard were not issued until December 10, 2009.

At least half of the alternative energy requirement must be satisfied from "renewable energy sources" which must include solar. The percentage required by year is provided on Exhibit 5-7. The other requirement is that at least 50 percent of the renewable energy must come from in-state facilities and the balance must come from facilities that can deliver into the state. Technologies that qualify under the renewable category include: solar, wind, hydroelectric, geothermal, waste derived fuel, biomass, biologically derive methane gas, wood waste, fuel cells, and storage facilities.

Exhibit 5-7
Renewable Energy Benchmark Requirements

Year	Renewable Energy	Minimum Solar
2009	0.25%	0.00%
2010	0.50%	0.01%
2011	1.00%	0.03%
2012	1.50%	0.06%
2013	2.00%	0.09%
2014	2.50%	0.12%
2015	3.50%	0.15%
2016	4.50%	0.18%
2017	5.50%	0.22%
2018	6.50%	0.26%
2019	7.50%	0.30%
2020	8.50%	0.34%
2021	9.50%	0.38%
2022	10.50%	0.42%
2023	11.50%	0.46%
2024	12.50%	0.50%

The remaining up to half of the alternative energy requirement can come from "advanced energy resources." Technologies which would qualify include: any method or device which would increase electricity output without an increase in carbon emissions; a distributed generation system consisting of customer cogeneration and thermal output; clean coal technology which limits emissions of carbon; advanced nuclear technology; fuel cells; and demand side management and energy efficiency improvements. Unlike the renewables, there are no interim requirements, simply a cumulative 25 percent requirement by 2025.

To ensure compliance with the alternative energy standards, utilities are required to file an annual report which details its performance. If the utility has failed to meet its requirements in any year and such under-compliance is deemed to have been avoidable, the utility will be assessed a monetary penalty referred to as the "alternative compliance payment ("ACP"). The non-solar ACP is initially set at $45 per MWh and will be adjusted annually by the PUCO according to changes in the Consumer Price Index. The solar ACP is initially set at $450 per MWh. In 2010 and 2011, the solar ACP is reduced to $400 per MWh and then gets reduced by $50 every two years thereafter until it hits $50 per MWh in 2024. ACPs are deposited into the Ohio Advanced Energy Fund which provides funding for renewable and energy efficient projects within the state. ACPs are not recoverable through the FAC.

Utilities can obtain relief from certain requirements and avoid paying the ACP. A utility does not have to comply if it demonstrates that compliance with the portfolio standard is "reasonably expected" to increase generating costs by three percent or more. In addition, a utility can obtain relief through the force majeure provisions which state that the PUCO has the ability to waive compliance if the utility can demonstrate there were insufficient renewable energy products in the market place.

2010 Alternative Energy Status And Compliance Reports

In Case No. 08-888-EL-ORD, the PUCO approved Rules for the Alternative Energy Portfolio Standard for electric utilities. The Rules require each utility to file an annual report by April 15th of each year. CSP and OPCO both complied with this requirement; a summary of each report is contained in this section. The Rules also require the filling of an annual Alternative Energy Portfolio Compliance Plan by April 15th which details plans for compliance with the future benchmarks. The Companies submitted a joint compliance plan which is also summarized below.

Columbus Southern Power Compliance Report

CSP's compliance status report is summarized in Exhibit 5-8. CSP indicated it met its non-solar and solar obligations. A review of the compliance report, however, shows that CSP added its entire 2009 force majeure solar obligations to its total solar obligations rather than keeping the Ohio solar requirement separate. The exhibit below adjusts the accounting to reflect the Ohio solar obligation. As CSP has been and expects to meet its solar requirement in-state, this has no impact on 2010 compliance and may have no impact on future compliance. Nevertheless, it is EVA's understanding that the intent was to keep the requirements separate and the accounting should reflect this.

Exhibit 5-8
CSP 2010 Alternative Energy Compliance Report

	Unadjusted MWH Sales	Proposed Adjustments	Adjusted MWH Sales
2007	22,009,241	1,657,015	20,352,226
2008	22,209,937	2,388,050	19,821,887
2009	20,677,981	1,997,076	18,680,905
Baseiline for 2010 Compliance Obligation			**19,618,339**
Statutory 2010 Compliance Obligations			
Non-Solar			0.49%
Solar			0.01%
2010 Compliance Obligations			
		Ohio or Other	Ohio
Non-Solar		48,065	48,065
Solar		981	981
Force Majeure Carry Over Obligations			
		Ohio or Other	Ohio
Solar		399	331
Adjustments			
		Ohio or Other	Ohio
Non-Solar		(141)	(141)
Solar		(2)	(2)
2010 Net Compliance Obligations			
		Ohio or Other	**Ohio**
Non-Solar		**47,924**	**47,924**
Solar		**1,378**	**1,310**

Ohio Power Compliance Report

OPCO's compliance status report is summarized in Exhibit 5-9. OPCO indicated it met its non-solar and solar obligations. A review of the compliance report, however, shows that OPCO added its entire 2009 force majeure solar obligations to its total solar obligations rather than keeping the Ohio solar requirement separate. The exhibit below adjusts the accounting to reflect the Ohio solar obligation. As OPCO has been and expects to meet its solar requirement in-state, this has no impact on 2010 compliance and may have no impact on future compliance. Nevertheless, it is EVA's understanding that the intent was to keep the requirements separate and the accounting should reflect this.

Exhibit 5-9
OPCO 2010 Alternative Energy Compliance Report

	Unadjusted MWH Sales	Proposed Adjustments	Adjusted MWH Sales
2007	27,727,743	1,492,228	26,235,515
2008	27,871,540	2,405,028	25,466,512
2009	24,936,379	2,061,805	22,874,574
Baseline for 2010 Compliance Obligation			**24,858,867**
Statutory 2010 Compliance Obligations			
Non-Solar			0.49%
Solar			0.01%
2010 Compliance Obligations			1028
		Ohio or Other	Ohio
Non-Solar		60,904	60,904
Solar		1,243	1,243
Force Majeure Carry Over Obligations			
		Ohio or Other	Ohio
Solar		-	
		514	419
Adjustments			
		Ohio or Other	Ohio
Non-Solar		(66)	(66)
Solar		(1)	(1)
2010 Net Compliance Obligations			
		Ohio or Other	**Ohio**
Non-Solar		**60,838**	**60,838**
Solar		**1,757**	**1,662**

Alternative Energy Portfolio Compliance Plan

The Alternative Energy Portfolio Compliance Plan was filed on a timely basis. The Compliance Plan provides the current estimates of the benchmarks based upon forecast generation. Highlights from the plan are as follows:

- The principal strategy for fulfilling the renewable energy benchmark requirements in the near-term is to acquire the energy through long-term power purchases agreements with the proposed 49.4 MW Turning Point solar project being the exception.
- There are a number of possible wind projects in Ohio that may be attractive primarily because of the 30 percent Treasury grants.

- The Companies are on track to meeting their annual benchmarks
- In November 2010, AEP Ohio entered into a long-term contract for wind energy from the Timber Road wind project. The contract is contingent upon obtaining approval from the Commission that will allow for full cost recovery throughout the term of the agreement.
- AEP has had some limited success with biofuels, particularly biodiesel which has been successfully tested at Picway. The Companies entered into a contract for biodiesel for Conesville, Muskingum River, and Picway.

Responsibilities For Compliance With The Alternative Energy Standards

According to AEP, the responsibilities for meeting the alternative energy standards are divided among multiple departments.

- Resource Planning and Operational Analysis – Responsible for development of IRP which incorporates inputs from multiple departments regarding load forecast, commodity prices, supply side cost options, demand side options and regulatory requirements.
- Renewable Energy Department (in Commercial Operations) – Responsible for the issuance of RFPS and assumes the lead in negotiations of agreements
- AEP Ohio Customer Services Alternative Energy Resources Department – Responsible for the development and implementation of programs that will promote the use of customer-sited renewable energy resource distributed generation.
- Fuel Procurement (in FEL) – Responsible for acquiring renewable fuels to integrate into the fuel supply.
- Energy Trading (in Commercial Operations) – Responsible for executing market purchases of RECs.

Accounting For RECs

AEPSC indicates that at least initially it intends to follow the same or similar policies and procedures for purchasing, selling, and accounting of RECs as it does for emission allowances. The Company currently uses the PJM Environmental Information Services Generation Attribute Tracking System (GATS) to document and track RECs. AEPSC indicated if it moves into a position of excess RECs it may move to a different inventory situation.

Activities In 2010

Non-Solar

AEPSC issued four RFP's in 2010 on behalf of AEP Ohio. According to Jay Godfrey:

> An RFP in April 2010 received three bids, one of which was priced unreasonably high. Another RFP in August 2010 yielded zero bids. A third RFP in October 2010 received

> two bids, one of which again was priced unreasonably high. Additionally, the fourth RFP in November 2010 resulted in one response which was identical to the previous unreasonably high offer. (Godfrey Testimony, Page 7, Lines 16-20)

In 2010 AEPSC entered into a contract for wind with Paulding Wind Energy LLC for its 99 MW Timber Road wind farm. The contract is contingent upon Commission approval with approval of cost recovery for the entire 20-year term.[31] The Companies would not provide EVA copies of this agreement despite repeated requests.

During the interview process, AEPSC made it clear that it did not compare the cost of this contract to the cost of a self-build option despite some suggestion in Mr. Godfrey's testimony to the contrary. There is no question from EVA's perspective that any approval of a 20-year contract should not be provided without a determination that in fact this was the least cost option. EVA recommends that the PUCO not provide approval until AEP properly evaluates the self build option.

Solar

AEP and Turning Point Solar LLC entered into a Memorandum of Understanding on October 5, 2010 wherein both parties agreed to work together on a relationship which would lead to the construction of a large solar project in Oho. On January 21, 2011, the parties executed a Term Sheet which outlined the general terms, conditions and structure of the proposed transaction. The parties are reported continuing to work towards the execution of definitive agreements.

AEP speaks to three specific advantages associated with Turning Point. They are (1) expanding Ohio manufacturing jobs, (2) maximizing the benefit to AEP Ohio ratepayers of the Federal tax benefits for solar projects, and (3) fulfilling the long-term need for Ohio solar REC's.

EVA agrees that this type of project would have enormous value for AEP. Further, the lack of purchase options provides the necessary justification for a self-build type option.

[31] AEP has proposed a separate rider for RECs in its new ESP.

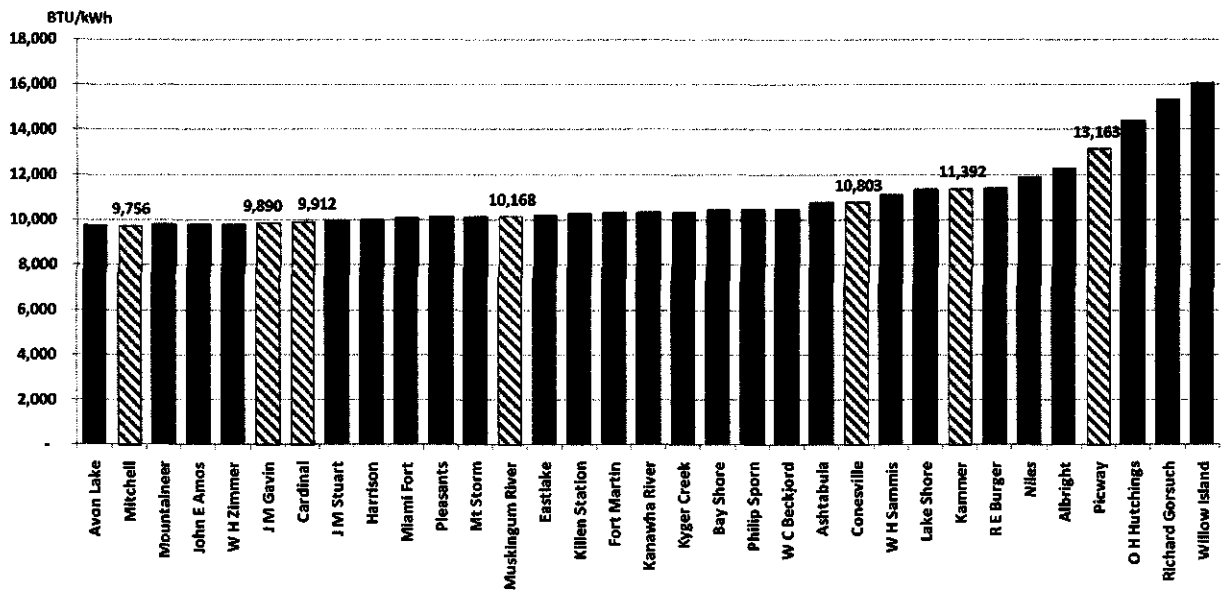
6 POWER PLANT PERFORMANCE

Benchmarking

AEP Ohio operates seven coal-fired power plants. AEP Ohio's performance with respect to these power plants can be measured by comparison with other coal-fired power plants in Ohio and West Virginia and with other coal-fired power plants in PJM. Two measures are used to demonstrate performance: heat rate and capacity factor. Heat rate is the Btu's consumed per kilowatt-hour generated. Capacity factor is the megawatt-hours generated over total potential generation during an equivalent time period.

The heat rates for the AEP Ohio plants compared to the heat rates for the other coal-fired plants in Ohio and West Virginia is provided for 2010 in Exhibit 6-1. The data used to generate these figures are from the Department of Energy, FERC, and EPA.[32] The AEP Ohio plants are highlighted. In 2010, Mitchell had the second best heat rate out of the group and three of AEP Ohio's plants were in the top 10.

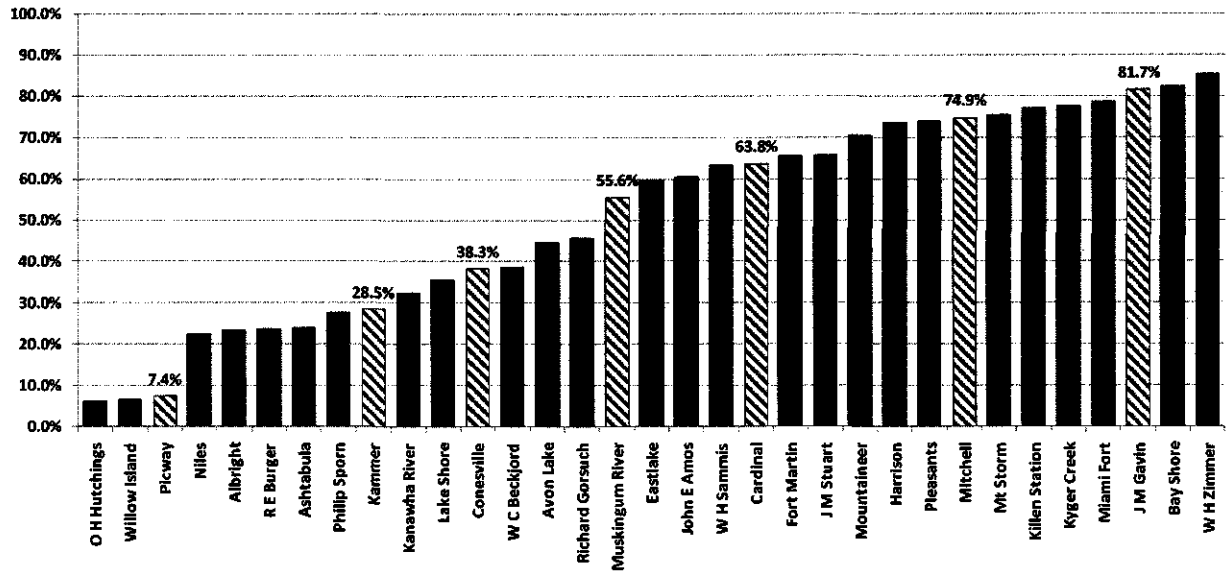
Exhibit 6-1
Coal-Fired Power Plant Heat Rates 2010



[32] All of the data (AEP and other plants) come from 2010 EIA-923 except Picway. Picway data come from FERC Form 1 (net generation) and EPA CEMS data (heat input).

The capacity factors for the same units for 2010 are provided in Exhibit 6-2. Gavin had the highest capacity factor of the AEP Ohio units with two other plants above a 60 percent capacity factor. There is a general correlation between heat rate and capacity factor. Conesville suffered again in 2010 due to the unexpected operating results of the scrubber on unit 4 and extended outages on units 5 and 6. The extended start-up program and the Kammer strategy also affected the capacity factors of Conesville, Kammer and Muskingum River plants.

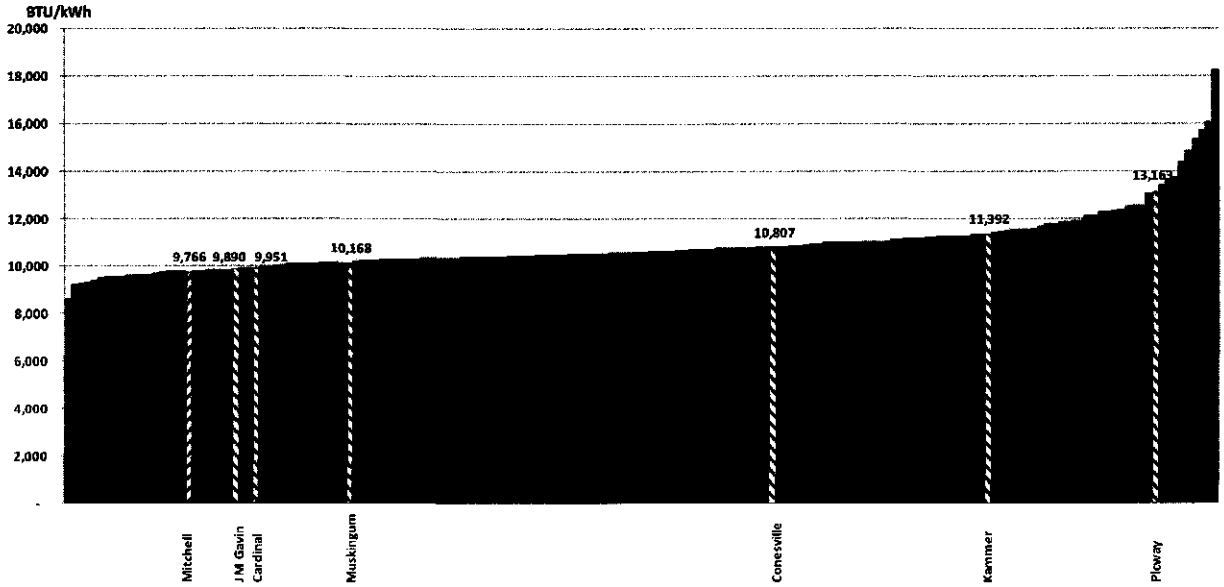
Exhibit 6-2
Coal-Fired Power Plant Capacity Factors 2010



The AEP Ohio plants are also benchmarked against the coal-fired PJM plants. AEP Ohio as a member of PJM gets dispatched by PJM. Therefore, the competitiveness of the AEP Ohio within PJM determines their utilization subject to transmission adders.

Exhibit 6-3 provides the heat rates for all PJM coal-fired plants in 2010. Four AEP Ohio plants fall in the top third.

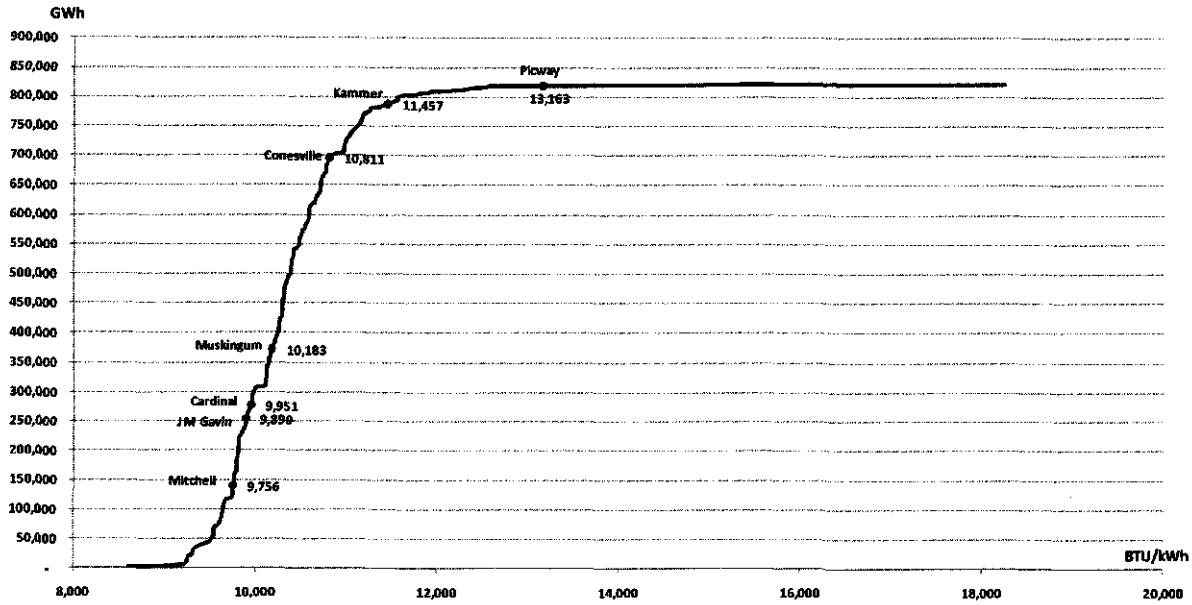
Exhibit 6-3
PJM Coal-Fired Power Plant Heat Rates 2010



The relative heat rate rankings for the AEP Ohio units with respect to total generation are provided on Exhibit 6-4 for 2010. This graph is a better measure of the competitiveness of the AEP Ohio units than the simple unit comparisons that do not capture plant size.

In this presentation, the same four units and Conesville are on the lower part of the curve. The biggest difference between the presentations is with respect to Kammer. Within the PJM system, Kammer continues to be a marginal unit.

Exhibit 6-4
PJM Coal-Fired Power Plant Cumulative Generation by Heat Rate, 2010



Findings

Three of the AEP units have good heat rates and high capacity factors compared to both the coal-fired utility plants in Ohio and West Virginia and the PJM coal-fired utility plants. With respect to fuel procurement, this means that there should a higher level of certainty surrounding the coal requirements for [redacted]. [redacted] is also a very competitive plant. Fuel procurement activity for Muskingum River must consider the current expectation for retirement by the end of 2015.

7 FINANCIAL AUDIT OF THE FUEL ADJUSTMENT CLAUSE RIDER (FAC) COMPONENT

Organization

The section of the report concerning the FAC filings audit is organized into the following sections:

- Certificate of Accountability of Independent Auditors
- Quarterly FAC Filing – First Quarter 2010
- Second Quarter 2010
- Third Quarter 2010
- Fourth Quarter 2010
- First Quarter 2011
- Minimum Review Requirements
- CSP Jointly Owned Generation
- OPCO Jointly Owned Generation
- FAC Deferrals
- Review Related to Coal Order Processing
- Purchase Orders and Approved Purchase Requisitions
- Invoice and Voucher Procedures
- Fuel Ledger
- BTU Adjustments
- Freight and Barge Vouchers
- Fuel Analysis Reports
- Retroactive Escalations
- Review Related to Station Visitation and Coal Processing Procedure
- Review Related to Fuel Supplies Owned or Controlled by the Company
- Review Related to Purchased Power
- Reliability Must Run Generation

- Review Related to Service Interruptions and Unscheduled Outages
- FAC Filings, Supporting Workpapers and Documentation
- Lawrenceburg Generating Station
- Audit Trail for Reconciling Adjustments
- Renewable Energy Resources
- Carrying Costs on Deferred Fuel Balances
- Active Management
- Emission Allowances
- Changes to Fuel, Purchased Power Procurement and Emission Allowance Procurement
- Internal Audits
- AEP River Transportation Division
- Findings
- Recommendations

Certificate Of Accountability Of Independent Auditors

To: American Electric Power-Ohio

We have examined the quarterly FAC filings of Columbus Southern Power Company and Ohio Power Company ("AEP Ohio") for the year ended December 31, 2010 which support the calculation of the Fuel Adjustment Clause rates for the 12 month period January through December 2010. In conducting our review, we were aware of and considered the guidance set forth in former Chapter 4901:1 – 11 and related appendices of the Ohio Administrative Code relating to "Uniform Financial Audit Program Standards and Specifications for the Electric Fuel Component". Our examination for this purpose was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants and, accordingly, included examining on a test basis, the accounting records and such other procedures as we considered necessary in the circumstances. We did not make a detailed examination as would be required to determine that each transaction was recorded in accordance with the financial procedural aspects of former Chapter 4901:1 – 11 and related appendices of the Ohio Administrative Code. Our examination does not provide a legal determination of AEP Ohio's compliance with specific requirements.

These filings are the responsibility of the Company's management. Our responsibility is to express an opinion as to AEP Ohio's fair determination of the FAC rates for January 2010 through March 2011 calculated with those quarterly filings, which include the Reconciliation Adjustments for the period July 2009 through September 2010 that were reflected by AEP Ohio through the Company's quarterly FAC filings.

In our opinion, except for the error corrections noted in this report, AEP Ohio has determined, in all material respects, the FAC rates for the 12-month period January through December 2010 for this period in accordance with its proposed procedures and its interpretation of what should be includable in the FAC rates.

Larkin & Associates PLLC

Larkin & Associates PLLC

Livonia, Michigan

Quarterly FAC Filing – First Quarter 2010

On December 1, 2010, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from July through September 2009 and projected data for the period January through March 2010. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 4 supporting the Companies' proposed calculations for CSP and OPCO, and the explanations of each schedule. In addition, this quarterly filing also included a third page to Schedule 3, reflecting a monthly rate deferral and associated carrying costs related to the Ormet Interim Agreement, which is discussed in further detail below. Moreover, AEP Ohio included workpapers with Schedule 4, which provide support for the Companies' contention that the proposed FAC rates were in compliance with the provision for the capped rate percentage increases approved by the PUCO in its ESP Orders.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's first quarter 2010 FAC filings by reproducing Schedules 1 through 4, broken out separately between CSP and OPCO as Exhibits 7.1 through 7.12, and then briefly summarizing each schedule.

Exhibit 7-1
Summary Proposed CSP FAC Rate, January – March 2010

Schedule 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
Summary - Proposed FAC Rate

			Cents Per kWh				
			A	B	C	D	F
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.09912	3.08485	0.65758	3.74243	3.65191
2	GS-1	Secondary	2.83715	3.08485	0.65758	3.74243	3.82381
3	GS-2	Secondary	2.73102	3.08485	0.65758	3.74243	3.68943
4	GS-2	Primary	2.61131	2.98424	0.63613	3.62037	3.56910
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	2.73102	3.08485	0.65758	3.74243	3.68943
6	GS-3	Secondary	2.96126	3.08485	0.65758	3.74243	3.47461
7	GS-3	Primary	2.83016	2.98424	0.63613	3.62037	3.36128
8	GS-3-LM-TOD	Secondary	2.96126	3.08485	0.65758	3.74243	3.47461
9	GS-4	Sub/Transmission	2.75375	2.92766	0.62407	3.55173	3.11671
10	IRP-D	Secondary	3.01564	3.08485	0.65758	3.74243	3.28405
11	IRP-D	Primary	2.88944	2.98424	0.63613	3.62037	3.17694
12	IRP-D	Sub/Transmission	2.75375	2.92766	0.62407	3.55173	3.11671
13	SL	Secondary	3.58863	3.08485	0.65758	3.74243	3.95288
14	AL	Secondary	3.70227	3.08485	0.65758	3.74243	4.50885
15	SBS	Secondary	2.89922	3.08485	0.65758	3.74243	3.53250
16	SBS	Primary	2.82543	2.98424	0.63613	3.62037	3.36577
17	SBS	Sub/Transmission	2.75375	2.92766	0.62407	3.55173	3.11671

Exhibit 7-2
Summary Proposed OPCO FAC Rate, January – March 2010

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
Summary - Proposed FAC Rate

			Cents Per kWh				
			A	B	C	D	F
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	1.90098	2.99679	3.70815	6.70494	2.56084
2	GS-1	Secondary	1.71505	2.99679	3.70815	6.70494	2.59206
3	GS-2	Secondary	1.69858	2.99679	3.70815	6.70494	2.44651
4	GS-2	Primary	1.66091	2.88942	3.57529	6.46471	2.35886
5	GS-2	Sub/Transmission	1.62897	2.82000	3.48939	6.30939	2.30218
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	1.69858	2.99679	3.70815	6.70494	2.44651
7	GS-3	Secondary	1.82132	2.99679	3.70815	6.70494	2.37838
8	GS-3	Primary	1.78192	2.88942	3.57529	6.46471	2.29317
9	GS-3	Sub/Transmission	1.75585	2.82000	3.48939	6.30939	2.23807
10	GS-3-ES	Secondary	1.82132	2.99679	3.70815	6.70494	2.37838
11	GS-4	Primary	1.64876	2.88942	3.57529	6.46471	2.13408
12	GS-4	Sub/Transmission	1.66488	2.82000	3.48939	6.30939	2.08280
13	IRP-D	Secondary	1.72188	2.99679	3.70815	6.70494	2.21338
14	IRP-D	Primary	1.64876	2.88942	3.57529	6.46471	2.13408
15	IRP-D	Sub/Transmission	1.66488	2.82000	3.48939	6.30939	2.08280
16	EHG	Secondary	1.98340	2.99679	3.70815	6.70494	2.48485
17	EHS	Secondary	2.26400	2.99679	3.70815	6.70494	2.29960
18	SS	Secondary	1.73533	2.99679	3.70815	6.70494	2.40193
19	OL	Secondary	2.05067	2.99679	3.70815	6.70494	3.22634
20	SL	Secondary	1.87303	2.99679	3.70815	6.70494	2.87354
21	SBS	Secondary	1.75954	2.99679	3.70815	6.70494	2.41267
22	SBS	Primary	1.75933	2.88942	3.57529	6.46471	2.29129
23	SBS	Sub/Transmission	1.67456	2.82000	3.48939	6.30939	2.10693

Schedule 1: This schedule presents the then current FAC rate by tariff and delivery voltage. Column B reflects the FC rate necessary to recover estimated fuel expense for the first quarter of 2010, and Column C reflects the RA rate necessary to recover the actual fuel under-recovery experienced through September 2009 with Column D being the sum of the FC and RA components. AEP Ohio stated that the amounts shown in Column D would have been its requested FAC rates if not for the ESP rate caps ordered by the PUCO. However, since AEP Ohio's FAC filings are subject to ESP rate caps, the Companies proposed to implement the FAC rates shown in Column E with the January 2010 billing cycle.

Exhibit 7-3
CSP FC Component, January – March 2010

Schedule 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
FC Component

Line	Description		Forecast Period January	February	March	Total
1	Fuel & Purchased Power		$ 57,518,000	$ 53,301,000	$ 61,271,000	$ 172,090,000
2	Environmental (Consumables and Allowances)		$ 3,365,000	$ 3,006,000	$ 3,241,000	$ 9,612,000
3	(Gains) and Losses On Sales of Allowances				$ (65,000)	$ (65,000)
4	Other					$ -
5	Total Includible FAC Costs		$ 60,883,000	$ 56,307,000	$ 64,447,000	$ 181,637,000
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 5,615,000	$ 6,011,000	$ 7,009,000	$ 18,635,000
7	FAC for Internal Load		$ 55,268,000	$ 50,296,000	$ 57,438,000	$ 163,002,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.97591	1.00000	1.00000	0.97591
9	FAC for Retail Load Before Renewables		$ 53,936,594	$ 50,296,000	$ 57,438,000	$ 159,075,282
10	Renewables/RECs		$ 1,624,000	$ 1,185,000	$ 1,146,000	$ 3,955,000
11	FAC for Retail Load		$ 55,560,594	$ 51,481,000	$ 58,584,000	$ 163,030,282
12	Retail Non-Shopping Sales - Generation Level Kwh		2,004,808,000	1,787,030,000	1,798,492,000	5,590,330,000
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.91629

			Secondary	Primary	Sub/Trans
14	FC Component of FAC Rate At Generation Level		2.91629	2.91629	2.91629
15	Loss Factor		1.0578	1.0233	1.0039
16	**FC at the Meter Level - Cents/kWh**	Line 14 x Line 15	**3.08485**	**2.98424**	**2.92766**

Exhibit 7-4
OPCO FC Component, January – March 2010

Schedule 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
FC Component

Line	Description		Forecast Period - 1st Quarter 2010 January	February	March	Total
1	Fuel & Purchased Power		$ 120,952,000	$ 109,210,000	$ 115,310,000	$ 345,472,000
2	Environmental (Consumables and Allowances)		$ 10,599,000	$ 11,860,000	$ 10,649,000	$ 33,108,000
3	(Gains) and Losses On Sales of Allowances		$ (200,000)	$ (200,000)	$ (449,000)	$ (849,000)
4	Other		$ -	$ -	$ -	$ -
5	Total Includible FAC Costs		$ 131,351,000	$ 120,870,000	$ 125,510,000	$ 377,731,000
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 59,061,000	$ 54,562,000	$ 57,887,000	$ 171,510,000
7	FAC for Internal Load		$ 72,290,000	$ 66,308,000	$ 67,623,000	$ 206,221,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92809	0.92643	0.92536	0.92809
9	FAC for Retail Load Before Renewables		$ 67,091,626	$ 61,429,720	$ 62,575,619	$ 191,391,648
10	Renewables/RECs		$ 1,652,000	$ 1,215,000	$ 1,178,000	$ 4,045,000
11	FAC for Retail Load		$ 68,743,626	$ 62,644,720	$ 63,753,619	$ 195,436,648
12	Retail Non-Shopping Sales - Generation Level Kwh		2,428,902,000	2,191,326,000	2,333,038,000	6,953,266,000
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.81072

			Secondary	Primary	Sub/Trans
14	FC Component of FAC Rate At Generation Level		2.81072	2.81072	2.81072
15	Loss Factor		1.0662	1.0280	1.0033
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**2.99679**	**2.88942**	**2.82000**

Schedule 2: This schedule reflects AEP Ohio estimates of monthly fuel costs it expected to incur during the period January through March 2010. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the first quarter of 2010, AEP Ohio's has projected includable FAC costs of $181.637 million for CSP and $377.731 million for OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies' then removed costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the first quarter of 2010, these projected off-system costs totaled $18.635 million for CSP and $171.510 million for OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component for renewable energy credits ("RECs"), which totaled $3.955 million for CSP and $4.045 million for OPCO. The addition of the RECs result in total FAC costs for retail load of $163.030 million for CSP and $195.437 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 2.91629 cents per kWh for CSP and 2.81072 cents per kWh for OPCO, and was calculated by dividing the projected FAC for internal load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. Similar to its initial quarterly filing, CSP applied loss factors of 1.0578, 1.0233 and 1.0039 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 3.08485, 2.98424 and 2.92766 cents per kWh. OPCO applied loss factors of 1.0662, 1.0280 and 1.0033 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC rates of 2.99679, 2.88942 and 2.82000 cents per kWh.

Exhibit 7-5
CSP RA Component, January – March 2010

Schedule 3, page 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
RA Component

Actual Period - July 2009 through September 2009

Line	Month	Kwh Retail Non-Shopping Sales	FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ 2,174,407
2	Jul-09	1,761,228,916	$ 51,279,369	$ 56,176,797	$ 4,897,428	$ 278,467	$ (4,893,657)	$ 282,238
3	Aug-09	1,919,595,757	$ 56,354,722	$ 60,085,535	$ 3,730,813	$ 324,552	$ (2,985,952)	$ 1,069,413
4	Sep-09	1,538,227,487	$ 45,104,381	$ 47,572,864	$ 2,468,483	$ 355,836	$ (2,723,152)	$ 101,167
5	**Ending Balance**	5,219,052,160	$ 152,738,472	$ 163,835,197	$ 11,096,725	$ 958,855	$ (10,602,761)	$ 3,627,225
6	Omnet Interim Agreement Deferral		Schedule 3, pg. 3					$ 31,124,968
7	Total (Over)/Under Recovery Balance							$ 34,752,193
8	Loss Adjusted Retail Sales Billing Period - kWh							5,590,330,000
9	RA Component at Generation - Cents/kWh							0.62165

			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		0.62165	0.62165	0.62165
11	Loss Factor		1.0578	1.0233	1.0039
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**0.65758**	**0.63613**	**0.62407**

Exhibit 7-6
OPCO RA Component, January – March 2010

Schedule 3, page 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
RA

Actual Period - July 2009 through September 2009

Line	Month	Kwh Retail Non-Shopping Sales	FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ 132,728,460
2	Jul-09	1,974,367,109	$ 37,895,735	$ 82,355,977	$ 24,460,242	$ 1,198,893	$ 1,628,745	$ 27,287,880
3	Aug-09	2,214,490,089	$ 39,291,137	$ 66,331,965	$ 27,040,828	$ 1,415,303	$ (4,229,680)	$ 24,226,451
4	Sep-09	1,895,888,649	$ 33,451,158	$ 58,520,576	$ 25,069,418	$ 1,640,528	$ (3,488,062)	$ 23,221,884
5	**Ending Balance**	6,084,745,847	$ 110,638,030	$ 187,208,518	$ 76,570,488	$ 4,254,724	$ (6,088,997)	$ 207,464,675
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 34,363,615
7	Total (Over)/Under Recovery Balance							$ 241,828,290
8	Loss Adjusted Retail Sales Billing Period - kWh							6,953,266,000
9	RA Component at Generation - Cents/kWh							3.47791

			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		3.47791	3.47791	3.47791
11	Loss Factor		1.0662	1.0280	1.0033
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**3.70815**	**3.57529**	**3.48939**

Schedule 3: This three-page schedule represents the Companies' RA components of their first quarter 2010 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the Companies' under-recovery of fuel expenses for each month during the period July through September 2009, which were calculated as the difference between the monthly FAC revenues for the third quarter of 2009 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of carrying costs associated with those under-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The addition of the carrying charges and other credits and charges resulted in total under-recoveries of $3.627 million for CSP and $207.465 million for OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with the Ormet Interim Agreement (see additional discussion below). For the period January through September 2009, these deferrals totaled $31,124,968 for CSP and $34,363,615 for OPCO. The derivation of these deferral amounts are summarized on Schedule 3, page 3.

After adding the amounts associated with Ormet, CSP's and OPCO's under recovery for the third quarter of 2009 was $34.752 million and $241.828 million, respectively. From these amounts, each Company then calculated the RA component of its FAC rate at Generation level by dividing the under recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for CSP for this filing was 0.62165 cents per kWh and 3.47791 cents per kWh for OPCO. The Companies then applied the loss factors discussed above as it relates to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. For CSP, as shown on Schedule 3, page 1 at line 12, application of the loss factors results in RA components of the FAC rate of 0.65758, 0.63613 and 0.62407 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively. For OPCO, applying the loss factors resulted in RA components of the FAC rate of 3.70815, 3.57529 and 3.48939 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

AEP Ohio stated in its filing that CSP may be in the position to begin recovering its actual fuel expense concurrently with the recovery of the deferrals prior to the end of the ESP period, whereas it is probable that OPCO will have a long-term deferral to be recovered subsequent to the end of the ESP period.

Exhibit 7-7
CSP RA Component Including Ormet Deferral, January – March 2010

Schedule 3, page 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC Cost
4	Jul-09	$ 80,152,062	$ 22,718,034	$ 57,434,028	0.97811	$ 56,176,797	$ -	$ 56,176,797
5	Aug-09	$ 85,808,845	$ 24,255,887	$ 61,552,958	0.97616	$ 60,085,535	$ -	$ 60,085,535
6	Sep-09	$ 66,154,555	$ 17,390,310	$ 48,764,245	0.97447	$ 47,519,294	$ 53,570	$ 47,572,864
7	Total	$ 232,115,462	$ 64,364,231	$ 167,751,231		$ 163,781,626	$ 53,570	$ 163,835,197

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (Wstville)	Retail	Total	Whlse (Wstville)	Retail
Actual						
8	Jul-09	41,132,368	1,838,103,377	1,879,235,745	0.02189	0.97811
9	Aug-09	48,926,669	2,003,381,172	2,052,307,841	0.02384	0.97616
10	Sep-09	42,033,480	1,604,110,502	1,646,143,982	0.02553	0.97447
Forecast						
11	Jan '10	49,491,911	2,004,808,000	2,054,299,911	0.02409	0.97591
12	Feb '10	-	1,787,030,000	1,787,030,000	0.00000	1.00000
13	Mar '10	-	1,798,492,000	1,798,492,000	0.00000	1.00000

CSP's FAC filing shows the wholesale (Westerville) sales forecast going from over 49 million Kwh in January 2010 to zero in Feb 2010 and subsequent months. The wholesale contract with Westerville ended in December of 2009. The forecasted amount for January 2010 should have been zero as it was for February 2010 and subsequent months. The forecasted amount for January 2010 was entered in error. CSP indicated in its April 1, 2011 response to an informal inquiry that this was an error in the forecasted amount for January 2010, and there was no impact to the FAC due to this entry.

Exhibit 7-8
OPCO RA Component Including Ormet Deferral, January – March 2010

Schedule 3, page 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC Cost
4	Jul-09	$ 142,297,414	$ 74,697,730	$ 67,599,684	0.92243	$ 62,355,977	$ -	$ 62,355,977
5	Aug-09	$ 148,848,838	$ 76,955,959	$ 71,892,879	0.92265	$ 66,331,965	$ -	$ 66,331,965
6	Sep-09	$ 119,774,518	$ 55,838,651	$ 63,935,867	0.91446	$ 58,466,793	$ 53,783	$ 58,520,576
7	Total	$ 410,920,770	$ 207,492,340	$ 203,428,430		$ 187,154,734	$ 53,783	$ 187,208,518

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
8	Jul-09	172,721,436	2,053,983,048	2,226,704,484	0.07757	0.92243
9	Aug-09	193,317,632	2,305,947,405	2,499,265,037	0.07735	0.92265
10	Sep-09	184,106,881	1,968,209,148	2,152,316,029	0.08554	0.91446
Forecast						
11	Jan '10	188,194,800	2,428,902,000	2,617,096,800	0.07191	0.92809
12	Feb '10	174,029,600	2,191,326,000	2,365,355,600	0.07357	0.92643
13	Mar '10	188,194,800	2,333,038,000	2,521,232,800	0.07464	0.92536

Page 2 of Schedule 3 reflects monthly data on the Companies' actual fuel costs during the third quarter of 2009. Specifically, page 2 of Schedule 3 (lines 4-7) shows, for each Company, total monthly FAC costs incurred from July through September 2009.[33] For each month (July through September), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". In September 2009, CSP and OPCO added $53,570 and $53,783, respectively for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Section 4928.64 of the revised Ohio Code. AEP Ohio stated that future FAC revenues will first be applied towards recovering renewable energy costs so that they are not embedded in the long-term deferrals of either CSP or OPCO. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the third quarter of 2009 were derived. Renewables are discussed in further detail in a later section of this report.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for July through September 2009. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for January through March 2010, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies

[33] The heading for Schedule 3, page 2, lines 4-7 of CSP's 2010 quarterly FAC filings was labeled "Ormet Interim Rate Deferral", as submitted by AEP. Through informal discovery, this heading was confirmed on April 1, 2011 to be incorrect. Larkin & Associates changed the heading to correctly read "Monthly Retail FAC Cost" for all CSP 2010 quarterly FAC filings for purposes of this report.

calculated retail jurisdictional allocation ratios of .97591 (January 2010) and 1.0000 (February and March 2010) for CSP and .92809, .92643 and .92536 (January, February and March 2010, respectively) for OPCO.

Exhibit 7-9
CSP Details Of Ormet Deferral In RA Component , January – March 2010

Schedule 3, page 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jan-09	$ 4,154,975	$ -	$ 4,154,975
2	Feb-09	$ 3,660,302	$ 39,306	$ 3,699,608
3	Mar-09	$ 4,149,056	$ 73,464	$ 4,222,520
4	Apr-09	$ 3,916,040	$ 112,584	$ 4,028,624
5	May-09	$ 3,549,316	$ 149,434	$ 3,698,750
6	Jun-09	$ 3,150,701	$ 182,833	$ 3,333,534
7	Jul-09	$ 3,211,313	$ 212,481	$ 3,423,794
8	Aug-09	$ 2,618,212	$ 242,700	$ 2,860,912
9	Sep-09	$ 1,437,755	$ 264,496	$ 1,702,251
10	Total	$ 29,847,670	$ 1,277,298	$ 31,124,968

Exhibit 7-10
OPCO Details Of Ormet Deferral In RA Component , January – March 2010

Schedule 3, page 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jan-09	$ 4,621,825	$ -	$ 4,621,825
2	Feb-09	$ 3,985,948	$ 42,105	$ 4,028,053
3	Mar-09	$ 4,608,436	$ 77,642	$ 4,686,078
4	Apr-09	$ 4,321,138	$ 120,003	$ 4,441,141
5	May-09	$ 3,922,750	$ 156,784	$ 4,079,534
6	Jun-09	$ 3,489,750	$ 194,857	$ 3,684,607
7	Jul-09	$ 3,568,282	$ 225,547	$ 3,793,829
8	Aug-09	$ 2,899,119	$ 256,948	$ 3,156,067
9	Sep-09	$ 1,592,553	$ 279,928	$ 1,872,481
10	Total	$ 33,009,801	$ 1,353,814	$ 34,363,615

As noted above, page 3 of Schedule 3 reflects the derivation of the monthly rate deferral and carrying costs associated with the Ormet Interim Agreement pursuant to Case No. 09-1094-EL-FAC. The deferrals included in the Companies' FACs are for the period January 1, 2009 through

September 17, 2009. Ormet related rate discounts that occurred subsequent to September 17, 2009 will be recovered through each Company's Economic Development Cost Recovery Rider.

Ormet Interim Agreement

In Case No. 07-1317-EL-UNC, the PUCO approved a market rate for 2008 of $53.03 per MWh related to power sold to the Ormet Primary Aluminum Corporation ("Ormet"). In a prior PUCO Order, Ormet's 2008 purchases were at a price of $43 per MWh. In order for AEP Ohio to be compensated for providing to Ormet for less than the market rate, the PUCO authorized the Companies to amortize a regulatory liability of $56.968 million that was created by AEP Ohio in June 2005 when the Ohio Franchise Tax was phased out. This amortization was based on the difference between the $53.03 per MWh market rate and the $43 per MWh rate paid by Ormet. Upon the regulatory liability being fully amortized, the Companies were authorized to recover the difference from customers.

In its Finding and Order dated January 7, 2009 (Case Nos. 08-1338-EL-AAM and 08-1339-EL-UNC, filed on December 29, 2008), the PUCO directed that the arrangement between the Companies and Ormet continue until the PUCO ruled on the Companies' then pending ESP application, or until Ormet submitted a new contract proposal to the PUCO. On February 17, 2009, in Case No. 09-119-EL-AEC, Ormet filed an application pursuant to Section 4905.31 of the Revised Code to establish a unique arrangement between CSP and OPCO as it relates to electric service being provided to Ormet's aluminum producing facility in Hannibal, Ohio. Ormet filed an amended application on April 10, 2009 in that proceeding.

The PUCO approved Ormet's amended application with several modifications in its Order and Opinion dated July 15, 2009. Specifically, the PUCO directed AEP Ohio to bill Ormet at a rate which averaged $38 per MWh for the periods when Ormet was fully operating (6 potlines), $35 per MWh for periods when Ormet curtailed production to 4.6 potlines, and $34 per MWh for periods when Ormet curtailed production to 4 potlines. This rate was authorized for the balance of 2009. In its Order and Opinion, the PUCO stated that further proceedings would be necessary as it relates to the recovery of "delta revenues" by AEP Ohio. Therefore, the PUCO authorized AEP Ohio to defer the delta revenues for the remainder of 2009. In addition, the PUCO directed AEP Ohio to file an application to recover the deferrals authorized in Case No. 08-1338-EL-AAM, as well as the delta revenues for 2009.

In its Application dated November 13, 2009 in Case No. 09-1094-EL-FAC, the Companies proposed to recover the deferrals authorized pursuant to the Interim Agreement. Specifically, the Companies' proposed to recover through each Company's FAC, the cumulative FAC under-recovery regulatory asset at September 17, 2009. As of September 17, 2009, the Companies had a deferred regulatory asset of $29,847,670 for CSP and $33,009,802 for OPCO. In addition, the Companies had a deferred regulatory asset in carrying charges of $1,556,972 for CSP and $1,610,301 for OPCO. These carrying costs were calculated based on each Company's Weighted Average Cost of Capital ("WACC").

After September 17, 2009, the Companies have continued to accrue carrying charges on the deferral related to the Ormet Interim Agreement, which the Companies have included in their RA adjustment calculations during 2010. According to Schedules LA-2010-43-M and LA-2010-

43-MM (referenced in the response to LA-2010-80), the carrying charges on the Ormet deferral was $3,528,380 for CSP and $5,809,807 for OPCO at December 31, 2010. However, the response to LA-2010-2-93, which asked the Companies to provide the level of carrying charges that accrued on the Ormet deferral during the review period January through December 2010, as well as the Ormet deferral amounts, stated in part the following:

> *Due to the SEET order by the PUCO in January 2011, CSP's Ormet interim agreement deferral amount (including carrying charges) at 12/31/10 effectively becomes zero. OPCO's Ormet interim agreement deferral amount, excluding carrying charges, is $33,009,801. OPCO's accumulated total carrying charges specific to the Ormet deferral is $5,809,807.*

As noted above, Schedule LA-2010-43-M indicates carrying charges for CSP totaling $3,528,380 at December 31, 2010. In addition, a schedule titled "Summary 2010 OH FAC" (also provided with LA-2010-43), indicates that CSP had an Ormet deferral of $10,451,350 at December 31, 2010. In response to our inquiry, AEP Ohio stated:

> *LA-2010-43 reflects the then recorded amounts at 12/31/10 (including an estimate for December). The PUCO SEET order (from January 2011), in effect applies the adjusted CSP actual balances, against the SEET liability of $43MM, creating a zero balance for CSP's FAC, after the fact.*

On September 1, 2010, AEP Ohio filed an application for a Significant Excessive Earnings Test ("SEET"), which utilities are required to file annually at the PUCO in order to demonstrate whether significantly excessive earnings were made. In its Opinion and Order dated January 11, 2011, the PUCO determined that CSP generated $42.6 million in significantly excessive earnings in 2009, which the Commission ordered be refunded to customers through bill credits and the elimination of any deferrals.

Although the Companies March 1, 2011 quarterly FAC filing is outside the scope of Larkin's review for the 2010 (second year) FAC audit, we noted that Schedule 3, page 1, line 8 of CSP's quarterly filing reflects a line item called "SEET Refund", which removes the deferral and Ormet carrying charges which totaled $18,717,599.

Exhibit 7-11
CSP FAC Rate Under ESP Cap, January – March 2010

Schedule 4

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.65191
2	GS-1	Secondary	3.82381
3	GS-2	Secondary	3.68943
4	GS-2	Primary	3.56910
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.68943
6	GS-3	Secondary	3.47461
7	GS-3	Primary	3.36128
8	GS-3-LM-TOD	Secondary	3.47461
9	GS-4	Sub/Transmission	3.11671
10	IRP-D	Secondary	3.28405
11	IRP-D	Primary	3.17694
12	IRP-D	Sub/Transmission	3.11671
13	SL	Secondary	3.95288
14	AL	Secondary	4.50885
15	SBS	Secondary	3.53250
16	SBS	Primary	3.36577
17	SBS	Sub/Transmission	3.11671

Exhibit 7-12
OPCO FAC Rate Under ESP Cap, January – March 2010

Schedule 4

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	2.56084
2	GS-1	Secondary	2.59206
3	GS-2	Secondary	2.44651
4	GS-2	Primary	2.35886
5	GS-2	Sub/Transmission	2.30218
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.44651
7	GS-3	Secondary	2.37838
8	GS-3	Primary	2.29317
9	GS-3	Sub/Transmission	2.23807
10	GS-3-ES	Secondary	2.37838
11	GS-4	Primary	2.13408
12	GS-4	Sub/Transmission	2.08280
13	IRP-D	Secondary	2.21338
14	IRP-D	Primary	2.13408
15	IRP-D	Sub/Transmission	2.08280
16	EHG	Secondary	2.48485
17	EHS	Secondary	2.29960
18	SS	Secondary	2.40193
19	OL	Secondary	3.22634
20	SL	Secondary	2.87354
21	SBS	Secondary	2.41267
22	SBS	Primary	2.29129
23	SBS	Sub/Transmission	2.10693

Schedule 4: This schedule reflects the Companies' proposed FAC rates by tariff to be effective with first billing cycle of January 2010. AEP Ohio stated that these rates are in compliance with the provision for the capped rate percent increases authorized by the PUCO in its ESP Orders. AEP Ohio provided workpapers with Schedule 4 which support the PUCO's directive that the Companies' phase-in of authorized rate increases do not exceed six percent for CSP and seven percent for OPCO during 2010 pursuant to its Opinion and Order dated March 18, 2009 (Case Nos. 08-917-EL-SSO and 08-918-EL-SSO).

Second Quarter 2010

On March 8, 2010, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from October through December 2009 and projected data for the period April through June 2010. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 4 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's second quarter 2010 FAC filings by reproducing Schedules 1 through 4, broken out separately between CSP and OPCO as Exhibits 7.13 through 7.24, and then briefly summarizing each schedule.

Exhibit 7-13
CSP Schedule 1, April – June 2010

Schedule 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
Summary - Proposed FAC Rate

			Cents Per kWh				
			A	B	C	D	E
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.65191	3.11855	0.80364	3.92219	**3.65191**
2	GS-1	Secondary	3.82381	3.11855	0.80364	3.92219	**3.82381**
3	GS-2	Secondary	3.68943	3.11855	0.80364	3.92219	**3.68943**
4	GS-2	Primary	3.56910	3.01684	0.77743	3.79427	**3.56910**
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.68943	3.11855	0.80364	3.92219	**3.68943**
6	GS-3	Secondary	3.47461	3.11855	0.80364	3.92219	**3.47461**
7	GS-3	Primary	3.36128	3.01684	0.77743	3.79427	**3.36128**
8	GS-3-LM-TOD	Secondary	3.47461	3.11855	0.80364	3.92219	**3.47461**
9	GS-4	Sub/Transmission	3.11671	2.95965	0.76269	3.72234	**3.11671**
10	IRP-D	Secondary	3.28405	3.11855	0.80364	3.92219	**3.28405**
11	IRP-D	Primary	3.17694	3.01684	0.77743	3.79427	**3.17694**
12	IRP-D	Sub/Transmission	3.11671	2.95965	0.76269	3.72234	**3.11671**
13	SL	Secondary	3.95288	3.11855	0.80364	3.92219	**3.95288**
14	AL	Secondary	4.50885	3.11855	0.80364	3.92219	**4.50885**
15	SBS	Secondary	3.53250	3.11855	0.80364	3.92219	**3.53250**
16	SBS	Primary	3.36577	3.01684	0.77743	3.79427	**3.36577**
17	SBS	Sub/Transmission	3.11671	2.95965	0.76269	3.72234	**3.11671**

Exhibit 7-14
OPCO Schedule 1, April – June 2010

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
Summary - Proposed FAC Rate

			Cents Per kWh				
			A	B	C	D	E
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	2.56084	2.91750	5.17386	8.09136	**2.56084**
2	GS-1	Secondary	2.59206	2.91750	5.17386	8.09136	**2.59206**
3	GS-2	Secondary	2.44651	2.91750	5.17386	8.09136	**2.44651**
4	GS-2	Primary	2.35886	2.81297	4.98849	7.80146	**2.35886**
5	GS-2	Sub/Transmission	2.30218	2.74538	4.86863	7.61401	**2.30218**
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.44651	2.91750	5.17386	8.09136	**2.44651**
7	GS-3	Secondary	2.37838	2.91750	5.17386	8.09136	**2.37838**
8	GS-3	Primary	2.29317	2.81297	4.98849	7.80146	**2.29317**
9	GS-3	Sub/Transmission	2.23807	2.74538	4.86863	7.61401	**2.23807**
10	GS-3-ES	Secondary	2.37838	2.91750	5.17386	8.09136	**2.37838**
11	GS-4	Primary	2.13408	2.81297	4.98849	7.80146	**2.13408**
12	GS-4	Sub/Transmission	2.08280	2.74538	4.86863	7.61401	**2.08280**
13	IRP-D	Secondary	2.21338	2.91750	5.17386	8.09136	**2.21338**
14	IRP-D	Primary	2.13408	2.81297	4.98849	7.80146	**2.13408**
15	IRP-D	Sub/Transmission	2.08280	2.74538	4.86863	7.61401	**2.08280**
16	EHG	Secondary	2.48485	2.91750	5.17386	8.09136	**2.48485**
17	EHS	Secondary	2.29960	2.91750	5.17386	8.09136	**2.29960**
18	SS	Secondary	2.40193	2.91750	5.17386	8.09136	**2.40193**
19	OL	Secondary	3.22634	2.91750	5.17386	8.09136	**3.22634**
20	SL	Secondary	2.87354	2.91750	5.17386	8.09136	**2.87354**
21	SBS	Secondary	2.41267	2.91750	5.17386	8.09136	**2.41267**
22	SBS	Primary	2.29129	2.81297	4.98849	7.80146	**2.29129**
23	SBS	Sub/Transmission	2.10693	2.74538	4.86863	7.61401	**2.10693**

Schedule 1: Column A of this schedule reflects the then current FAC rate by tariff and delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period April through June 2010. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through December 2009. Column D reflects the sum of the FC and RA components. AEP Ohio stated that the amounts shown in Column D would have been its requested FAC rates if not for the ESP rate caps ordered by the PUCO. However, since AEP Ohio's FAC filings are subject to ESP rate caps, the Companies' filings reflect the then current FAC rates as shown in Column E. Therefore, AEP Ohio did not request an increase in customer rates in its second quarter 2010 filing.

Exhibit 7-15
CSP Schedule 2, April – June 2010

Schedule 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
FC Component

Line	Description		Forecast Period April	May	June	Total
1	Fuel & Purchased Power		$ 52,985,000	$ 51,677,000	$ 62,020,000	$ 166,682,000
2	Environmental (Consumables and Allowances)		$ 3,106,000	$ 2,887,000	$ 2,922,000	$ 8,915,000
3	(Gains) and Losses On Sales of Allowances				$ -	$ -
4	Other					$ -
5	*Total Includible FAC Costs*		$ 56,091,000	$ 54,564,000	$ 64,942,000	$ 175,597,000
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 7,824,000	$ 6,671,000	$ 10,157,000	$ 24,652,000
7	FAC for Internal Load		$ 48,267,000	$ 47,893,000	$ 54,785,000	$ 150,945,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.96103	0.96101	0.96084	0.96103
9	FAC for Retail Load Before Renewables		$ 46,386,035	$ 46,025,652	$ 52,639,619	$ 145,062,673
10	Renewables/RECs		$ 1,299,952	$ 948,952	$ 726,952	$ 2,975,856
11	FAC for Retail Load		$ 47,685,987	$ 46,974,604	$ 53,366,571	$ 148,038,529
12	Retail Non-Shopping Sales - Generation Level Kwh		1,594,260,000	1,618,226,000	1,808,912,000	5,021,398,000
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.94815

			Secondary	Primary	Sub/Trans
14	FC Component of FAC Rate At Generation Level		2.94815	2.94815	2.94815
15	Loss Factor		1.0578	1.0233	1.0039
16	**FC at the Meter Level - Cents/kWh**	Line 14 x Line 15	**3.11855**	**3.01684**	**2.95965**

Exhibit 7-16
OPCO Schedule 2, April – June 2010

Schedule 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
FC Component

Line	Description		Forecast Period - 2nd Quarter 2010 April	May	June	Total
1	Fuel & Purchased Power		$ 83,735,000	$ 78,573,000	$ 99,693,000	$ 262,001,000
2	Environmental (Consumables and Allowances)		$ 6,765,000	$ 6,842,000	$ 9,016,000	$ 22,623,000
3	(Gains) and Losses On Sales of Allowances		$ (200,000)	$ (200,000)	$ (200,000)	$ (600,000)
4	Other		$ -	$ -	$ -	$ -
5	Total Includible FAC Costs		$ 90,300,000	$ 85,215,000	$ 108,509,000	$ 284,024,000
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 29,307,000	$ 24,317,000	$ 43,988,000	$ 97,612,000
7	FAC for Internal Load		$ 60,993,000	$ 60,898,000	$ 64,521,000	$ 186,412,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92545	0.88191	0.92719	0.92545
9	FAC for Retail Load Before Renewables		$ 56,445,972	$ 53,706,555	$ 59,823,226	$ 172,514,985
10	Renewables/RECs		$ 1,333,976	$ 983,976	$ 761,976	$ 3,079,928
11	FAC for Retail Load		$ 57,779,948	$ 54,690,531	$ 60,585,202	$ 175,594,913
12	Retail Non-Shopping Sales - Generation Level Kwh		2,084,690,974	2,096,134,541	2,236,305,167	6,417,130,682
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.73635
			Secondary	Primary	Sub/Trans	
14	FC Component of FAC Rate At Generation Level		2.73635	2.73635	2.73635	
15	Loss Factor		1.0662	1.0280	1.0033	
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**2.9175**	**2.81297**	**2.74538**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period April through June 2010. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the second quarter of 2010, AEP Ohio has projected includable FAC costs totaling $175.597 million for CSP and $284.024 million for OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the second quarter of 2010, these projected off-system costs totaled $24.652 million for CSP and $97.612 million for OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component for renewable energy credits ("RECs"), which totaled $2.976 million for CSP and $3.080 million for OPCO. The addition of the RECs result in total FAC costs for retail load of $148.039 million for CSP and $175.595 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to2.94815 cents per kWh for CSP and 2.73635 cents per kWh for OPCO and was calculated by dividing the projected FAC for internal load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. CSP applied the loss factors of 1.0578, 1.0233 and 1.0039 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 3.11855, 3.01684 and 2.95965 cents per kWh. OPCO applied the loss factors of 1.0662, 1.0280 and 1.0033 cents per kWh for

secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 2.9175, 2.81297 and 2.74538 cents per kWh.

Exhibit 7-17
CSP Schedule 3, Page 1, April – June 2010

Schedule 3, page 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
RA Component

Actual Period - October 2009 through December 2009

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ 34,752,193
2	Oct-09	1,577,809,201	$ 46,118,090	$ 47,757,030	$ 1,638,940	$ 380,757	$ (2,240,591)	$ (220,894)
3	Nov-09	1,511,929,804	$ 44,315,547	$ 46,823,441	$ 2,507,894	$ 396,058	$ (2,301,453)	$ 602,499
4	Dec-09	1,797,074,905	$ 53,092,369	$ 57,509,333	$ 4,416,964	$ 419,502	$ (2,660,208)	$ 2,176,258
5	**Ending Balance**	4,886,813,910	$ 143,526,006	$ 152,089,804	$ 8,563,798	$ 1,196,317	$ (7,202,252)	$ 37,310,056
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 839,019
7	Total (Over)/Under Recovery Balance							$ 38,149,075
8	Loss Adjusted Retail Sales Billing Period - kWh							5,021,398,000
9	RA Component at Generation - Cents/kWh							0.75973

			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		0.75973	0.75973	0.75973
11	Loss Factor		1.0578	1.0233	1.0039
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**0.80364**	**0.77743**	**0.76269**

Exhibit 7-18
OPCO Schedule 3, Page 1, April – June 2010

Schedule 3, page 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
RA

Actual Period - October 2009 through December 2009

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ 241,828,290
2	Oct-09	1,993,951,473	$ 35,193,489	$ 58,392,454	$ 23,198,965	$ 1,625,001	$ (2,238,860)	$ 22,585,106
3	Nov-09	1,878,190,513	$ 33,245,734	$ 54,446,894	$ 21,201,160	$ 2,088,654	$ (2,388,398)	$ 20,901,416
4	Dec-09	2,300,659,121	$ 40,941,630	$ 66,588,089	$ 25,646,459	$ 2,276,663	$ (2,688,637)	$ 25,234,486
5	**Ending Balance**	6,172,801,107	$ 109,380,853	$ 179,427,437	$ 70,046,584	$ 5,990,318	$ (7,315,894)	$ 310,549,298
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 849,672
7	Total (Over)/Under Recovery Balance							$ 311,398,970
8	Loss Adjusted Retail Sales Billing Period - kWh							6,417,130,682
9	RA Component at Generation - Cents/kWh							4.85262

			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		4.85262	4.85262	4.85262
11	Loss Factor		1.0662	1.0280	1.0033
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**5.17386**	**4.98849**	**4.86863**

Schedule 3: This three-page schedule represents the Companies RA components of its second quarter 2010 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under-recovery of fuel expenses for each month during the period October through December 2009, which were calculated as the difference between the monthly FAC revenues for the fourth quarter of 2009 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the

carrying costs associated with those under-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The addition of the carrying charges and other credits and charges resulted in total under-recoveries of $37.310 million for CSP and $310.549 million for OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with Ormet. For the fourth quarter of 2009, these deferrals totaled $839,019 for CSP and $849,672 for OPCO. The derivation of these deferral amounts are summarized on Schedule 3, page 3.

After adding the amounts associated with Ormet, CSP's and OPCO's under recovery for the fourth quarter of 2009 was $38.149 million and $311.399 million, respectively. From these amounts, each Company calculated the RA component of its FAC rate at Generation level by dividing the under recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for CSP for this filing was 0.75973 cents per kWh and 4.85262 cents per kWh for OPCO. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. For CSP, the application of the loss factors results in RA components of the FAC rate of 0.80364, 0.77743 and 0.76269 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively. For OPCO, applying the loss factors resulted in RA components of the FAC rate of 5.17386, 4.98849 and 4.86863 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Similar to its first quarterly filing, AEP Ohio stated that CSP may be in the position to begin recovering its actual fuel expense concurrently with the recovery of the deferrals prior to the end of the ESP period, whereas it is probable that OPCO will have a long-term deferral to be recovered subsequent to the end of the ESP period.

Exhibit 7-19
CSP Schedule 3, Page 2, April – June 2010

Schedule 3, page 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
4	Oct-09	$ 62,652,943	$ 13,786,738	$ 48,866,205	0.97718	$ 47,751,078	$ 5,952	$ 47,757,030
5	Nov-09	$ 63,827,561	$ 16,310,063	$ 47,517,498	0.97696	$ 46,422,695	$ 400,746	$ 46,823,441
6	Dec-09	$ 81,049,409	$ 23,687,582	$ 57,361,827	0.97634	$ 56,004,646	$ 1,504,687	$ 57,509,333
7	Total	$ 207,529,913	$ 53,784,383	$ 153,745,530		$ 150,178,419	$ 1,911,385	$ 152,089,804

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (Wstville)	Retail	Total	Whlse (Wstville)	Retail
Actual						
8	Oct-09	38,387,385	1,643,611,320	1,681,998,705	0.02282	0.97718
9	Nov-09	37,165,102	1,575,606,737	1,612,771,839	0.02304	0.97696
10	Dec-09	45,470,301	1,876,645,453	1,922,115,754	0.02366	0.97634
Forecast						
11	April '10	64,642,496	1,594,260,000	1,658,902,496	0.03897	0.96103
12	May '10	65,652,535	1,618,226,000	1,683,878,535	0.03899	0.96101
13	June '10	73,732,847	1,808,912,000	1,882,644,847	0.03916	0.96084

Exhibit 7-20
OPCO Schedule 3, Page 2, April – June 2010

Schedule 3, page 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
4	Oct-09	$ 136,540,400	$ 73,372,764	$ 63,167,636	0.92431	$ 58,386,478	$ 5,976	$ 58,392,454
5	Nov-09	$ 128,587,451	$ 69,666,181	$ 58,921,270	0.91726	$ 54,046,124	$ 400,770	$ 54,446,894
6	Dec-09	$ 162,894,359	$ 92,755,013	$ 70,139,346	0.92529	$ 64,899,235	$ 1,688,854	$ 66,588,089
7	Total	$ 428,022,210	$ 235,793,958	$ 192,228,252		$ 177,331,837	$ 2,095,600	$ 179,427,437

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
8	Oct-09	169,607,736	2,071,176,358	2,240,784,094	0.07569	0.92431
9	Nov-09	176,092,035	1,952,041,637	2,128,133,672	0.08274	0.91726
10	Dec-09	193,642,580	2,398,420,474	2,592,063,054	0.07471	0.92529
Forecast						
11	Apr-10	167,942,194	2,084,690,974	2,252,633,169	0.07455	0.92545
12	May-10	280,672,189	2,096,134,541	2,376,806,730	0.11809	0.88191
13	Jun-10	175,616,698	2,236,305,167	2,411,921,865	0.07281	0.92719

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the fourth quarter of 2009. Specifically, page 2 of Schedule 3 (lines 4-7) shows, for each Company, total monthly FAC costs incurred from October through December 2009. For each month (October through December), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the fourth quarter of 2010, CSP and OPCO added amounts totaling $1,911,385 and $2,095,600, respectively for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that future FAC revenues will first be applied towards recovering renewable energy costs so that they are not embedded in the long-term deferrals of either CSP or OPCO. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the fourth quarter of 2009 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for October through December 2009. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for April through June 2010, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of .96103, .96101 and .96084 (April, May and June 2010, respectively) CSP and .92545, .88191 and .92719 (April, May and June 2010, respectively) for OPCO.

CSP's FAC filing dated March 8, 2010, at Schedule 3, page 2 of 3 showed amounts for the wholesale (Westerville) sales forecast for each month April, May and June 2010, erroneously. Those errors caused the Retail Jurisdictional Ratios on Schedule 2, line 8 to be less than 1.00000. These Company errors thus caused the FAC for Retail Load Before Renewables on Schedule 2, line 9, to be understated. The wholesale contract with Westerville ended in December of 2009. The forecasted sales amounts for wholesale for the months of April through June 2010 on Schedule 3, page 2 of 3 should have been zero as it was for February and March 2010 and for months subsequent to June 2010. The forecasted wholesale kWh sales amounts for the months of April through June 2010 on Schedule 3, page 2 of 3, were entered in error. CSP acknowledged this error in an April 1, 2011 response to an informal inquiry. Because CSP's FAC filings have appropriately reflected the termination of the Westerville wholesale contract in December 2009 in computing the RA adjustments, the errors in CSP's FAC forecast for the months in 2010 when CSP understated the amounts for FAC for Retail Load Before Renewables on Schedule 2, line 9, are being corrected via the application of the RA adjustments. After the application of the RA adjustments for the months of April, May and June 2010, for which CSP showed zero wholesale kWh, there should no net impact to the FAC due to the aforementioned CSP forecast errors which had affected the forecast retail jurisdictional allocation ratios for the April through June 2010 period.

Exhibit 7-21
CSP Schedule 3, Page 3, April – June 2010

Schedule 3, page 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Oct-09	$ -	$ 279,673	$ 279,673
2	Nov-09	$ -	$ 279,673	$ 279,673
3	Dec-09	$ -	$ 279,673	$ 279,673
4	Total	$ -	$ 839,019	$ 839,019

Exhibit 7-22
OPCO Schedule 3, Page 3, April – June 2010

Schedule 3, page 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Oct-09	$ -	$ 256,486	$ 256,486
2	Nov-09	$ -	$ 296,758	$ 296,758
3	Dec-09	$ -	$ 296,428	$ 296,428
10	Total	$ -	$ 849,672	$ 849,672

As noted above, page 3 of Schedule 3 reflects the derivation of the monthly rate deferral and carrying costs associated with Ormet Interim Agreement pursuant to Case No. 09-1094-EL-FAC. The deferrals included in the Companies' FACs are for the period January 1, 2010 through September 17, 2009. Ormet related rate discounts that occurred subsequent to September 17, 2009 will be recovered through each Company's Economic Development Cost Recovery Rider.

Exhibit 7-23
CSP Schedule 4, April – June 2010

Schedule 4

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.65191
2	GS-1	Secondary	3.82381
3	GS-2	Secondary	3.68943
4	GS-2	Primary	3.56910
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.68943
6	GS-3	Secondary	3.47461
7	GS-3	Primary	3.36128
8	GS-3-LM-TOD	Secondary	3.47461
9	GS-4	Sub/Transmission	3.11671
10	IRP-D	Secondary	3.28405
11	IRP-D	Primary	3.17694
12	IRP-D	Sub/Transmission	3.11671
13	SL	Secondary	3.95288
14	AL	Secondary	4.50885
15	SBS	Secondary	3.53250
16	SBS	Primary	3.36577
17	SBS	Sub/Transmission	3.11671

Exhibit 7-24
OPCO Schedule 4, April – June 2010

Schedule 4

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	2.56084
2	GS-1	Secondary	2.59206
3	GS-2	Secondary	2.44651
4	GS-2	Primary	2.35886
5	GS-2	Sub/Transmission	2.30218
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.44651
7	GS-3	Secondary	2.37838
8	GS-3	Primary	2.29317
9	GS-3	Sub/Transmission	2.23807
10	GS-3-ES	Secondary	2.37838
11	GS-4	Primary	2.13408
12	GS-4	Sub/Transmission	2.08280
13	IRP-D	Secondary	2.21338
14	IRP-D	Primary	2.13408
15	IRP-D	Sub/Transmission	2.08280
16	EHG	Secondary	2.48485
17	EHS	Secondary	2.29960
18	SS	Secondary	2.40193
19	OL	Secondary	3.22634
20	SL	Secondary	2.87354
21	SBS	Secondary	2.41267
22	SBS	Primary	2.29129
23	SBS	Sub/Transmission	2.10693

Schedule 4: This schedule breaks out current FAC rates by tariff. AEP Ohio stated that these rates are in compliance with the provision for the capped rate percent increases approved by the PUCO in its Opinion and Order dated March 18, 2009. As noted above in the discussion of Schedule 1, AEP Ohio proposes that the current FAC rates remain in place for the second quarter of 2010 (i.e., the proposed FAC rates from AEP Ohio's first quarter 2010 FAC filing).

Third Quarter 2010

On June22, 2010, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from January through March 2010 and projected data for the period July through September 2010. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 4 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's third quarter 2010

FAC filings by reproducing Schedules 1 through 4, broken out separately between CSP and OPCO as Exhibits 7.25 through 7.36, and then briefly summarizing each schedule.

Exhibit 7-25
CSP Schedule 1, July – September 2010

Schedule 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2010 through September 2010
Summary - Proposed FAC Rate

Cents Per kWh

Line	Tariff	Delivery Voltage	A Current FAC Rate	B Schedule 2 Forecast (FC) Component	C Schedule 3 Reconciliation (RA) Adjustment Comp.	D Total of FC and RA Components	E Schedule 4 FAC Rate Permitted Under ESP Cap
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.65191	3.21549	0.19635	3.41184	**3.65191**
2	GS-1	Secondary	3.82381	3.21549	0.19635	3.41184	**3.82381**
3	GS-2	Secondary	3.68943	3.21549	0.19635	3.41184	**3.68943**
4	GS-2	Primary	3.56910	3.11062	0.18995	3.30057	**3.56910**
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.68943	3.21549	0.19635	3.41184	**3.68943**
6	GS-3	Secondary	3.47461	3.21549	0.19635	3.41184	**3.47461**
7	GS-3	Primary	3.36128	3.11062	0.18995	3.30057	**3.36128**
8	GS-3-LM-TOD	Secondary	3.47461	3.21549	0.19635	3.41184	**3.47461**
9	GS-4	Sub/Transmission	3.11671	3.05165	0.18635	3.23800	**3.11671**
10	IRP-D	Secondary	3.28405	3.21549	0.19635	3.41184	**3.28405**
11	IRP-D	Primary	3.17694	3.11062	0.18995	3.30057	**3.17694**
12	IRP-D	Sub/Transmission	3.11671	3.05165	0.18635	3.23800	**3.11671**
13	SL	Secondary	3.95288	3.21549	0.19635	3.41184	**3.95288**
14	AL	Secondary	4.50885	3.21549	0.19635	3.41184	**4.50885**
15	SBS	Secondary	3.53250	3.21549	0.19635	3.41184	**3.53250**
16	SBS	Primary	3.36577	3.11062	0.18995	3.30057	**3.36577**
17	SBS	Sub/Transmission	3.11671	3.05165	0.18635	3.23800	**3.11671**

Exhibit 7-26
OPCO Schedule 1, July – September 2010

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2010 through September 2010
Summary - Proposed FAC Rate

Cents Per kWh

Line	Tariff	Delivery Voltage	A Current FAC Rate	B Schedule 2 Forecast (FC) Component	C Schedule 3 Reconciliation (RA) Adjustment Comp.	D Total of FC and RA Components	E Schedule 4 FAC Rate Permitted Under ESP Cap
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	2.56084	2.93060	5.48704	8.41764	**2.56084**
2	GS-1	Secondary	2.59206	2.93060	5.48704	8.41764	**2.59206**
3	GS-2	Secondary	2.44651	2.93060	5.48704	8.41764	**2.44651**
4	GS-2	Primary	2.35886	2.82560	5.29045	8.11605	**2.35886**
5	GS-2	Sub/Transmission	2.30218	2.75771	5.16334	7.92105	**2.30218**
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.44651	2.93060	5.48704	8.41764	**2.44651**
7	GS-3	Secondary	2.37838	2.93060	5.48704	8.41764	**2.37838**
8	GS-3	Primary	2.29317	2.82560	5.29045	8.11605	**2.29317**
9	GS-3	Sub/Transmission	2.23807	2.75771	5.16334	7.92105	**2.23807**
10	GS-3-ES	Secondary	2.37838	2.93060	5.48704	8.41764	**2.37838**
11	GS-4	Primary	2.13408	2.82560	5.29045	8.11605	**2.13408**
12	GS-4	Sub/Transmission	2.08280	2.75771	5.16334	7.92105	**2.08280**
13	IRP-D	Secondary	2.21338	2.93060	5.48704	8.41764	**2.21338**
14	IRP-D	Primary	2.13408	2.82560	5.29045	8.11605	**2.13408**
15	IRP-D	Sub/Transmission	2.08280	2.75771	5.16334	7.92105	**2.08280**
16	EHG	Secondary	2.48485	2.93060	5.48704	8.41764	**2.48485**
17	EHS	Secondary	2.29960	2.93060	5.48704	8.41764	**2.29960**
18	SS	Secondary	2.40193	2.93060	5.48704	8.41764	**2.40193**
19	OL	Secondary	3.22634	2.93060	5.48704	8.41764	**3.22634**
20	SL	Secondary	2.87354	2.93060	5.48704	8.41764	**2.87354**
21	SBS	Secondary	2.41267	2.93060	5.48704	8.41764	**2.41267**
22	SBS	Primary	2.29129	2.82560	5.29045	8.11605	**2.29129**
23	SBS	Sub/Transmission	2.10693	2.75771	5.16334	7.92105	**2.10693**

Schedule 1: Column A of this schedule reflects the then current FAC rate by tariff and delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period July through September 2010. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through March 2010. Column D reflects the sum of the FC and RA components. AEP Ohio stated that the amounts shown in Column D would have been its requested FAC rates if not for the ESP rate caps ordered by the PUCO. However, since AEP Ohio's FAC filings are subject to ESP rate caps, the Companies' filings reflect the then current FAC rates as shown in Column E. Therefore, AEP Ohio did not request an increase in customer rates in its third quarter 2010 filing.

Exhibit 7-27
CSP Schedule 2, July – September 2010

Schedule 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2010 through September 2010
FC Component

Line	Description		Forecast Period July	August	September	Total
1	Fuel & Purchased Power		$ 78,963,000	$ 80,468,000	$ 54,168,000	$ 213,599,000
2	Environmental (Consumables and Allowances)		$ 3,258,000	$ 3,380,000	$ 3,059,000	$ 9,697,000
3	(Gains) and Losses On Sales of Allowances				$ -	$ -
4	Other					$ -
5	Total Includible FAC Costs		$ 82,221,000	$ 83,848,000	$ 57,227,000	$ 223,296,000
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 18,495,000	$ 21,355,000	$ 7,271,000	$ 47,121,000
7	FAC for Internal Load		$ 63,726,000	$ 62,493,000	$ 49,956,000	$ 176,175,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	1.00000	1.00000	1.00000	1.00000
9	FAC for Retail Load Before Renewables		$ 63,726,000	$ 62,493,000	$ 49,956,000	$ 176,175,000
10	Renewables/RECs		$ 782,000	$ 654,000	$ 800,000	$ 2,236,000
11	FAC for Retail Load		$ 64,508,000	$ 63,147,000	$ 50,756,000	$ 178,411,000
12	Retail Non-Shopping Sales - Generation Level Kwh		2,071,848,367	1,977,282,331	1,820,051,263	5,869,181,961
13	FC Component of FAC Rate At Generation Level - Cents/kWh					3.03979
			Secondary	Primary	Sub/Trans	
14	FC Component of FAC Rate At Generation Level		3.03979	3.03979	3.03979	
15	Loss Factor		1.0578	1.0233	1.0039	
16	**FC at the Meter Level - Cents/kWh**	Line 14 x Line 15	**3.21549**	**3.11062**	**3.05165**	

Exhibit 7-28
OPCO Schedule 2, July – September 2010

Schedule 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2010 through September 2010
FC Component

Line	Description		Forecast Period - 3rd Quarter 2010 July	August	September	Total
1	Fuel & Purchased Power		$ 110,808,000	$ 111,928,000	$ 100,913,000	$ 323,649,000
2	Environmental (Consumables and Allowances)		$ 10,336,000	$ 10,644,000	$ 10,159,000	$ 31,139,000
3	(Gains) and Losses On Sales of Allowances		$ (200,000)	$ (200,000)	$ (200,000)	$ (600,000)
4	Other		$ -	$ -	$ -	$ -
5	Total Includible FAC Costs		$ 120,944,000	$ 122,372,000	$ 110,872,000	$ 354,188,000
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 49,814,000	$ 51,521,000	$ 48,221,000	$ 149,556,000
7	FAC for Internal Load		$ 71,130,000	$ 70,851,000	$ 62,651,000	$ 204,632,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92490	0.92379	0.88532	0.92490
9	FAC for Retail Load Before Renewables		$ 65,788,137	$ 65,451,445	$ 55,466,183	$ 189,264,137
10	Renewables/RECs		$ 823,976	$ 694,976	$ 838,976	$ 2,357,928
11	FAC for Retail Load		$ 66,612,113	$ 66,146,421	$ 56,305,159	$ 191,622,065
12	Retail Non-Shopping Sales - Generation Level Kwh		2,408,235,591	2,390,947,268	2,172,347,632	6,971,530,491
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.74864
			Secondary	Primary	Sub/Trans	
14	FC Component of FAC Rate At Generation Level		2.74864	2.74864	2.74864	
15	Loss Factor		1.0662	1.0280	1.0033	
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**2.9306**	**2.8256**	**2.75771**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period July through September 2010. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the third quarter of 2010, AEP Ohio has projected includable FAC costs totaling $223.296 million for CSP and $354.188 million for OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the third quarter of 2010, these projected off-system costs totaled $47.121 million for CSP and $149.556 million for OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived their FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component for renewable energy credits ("RECs"), which totaled $2.236 million for CSP and $2.358 million for OPCO. The addition of the RECs result in total FAC costs for retail load of $178.411 million for CSP and $191.622 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.03979 cents per kWh for CSP and 2.74864 cents per kWh for OPCO and was calculated by dividing the projected FAC for internal load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. CSP applied the loss factors of 1.0578, 1.0233 and 1.0039 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 3.21549, 3.11062 and 3.05165 cents per kWh. OPCO applied the loss factors of 1.0662, 1.0280 and 1.0033 cents per kWh for

secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 2.9306, 2.8256 and 2.75771 cents per kWh.

Exhibit 7-29
CSP Schedule 3, Page 1, July – September 2010

Schedule 3, page 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2010 through September 2010
RA Component

Actual Period - January 2010 through March 2010

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ 38,149,075
2	Jan-10	1,900,678,687	$ 68,859,399	$ 57,748,148	$ (11,111,251)	$ 460,833	$ (401,342)	$ (11,051,760)
3	Feb-10	1,709,864,574	$ 59,726,914	$ 50,806,943	$ (8,919,971)	$ 401,342	$ (401,342)	$ (8,919,971)
4	Mar-10	1,701,424,532	$ 59,497,197	$ 51,548,458	$ (7,948,739)	$ 401,342	$ (401,342)	$ (7,948,739)
5	**Ending Balance**	5,311,967,793	$ 188,083,510	$ 160,103,549	$ (27,979,961)	$ 1,263,517	$ (1,204,026)	$ 10,228,605
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 666,027
7	Total (Over)/Under Recovery Balance							$ 10,894,632
8	Loss Adjusted Retail Sales Billing Period - kWh							5,869,181,961
9	RA Component at Generation - Cents/kWh							0.18562

			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		0.18562	0.18562	0.18562
11	Loss Factor		1.0578	1.0233	1.0039
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**0.19635**	**0.18995**	**0.18635**

Exhibit 7-30
OPCO Schedule 3, Page 1, July – September 2010

Schedule 3, page 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2010 through September 2010
RA

Actual Period - January 2010 through March 2010

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ 311,398,970
2	Jan-10	2,403,847,281	$ 60,609,377	$ 72,706,563	$ 12,097,186	$ 2,506,915	$ (137,291)	$ 14,466,810
3	Feb-10	2,142,586,708	$ 50,337,696	$ 63,705,085	$ 13,367,389	$ 2,618,406	$ (137,444)	$ 15,848,351
4	Mar-10	2,175,889,577	$ 50,650,064	$ 64,227,885	$ 13,577,821	$ 2,735,479	$ (137,291)	$ 16,176,009
5	**Ending Balance**	6,722,323,566	$ 161,597,136	$ 200,639,532	$ 39,042,396	$ 7,860,800	$ (412,026)	$ 357,890,140
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 889,614
7	Total (Over)/Under Recovery Balance							$ 358,779,754
8	Loss Adjusted Retail Sales Billing Period - kWh							6,971,530,491
9	RA Component at Generation - Cents/kWh							5.14636

			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		5.14636	5.14636	5.14636
11	Loss Factor		1.0662	1.0280	1.0033
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**5.48784**	**5.29045**	**5.16334**

Schedule 3: This three-page schedule represents the Companies' RA components of their third quarter 2010 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under-recovery of fuel expenses for each month during the period January through March 2010, which were calculated as the difference between the monthly FAC revenues for the first quarter of 2010 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the

carrying costs associated with those under-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The addition of the carrying charges and other credits and charges resulted in total under-recoveries of $10.229 million for CSP and $357.890 million for OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with Ormet. For the first quarter of 2010, these deferrals totaled $666,027 for CSP and $889,614 for OPCO. The derivation of these deferral amounts are summarized on Schedule 3, page 3.

After adding the amounts associated with Ormet, CSP's and OPCO's under recovery for the first quarter of 2010 was $10.895 million and $358.780 million, respectively. From these amounts, each Company calculated the RA component of its FAC rate at Generation level by dividing the under recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for CSP for this filing was 0.18562 cents per kWh and 5.14636 cents per kWh for OPCO. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. For CSP, the application of the loss factors results in RA components of the FAC rate of 0.19635, 0.18995 and 0.18635 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively. For OPCO, applying the loss factors resulted in RA components of the FAC rate of 5.48704, 5.29045 and 5.516334 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Similar to its previous quarterly filings, AEP Ohio stated that CSP may be in the position to begin recovering its actual fuel expense concurrently with the recovery of the deferrals prior to the end of the ESP period, whereas it is probable that OPCO will have a long-term deferral to be recovered subsequent to the end of the ESP period.

Exhibit 7-31
CSP Schedule 3, Page 2, July – September 2010

Schedule 3, page 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2010 through September 2010
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
4	Jan-10	$ 80,961,618	$ 24,262,721	$ 56,698,897	1.00000	$ 56,698,897	$ 1,049,251	$ 57,748,148
5	Feb-10	$ 74,140,104	$ 24,257,096	$ 49,883,008	1.00000	$ 49,883,008	$ 923,935	$ 50,806,943
6	Mar-10	$ 70,882,092	$ 20,882,732	$ 49,999,360	1.00000	$ 49,999,360	$ 1,549,098	$ 51,548,458
7	Total	$ 225,983,814	$ 69,402,549	$ 156,581,265		$ 156,581,265	$ 3,522,284	$ 160,103,549

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (Wstville)	Retail	Total	Whlse (Wstville)	Retail
Actual						
8	Jan-10	-	1,987,415,006	1,987,415,006	0.00000	1.00000
9	Feb-10	-	1,784,670,346	1,784,670,346	0.00000	1.00000
10	Mar-10	-	1,776,927,098	1,776,927,098	0.00000	1.00000
Forecast						
11	July '10		2,071,848,367	2,071,848,367	0.00000	1.00000
12	August '10		1,977,282,331	1,977,282,331	0.00000	1.00000
13	September '10		1,820,051,263	1,820,051,263	0.00000	1.00000

Exhibit 7-32
OPCO Schedule 3, Page 2, July – September 2010

Schedule 3, page 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2010 through September 2010
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
4	Jan-10	$ 168,926,600	$ 91,110,460	$ 77,816,140	0.92085	$ 71,656,993	$ 1,049,570	$ 72,706,563
5	Feb-10	$ 143,375,445	$ 75,234,734	$ 68,140,711	0.92087	$ 62,748,737	$ 956,348	$ 63,705,085
6	Mar-10	$ 141,495,326	$ 73,443,992	$ 68,051,334	0.91840	$ 62,498,345	$ 1,729,540	$ 64,227,885
7	Total	$ 453,797,371	$ 239,789,186	$ 214,008,185		$ 196,904,074	$ 3,735,458	$ 200,639,532

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
8	Jan-10	215,517,203	2,507,434,798	2,722,952,001	0.07915	0.92085
9	Feb-10	191,648,582	2,230,433,608	2,422,082,190	0.07913	0.92087
10	Mar-10	200,740,815	2,259,436,080	2,460,176,895	0.08160	0.91840
Forecast						
11	Jul-10	195,546,750	2,408,235,591	2,603,782,341	0.07510	0.92490
12	Aug-10	197,257,817	2,390,947,268	2,588,205,085	0.07621	0.92379
13	Sep-10	281,389,343	2,172,347,632	2,453,736,975	0.11468	0.88532

Page 2 of Schedule 3 reflects monthly data on the Companies' actual fuel costs during the first quarter of 2010. Specifically, page 2 of Schedule 3 (lines 4-7) shows, for each Company, total monthly FAC costs incurred from January through March 2010. For each month (January through March), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the first quarter of 2010, CSP and OPCO added amounts totaling $3,522,284 and $3,735,458, respectively for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that future FAC revenues will first be applied towards recovering renewable energy costs so that they are not embedded in the long-term deferrals of either CSP or OPCO. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the first quarter of 2010 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for January through March 2010. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for July through September 2010, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of 1.00000 for each month of July, August and September 2010 for CSP and .92490, .92379 and .88532 (July, August and September 2010, respectively) for OPCO.

Exhibit 7-33
CSP Schedule 3, Page 3, July – September 2010

Schedule 3, page 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2010 through September 2010
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jan-10	$ -	$ 279,673	$ 279,673
2	Feb-10	$ -	$ 234,995	$ 234,995
3	Mar-10	$ -	$ 151,359	$ 151,359
4	Total	$ -	$ 666,027	$ 666,027

Exhibit 7-34
OPCO Schedule 3, Page 3, July – September 2010

Schedule 3, page 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July2010 through September 2010
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jan-10	$ -	$ 296,428	$ 296,428
2	Feb-10	$ -	$ 296,758	$ 296,758
3	Mar-10	$ -	$ 296,428	$ 296,428
10	Total	$ -	$ 889,614	$ 889,614

As noted above, page 3 of Schedule 3 reflects the derivation of the monthly rate deferral and carrying costs associated with Ormet Interim Agreement pursuant to Case No. 09-1094-EL-FAC. The deferrals included in the Companies' FACs are for the period January 1, 2010 through September 17, 2009. Ormet related rate discounts that occurred subsequent to September 17, 2009 will be recovered through each Company's Economic Development Cost Recovery Rider.

Exhibit 7-35
CSP Schedule 4, July – September 2010

Schedule 4

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2010 through September 2010
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.65191
2	GS-1	Secondary	3.82381
3	GS-2	Secondary	3.68943
4	GS-2	Primary	3.56910
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.68943
6	GS-3	Secondary	3.47461
7	GS-3	Primary	3.36128
8	GS-3-LM-TOD	Secondary	3.47461
9	GS-4	Sub/Transmission	3.11671
10	IRP-D	Secondary	3.28405
11	IRP-D	Primary	3.17694
12	IRP-D	Sub/Transmission	3.11671
13	SL	Secondary	3.95288
14	AL	Secondary	4.50885
15	SBS	Secondary	3.53250
16	SBS	Primary	3.36577
17	SBS	Sub/Transmission	3.11671

Exhibit 7-36
OPCO Schedule 4, July – September 2010

Schedule 4

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2010 through September 2010
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	2.56084
2	GS-1	Secondary	2.59206
3	GS-2	Secondary	2.44651
4	GS-2	Primary	2.35886
5	GS-2	Sub/Transmission	2.30218
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.44651
7	GS-3	Secondary	2.37838
8	GS-3	Primary	2.29317
9	GS-3	Sub/Transmission	2.23807
10	GS-3-ES	Secondary	2.37838
11	GS-4	Primary	2.13408
12	GS-4	Sub/Transmission	2.08280
13	IRP-D	Secondary	2.21338
14	IRP-D	Primary	2.13408
15	IRP-D	Sub/Transmission	2.08280
16	EHG	Secondary	2.48485
17	EHS	Secondary	2.29960
18	SS	Secondary	2.40193
19	OL	Secondary	3.22634
20	SL	Secondary	2.87354
21	SBS	Secondary	2.41267
22	SBS	Primary	2.29129
23	SBS	Sub/Transmission	2.10693

Schedule 4: This schedule breaks out current FAC rates by tariff. AEP Ohio stated that these rates are in compliance with the provision for the capped rate percent increases approved by the PUCO in its Opinion and Order dated March 18, 2009. As noted above in the discussion of Schedule 1, AEP Ohio proposes that the current FAC rates remain in place for the third quarter of 2010 (i.e. the proposed FAC rates from AEP Ohio's first quarter 2010 FAC filing).

Third Quarter 2010 - Mid-Quarter FAC Update

On August 27, 2010, AEP Ohio submitted a mid-quarter filing. Three PUCO decisions were made authorizing rider rate changes for CSP and OPCO: On August 11, 2010, PUCO issued a Finding and Order in Case No. 10-164-EL-RDR regarding CSP's grid SMART Rider rate; on August 25, 2010, PUCO issued a Finding and Order in Case No. 10-155-EL-RDR regarding CSP and OPCO's EICC Riders; and also on August 25, 2010, PUCO issued a Finding and Order in Case No. 10-163-EL-RDR regarding CSP and OPCO's ESR Riders. Compliance tariff filings were also made on August 27, 2010 to implement these new rider rate changes effective immediately for billing with the first billing cycle of September 2010. Based on the compliance

filings, CSP and OPCO updated their FAC rates to maintain compliance with the provision for the capped rate percentage increases approved by the PUCO in its ESP Orders.

Fourth Quarter 2010

On September2, 2010, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from April through June 2010 and projected data for the period October through December 2010. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 4 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's fourth quarter 2010 FAC filings by reproducing Schedules 1 through 4, broken out separately between CSP and OPCO as Exhibits 7.37 through 7.48, and then briefly summarizing each schedule.

Exhibit 7-37
CSP Schedule 1, October – December 2010

Schedule 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2010 through December 2010
Summary - Proposed FAC Rate

			Cents Per kWh				
			A	B	C	D	E
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.56086	3.07392	0.19196	3.26588	**3.56086**
2	GS-1	Secondary	3.26772	3.07392	0.19196	3.26588	**3.26772**
3	GS-2	Secondary	3.48211	3.07392	0.19196	3.26588	**3.48211**
4	GS-2	Primary	3.36854	2.97367	0.18570	3.15937	**3.36854**
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.48211	3.07392	0.19196	3.26588	**3.48211**
6	GS-3	Secondary	3.38891	3.07392	0.19196	3.26588	**3.38891**
7	GS-3	Primary	3.27838	2.97367	0.18570	3.15937	**3.27838**
8	GS-3-LM-TOD	Secondary	3.38891	3.07392	0.19196	3.26588	**3.38891**
9	GS-4	Sub/Transmission	3.07255	2.91729	0.18218	3.09947	**3.07255**
10	IRP-D	Secondary	3.23751	3.07392	0.19196	3.26588	**3.23751**
11	IRP-D	Primary	3.13192	2.97367	0.18570	3.15937	**3.13192**
12	IRP-D	Sub/Transmission	3.07255	2.91729	0.18218	3.09947	**3.07255**
13	SL	Secondary	4.00588	3.07392	0.19196	3.26588	**4.00588**
14	AL	Secondary	4.57832	3.07392	0.19196	3.26588	**4.57832**
15	SBS	Secondary	3.41400	3.07392	0.19196	3.26588	**3.41400**
16	SBS	Primary	3.28062	2.97367	0.18570	3.15937	**3.28062**
17	SBS	Sub/Transmission	3.07255	2.91729	0.18218	3.09947	**3.07255**

Exhibit 7-38
OPCO Schedule 1, October – December 2010

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2010 through December 2010
Summary - Proposed FAC Rate

			Cents Per kWh				
			A	B	C	D	E
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	2.44290	2.70802	6.58812	9.29614	**2.44290**
2	GS-1	Secondary	2.42730	2.70802	6.58812	9.29614	**2.42730**
3	GS-2	Secondary	2.30404	2.70802	6.58812	9.29614	**2.30404**
4	GS-2	Primary	2.22150	2.61100	6.35208	8.96308	**2.22150**
5	GS-2	Sub/Transmission	2.16812	2.54826	6.19946	8.74772	**2.16812**
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.30404	2.70802	6.58812	9.29614	**2.30404**
7	GS-3	Secondary	2.28159	2.70802	6.58812	9.29614	**2.28159**
8	GS-3	Primary	2.19984	2.61100	6.35208	8.96308	**2.19984**
9	GS-3	Sub/Transmission	2.14699	2.54826	6.19946	8.74772	**2.14699**
10	GS-3-ES	Secondary	2.28159	2.70802	6.58812	9.29614	**2.28159**
11	GS-4	Primary	2.05659	2.61100	6.35208	8.96308	**2.05659**
12	GS-4	Sub/Transmission	2.00717	2.54826	6.19946	8.74772	**2.00717**
13	IRP-D	Secondary	2.13301	2.70802	6.58812	9.29614	**2.13301**
14	IRP-D	Primary	2.05659	2.61100	6.35208	8.96308	**2.05659**
15	IRP-D	Sub/Transmission	2.00717	2.54826	6.19946	8.74772	**2.00717**
16	EHG	Secondary	2.40514	2.70802	6.58812	9.29614	**2.40514**
17	EHS	Secondary	2.32055	2.70802	6.58812	9.29614	**2.32055**
18	SS	Secondary	2.28630	2.70802	6.58812	9.29614	**2.28630**
19	OL	Secondary	3.01628	2.70802	6.58812	9.29614	**3.01628**
20	SL	Secondary	2.70546	2.70802	6.58812	9.29614	**2.70546**
21	SBS	Secondary	2.29305	2.70802	6.58812	9.29614	**2.29305**
22	SBS	Primary	2.19461	2.61100	6.35208	8.96308	**2.19461**
23	SBS	Sub/Transmission	2.02740	2.54826	6.19946	8.74772	**2.02740**

Schedule 1: Column A of this schedule reflects the then current FAC rate by tariff and delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period October through December 2010. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through June 2010. Column D reflects the sum of the FC and RA components. AEP Ohio stated that the amounts shown in Column D would have been its requested FAC rates if not for the ESP rate caps ordered by the PUCO. However, since AEP Ohio's FAC filings are subject to ESP rate caps, the Companies' filings reflect the then current FAC rates as shown in Column E. Therefore, AEP Ohio did not request an increase in customer rates in its fourth quarter 2010 filing.

Exhibit 7-39
CSP Schedule 2, October – December 2010

Schedule 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2010 through December 2010
FC Component

Line	Description		Forecast Period October	November	December	Total
1	Fuel & Purchased Power		$ 50,820,000	$ 52,362,000	$ 56,442,000	$ 159,624,000
2	Environmental (Consumables and Allowances)		$ 2,573,000	$ 2,555,000	$ 2,712,000	$ 7,840,000
3	(Gains) and Losses On Sales of Allowances				$ (3,160,000)	$ (3,160,000)
4	Other					$ -
5	Total Includible FAC Costs		$ 53,393,000	$ 54,917,000	$ 55,994,000	$ 164,304,000
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 4,634,000	$ 5,022,000	$ 4,546,000	$ 14,202,000
7	FAC for Internal Load		$ 48,759,000	$ 49,895,000	$ 51,448,000	$ 150,102,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	1.00000	1.00000	1.00000	1.00000
9	FAC for Retail Load Before Renewables		$ 48,759,000	$ 49,895,000	$ 51,448,000	$ 150,102,000
10	Renewables/RECs		$ 1,168,952	$ 1,244,952	$ 1,632,952	$ 4,046,856
11	FAC for Retail Load		$ 49,927,952	$ 51,139,952	$ 53,080,952	$ 154,148,856
12	Retail Non-Shopping Sales - Generation Level Kwh		1,645,201,428	1,715,170,714	1,944,203,139	5,304,575,281
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.90596
			Secondary	Primary	Sub/Trans	
14	FC Component of FAC Rate At Generation Level		2.90596	2.90596	2.90596	
15	Loss Factor		1.0578	1.0233	1.0039	
16	**FC at the Meter Level - Cents/kWh**	Line 14 x Line 15	**3.07392**	**2.97367**	**2.91729**	

Exhibit 7-40
OPCO Schedule 2, October – December 2010

Schedule 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2010 through December 2010
FC Component

Line	Description		Forecast Period - 4th Quarter 2010 October	November	December	Total
1	Fuel & Purchased Power		$ 104,329,000	$ 99,637,000	$ 112,316,000	$ 316,282,000
2	Environmental (Consumables and Allowances)		$ 10,041,000	$ 10,033,000	$ 12,696,000	$ 32,770,000
3	(Gains) and Losses On Sales of Allowances		$ (200,000)	$ (200,000)	$ 4,202,000	$ 3,802,000
4	Other		$ -	$ -	$ -	$ -
5	Total Includible FAC Costs		$ 114,170,000	$ 109,470,000	$ 129,214,000	$ 352,854,000
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 52,456,000	$ 47,108,000	$ 58,161,000	$ 157,725,000
7	FAC for Internal Load		$ 61,714,000	$ 62,362,000	$ 71,053,000	$ 195,129,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.83505	0.81444	0.81503	0.83505
9	FAC for Retail Load Before Renewables		$ 51,534,276	$ 50,790,107	$ 57,910,327	$ 162,942,471
10	Renewables/RECs		$ 1,199,976	$ 1,272,976	$ 1,659,976	$ 4,132,928
11	FAC for Retail Load		$ 52,734,252	$ 52,063,083	$ 59,570,303	$ 167,075,399
12	Retail Non-Shopping Sales - Generation Level Kwh		2,110,177,046	2,034,822,912	2,433,083,388	6,578,083,346
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.53988
			Secondary	Primary	Sub/Trans	
14	FC Component of FAC Rate At Generation Level		2.53988	2.53988	2.53988	
15	Loss Factor		1.0662	1.0280	1.0033	
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**2.70882**	**2.611**	**2.54826**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period October through December 2010. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the fourth quarter of 2010, AEP Ohio has projected includable FAC costs totaling $164.304 million for CSP and $352.854 million for OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the fourth quarter of 2010, these projected off-system costs totaled $14.202 million for CSP and $157.725 million for OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component for renewable energy credits ("RECs"), which totaled $4.047 million for CSP and $4.133 million for OPCO. The addition of the RECs result in total FAC costs for retail load of $154.149 million for CSP and $167.075 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 2.90596 cents per kWh for CSP and 2.53988 cents per kWh for OPCO and was calculated by dividing the projected FAC for internal load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. CSP applied the loss factors of 1.0578, 1.0233 and 1.0039 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 3.07392, 2.97367 and 2.91729 cents per kWh. OPCO applied the loss factors of 1.0662, 1.0280 and 1.0033 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 2.70802, 2.611 and 2.54826 cents per kWh.

Exhibit 7-41
CSP Schedule 3, Page 1, October – December 2010

Schedule 3, page 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2010 through December 2010
RA Component

Actual Period - April 2010 through June 2010

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ 10,894,632
2	Apr-10	1,419,323,290	$ 49,159,696	$ 49,546,851	$ 387,155	$ 409,111	$ (395,774)	$ 400,492
3	May-10	1,630,446,449	$ 56,542,503	$ 56,509,941	$ (32,562)	$ 407,955	$ (394,060)	$ (18,668)
4	Jun-10	1,832,411,829	$ 63,758,718	$ 61,901,577	$ (1,857,141)	$ 407,893	$ (394,060)	$ (1,843,309)
5	**Ending Balance**	4,882,181,568	$ 169,460,917	$ 167,958,369	$ (1,502,548)	$ 1,224,958	$ (1,183,895)	$ 9,433,148
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 193,044
7	Total (Over)/Under Recovery Balance							$ 9,626,191
8	Loss Adjusted Retail Sales Billing Period - kWh							5,304,575,281
9	RA Component at Generation - Cents/kWh							0.18147

			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		0.18147	0.18147	0.18147
11	Loss Factor		1.0578	1.0233	1.0039
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**0.19196**	**0.18570**	**0.18218**

Exhibit 7-42
OPCO Schedule 3, Page 1, October – December 2010

Schedule 3, page 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2010 through December 2010
RA

Actual Period - April 2010 through June 2010

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ 358,779,754
2	Apr-10	1,866,088,926	$ 43,038,033	$ 58,082,775	$ 15,044,742	$ 2,844,627	$ (136,680)	$ 17,752,689
3	May-10	2,060,831,487	$ 47,631,659	$ 62,992,181	$ 15,360,522	$ 3,069,045	$ (140,808)	$ 18,288,759
4	Jun-10	2,236,523,115	$ 52,114,013	$ 59,798,677	$ 7,684,664	$ 3,196,517	$ (140,196)	$ 10,740,985
5	**Ending Balance**	6,163,443,528	$ 142,783,705	$ 180,873,632	$ 38,089,927	$ 9,110,189	$ (417,684)	$ 405,562,187
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 901,828
7	Total (Over)/Under Recovery Balance							$ 406,464,015
8	Loss Adjusted Retail Sales Billing Period - kWh							6,578,083,346
9	RA Component at Generation - Cents/kWh							6.17906

			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		6.17906	6.17906	6.17906
11	Loss Factor		1.0662	1.0280	1.0033
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**6.58812**	**6.35288**	**6.19946**

Schedule 3: This three-page schedule represents the Companies' RA components of their fourth quarter 2010 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under-recovery of fuel expenses for each month during the period April through June2010, which were calculated as the difference between the monthly FAC revenues for the second quarter of 2010 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the carrying costs associated with those under-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The addition of the carrying charges and other credits and charges resulted in total under-recoveries of $9.433 million for CSP and $405.562 million for OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with Ormet. For the second quarter of 2010, these deferrals totaled $193,044 for CSP and $901,828 for OPCO. The derivation of these deferral amounts are summarized on Schedule 3, page 3.

After adding the amounts associated with Ormet, CSP's and OPCO's under recovery for the second quarter of 2010 was $9.626 million and $406.464 million, respectively. From these amounts, each Company calculated the RA component of its FAC rate at Generation level by dividing the under recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for CSP for this filing was 0.18147 cents per kWh and 6.17906 cents per kWh for OPCO. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. For CSP, the application of the loss factors results in RA components of the FAC rate of 0.19196, 0.18570 and 0.18218 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively. For OPCO, applying the loss factors resulted in RA components of the FAC rate of 6.58812, 6.35208 and 6.19946 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Similar to its previous quarterly filings, AEP Ohio stated that CSP may be in the position to begin recovering its actual fuel expense concurrently with the recovery of the deferrals prior to

the end of the ESP period, whereas it is probable that OPCO will have a long-term deferral to be recovered subsequent to the end of the ESP period.

Exhibit 7-43
CSP Schedule 3, Page 2, October – December 2010

Schedule 3, page 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2010 through December 2010
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Apr-10	$ 65,620,722	$ 17,326,249	$ 48,294,473	1.00000	$ 48,294,473	$ 1,252,378	$ 49,546,851
2	May-10	$ 71,012,237	$ 16,278,377	$ 54,733,860	1.00000	$ 54,733,860	$ 1,776,081	$ 56,509,941
3	Jun-10	$ 90,632,112	$ 28,987,155	$ 61,644,957	1.00000	$ 61,644,957	$ 256,620	$ 61,901,577
4	Total	$ 227,265,071	$ 62,591,781	$ 164,673,290		$ 164,673,290	$ 3,285,079	$ 167,958,369

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (Wstville)	Retail	Total	Whlse (Wstville)	Retail
Actual						
5	Apr-10	-	1,477,943,047	1,477,943,047	0.00000	1.00000
6	May-10	-	1,699,030,087	1,699,030,087	0.00000	1.00000
7	Jun-10	-	1,911,346,037	1,911,346,037	0.00000	1.00000
Forecast						
8	October '10		1,645,201,428	1,645,201,428	0.00000	1.00000
9	November '10		1,715,170,714	1,715,170,714	0.00000	1.00000
10	December '10		1,944,203,139	1,944,203,139	0.00000	1.00000

Exhibit 7-44
OPCO Schedule 3, Page 2, October – December 2010

Schedule 3, page 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2010 through December 2010
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Apr-10	$ 100,615,819	$ 38,028,716	$ 62,587,103	0.90784	$ 56,819,076	$ 1,263,699	$ 58,082,775
2	May-10	$ 105,828,053	$ 38,488,695	$ 67,339,358	0.91922	$ 61,899,685	$ 1,092,496	$ 62,992,181
3	Jun-10	$ 132,389,609	$ 68,995,539	$ 63,394,070	0.92581	$ 58,690,864	$ 1,107,813	$ 59,798,677
4	Total	$ 338,833,481	$ 145,512,950	$ 193,320,531		$ 177,409,624	$ 3,464,008	$ 180,873,632

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
5	Apr-10	196,278,367	1,933,368,015	2,129,646,382	0.09216	0.90784
6	May-10	187,658,042	2,135,418,603	2,323,076,645	0.08078	0.91922
7	Jun-10	186,235,482	2,323,977,231	2,510,212,713	0.07419	0.92581
Forecast						
8	Oct-10	416,817,994	2,110,177,046	2,526,995,040	0.16495	0.83505
9	Nov-10	463,596,830	2,034,822,912	2,498,419,742	0.18556	0.81444
10	Dec-10	552,182,814	2,433,083,388	2,985,266,202	0.18497	0.81503

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the second quarter of 2010. Specifically, page 2 of Schedule 3 (lines 4-7) shows, for each Company, total

monthly FAC costs incurred from April through June2010. For each month (April through June), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the second quarter of 2010, CSP and OPCO added amounts totaling $3,285,079 and $3,464,008, respectively for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that future FAC revenues will first be applied towards recovering renewable energy costs so that they are not embedded in the long-term deferrals of either CSP or OPCO. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the second quarter of 2010 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for April through June2010. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for October through December 2010, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of 1.00000 for each month of October, November and December 2010 for CSP and .83505, .81444 and .81503 (October, November and December 2010, respectively) for OPCO.

Exhibit 7-45
CSP Schedule 3, Page 3, October – December 2010

Schedule 3, page 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2010 through December 2010
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Apr-10	$ -	$ 62,698	$ 62,698
2	May-10	$ -	$ 65,319	$ 65,319
3	Jun-10	$ -	$ 65,027	$ 65,027
4	Total	$ -	$ 193,044	$ 193,044

Exhibit 7-46
OPCO Schedule 3, Page 3, October – December 2010

Schedule 3, page 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2010 through December 2010
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Apr-10	$ -	$ 295,108	$ 295,108
2	May-10	$ -	$ 304,020	$ 304,020
3	Jun-10	$ -	$ 302,700	$ 302,700
4	Total	$ -	$ 901,828	$ 901,828

As noted above, page 3 of Schedule 3 reflects the derivation of the monthly rate deferral and carrying costs associated with Ormet Interim Agreement pursuant to Case No. 09-1094-EL-FAC. The deferrals included in the Companies' FACs are for the period January 1, 2010 through September 17, 2009. Ormet related rate discounts that occurred subsequent to September 17, 2009 will be recovered through each Company's Economic Development Cost Recovery Rider.

Exhibit 7-47
CSP Schedule 4, October – December 2010

Schedule 4

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2010 through December 2010
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.56086
2	GS-1	Secondary	3.26772
3	GS-2	Secondary	3.48211
4	GS-2	Primary	3.36854
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.48211
6	GS-3	Secondary	3.38891
7	GS-3	Primary	3.27838
8	GS-3-LM-TOD	Secondary	3.38891
9	GS-4	Sub/Transmission	3.07255
10	IRP-D	Secondary	3.23751
11	IRP-D	Primary	3.13192
12	IRP-D	Sub/Transmission	3.07255
13	SL	Secondary	4.00588
14	AL	Secondary	4.57832
15	SBS	Secondary	3.41400
16	SBS	Primary	3.28062
17	SBS	Sub/Transmission	3.07255

Exhibit 7-48
OPCO Schedule 4, October – December 2010

Schedule 4

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2010 through December 2010
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	2.44290
2	GS-1	Secondary	2.42730
3	GS-2	Secondary	2.30404
4	GS-2	Primary	2.22150
5	GS-2	Sub/Transmission	2.16812
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.30404
7	GS-3	Secondary	2.28159
8	GS-3	Primary	2.19984
9	GS-3	Sub/Transmission	2.14699
10	GS-3-ES	Secondary	2.28159
11	GS-4	Primary	2.05659
12	GS-4	Sub/Transmission	2.00717
13	IRP-D	Secondary	2.13301
14	IRP-D	Primary	2.05659
15	IRP-D	Sub/Transmission	2.00717
16	EHG	Secondary	2.40514
17	EHS	Secondary	2.32055
18	SS	Secondary	2.28630
19	OL	Secondary	3.01628
20	SL	Secondary	2.70546
21	SBS	Secondary	2.29305
22	SBS	Primary	2.19461
23	SBS	Sub/Transmission	2.02740

Schedule 4: This schedule breaks out current FAC rates by tariff. AEP Ohio stated that these rates are in compliance with the provision for the capped rate percent increases approved by the PUCO in its Opinion and Order dated March 18, 2009. As noted above in the discussion of Schedule 1, AEP Ohio proposes that the current FAC rates remain in place for the fourth quarter of 2010 (i.e. the proposed FAC rates from AEP Ohio's first quarter 2010 FAC filing).

First Quarter 2011

On December14, 2010, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from July through September 2010 and projected data for the period January through March2011. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 4 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's first quarter 2011 FAC filings by reproducing Schedules 1 through 4, broken out separately between CSP and OPCO as Exhibits 7.49 through 7.60, and then briefly summarizing each schedule.

Exhibit 7-49
CSP Schedule 1, January – March 2011

Schedule 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
Summary - Proposed FAC Rate

			Cents Per kWh				
			A	B	C	D	E
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.56086	3.35790	0.32622	3.68412	**4.21352**
2	GS-1	Secondary	3.26772	3.35790	0.32622	3.68412	**4.07779**
3	GS-2	Secondary	3.48211	3.35790	0.32622	3.68412	**4.19207**
4	GS-2	Primary	3.36854	3.24838	0.31558	3.56396	**4.05535**
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.48211	3.35790	0.32622	3.68412	**4.19207**
6	GS-3	Secondary	3.38891	3.35790	0.32622	3.68412	**3.88835**
7	GS-3	Primary	3.27838	3.24838	0.31558	3.56396	**3.76153**
8	GS-3-LM-TOD	Secondary	3.38891	3.35790	0.32622	3.68412	**3.88835**
9	GS-4	Sub/Transmission	3.07255	3.18680	0.30960	3.49640	**3.39096**
10	IRP-D	Secondary	3.23751	3.35790	0.32622	3.68412	**3.57303**
11	IRP-D	Primary	3.13192	3.24838	0.31558	3.56396	**3.45649**
12	IRP-D	Sub/Transmission	3.07255	3.18680	0.30960	3.49640	**3.39096**
13	SL	Secondary	4.00588	3.35790	0.32622	3.68412	**4.79251**
14	AL	Secondary	4.57832	3.35790	0.32622	3.68412	**5.81988**
15	SBS	Secondary	3.41400	3.35790	0.32622	3.68412	**3.97020**
16	SBS	Primary	3.28062	3.24838	0.31558	3.56396	**3.76788**
17	SBS	Sub/Transmission	3.07255	3.18680	0.30960	3.49640	**3.39096**

Exhibit 7-50
OPCO Schedule 1, January – March 2011

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
Summary - Proposed FAC Rate

			Cents Per kWh				
			A	B	C	D	E
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	2.44290	3.03090	6.68622	9.71712	**3.18012**
2	GS-1	Secondary	2.42730	3.03090	6.68622	9.71712	**3.29131**
3	GS-2	Secondary	2.30404	3.03090	6.68622	9.71712	**3.00046**
4	GS-2	Primary	2.22150	2.92231	6.44666	9.36897	**2.89296**
5	GS-2	Sub/Transmission	2.16812	2.85209	6.29176	9.14385	**2.82345**
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.30404	3.03090	6.68622	9.71712	**3.00046**
7	GS-3	Secondary	2.28159	3.03090	6.68622	9.71712	**2.82459**
8	GS-3	Primary	2.19984	2.92231	6.44666	9.36897	**2.72339**
9	GS-3	Sub/Transmission	2.14699	2.85209	6.29176	9.14385	**2.65795**
10	GS-3-ES	Secondary	2.28159	3.03090	6.68622	9.71712	**2.82459**
11	GS-4	Primary	2.05659	2.92231	6.44666	9.36897	**2.43472**
12	GS-4	Sub/Transmission	2.00717	2.85209	6.29176	9.14385	**2.37622**
13	IRP-D	Secondary	2.13301	3.03090	6.68622	9.71712	**2.52519**
14	IRP-D	Primary	2.05659	2.92231	6.44666	9.36897	**2.43472**
15	IRP-D	Sub/Transmission	2.00717	2.85209	6.29176	9.14385	**2.37622**
16	EHG	Secondary	2.40514	3.03090	6.68622	9.71712	**3.02127**
17	EHS	Secondary	2.32055	3.03090	6.68622	9.71712	**2.60641**
18	SS	Secondary	2.28630	3.03090	6.68622	9.71712	**2.91048**
19	OL	Secondary	3.01628	3.03090	6.68622	9.71712	**4.44636**
20	SL	Secondary	2.70546	3.03090	6.68622	9.71712	**3.81544**
21	SBS	Secondary	2.29305	3.03090	6.68622	9.71712	**2.91311**
22	SBS	Primary	2.19461	2.92231	6.44666	9.36897	**2.72600**
23	SBS	Sub/Transmission	2.02740	2.85209	6.29176	9.14385	**2.42134**

Schedule 1: Column A of this schedule reflects the then current FAC rate by tariff and delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period January through March2011. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through September 2010. Column D reflects the sum of the FC and RA components. AEP Ohio stated that the amounts shown in Column D would have been its requested FAC rates if not for the ESP rate caps ordered by the PUCO. However, since AEP Ohio's FAC filings are subject to ESP rate caps, the Companies' filings reflect the then current FAC rates as shown in Column E. Therefore, AEP Ohio did not request an increase in customer rates in its first quarter 2011 filing.

Exhibit 7-51
CSP Schedule 2, January – March 2011

Schedule 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
FC Component

Line	Description		Forecast Period January	February	March	Total
1	Fuel & Purchased Power		$ 120,051,098	$ 108,647,197	$ 107,831,495	$ 336,529,790
2	Environmental (Consumables and Allowances)		$ 4,652,676	$ 4,641,033	$ 4,060,317	$ 13,354,026
3	(Gains) and Losses On Sales of Allowances		$ -	$ -	$ (17,100)	$ (17,100)
4	Other					$ -
5	Total Includible FAC Costs		$ 124,703,774	$ 113,288,230	$ 111,874,712	$ 349,866,716
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 69,401,024	$ 60,887,134	$ 60,442,529	$ 190,730,687
7	FAC for Internal Load		$ 55,302,750	$ 52,401,096	$ 51,432,183	$ 159,136,029
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	1.00000	1.00000	1.00000	1.00000
9	FAC for Retail Load Before Renewables		$ 55,302,750	$ 52,401,096	$ 51,432,183	$ 159,136,029
10	Renewables/RECs		$ 1,556,866	$ 1,258,558	$ 1,309,737	$ 4,125,161
11	FAC for Retail Load		$ 56,859,616	$ 53,659,654	$ 52,741,920	$ 163,261,190
12	Retail Non-Shopping Sales - Generation Level Kwh		1,825,538,075	1,691,940,147	1,625,543,053	5,143,021,275
13	FC Component of FAC Rate At Generation Level - Cents/kWh					3.17442
			Secondary	Primary	Sub/Trans	
14	FC Component of FAC Rate At Generation Level		3.17442	3.17442	3.17442	
15	Loss Factor		1.0578	1.0233	1.0039	
16	**FC at the Meter Level - Cents/kWh**	Line 14 x Line 15	**3.3579**	**3.24838**	**3.1868**	

Exhibit 7-52
OPCO Schedule 2, January – March 2011

Schedule 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
FC Component

Line	Description		Forecast Period - 1st Quarter 2011 January	February	March	Total
1	Fuel & Purchased Power		$ 61,105,151	$ 55,411,655	$ 54,550,945	$ 171,067,751
2	Environmental (Consumables and Allowances)		$ 12,796,010	$ 13,987,877	$ 11,927,580	$ 38,711,467
3	(Gains) and Losses On Sales of Allowances		$ (174,623)	$ (174,623)	$ (239,943)	$ (589,189)
4	Other		$ -	$ -	$ -	$ -
5	Total Includible FAC Costs		$ 73,726,538	$ 69,224,909	$ 66,238,582	$ 209,190,029
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ (2,317,178)	$ (1,284,379)	$ (6,060,677)	$ (9,662,234)
7	FAC for Internal Load		$ 76,043,716	$ 70,509,288	$ 72,299,259	$ 218,852,263
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92438	0.92461	0.91534	0.92438
9	FAC for Retail Load Before Renewables		$ 70,293,290	$ 65,193,593	$ 66,178,404	$ 202,302,655
10	Renewables/RECs		$ 1,632,139	$ 1,342,408	$ 1,407,876	$ 4,382,423
11	FAC for Retail Load		$ 71,925,429	$ 66,536,001	$ 67,586,280	$ 206,685,078
12	Retail Non-Shopping Sales - Generation Level Kwh		2,548,012,644	2,333,024,187	2,389,672,488	7,270,709,319
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.84271
			Secondary	Primary	Sub/Trans	
14	FC Component of FAC Rate At Generation Level		2.84271	2.84271	2.84271	
15	Loss Factor		1.0662	1.0280	1.0033	
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**3.0309**	**2.92231**	**2.85209**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period January through March2011. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the first quarter of 2011, AEP Ohio has projected includable FAC costs totaling $349.867 million for CSP and $209.190 million for OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the first quarter of 2011, these projected off-system costs totaled $190.731 million for CSP and ($9.662) million for OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component for renewable energy credits ("RECs"), which totaled $4.125 million for CSP and $4.382 million for OPCO. The addition of the RECs result in total FAC costs for retail load of $163.261 million for CSP and $206.685 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.17442 cents per kWh for CSP and 2.84271 cents per kWh for OPCO and was calculated by dividing the projected FAC for internal load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. CSP applied the loss factors of 1.0578, 1.0233 and 1.0039 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 3.3579, 3.24838 and 3.1868 cents per kWh. OPCO applied the loss factors of 1.0662, 1.0280 and 1.0033 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 3.0309, 2.92231 and 2.85209 cents per kWh.

Exhibit 7-53
CSP Schedule 3, Page 1, January – March 2011

Schedule 3, page 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2011
RA Component

Actual Period - July 2010 through Sept 2010

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ 9,626,191
2	Jul-10	2,028,770,725	$ 70,991,642	$ 72,343,388	$ 1,351,746	$ 412,056	$ 3,771,502	$ 5,535,305
3	Aug-10	1,993,965,411	$ 67,593,424	$ 68,182,047	$ 588,623	$ 414,393	$ (575,451)	$ 427,565
4	Sep-10	1,533,385,603	$ 53,015,582	$ 52,868,980	$ (146,602)	$ 415,564	$ (293,760)	$ (24,799)
5	**Ending Balance**	5,556,121,739	$ 191,600,648	$ 193,394,415	$ 1,793,767	$ 1,242,013	$ 2,902,291	$ 15,564,261
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 296,659
7	Total (Over)/Under Recovery Balance							$ 15,860,920
8	Loss Adjusted Retail Sales Billing Period - kWh							5,143,021,275
9	RA Component at Generation - Cents/kWh							0.30840

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		0.30840	0.30840	0.30840
11	Loss Factor		1.0578	1.0233	1.0039
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**0.32622**	**0.31558**	**0.30960**

Exhibit 7-54
OPCO Schedule 3, Page 1, January – March2011

Schedule 3, page 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
RA

Actual Period - July 2010 through September 2010

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ 406,464,015
2	Jul-10	2,451,401,180	$ 57,596,084	$ 68,342,007	$ 10,745,923	$ 3,268,380	$ (140,349)	$ 13,873,955
3	Aug-10	2,386,946,908	$ 54,777,265	$ 69,841,878	$ 15,064,613	$ 3,374,308	$ (372,141)	$ 18,066,780
4	Sep-10	1,975,115,589	$ 43,889,812	$ 57,185,715	$ 13,295,903	$ 3,482,301	$ (139,432)	$ 16,638,773
5	**Ending Balance**	6,813,463,677	$ 156,263,161	$ 195,369,600	$ 39,106,439	$ 10,124,990	$ (651,922)	$ 455,043,522
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 907,770
7	Total (Over)/Under Recovery Balance							$ 455,951,292
8	Loss Adjusted Retail Sales Billing Period - kWh							7,270,709,319
9	RA Component at Generation - Cents/kWh							6.27107

			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		6.27107	6.27107	6.27107
11	Loss Factor		1.0662	1.0280	1.0033
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**6.68622**	**6.44666**	**6.29176**

Schedule 3: This three-page schedule represents the Companies RA components of its third quarter 2010 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under-recovery of fuel expenses for each month during the period July through September2010, which were calculated as the difference between the monthly FAC revenues for the third quarter of 2010 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the carrying costs associated with those under-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The addition of the carrying charges and other credits and charges resulted in total under-recoveries of $15.564 million for CSP and $455.044 million for OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with Ormet. For the third quarter of 2010, these deferrals totaled $296,659 for CSP and $907,770 for OPCO. The derivation of these deferral amounts are summarized on Schedule 3, page 3.

After adding the amounts associated with Ormet, CSP's and OPCO's under recovery for the third quarter of 2010 was $15.860 million and $455.951 million, respectively. From these amounts, each Company calculated the RA component of its FAC rate at Generation level by dividing the under recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for CSP for this filing was 0.30840 cents per kWh and 6.27107 cents per kWh for OPCO. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. For CSP, the application of the loss factors results in RA components of the FAC rate of 0.32622, 0.31558 and 0.30960 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively. For OPCO, applying the loss factors resulted in RA components of the FAC rate of 6.68622, 6.44666 and 6.29176 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Similar to its 2010 quarterly filings, AEP Ohio stated that CSP may be in the position to begin recovering its actual fuel expense concurrently with the recovery of the deferrals prior to the end

of the ESP period, whereas it is probable that OPCO will have a long-term deferral to be recovered subsequent to the end of the ESP period.

Exhibit 7-55
CSP Schedule 3, Page 2, January – March 2011

Schedule 3, page 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Jul-10	$ 114,219,640	$ 42,479,667	$ 71,739,973	1.00000	$ 71,739,973	$ 603,415	$ 72,343,388
2	Aug-10	$ 103,385,838	$ 35,770,879	$ 67,614,959	1.00000	$ 67,614,959	$ 567,088	$ 68,182,047
3	Sep-10	$ 68,557,689	$ 16,715,360	$ 51,842,329	1.00000	$ 51,842,329	$ 1,026,651	$ 52,868,980
4	Total	$ 286,163,167	$ 94,965,906	$ 191,197,261		$ 191,197,261	$ 2,197,154	$ 193,394,415

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (Wstville)	Retail	Total	Whlse (Wstville)	Retail
Actual						
5	Jul-10	-	2,119,280,726	2,119,280,726	0.00000	1.00000
6	Aug-10	-	2,081,664,229	2,081,664,229	0.00000	1.00000
7	Sep-10	-	1,598,196,179	1,598,196,179	0.00000	1.00000
Forecast						
8	January '11		1,825,538,075	1,825,538,075	0.00000	1.00000
9	February '11		1,691,940,147	1,691,940,147	0.00000	1.00000
10	March '11		1,625,543,053	1,625,543,053	0.00000	1.00000

Exhibit 7-56
OPCO Schedule 3, Page 2, January – March 2011

Schedule 3, page 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Jul-10	$ 159,756,288	$ 86,358,375	$ 73,397,913	0.92220	$ 67,687,555	$ 654,452	$ 68,342,007
2	Aug-10	$ 150,946,731	$ 76,250,152	$ 74,696,579	0.92636	$ 69,195,923	$ 645,955	$ 69,841,878
3	Sep-10	$ 114,830,128	$ 53,842,110	$ 60,988,018	0.91971	$ 56,091,290	$ 1,094,425	$ 57,185,715
4	Total	$ 425,533,147	$ 216,450,637	$ 209,082,510		$ 192,974,768	$ 2,394,832	$ 195,369,600

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
5	Jul-10	215,379,943	2,553,171,638	2,768,551,581	0.07780	0.92220
6	Aug-10	197,590,195	2,485,640,230	2,683,230,425	0.07364	0.92636
7	Sep-10	178,894,575	2,049,327,670	2,228,222,245	0.08029	0.91971
Forecast						
8	Jan-11	208,451,434	2,548,012,644	2,756,464,077	0.07562	0.92438
9	Feb-11	190,229,720	2,333,024,187	2,523,253,907	0.07539	0.92461
10	Mar-11	221,029,374	2,389,672,488	2,610,701,862	0.08466	0.91534

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the third quarter of 2010. Specifically, page 2 of Schedule 3 (lines 4-7) shows, for each Company, total monthly FAC costs incurred from July through September2010. For each month (July through September), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the third quarter of 2010, CSP and OPCO added amounts totaling $2,197,154 and $2,394,832, respectively for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that future FAC revenues will first be applied towards recovering renewable energy costs so that they are not embedded in the long-term deferrals of either CSP or OPCO. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the third quarter of 2010 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for July through September2010. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for January through March2011, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of 1.00000 for each month of January, February and March2011 for CSP and .92438, .92461 and .91534 (January, February and March2011, respectively) for OPCO.

Exhibit 7-57
CSP Schedule 3, Page 3, January – March 2011

Schedule 3, page 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jul-10	$ -	$ 82,587	$ 82,587
2	Aug-10	$ -	$ 93,571	$ 93,571
3	Sep-10	$ -	$ 99,075	$ 99,075
4	Total	$ -	$ 275,232	$ 275,232

Exhibit 7-58
OPCO Schedule 3, Page 3, January – March 2011

Schedule 3, page 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jul-10	$ -	$ 303,030	$ 303,030
2	Aug-10	$ -	$ 303,690	$ 303,690
3	Sep-10	$ -	$ 301,049	$ 301,049
4	Total	$ -	$ 907,770	$ 907,770

As noted above, page 3 of Schedule 3 reflects the derivation of the monthly rate deferral and carrying costs associated with Ormet Interim Agreement pursuant to Case No. 09-1094-EL-FAC. The deferrals included in the Companies' FACs are for the period January 1, 2010 through September 17, 2009. Ormet related rate discounts that occurred subsequent to September 17, 2009 will be recovered through each Company's Economic Development Cost Recovery Rider.

Exhibit 7-59
CSP Schedule 4, January – March 2011

Schedule 4

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	4.21352
2	GS-1	Secondary	4.07779
3	GS-2	Secondary	4.19207
4	GS-2	Primary	4.05535
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	4.19207
6	GS-3	Secondary	3.88835
7	GS-3	Primary	3.76153
8	GS-3-LM-TOD	Secondary	3.88835
9	GS-4	Sub/Transmission	3.39096
10	IRP-D	Secondary	3.57303
11	IRP-D	Primary	3.45649
12	IRP-D	Sub/Transmission	3.39096
13	SL	Secondary	4.79251
14	AL	Secondary	5.81988
15	SBS	Secondary	3.97020
16	SBS	Primary	3.76788
17	SBS	Sub/Transmission	3.39096

Exhibit 7-60
OPCO Schedule 4, January – March 2011

Schedule 4

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	3.18012
2	GS-1	Secondary	3.29131
3	GS-2	Secondary	3.00046
4	GS-2	Primary	2.89296
5	GS-2	Sub/Transmission	2.82345
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	3.00046
7	GS-3	Secondary	2.82459
8	GS-3	Primary	2.72339
9	GS-3	Sub/Transmission	2.65795
10	GS-3-ES	Secondary	2.82459
11	GS-4	Primary	2.43472
12	GS-4	Sub/Transmission	2.37622
13	IRP-D	Secondary	2.52519
14	IRP-D	Primary	2.43472
15	IRP-D	Sub/Transmission	2.37622
16	EHG	Secondary	3.02127
17	EHS	Secondary	2.60641
18	SS	Secondary	2.91048
19	OL	Secondary	4.44636
20	SL	Secondary	3.81544
21	SBS	Secondary	2.91311
22	SBS	Primary	2.72600
23	SBS	Sub/Transmission	2.42134

Schedule 4: This schedule breaks out current FAC rates by tariff. AEP Ohio stated that these rates are in compliance with the provision for the capped rate percent increases approved by the PUCO in its Opinion and Order dated March 18, 2009. As noted above in the discussion of Schedule 1, AEP Ohio proposes that the current FAC rates remain in place for the first quarter of 2011 (i.e. the proposed FAC rates from AEP Ohio's first quarter 2010 FAC filing).

Minimum Review Requirements

As noted above, Larkin referred to the objectives and procedures outlined in Appendix E of former Chapter 4901:1-11 of the Ohio Administrative Code as guidance for the review requirements of this project. The purpose of the Uniform Financial Audit Program Standards and Specifications for the Electric Fuel Component is to provide uniform standards and specifications as guidelines for an independent auditing firm which

conducted an EFC "financial audit"[34] pursuant to former section 4905.66(B)(2) of the Revised Code and former rule 4901:1-11-09 of the Administrative Code. The EFC "financial audit" program is only a guide for the auditor and should not be used to the exclusion of the auditor's initiative, imagination and thoroughness.

Section E of those Standards provides for the following Minimum Review Requirements:

The auditor's review shall include, but not be limited to, a review of:

(1) Purchasing procedures for fuel procurement not under long-term contracts;

(2) Procedures for accounting for fuel receipts, testing, and payments;

(3) Procedures for weighing, testing and reporting coal burned;

(4) Procedures for amortizing nuclear fuel costs corresponding to nuclear generated energy;

(5) Procedures for recording purchases and interchanges;

(6) Procedures for accounting treatment of emission allowances; and

(7) Procedures for calculating the FAC rate, including an evaluation of the company's compliance with the financial procedural aspects of former Chapter 4901:1-11 of the Administrative Code, and its application to customer bills.

Larkin reviewed AEP Ohio's procedures for accounting for fuel receipts, testing of samples to ensure quality, and payments to vendors. CSP and OPCO use the same accounting procedures for fuel receipts, testing and payments. These procedures are as follows:

- Plant personnel enter the fuel receipts information into the Companies' fuel accounting system [redacted]. This system contains the terms and conditions associated with fuel contracts. The system is also utilized to make payments to suppliers and transportation vendors. In addition, the Accounting Department creates payment requests through [redacted], which in turn is run through a feed to the [redacted] system, where such payments are executed.
- After testing is performed, the resulting analysis is fed into the [redacted] system from the Central Coal Lab system software. Certain purchases are paid for based on information provided by the Companies' suppliers, which is then entered into the [redacted] system by plant personnel.

Larkin also reviewed the Companies' procedures for weighing, testing and reporting coal burned per data request LA-2010-02. Specifically, consumed tonnage is measured either by belt scales or weigh feeders as coal is fed into units and/or bunkers. Unit burn samples are collected using

[34] As noted above, the review of AEP Ohio's quarterly FAC filings were conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants.

mechanical sampling systems that are in accordance with American Society for Testing Standards ("ASTM") standards. In addition, unit samples are collected and sent to the AEP Central Coal Lab to be analyzed. The analyzed results are then fed into the [redacted] system. Burn reports, which include tonnage and quality characteristics, can be generated by [redacted] systems for the relevant reporting period.

CSP and OPCO's procedures for recording purchases and interchanges of energy, as described in response to LA-2010-03, involve each Company's Accounting Department being provided information regarding power purchases from third parties and/or affiliates. The Accounting Department then records such data into Account 555 – Purchased Power.

The Companies account for fuel at jointly owned generation plants as follows:

CSP Jointly Owned Generation

CSP participates in four jointly owned power plants. In addition to CSP, the joint owners are Duke Energy-Ohio ("Duke") and Dayton Power & Light ("DP&L"). The four jointly owned plants include the following:

- Conesville Plant Unit 4 (operated by CSP)
- Zimmer Plant (operated by Duke)
- Beckjord Plant Unit 6 (operated by Duke)
- Stuart Plant (operated by DP&L)

The same accounting methodology is used at all four jointly owned power plants as illustrated below:

- The total costs of each plant are recorded in a fuel ledger and then such costs are allocated to the joint owners.
- The current month's fuel receipts are added to Beginning Inventory. From this a weighted average rate is determined for Available Tons in Inventory. Consumed expense is then calculated at the available rate for the consumed tons.
- Ending inventory is calculated as Available Inventory less Consumption.
- CSP, Duke and DP&L all have an ownership share of each plant's ending inventory. Each joint owner's consumption is calculated based on a composite ratio. This ratio represents the energy used for the month plus an ownership portion, which represents the energy necessary to maintain each unit in a state of readiness. Each joint owner's receipts are calculated as the difference between Beginning Inventory and Available Inventory with Available Inventory calculated as Ending Inventory plus Consumption.
- An additional allocation is calculated for both the Conesville Unit 4 and Beckjord Unit 6 power plants. Plant inventory is allocated, based on historic consumption, to segregate a portion of the total coal pile between the jointly owned unit and the non-jointly owned unit(s). With respect to the units operated by Duke and DP&L, those companies bill the

other Cincinnati, Columbus and Dayton ("CCD") owners for their respective portion of coal optimization credits/charges which are recorded as part of fuel consumed.

OPCO Jointly Owned Generation

OPCO participates in three jointly-owned power plants. The three jointly owned power plants are comprised of the following:

- Cardinal Plant Units 2 and 3 are operated by Cardinal Operating Company and are co-owned with Buckeye Power, a non-affiliated partner.
- Amos Plant Unit 3 is operated and co-owned by Appalachian Power Company ("APCo").
- APCo also operates Sporn Plant Units 2, 4 and 5, but these units are owned 100 percent by OPCO.

Cardinal Plant Units 2 and 3

- The total costs of the entire plant are recorded in a fuel ledger and then such costs are allocated to the joint owners.
- The current month's fuel receipts are added to Beginning Inventory. From this, a weighted average rate is determined for Available Tons in Inventory. Consumed expense is then calculated at the available rate for the consumed tons.
- Ending Inventory is calculated as Available Inventory less Consumption.
- The joint owners' share of ending inventory is based on twelve-month generation taken. This amount is updated quarterly.
- The calculation for the joint owners' consumption is based on the energy taken each month. Joint owners' receipts are calculated as the difference between Beginning Inventory and Available Inventory.
- Available Inventory is calculated as Ending Inventory plus Consumption.

Amos Plant Unit 3

- The total costs of the entire plant are recorded in a fuel ledger and then such costs are allocated to the joint owners.
- The current month's fuel receipts are added to Beginning Inventory. From this, a weighted average rate is determined for Available Tons in Inventory. Consumed expense is then calculated at the available rate for the consumed tons.
- Ending Inventory is calculated as Available Inventory less Consumption.
- A portion of this plant's Ending Inventory is allocated to segregate the jointly-owned Unit 3 from the non-jointly owned units. This allocation is based on projected consumption by unit.
- OPCo owns two-thirds of Unit 3 Ending Inventory and associated monthly consumption.

- The joint owners' receipts are calculated as the difference between Beginning Inventory and Available Inventory.
- Available Inventory is calculated as Ending Inventory plus Consumption.

Sporn Plant Units 2, 4 and 5

- The total costs of the entire plant are recorded in a fuel ledger and then such costs are allocated to the joint owners.
- The current month's fuel receipts are added to Beginning Inventory. From this, a weighted average rate is determined for Available Tons in Inventory. Consumed expense is then calculated at the available rate for the consumed tons.
- Ending Inventory is calculated as Available Inventory less Consumption.
- A portion of this plant's Ending Inventory is allocated to segregate the units owned by APCo (Units 1 and 3) and the units owned by OPCO (Units 2, 4 and 5). This allocation is based on projected consumption by unit.
- Consumption is calculated based on the tons consumed by unit at the available rate for total plant inventory.
- The joint owners' receipts are calculated as the difference between Beginning Inventory and Available Inventory.
- Available Inventory is calculated as Ending Inventory plus Consumption.

FAC Deferrals

In its July 31, 2008 Application for an Electric Security Plan (and FAC), AEP Ohio proposed mitigating the rate impact of any FAC increases on its customers by phasing in the new ESP rates by deferring a portion of the annual incremental FAC costs during the three-year ESP period ending December 31, 2011. Specifically, AEP Ohio proposed that the amount of incremental FAC costs to be recovered from customers would be such that total bill increases would not be more than 15 percent during each year of the ESP. However, in its Opinion and Order dated March 18, 2009, the PUCO modified AEP Ohio's proposal to mitigate the rate impact on customers by limiting the phase-in of any FAC cost increases on a total bill basis by the following percentages:

	2009	2010	2011
Columbus Southern Power	7%	6%	6%
Ohio Power Company	8%	7%	8%

As a result of implementing this Order, CSP now has 17 different FAC rates and OPCO has 23 different FAC rates. The PUCO stated that the collection of any deferrals, including carrying

costs that are remaining at the end of the ESP "shall occur from 2012 through 2018 as necessary to recover the actual fuel expenses incurred plus carrying costs."[35]

In LA-2010-52, Larkin requested that AEP Ohio provide, for CSP and OPCO separately, the most current estimates and projections of the deferred FAC costs through the end of the ESP period. LA-2010-52 also requested the Companies' estimate of the collection period necessary to fully recover the deferred FAC costs after the ESP period, including an estimate of the prospective surcharge and rate impact. AEP Ohio objected to this question stating that it sought information that was beyond the audit period and instead referred to LA-2010-42, which requested copies of AEP-Ohio's quarterly FAC filings. In other words, AEP-Ohio's response to LA-2010-52 was confined to providing the deferred FAC balances for the 2010 review period.[36]

The Companies' response to data request LA-2010-43, which requested a complete set of supporting workpapers for all the calculations in the quarterly FAC filings for the review period (and discussed in more detail later in this report), included a workpaper titled "Summary of Under/Over-Recovery Journals by Month – General Ledger Account 501005 – (FAC) Fuel Deferred" for both CSP and OPCO during the period January through December 2010. For CSP, this workpaper indicates that at December 31, 2010, CSP had an over-recovery of $23,228,616. This amount was netted against CSP's under-recovery of $36,028,133 at December 31, 2009 as well as an additional item which the Company described as a "December balance sheet entry to accrue for FAC effect after pre-tax income was closed" in the amount of $1,436,284. The netting of these three items resulted in an under-recovery in Account No. 1823227 of $14,235,801.

For OPCo, this workpaper indicates an under-recovery of $153,642,822 for 2010, which when added to OPCo's December 31, 2009 under-recovery of $297,570,318, results in an under-recovery of $451,213,140 recorded in Account No. 1823144.

LA-2010-05 asked the Companies to identify, by amount and account, any fuel amounts being deferred that affected the review period and to explain why such amounts were being deferred. In its confidential response, AEP Ohio stated that [redacted].

Review Related To Coal Order Processing

The following is a description of AEP Ohio's procedures for processing fuel purchase orders (per LA-2010-6):

[35] See PUCO's Opinion and Order dated March 18, 2009 at page 23.

[36] As previously described, Larkin's review also examined AEP Ohio's December 14, 2010 Quarterly FAC Filings, which covered projected information for January through March 2011 and actual information for the RA component for July through September 2010.

- A coal buyer initiates request for proposal, which is based on the following: (1) projected coal needs, (2) inventory levels of an operating unit and/or plant, and (3) the availability and price of coal in the markets.
- The buyer will analyze the offers received. An award will be made based on the following: (1) cost, (2) compatible quality, and (3) credit approval.
- The coal buyer also creates a justification, which is the basis for a proposed fuel purchase order. This justification is routed to key management personnel whose approval is required for the fuel purchase order to be executed.
- Once internal approval of the purchase order has been met and it has been returned by the counterparty, a formal purchase order is assembled and entered into the Company's fuel accounting system.

Purchase Orders And Approved Purchase Requisitions

Data requests LA-2010-7 and LA-2010-8 requested copies of fuel purchase orders ("POs") recorded in July 2010 and approved purchase requisitions for fuel purchases recorded in July 2010. In response, AEP Ohio stated that copies of the fuel POs recorded in July 2010 and the approved purchase requisitions were provided in the confidential response to EVA-2010-1-3. The Companies response to EVA-2010-1-3 stated that all new coal POs for 2010 as well as any amendments and justifications for those amendments were included in the confidential attachments. Included in the confidential attachments was a summary of the coal POs that were either executed in 2010 or already in place. This summary also included a listing of any POs to which amendments were made along with a notation which indicated the reason for the amendments. As the number of POs in the confidential attachment were voluminous, Larkin selected a sample of POs for review. Each PO that Larkin selected was properly executed and was accompanied by an intercompany memo which summarized the details of the corresponding PO. No exceptions were noted.

Invoice And Voucher Procedures

In order to enable us to track the Company's processing of fuel invoices, Larkin obtained copies of cash vouchers and payment documentation for fuel purchases recorded in July 2010. These were provided in the confidential response to data request LA-2010-9. In addition, the response to LA-2010-9 stated in part:

> *...OPCO receives a share of receipts at the Amos, Cardinal, and Sporn plants and CSP receives a share of receipts at the Beckjord, Stuart, and Zimmer plants in accordance with the joint plant agreements governing each of these plants.*

For CSP, the confidential information provided in LA-2010-9 included payment documentation for the Conesville and Picway plants. For OPCO, the information provided in LA-2010-9 included payment documentation for the Gavin, Kammer, Mitchell and Muskingum River plants. For each purchase, this documentation included a summary of invoices paid by CSP and OPCo, invoices, payment vouchers (with supporting detail) and a report titled "Penalty/Premium Pricing

Report", which is a detailed calculation report of the amounts due to the Companies vendors for deliveries under a given contract or purchase order.

Larkin's review included tracing the invoices to the supporting data that was provided by the Companies. Larkin first examined each invoice and compared the vendor name, invoice number and invoice date to the accompanying voucher and voucher supporting detail (a document called a "Request for Payment Detail"). The Request for Payment Detail broke out the purchases by station, source date, commodity, entry type, description, quantity and value. We then traced the total of the amount(s) listed for each generating station on the Requests for Payment Detail to the invoices and Penalty/Premium Pricing Reports. No exceptions were noted.

Fuel Ledger

Larkin reviewed the data the Companies provided in response to LA-2010-10, which requested CSP's and OPCO's fuel ledgers for the period January through December 2010. Upon reviewing the fuel ledgers, including accompanying reconciliation pages, Larkin was able to tie the amounts shown to the FAC workbooks provided in LA-2010-43 and the general ledger. (See additional discussion below)

BTU Adjustments

As part of its review, Larkin requested that the Companies provide documentation for Btu adjustments for fuel purchases recorded in July 2010 per data request LA-2010-11. In its confidential response, AEP Ohio referred to the response to data request EVA-2010-1-17, in which AEP Ohio provided confidential documents titled "Penalty/Premium Pricing Report". AEP Ohio provided these confidential reports for the following power plants: Cook Coal Terminal, Conesville, Conesville Prep, Gavin, Kammer, Mitchell, and Muskingum River. Upon its initial review of the Penalty/Premium Pricing Reports, Larkin noted that each such report had a calculation under the heading "Btu Adjustment". Larkin asked AEP Ohio to provide clarification as to how the calculations are derived as well as their relationship to the Penalty/Premium Pricing Reports. In response, the Companies provided the following narrative:

> *"The Penalty/Premium Pricing Reports provide detail into the dollar value to be calculated not only for the BTU quality adjustments, but for all coal related pricing components. These costs are calculated based on the terms of the particular contract. The report outlines the calculation being used for the specific contract pricing component, again based on the defined calculation of the contract. The below examples reflect two different BTU adjustments.*

[redacted]

From these reports, Larkin compared the Btu adjustment calculation to the specific contract as well as recalculated the amounts used in the Btu adjustment calculation. No exceptions were noted.

Freight And Barge Vouchers

LA-2010-12 requested that AEP Ohio provide freight cash vouchers for two days of coal receipts in July 2010 as well as copies of the portions of the corresponding coal received reports. For CSP, the confidential response to LA-2010-12 included documentation related to four payments that CSP made for freight associated with coal received at the Specifically, this documentation included:

- Copies of four invoices for the payments referenced above;
- Copies of four payment vouchers (each also including a Request for Payment Detail) that are associated with those payments; and
- Copies of four documents titled "Transportation Cost Report", which provides a breakout of the coal deliveries to which the total freight costs shown on the payment vouchers and invoices relate.

Upon reviewing the aforementioned documents, Larkin verified the freight costs reflected on the Transportation Cost Reports to the invoices. In addition, Larkin tied out the amounts reflected

on the invoices and Transportation Cost Reports to the payment vouchers. No exceptions were noted.

For OPCO, the confidential response to LA-2010-12 included [redacted]

Larkin verified the freight costs reflected on the Transportation Cost Reports to the invoices. In addition, Larkin tied out the amounts reflected on the invoices and Transportation Cost Reports to the payment vouchers. No exceptions were noted.

LA-2010-13 requested that AEP Ohio provide two cash vouchers from each barge company for coal unloaded at Company plants during July 2010 as well as copies of the portions of the corresponding coal unloading reports and purchase orders. In a confidential response, AEP Ohio stated that CSP does not incur any barging costs, but that OPCO's barging services are provided by the RTD. OPCO's barging services are discussed in further detail in the AEP River Transportation Division section of this report. As the RTD is an affiliated company of OPCO, RTD issues a monthly invoice, which is settled by an inter-unit journal entry. As part of its response to LA-2010-13, AEP Ohio provided a copy of the RTD invoice for July 2010, which included data related to coal shipments received at the Gavin, Kammer and Mitchell plants. In addition, the Companies' provided a copy of the [redacted] Transportation Cost Report which details barging shipments of coal received in July 2010 for the those plants

Upon reviewing and comparing the data listed on the July 2010 RTD invoice (document titled Billed Freight – Coal – Captive) and the July 2010 [redacted] Transportation Cost report, Larkin was able to verify the quantities and prices from the [redacted] reports to the RTD invoice. However, Larkin noted that in one instance with coal delivered to the Kammer plant the billed rate indicated on the [redacted] report was [redacted] while the RTD invoice indicated [redacted] In other instances, the quantities for certain deliveries (as identified by Transportation Unit Number) listed on the [redacted] reports did not match the quantities on the RTD invoice. In response to our inquiry, AEP Ohio provided the following explanations:

- Price Discrepancy

AEP Ohio explained that there are occasionally very small differences in the rate per ton billed by RTD and the rate documented in [redacted]. These small differences are settled between OPCO and RTD when the quarterly true-up bill is booked.

- Quantity Discrepancies

  AEP Ohio explained that the transportation unit numbers can be used multiple times in a given month, thus for a given transportation unit number, the [redacted] reports may reflect different load/unload dates (and therefore different tonnages) than what is reflected on the RTD invoice. In addition, shipments that are delivered close to the end of the month may not be reflected on the RTD invoice until the following month.

Fuel Analysis Reports

LA-2010-14 requested that AEP Ohio provide the Company's procedures for preparing monthly fuel analysis reports. In response, AEP Ohio stated that fuel analysis data was captured in the [redacted] and fed to the [redacted] system. In addition, AEP Ohio stated that fuel analysis reports can be generated for each plant from the [redacted] reports.

LA-2010-15 requested that AEP Ohio provide copies of fuel analysis reports related to fuel purchases recorded during July 2010. In its confidential response the Company provided such reports for the Cardinal, Conesville, Conesville Prep, Gavin, Mitchell and Muskingum River plants. These reports listed the Companies' fuel purchases by mine, plant, vendor, tons purchased, and coal content. Upon reviewing these reports, Larkin noted many instances where the line items for coal deliveries had an asterisk next to it. The tickmark legend at the bottom of each page of the fuel analysis reports stated that the asterisk "indicates no analysis found". LA-2010-2-134 requested that the Companies to explain the circumstances surrounding each instance where the fuel analysis reports indicated that no analysis was found. In its confidential response, AEP Ohio provided the following explanations along with the shipments and dates affected:

[redacted]

- [redacted].

Retroactive Escalations

Larkin requested that AEP Ohio identify all pending or approved retroactive escalations that affect fuel cost for the period January through December 2010. In response to LA-2010-16, the Company stated that there are no pending retroactive escalations and that approved escalations were provided with EVA-2010-1-1 in a confidential attachment.

Review Related To Station Visitation And Coal Processing Procedure

Larkin conducted a site visit to OPCO's Gavin plant on March 9, 2011. Document requests LA-2010-17 through LA-2010-35 relate to fulfilling the objectives of the station visit and the review of the Company's coal processing procedure from the receipt of coal to the disposition of fly ash.

A description of the Companies' coal receiving procedures and controls for shortages, overages, and other discrepancies for the Gavin plant was provided in AEP Ohio's response to LA-2010-17. Once the barges are in place for unloading, the coal is moved onto conveyor belts to be transported to the stak rake. The coal is then either sent directly to the feeders or to the reclaim pile to be moved into storage for consumption at a later date.

Scale Calibrations and the Company's Shipped vs. Unloaded report serve as controls for shortages, overages, and other discrepancies.

LA-2010-18 asked AEP Ohio to describe the process of how coal is weighed when it is received. In response, the Companies stated that coal received at the Gavin Plant is weighed by belt scales.

LA-2010-19 and LA-2010-20 asked AEP Ohio to describe how freight bill and car number discrepancies as well as damaged cars are handled. In both responses, the Companies stated that the Gavin plant does not have coal delivered via rail.

LA-2010-34 requested a description of how freight bills, barge number and coal quantity and quality discrepancies are handled. In response, the Companies stated that such discrepancies are handled in the following manner:

- The weight of each barge unloaded at each plant is verified. In the event a discrepancy is discovered, the appropriate billing department will be notified.
- Coal quality discrepancies can occur (1) prior to the shipment leaving the supplier's facility; (2) while the shipment is enroute; or (3) after the shipment is received at the plant. If a coal quality discrepancy can be traced to the supplier, the Fuel Buyer will determine whether the shipment can be delivered as scheduled, diverted to another plant, or rejected and returned to the supplier. In the event of the latter scenario, the related costs are typically assumed by the supplier. In addition, a penalty or premium adjustment can be made to the supplier invoice. This adjustment is made based on the terms of the contract when tonnage received and quality does not conform to the terms of the contract.

LA-2010-35 requested a description of how damaged barges are checked and who instigates claims for shortages. In response, AEP Ohio stated that barges at the Gavin plant are inspected upon being picked up by the deck crew and they are also inspected by internal barge inspectors on a random basis. If damage is noted, a Barge Condition and Damage Report is completed and faxed to the Maintenance Department for review.

- If damage appears to be recent and a third party is responsible, an independent marine surveyor is hired to document the age and possible origin of the damage. In the event a third party is responsible, a claim is filed against such third party.
- In the event that part of a barge's cargo is lost, a claim is processed by the first party to document the loss.

As it relates to month-end cut-off procedures, AEP Ohio stated in LA-2010-21 that the month end cut-off is typically at midnight on the last day of the month at the Gavin plant.

A description of the Company's coal sampling procedures was provided in response to LA-2010-22 as follows:

- One hundred percent of the coal delivered by barge to Gavin is sampled by a belt sampler. However, this does not apply to Powder River Basin ("PRB") coal due to combustibility issues (see additional discussion below).
- The coal samples are collected by a primary and a secondary cutter which swipes across the coal belts in order to obtain a statistical representation of the coal. The coal flows into plastic bags and each bag is labeled by coal yard personnel.
- AEP Lab Technicians collect samples daily (along with the unloading sheets) and process the coal into two samples by way of riffling techniques. The first sample is labeled with an ATN and sent to the coal lab to be analyzed. The second sample is kept at the plant in case a double check is required.

As noted above, due to the combustibility associated with PRB, it is not sampled at the Companies coal plants. LA-2010-2-114 asked the Companies to provide their procedures for sampling and testing PRB coal and to also provide the associated documentation from the Companies vendors. In its confidential response, [redacted]

LA-2010-2-115 requested that the Companies provide copies of reports related to the annual field visit and inspection of PRB mines that are conducted by AEP and which includes sampling procedures used at the mines and/or load-out locations from each mine that is owned or operated by CSP and OPCO. In its response, AEP Ohio stated:

> *During the period of September 20th – 22nd, 2010 Freelin Wright, Manager of the AEP Central Coal Lab, accompanied by Christy Barrett, Chemist, and Russell Stanfield, FEL Western Field Representative visited the following PRB load outs and their onsite labs:* [redacted]
>
> *During the visits the sample systems at each location that generated the payment samples were visually inspected and an explanation of their sampling processes was given by the Coal Company representatives. All the systems were found to be in good mechanical condition and sized correctly for the lots to be sampled. All the locations had documentation of Bias Tests and ongoing sample system quality control reports.*
>
> *The on site labs for each site were toured and quality control procedures and documentation were shared by the Lab supervisors. The labs were all third party facilities either managed by SGS or Standard Labs. All the facilities were found to contain up to date equipment and knowledgeable employees.*
>
> *Overall there was nothing that was observed that would lead us to believe that ASTM D05 procedures and best industry practices were not being adhered to in the collection and analysis of the payment samples at the locations visited.*

Scale calibration logs for the period January through July2010 were requested in LA-2010-23. In its confidential response, AEP Ohio provided four attachments with belt scale calibration logs and accompanying Company memos which covered the noted period for the Gavin plant's 8A, 9F, 12N and 12S coal scales.

A description of the procedure followed when coal scales are inoperable was provided in the response to LA-2010-24. If one of the scales is out, the operable scale is used for all the unloading. If both scales are out, inventory tonnage is used until at least one of the scales is operational. The plant hires an outside vendor for longer outage periods to create draft weights at the river until at least one scale is operational. Vendor weights may also be accepted if necessary.

Copies of laboratory sampling reports for coal purchases recorded in July 2010 were requested in LA-2010-25 in order to compare such reports with accounting and purchasing records. The Companies' confidential response included documents titled "Analysis Results Report" and included data related to coal sampling for each day in July 2010.

AEP Ohio's procedure for handling coal from the stockpile to the firebox or boiler at Gavin was provided in response to LA-2010-26. Coal is moved from the storage area to coal feeders by four scrapers. The coal is subsequently distributed onto conveyer belts to be transferred to storage silos. Finally, the coal is fed from the silos by conveyor belts where it is pulverized and blown into the boiler.

AEP Ohio's procedure for taking physical inventories of coal is described in the response to LA-2010-27. Physical inventories of coal are conducted at a minimum of once a year. If the difference between book and physical inventory is two percent or greater of the coal consumed, then a second physical inventory is conducted within six months. A Circular Letter dated October 17, 1996 (and revised April 8, 2008), which outlined specific coal pile inventory procedures and guidelines, was provided as a confidential attachment to AEP Ohio's response to LA-2010-27.

The Company provided working papers on the 2010 physical inventories taken at the Gavin plant inJune2010 and September 2010 per the responses to LA-2010-28 and LA-2010-29, which consisted of the following documentation:

- Journal Entry Detail Reports
- Intercompany emails
- Company memos
- Inventory Ledger for the Gavin plant
- Coal Receipts Ledger for the Gavin plant
- Daily Fuel Reports
- Coal Storage Inventory Reports
- General Ledger pages for FERC Accounts 151 and 501

The Company memos described the results of the Coal Storage Inventory Reports. The spring 2010 memo (dated June 28, 2010), which discusses a coal pile survey conducted at the Gavin plant on June 14, 2010, stated in part:

> *The survey results give an overage of 144,859 tons. This is 5.7% over the book inventory. According to the accounting bulletin #4 revision, 100% of the difference between the physical survey and the book inventory can be used to record adjustments to the books. The total consumed over the period (11/18/09 - 6/14/10) was 4,451,171 tons. The difference between the books and the survey tonnage is 3.3% of the coal consumed. The breakdown of the consumed per unit is 43.4% for unit 1 and 56.6% for unit 2. Another survey will conducted in the Fall, 2010.*

The fall 2010 memo (dated September 29, 2010), which discusses the follow-up coal pile survey conducted at the Gavin plant on September 15, 2010, stated the following results:

> *The results show an overage of 52,878 tons. This is 2.0% over the book inventory. According to the accounting bulletins #4 revision, 100% of the difference between the physical survey and the book inventory can be used to record adjustments on the books. The total consumed over the period (6/14/10 – 9/15/10) was 2,137,694 tons. The difference between the books and the survey tonnage is 2.5% of the coal consumed. The breakdown of the consumed per unit is 51.3% for unit 1 and 48.7% for unit 2. Another survey will be conducted in the Spring, 2011.*

The journal entry detail reports referenced above reflect the recording of the dollars associated with the two inventory adjustments discussed above. Specifically, a journal entry dated June 30, 2010 shows a debit to FERC Account 151 for OPCO in the amount of $6,575,400, which reflects the dollar amount associated with the overage of 144,589 tons discussed in the June 28, 2010 memo referenced above. The corresponding credits to FERC Account 501 were for $2,853,863 and $3,721,838, which represented the inventory adjustments to Units 1 and 2, respectively as shown on OPCO's inventory ledger for the Gavin plant for June 2010. In addition, a journal entry dated September 30, 2010 shows a debit to FERC Account 151 for OPCO in the amount of $2,339,645, which reflects the dollar amount associated with the overage of 52,878 tons discussed in the September 29, 2010 memo referenced above. For this inventory adjustment, the corresponding credits to FERC Account 501 were for $1,200,220 and $1,139,426, which represented the inventory adjustments to Units 1 and 2, respectively, as shown on OPCO's inventory ledger for the Gavin plant for September 2010.

AEP Ohio's response to LA-2010-30provides the following description related to the levels of review applicable to plant operating statistics:

- The [redacted] has three general types of data which is derived directly from the plants: fuel consumption; generation; and outages and curtailments.
- Scale readings measure fuel consumption. These readings are corrected periodically through coal pile surveys if necessary.
- The [redacted] application transmits generation data. The Companies verify the accuracy of the data entered into [redacted] by performing a generation-checkout process.

- Outage and curtailment events are entered into "Outage Management", a front-end system. Records are reviewed with plant staff throughout the operating month. After month-end, the plants have 10 days to review, correct, and approve the event records before being submitted to [redacted].

Larkin requested copies of generating station reports for the period January through December 2010 in LA-2010-31. In its confidential response, AEP Ohio stated that it does not have a document titled "generating station report", but the Companies provided a confidential attachment titled "Monthly Generation Station Report" for Gavin Units 1 and 2 (and the aggregate for both units) for the period January through December 2010.
These confidential attachments reflected the service hours, available service hours, net heat rate, operating (gross) heat rate, gross generation, net generation, and startups and trips for each generating unit at the Gavin plant.

LA-2010-32asked the Companies to identify any internal investigations which resulted from what was reported on the Monthly Generating Station Reports provided in LA-2010-31 for the review period. AEP Ohio responded that that no internal investigations were conducted during the review period.

Larkin requested copies of the station reports for the review period January through December 2010 which were sent to the Companies' general office for incorporation into company statistics and to provide workpapers sufficient to trace the reports to those statistics in LA-2010-33. In response, AEP Ohio stated:

> *While some aspects of plant operation, such as outage events and coal scale data, are manually entered into a computer program at the generating plant, there are no "reports" that are sent to the Companies' general office for incorporation into Companies' statistics and workpapers. The electronic versions of these files are reviewed at the generating plant level as described in response to LA-2010-30, but the electronic reports themselves are the "station reports", and not workpapers.*

Review Related To Fuel Supplies Owned Or Controlled By The Company

In response to LA-2010-36, AEP Ohio confirmed that no AEP affiliates supply fuel to CSP or OPCO. In addition, none of the AEP Ohio companies own or control any coal mines or entities that supply fuel to the Companies.

Review Related To Purchased Power

Documentation relating to the review of purchased power is included in the responses to LA-2010-37 through LA-2010-39. LA-2010-37 asked the Company to provide the following information: "For purchases of power recorded in July 2010 that are included in the FAC, please provide the related invoices, and paid cash voucher or cash receipts." In the confidential response to LA-2010-37, the Company provided (1) a summary of July 2010 invoices; and (2) Counterparty invoices.

[redacted]

[redacted]

Larkin attempted to tie out the amounts allocated to CSP and OPCO that were reflected on the invoice summary to workpapers "EXH CSP 1" and "EXH OPCO 1" from the FAC workbooks for CSP and OPCO for July 2010.Larkin was able to tie out most of these amounts, but not all. However, in deference to Larkin's recommendation from the 2009 FAC audit that the Companies provide a better audit trail pursuant to tracing its purchased power costs to the FAC workbooks, in LA-2010-46, AEP Ohio provided monthly reconciliations between recorded purchased power in the general ledger and the amounts included in the monthly FAC workbooks. Upon reviewing the monthly reconciliations provided in LA-2010-46, Larkin was able to tie out the remaining amounts noted above from LA-2010-37. There were minor unreconciled differences on the monthly reconciliations, but such amounts were immaterial.

Reliability Must Run Generation

As confirmed in the response to LA-2010-38, dispatch of the Companies' generating units was under the control of PJM during the review period of January through December 2010.

LA-2010-39 asked: "During the review period were any of the Companies' generating units designated as 'must run' for reliability or voltage control purposes? If so, please identify the units, hours, and cost/Mwh for each 'must run' situation at the Companies' generating units during this period."

In its confidential response, AEP Ohio stated that Conesville Unit 3, Kammer Units 1, 2 &3, Muskingum River Units 1 and 3 and Sporn Units 2 and 4 are designated as "must run" for reliability or voltage control purposes. In addition, as it relates to the four generating plants referenced above, AEP Ohio stated in part:

> *...each of the above generating units was required to operate as a Must Run resource by PJM in 2010. Regarding the cost/MWh for each "Must Run" situation, the intent of the Must Run is not to penalize a utility for operating a unit that is required to support the reliability and voltage levels of the PJM Interconnection. Thus, if the units selected would not otherwise be economic to operate, they are awarded at a $/MWh rate relative to their cost-based offer (i.e. the utility is "made whole"). Costs to operate a generating unit as a Must-Run resource are the same as for normal economic operation, i.e. at production cost.*

As part of its response to LA-2010-39, AEP Ohio provided two confidential attachments. The first such attachment (Attachment 1) was an extensive listing of the hours that the Conesville, Kammer, Muskingum River and Sporn plants were required to operate as a "must run" resource by PJM during 2010. This listing covered the entire review period of January through December 2010. The second confidential attachment (Attachment 2) provided the average production cost

of each "must run" generating unit referenced above. This was expressed in terms of $/MW for each month of 2010 and is reproduced in the exhibit below.

Exhibit 7-61
Average Production Cost of "Must Run" Generating Units

[redacted]

Information related to the Companies "must run" units was provided in LA-2010-2-128.

For each plant running as a Reliability Must Run ("RMR") unit in 2010, Larkin asked AEP Ohio to explain how its separates the "must run" value from the fuel cost for purposes of charging fuel costs through the FAC. In addition, payments received for operating reserves and other ancillary services provided to PJM do not flow through the FAC.AEP Ohio stated that the operating reserve credits paid to AEP when an East Pool unit is running uneconomically per PJM's request is not accounted for in an economic cost reconstruction ("ECR process")

The Company was asked whether AEP received full cost reimbursement via PJM for all hours for which RMR generation occurred in 2010.AEPOhio stated that any AEP East Pool unit is made whole to its offer price when dispatched out of economic merit by PJM.

The Company was asked whether AEP runs the re-dispatch model to identify costs that are assigned to native/captive generation, and if so, to explain how the costs of the units that are being operated for voltage support or otherwise designated by PJM as RMR units are identified, quantified and addressed for FAC recovery purposes. AEP Ohio stated that a unit's ECR dispatch does not change regardless of the reason a unit is generating for PJM (economically or for RMR purposes). All dispatchable East Pool resources are stacked in ECR with the most expensive assigned to off system sales obligations. In addition, the most economic resources serve the AEP East Pool internal (native) load. Operating reserve charges and credits are not recovered or credited through the FAC.

The Company was asked to identify the dates and hours in 2010 when the Kammer plant was running out of economic dispatch to provide voltage support to Ormet. AEP Ohio referred to the attachment provided in LA-2010-39 related to the Kammer plant and stated that all of the RMR dates and hours for Kammer (per LA-2010-39) are related to Ormet.

The Kammer plant was designated as a RMR unit for PJM dispatching purposes when Kammer was running out of economic dispatch in order to provide support to Ormet.

Review Related to Service Interruptions And Unscheduled Outages

Documentation relating to the review of Service Interruptions and Unscheduled Outages includes AEP-Ohio's responses to LA-2010-40 and LA-2010-41.

LA-2010-40 asked about instances in which customer power supplies were interrupted (or requested to be interrupted) during the review period January through December 2010. In response, AEP Ohio stated that neither CSP's nor OPCO's customers experienced a single generation-caused customer interruption during the review period of January through December 2010.

LA-2010-41 requested AEP Ohio to identify instances during the review period in which the Companies' generating units experienced unscheduled outages and to provide documentation concerning the following:

The cause(s) of the outage.

Steps taken by the Companies to minimize the impacts of the unscheduled outage.

Efforts made to secure replacement power, if applicable.

The methodology employed to price the replacement power, if applicable.

The cost impacts resulting from the periods during which the unscheduled outage occurred.

In response to item 1, AEP Ohio provided an attachment, which provided a brief description of what caused the unscheduled outages during the review period at the CSP and OPCO generating units listed below.

- Amos Unit 3
- Beckjord Unit 6
- Cardinal Unit 1
- Conesville Units 3, 4, 5 & 6
- Darby Units 1, 2, 3, 4, 5 & 6
- Gavin Units 1 & 2
- Kammer Units 1, 2 &3
- Lawrenceburg 1A, 1B, 1S, 2A, 2B & 2S
- Mitchell Units 1 & 2
- Mone Units 1, 2 & 3
- Muskingum River Units 1, 2, 3, 4 & 5
- Racine Unit 2
- Sporn Units 2, 4 & 5
- Stuart Units 1, 2, 3 & 4
- Waterford Units CT1, CT2, CT3 & ST1
- Zimmer Unit 1

With respect to items 2 through 5 from LA-2010-41, AEP Ohio stated:

Ohio Power Company and Columbus Southern Power Company are members of the AEP East Pool. Forced outages and curtailments to the Companies' generating resources, as well as other impacts due to weather or load variations are managed on an AEP East fleet basis along with those of the other AEP East pool members. Multiple steps are taken to minimize the effects of forced outages concerning the generating plants. These steps include planning work as soon as possible when necessary, or attempting to safely operate the unit as long as possible until such time that any required maintenance can be performed when it will have less of an impact on the fleet.

Power may be secured, if needed, to minimize the effects of any generation or load variations on an AEP East fleet basis. That power is not categorized as replacing any specific generating capacity. Therefore, it is not possible to determine whether power purchases were made to replace power lost due to an unscheduled outage versus, say, power purchased to offset a curtailment at another unit, owned by another pool member, that may have occurred at the same time as an unscheduled outage. Consequently, it is not possible to price the "replacement" power or determine, from a lost generation perspective, cost impacts resulting from periods during which the unscheduled outage occurred.

FAC Filings, Supporting Workpapers And Documentation

Documentation relating to the review of supporting workpapers for calculations in the FAC filings was requested in data requests LA-2010-42 through LA-2010-49. LA-2010-42 requested copies of AEP Ohio's quarterly FAC filings. The Companies provided CSP's and OPCO's fuel filings for the second, third and fourth quarters of 2010 as well as for the first quarter of 2011. The RA portion of the first quarter 2011 fuel filing included actual data through September 2010. AEP Ohio's second quarter 2011 fuel filing, the RA portion of which contains actual data through December 2010, was filed on March 1, 2011. This actual data contained in this filing was made available subsequent to the issuance of the Companies responses to the data requests listed above. Therefore, Larkin did not conduct a detailed review of the actual data for the fourth quarter of 2010. Such review will take place during AEP Ohio's 2011 FAC audit.

Data requests LA-2010-45, LA-2010-47, LA-2010-48 and LA-2010-49 requested the Excel files associated with the FAC filings as well as all documentation which provides a complete audit trail to the Companies FAC calculations. AEP Ohio's responses to these data requests all referred to the response to LA-2010-43.

LA-2010-43 asked for a complete set of supporting workpapers for all calculations in the FAC filings for the review period January through December 2010 and/or which pertained to costs incurred or revenues recorded in the review period. In response, AEP Ohio provided an index of attachments and the Accounting Department's summary schedules and what it referred to as monthly FAC workbooks of under/recovery and carrying charge calculations, which are the main support for the Companies' FAC filings including the RA portion of such filings. The FAC workbooks are comprised of several pages of data, which is culminated from several sources including:

1. General Ledger
2. NER/NEC – Net Energy Requirements and Net Energy Cost reports
3. PSUM Report – Monthly Purchase Summary Report from ECR

4. MCSR0162 Final Reports - Tariff Summary Revenue – by voltage level – one month billed & accrued
5. East Pool Interchange Power Statements

In addition to the foregoing sources of data, the monthly FAC workbooks also contained the following workpapers:

1. Computation of Firm Retail Revenues, FAC Costs and the total Over/Under recovery for each month. The amounts calculated on this workpaper are reflected on Schedule 3 from the Companies' quarterly FAC filings.
2. A workpaper which calculates the FAC retail allocators.
3. A workpaper showing the FAC rates.
4. A workpaper which calculates the allocation factor for the FAC allowance accounts.
5. A workpaper which calculates the kWh delivered to customers served under OAD tariffs (Shopping kWh).

Upon reviewing the monthly FAC workbooks, Larkin was able to tie out the amounts reflected in the workbooks to the FAC filings using the source data listed above and performing recalculations. AEP Ohio adequately addressed Larkin's recommendations from the 2009 FAC audit as it relates to providing a better audit trail in terms of being able to trace the amounts in the FAC workbooks to the source documents (e.g. general ledger, MCSR0162 Reports, etc.). In addition, the monthly purchased power reconciliations provided in the response to LA-2010-46 also facilitated Larkin's ability to tie out the amounts reflected in the FAC workbooks.

Larkin noted the discrepancy discussed below with respect to the Lawrenceburg generating station for which the Companies provided an explanation.

Lawrenceburg Generating Station

On March 15, 2007, CSP entered into an agreement to purchase the Lawrenceburg Generating Station ("Lawrenceburg") from AEP Generating Company. Lawrenceburg is a combined-cycle natural gas power plant with a generating capacity of 1,096 MW and is located in Lawrenceburg, Indiana.

The non-fuel purchased power costs associated with Lawrenceburg are included in the FAC for CSP as shown on the EXH CSP-1 workpaper, which was included in the FAC workbooks provided in LA-2010-43. In data request LA-2010-2-130, Larkin asked for a summary of the non-energy components related to Lawrenceburg that were included in the FAC during 2010 and to also show how the capacity factor associated with Lawrenceburg was derived. In response, AEP Ohio provided a schedule which showed a breakout (by amount and account) of the Lawrenceburg related costs included in the FAC for each month of 2010. Larkin compared this schedule to the EXH CSP-1 workpaper and agreed all but one of the amounts to EXH CSP-1. The discrepancy related to Account No. 5550046, which, in December 2010 reflected costs totaling $217,605 per the schedule provided in LA-2010-2-130. However, the EXH CSP-1 workpaper reflected costs of $267,161 for December 2010, or a difference of $49,556. In response to our inquiry, AEP Ohio stated that the amount shown on the schedule from LA-2010-2-130 reflected the actual December 2010 amount for non-fuel Lawrenceburg costs and that the

amount shown on EXH CSP-1 was an estimate, so the $49,556 difference flowed through in January 2011[37].

In addition, AEP Ohio stated that the Lawrenceburg purchased power agreement ("PPA") does not have a capacity factor nor is it defined in the terms of the agreement. The Companies further stated that the capacity factor is a plant performance statistic and referred to the response to EVA-2010-1-32 for Lawrenceburg's 2010 capacity factor. The exhibit below summarizes the plant operating statistics (including the net capacity factor) for each unit of the Lawrenceburg plant.

Exhibit 7-62
Lawrenceburg Plant Operating Statistics

[redacted]

Audit Trail for Reconciling Adjustments

As discussed previously, LA-2010-46 requested a complete audit trail for all amounts in the RA portions of the FAC filings for each sub-account of purchased power during the review period. In response, the Companies provided monthly reconciliations between purchased power recorded in the general ledger and purchased power included as part of monthly FAC costs. These monthly reconciliations were provided as part of AEP's implementation of Larkin's recommendation from the 2009 FAC audit that AEP Ohio provide a better audit trail as it relates to being able trace the Companies monthly purchased power costs from the vendor invoices and paid cash vouchers (provided in the response to LA-2010-37) to the FAC workbooks provided in LA-2010-43.

Renewable Energy Resources

As discussed in the management audit section of this report, AEP Ohio is subject to the compliance standards as set forth in Section 4928.64 of the revised Ohio Code as it relates to an electric utility being required to provide electricity from alternative sources. Specifically, Section 4928.64, subsection (B) states in part that:

[37] This item will be reviewed during AEP Ohio's 2011 FAC audit, as part of the 2011 RAs.

The baseline for a utility's or company's compliance with the alternative energy resource requirements of this section shall be the average of such total kilowatt hours it sold in the preceding three calendar years, except that the PUCO may reduce a utility's or company's baseline to adjust for new economic growth in the utility's certified territory or, in the case of an electric services company, in the company's service area in this state. Of the alternative energy resources implemented by the subject utility or company by 2025 and thereafter:

(1) Half may be generated by advanced energy resources;

(2) At least half shall be generated from renewable energy resources, including one-half percent from solar energy resources, in accordance with the following benchmarks:

Exhibit 7-63
Renewable And Solar Benchmarks

By End of Year	Renewable Energy Resources	Solar Energy Resources
2009	0.25%	0.004%
2010	0.50%	0.010%
2011	1.00%	0.030%
2012	1.50%	0.060%
2013	2.00%	0.090%
2014	2.50%	0.12%
2015	3.50%	0.15%
2016	4.50%	0.18%
2017	5.50%	0.22%
2018	6.50%	0.26%
2019	7.50%	0.30%
2020	8.50%	0.34%
2021	9.50%	0.38%
2022	10.50%	0.42%
2023	11.50%	0.46%
2024 and beyond	12.50%	0.50%

(3) At least one-half of the renewable energy resources implemented by the utility or company shall be met through facilities located in this state; the remainder shall be met with resources that can be shown to be deliverable to this state.

In its July 31, 2008 Application for an Electric Security Plan (and FAC), AEP Ohio requested full cost recovery of its renewable energy purchases and renewable energy credits ("RECs") with

the caveat that the Companies proposed including all of its renewable energy costs within the FAC mechanism, and not as part of the deferred FAC costs pursuant to Section 4928.144 of the revised Ohio Code. In its Opinion and Order dated March 18, 2009, the PUCO approved the Companies' proposed inclusion of renewable energy purchases and RECs as includable FAC costs citing Section 4928.64(E) which states:

> *All costs incurred by an electric distribution utility in complying with the requirements of this section shall be bypassable by any consumer that has exercised choice of supplier under Section 4928.03 of the Revised Code.*

On January 27, 2011, AEP Ohio witness Philip J. Nelson submitted direct testimony in Case Nos. 11-346-EL-SSO and 11-348-EL-SSO in which the Companies proposed the implementation of an Alternative Energy Rider ("AER") which would segregate the REC value from Renewable Energy Purchase Agreements ("REPA"). In other words, the REC component of renewable energy costs would be recovered through the AER and the non-REC portion of such costs would continue to be recovered through the FAC. AEP Ohio is proposing that this methodology begin with the review period January through December 2012. Therefore, AEP Ohio's proposed methodology for segregating the REC value of renewable energy purchases was not applied by the Company during the January through December 2010 FAC review period.

As part of its review renewable energy resources, Larkin asked AEP Ohio a series of questions pertaining to its renewable energy purchases and RECs. In LA-2010-58, Larkin asked whether the Companies maintained an inventory system for its RECs, and if so, to provide the REC inventory for each month of 2010. In response, AEP Ohio stated that the Companies' maintain their respective RECs in PJM's Environmental Information Service's Generation Attribute Tracking System ("PJM EIS GATS" or "GATS"). In addition, the Companies provided a confidential attachment, reproduced below, which reflected CSP's and OPCO's monthly 2010 REC inventory.

Exhibit 7-64
CSP and OPCO Monthly 2010 REC Inventory Quantities

In a follow-up to LA-2010-58, in LA-2-97, Larkin asked AEP Ohio to provide separately for CSP and OPCO, an accurate listing of the "Out of State Non-Solar" inventory position of for

each month of 2010, and within this listing to identify the quantities of "Out of State Non-Solar" RECs for each of the following:

RECs related to previous year compliance.

RECs used for 2010 compliance in each month.

Unused "Out of State Non-Solar" RECs that are in inventory that could be used for 2010 or subsequent period compliance.

In response, AEP Ohio provided two confidential attachments, which are reproduced in Exhibit 7-65 below.

Exhibit 7-65
Non-Ohio Non-Solar Month-End REC Inventory Quantities

[redacted]

LA-2010-2-104 requested that the Companies provide a schedule showing the accruals and consumption of 1/12 of the 2010 obligation for non-Ohio non-solar RECs inventory for each month of 2010. In response, AEP Ohio referred to the data provided in LA-2010-2-97 (and shown in Exhibit 7-65 above), which reflects the non-Ohio non-solar REC quantities added, consumed and inventoried during 2010. The Companies also stated that those RECs were obtained through a Renewable Energy Purchase Agreement ("REPA", as discussed below) and that the accounting through the REPA charged purchased power expense and assigned none of the purchase price to REC value due to immateriality.

On February 5, 2009, CSP and OPCO entered into separate REPA for wind energy with the Fowler Ridge II Wind Farm LLC ("Fowler Ridge") which provided for the purchase of wind generation amounting to 50 megawatts ("MW") each for CSP and OPCO. The Fowler Ridge facility began commercial operations on December 17 2009.

LA-2010-2-98, which referred to the information provided in LA-2010-58, asked AEP Ohio to identify the quantity of Fowler Ridge wind RECs in each category for each month of 2010. In

response, the Companies referred to the confidential information shown in Exhibit 7-65 (provided in LA-2010-2-97) above and stated that all of its 2010 out of state non-solar RECs (for CSP and OPCO) were purchased from Fowler Ridge. In addition, the Companies stated that the non-Ohio portion of its non-solar REC obligation was fulfilled entirely by RECs purchased from Fowler Ridge and that were no spot market or contract purchases[38].

In LA-2010-2-111, Larkin asked AEP Ohio to provide with respect to the Fowler Ridge REPA, the capacity quantities and percentages used for the Fowler Ridge REPA.

AEP Ohio stated that the Fowler Ridge II Wind Farm ran at a [redacted] capacity factor as a percentage of 100 MW nameplate capacity. In PJM, the AEP Ohio portion of Fowler Ridge has a UCAP capacity of 13 MW.

Concerning whether there is a capacity value associated with Fowler Ridge, and the value of the capacity for PJM capacity requirement purposes in 2010, AEP Ohio stated that as part of the bundled price of the Fowler Ridge REPA, the Companies are entitled to the capacity from its contractual share of the Fowler Ridge REPA. In addition, AEP Ohio stated that its capacity from Fowler Ridge was included as part of the AEP East Pool's fixed resource requirement ("FRR") plan in PJM during 2010. As an FRR entity within PJM, the AEP East Pool supplies its LSE load capacity obligation and AEP Ohio is neither charged nor credited for its FRR capacity obligation by PJM.

Concerning whether it is possible to assign or estimate a value for the energy, capacity and REC portions of the bundled contract price associated with the Fowler Ridge REPA, AEP Ohio stated that it is possible to assign or estimate a value for the referenced attributes of the Fowler Ridge REPA, but the Companies did not unbundle these items during 2010.

Larkin asked AEP Ohio to confirm that the Companies were in a short position during 2010 as it relates to Ohio non-solar RECs, but fulfilled their 2010 requirements pursuant to Senate Bill 221 from purchases made during the first quarter of 2011 in LA-2-99. In response, the Companies confirmed, stating that an REC purchase was executed on January 13, 2011 for Ohio non-solar RECs which fulfilled their 2010 obligations. In addition, AEP Ohio stated that it did not record a dollar inventory for Ohio non-solar RECs due to its short position during 2010.

LA-2010-59 asked whether AEP Ohio maintains more than one REC inventory and to describe the purpose of each such inventory. In response, AEP Ohio stated that PJM EIS GATS is the only REC inventory tracking system being used by both CSP and OPCO. In addition, the Companies track the associated dollars in the general ledger for accounting purposes.

LA-2010-60 asked whether the Companies' participate in any speculative REC purchases utilizing below-the-line shareholder funds and if so, to describe the procurement and inventory methodologies used to account for such RECs. In response, AEP Ohio stated that neither CSP nor OPCO have participated in speculative REC transactions.

As it relates to maintaining REC inventory, LA-2010-61 requested that AEP Ohio indicate whether the Companies are relying on any particular accounting guidance for how items are entered into or extracted from REC inventory, and if so, to describe such guidance. AEP Ohio stated that it is relying on FERC accounting guidance for emission allowances as the framework for accounting for RECs. To the extent that acquired RECs are in excess of accrued obligations

[38]Per the responses to LA-2-107 and LA-2-108.

and can be used for future periods, an REC book inventory is maintained. This book inventory is based on the weighted average cost of RECs acquired but not yet utilized to meet the Companies obligation. The number and cost of RECs acquired will be added to book inventory. In addition, the extraction of RECs from book inventory will be based on the periodic utilization of RECs to meet the Companies obligation with the periodic REC expense calculated based on the weighted average cost of inventory for that period.

Concerning the kinds of costs, other than REC purchase costs, that are included in REC inventory, AEP Ohio stated that only direct third-party REC purchase costs are added to REC inventory.

Concerning the value at which RECs are entered into inventory if they are generated by AEP Ohio, and if other than zero, to describe the methodology used for determining the value, AEP Ohio stated that solar RECs generated by the Companies are added to inventory at zero cost, but serve to reduce the Companies REC quantity obligation.

Concerning the value at which RECs are entered into inventory if they are purchased as part of a bundled energy transaction, AEP Ohio stated that the solar REC portion of the bundled energy purchases from Wyandot is valued at approximately [redacted] of the price paid.

AEP was asked to explain when RECs are considered consumed or surrendered and when the costs appear in the Companies' rates. AEP Ohio stated that it uses accrual accounting. Each month, a cost approximating one-twelfth of the Ohio mandated obligation is charged to an expense account which is included in the FAC calculation.

LA-2010-61(a) requested a citation to the FERC accounting guidance for emission allowances that AEP Ohio had used as a framework for its accounting for RECs. In response to LA-2-100, AEP Ohio stated the framework is provided by FERC General Instruction No. 21 – Allowances.

LA-2010-62 asked AEP Ohio to identify all specific costs, by amount and account, in REC inventory that were charged to FAC-includable accounts during 2010. In response, AEP Ohio indicated that REC expense was [redacted] for CSP and [redacted] for OPCO and is recorded in Account 5570009. In addition, ending solar REC book inventory in the amounts of [redacted] and [redacted] for CSP and OPCO, respectively, was recorded in Account 1740036.

Referencing the ending solar REC book inventory amounts for CSP and OPCO of [redacted] and [redacted], respectively, in LA-2010-2-101, requested that AEP Ohio identify the corresponding quantities of solar RECs. In its confidential response, the Companies indicated the following inventory quantities: [redacted] AEP Ohio also provided the accounting entries and journal entry support related to a sale of 2010 Ohio solar RECs to [redacted]

Larkin also requested that the Companies provide the accounting entries and journal entry support related to the purchase of non-solar RECs from [redacted] (or another source) in 2011 that was used to fulfill its remaining obligation for Ohio non-solar RECs at December 31, 2010. In its confidential response, AEP Ohio stated that the expense for its 2010 REC obligations was accrued in full during 2010 and that payments made in 2011 for 2010 RECs are not expensed, but are recorded as a debit against the accrued liability.

Larkin attempted to verify that the [redacted] and [redacted] identified in the response to LA-2010-62, reflected the total REC expense in CSP's and OPCO's FAC workbooks (provided in

LA-2010-43) for the review period of January through December 2010. However, the REC expense for CSP in the FAC workbooks totaled [redacted] or $1,407 less than the [redacted] indicated above. The REC expense for OPCO in the FAC workbooks totaled [redacted] or $1,638 less than the [redacted] indicated above. Upon our inquiry, AEP Ohio stated the following with respect to CSP:

The CSP variance of $1,407 represented an expense recorded to the December 2009 general ledger relating to Wholesale RECs which are not recoverable through the FAC. The expense was mistakenly added to the December 2009 FAC calculation. This mistake was corrected in February 2010's FAC workbook by deducting it. Thus the FAC workbooks provided in LA-2010-43 were $1,407 less than the REC expense provided by LA-2010-62, which used the 2010 general ledger as its source. Note that in February 2010, we established a new account in the general ledger to record retail REC activity separate from wholesale REC activity to avoid such mistakes as this $1,407.

AEP Ohio provided a similar explanation for the $1,638 variance associated with OPCO's 2010 REC expense.

LA-2010-63 asked AEP Ohio to indicate the accounts in which the following renewable items were booked in 2010 and to provide the 2010 detail general ledger pages for each such account:

- REC purchase costs
- Gains on sale of RECs
- Loss on sale of RECs
- Costs associated with Attribute Tracking System(s)

In response, the Companies stated that the items referenced above are not reflected in the general ledger, but provided the schedule below which shows the accounts and amounts associated with the above referenced items.

Exhibit 7-66
REC Purchases, Gains, Losses &Consumption Not in G/L

[redacted]

The amounts shown for the last three line items (GATS Annual Fee, Non-Solar RECs and Solar RECs) total the [redacted] and [redacted] that AEP Ohio stated were included in the FAC for 2010 for CSP and OPCO, respectively (per LA-2010-62).

Since the amounts associated with the Companies REC purchases, gains, losses and consumption are not recorded in the general ledger (as noted above), Larkin requested that AEP Ohio provide documentation which supports the amounts shown in the exhibit above, including all journal entries and accompanying detail. The Companies provided the requested support in the confidential response to LA-2010-2-102. Exhibit 7-67 below provides a breakout of the component detail associated with CSP's and OPCO's REC dollars and quantities. As can be seen, the dollar amounts correspond with the [redacted] and [redacted] that were included in the FAC.

Exhibit 7-67
Breakout of REC Expense Charged to FAC During 2010

[redacted]

As it relates to the line item "2009 REC Expense Accrual Adjustment", AEP Ohio's response to LA-2010-2-102 stated that, it had underestimated REC expense in 2009. At the end of 2009, an REC short position was being accrued @ [redacted]/REC. When final 2009-vintage purchases were executed in 2010, the contract price was $[redacted].

In LA-2010-2-102, AEP Ohio stated that the non-solar purchases of [redacted] (CSP) and [redacted] (OPCO), shown in Exhibit 7-66 above, were charged to an expense account, while the solar REC purchases of [redacted] (CSP) and [redacted] (OPCO), also shown in Exhibit 7-66, were recorded to an inventory account. In addition, monthly solar REC consumption was recorded by crediting the inventory account and debiting the expense account.

LA-2010-64 requested a summary and details of CSP's and OPCO's status regarding renewable energy (wind and solar) objectives and minimum requirements for 2010 and whether there was a shortfall in achieving the minimum requirements, and if so, to identify and quantify the amount of the shortfall as well as the reason(s) for such shortfall. Larkin also requested that the Companies identify and provide a copy of any waivers obtained related to its meeting its 2010 renewable energy objectives for 2010. In response, AEP Ohio stated that the Companies were able to meet their 2010 renewable energy minimum requirements and provided the 2010 Renewable Energy Benchmark Minimum Requirements, expressed in terms of MWh, as shown in the table below.

Exhibit 7-68
CSP and OP 2010 Renewable Benchmark Minimum Requirements (Mwh)

Description	CSP	OPCO
Solar	1,969	2,488
Non-Solar	96,505	121,891

Through interviews conducted with AEP Ohio personnel during the onsite field visit on March 9, 2011, the Companies stated that they assigned a zero dollar value to the quantities of non-Ohio non-solar RECs in each month of 2010 and that the guidance for this accounting treatment was provided AEP Ohio's Accounting Policy Group. Larkin requested that the Companies provide all written guidance, emails, accounting policy directives and any other written documentation from the Accounting Policy Group that relates to the use of a zero dollar inventory value for 2010 non-Ohio non-solar RECs. AEP Ohio provided a Company memo in its confidential response to LA-2010-2-105. This memo, which is dated January 31, 2009, discusses the REPAs that both companies entered into with Fowler Ridge.

Upon reviewing the memo, Larkin noted that the only portion that appears to relate to assigning a zero dollar value to non-Ohio non-solar RECs is in a section referred to as "Accounting Issues". Accounting Issue No. 4 asks: "How will the purchases of power and RECs be recorded in the financial statements?" Specifically, on page 4 of the memo it states in part:

[redacted]

Larkin also asked AEP Ohio to identify and provide all comparable market information which supports the use of a zero dollar value for the 2010 non-Ohio non-solar REC inventory in LA-2010-2-106. In response, AEP Ohio provided two attachments which contained quotes from the National Voluntary REC Market that were issued in January and February 2010. These documents indicated that in the National Voluntary Market, REC trading in 2010 was expected to occur in the $.90 to $1.20 range (January 2010) and the $1.00 to $1.20 range (February 2010). The Companies also provided four confidential attachments, each of which was a document titled "SNL Energy Power Daily", issued by SNL Financial LC ("SNL")[39], and which listed SNL's RECs indices for the weeks ending December 24, 2010, January 28, 2011, February 25, 2011 and March 18, 2011. AEP Ohio indicated that the relevant quotes in these indices centered on Ohio contiguous RECs. [redacted]

[39] SNL Financial LC is a provider of breaking news, financial data and analysis on business sectors including the banking, financial services, insurance, real estate, media communications and energy industries.

The zero value AEP assigned to its non-Ohio non-solar REC inventory is questionable. A reasonable value for the REC should be assigned. The market information provided would appear to support a nominal value of $1.00 per REC, if not more. Because AEP failed to assign any valued to such REC inventory, its fuel costs for 2010 would be overstated by the amount of REC inventory value. Based on the information provided in response to LA-2010-2-97 and LA-2010-2-104, the difference between assigning a zero value and a $1.00 value to the non-Ohio, non-solar REC inventory for 2010 is approximately [redacted] for CSP and [redacted] for OPCo.

Carrying Costs on Deferred Fuel Balances

AEP Ohio's FAC rider adjusts quarterly. AEP Ohio was granted a carrying cost ratio based on its weighted average cost of capital ("WACC"). The equity portion of the WACC was grossed-up for income taxes. The gross-of-tax WACC allows the Company to recover the cost of investor-supplied financing, including (1) the cost of debt, (2) the cost of equity, and (3) income taxes related to the cost of equity. The carrying cost changes as the debt rate changes.

AEP has applied the gross-of-tax WACC-based carrying cost rate on a monthly basis to the monthly Deferred Fuel balances. AEP supplied detailed calculations of carrying costs for 2010 in response to LA-2010-43 in Excel files for CSP and OP, respectively.

As an example, for January 2010 carrying charges, the WACC is applied, separately for the debt and equity pieces, to the 12/31/2009 Deferred Fuel balance.[40]

Both CSP and Ohio Power have been in an under-recovery position.

In Commission Case Nos. 08-917 and 08-918, originally in the March 18, 2009 Opinion and Order at page 23, and subsequent on rehearing, the Commission authorized AEP Ohio to apply the gross-of-tax WACC to the under-recovered FAC balances. Larkin examined those orders and various filings from those proceedings which were provided to us by AEP Ohio and Staff. Those Commission Orders would appear to allow AEP Ohio to apply the gross-of-tax WACC to the under-recovered FAC balances without any recognition of, or offset for, the related non-investor supplied financing in the form of Accumulated Deferred Income Taxes (ADIT) that is recorded in Account 283, ADIT-Other, for the tax savings that are directly related to the under-recovered FAC balances. However, based on our review, it appears there is a mismatch concerning the authorization of a gross-of-tax WACC based on debt and equity capital, and the application of such a rate to deferred fuel under-recovery balances that were/are financed in part with non-investor supplied capital in the form of directly related credit-balance ADIT.

We did not see in the materials examined from that proceeding, in the context of the Company's carrying cost proposal, a clear presentation from AEP Ohio of the income tax deductions being taken by the Company for fuel costs that are currently deductible for income tax purposes but which are being deferred on its books for future recovery. The Company should address the income tax savings it was/is recording related to the under-recovered FAC balances, and how those provide non-investor supplied capital that is financing a portion of the Deferred Fuel balances that have been recorded in Account 1823144. The Company should specifically address the related credit-balance ADIT that is recorded in Account 283, ADIT-Other, for the tax savings-based financing that appears to be directly related to the under-recovered FAC balances.

[40] This is also referred to as the under-recovered FAC balance.

AEP Ohio is applying the gross-of-tax WACC to the under-recovered FAC balances in the following manner.

For both CSP and OP, AEP is using an ROE of 10.5% at a 50% equity ratio for a weighted cost of 5.25% per month. AEP periodically varies the cost rate for LTD. AEP computes each month a pre-tax cost of capital (based on grossing up the equity return). AEP then adjusts the monthly ROE component each month for an income tax gross up by subtracting the cost of debt from the pre-tax WACC. This results in an applied monthly pre-tax equity rate that fluctuates each month.

Larkin reviewed AEP's calculations of carrying charges for each month of 2010 provided in response to LA-2010-43. The following exhibit provides an illustration of how AEP Ohio has derived the pre-tax WACC and the monthly debt and equity carrying cost rates:

Exhibit 7-69
Illustrative Example of How AEP Ohio Derives the Pre-Tax WACC and Monthly Debt and Equity Carrying Cost Rates

	Columbus Southern		Ohio Power	
Description	Capital Ratio	Cost of Capital	Capital Ratio	Cost of Capital
Debt	50.0%	5.73%	50.0%	5.71%
Equity	50.0%	10.50%	50.0%	10.50%
Total	100.0%		100.0%	
	Weighted Average Cost of Capital	Weighted Pre-tax Cost of Capital	Weighted Average Cost of Capital	Weighted Pre-tax Cost of Capital
Debt	2.86%	2.86%	2.86%	2.86%
Equity	5.25%	8.40%	5.25%	8.40%
Total	8.11%	11.26%	8.11%	11.26%
Annual Debt Rate to be used		5.71% *		5.71% *
Annual Equity Rate to be used		5.55%		5.55%
		11.26%		11.26%
Monthly Debt Rate to be used		0.476% *		0.476% *
Monthly Equity Rate to be used		0.462%		0.462%

Per the response to LA-2010-43, carrying charge calculation Excel files
* As applied by AEP Ohio the cost of debt changes periodically

The gross-of-tax WACC based on a combination of debt and common equity financing represents the cost of investor-supplied capital. As such, it should generally be applied only to the portion of the deferred cost that has been financed by investor-supplied capital. It would generally be a mis-match, and hence inappropriate, to apply such a gross-of-tax WACC to the

portion of a deferred cost balance that has actually been financed with non-investor supplied cost-free capital in the form of credit-balance ADIT that is directly related to the cost deferral.

AEP Ohio is applying the monthly debt and pre-tax equity cost rates to under-recovered fuel balances in Account 1823144 without any offset for related credit-balance ADIT it has recorded in Account 283, ADIT-Other. There would typically be credit-balance ADIT related to the fuel under-recoveries.[41] Assuming that the Company's fuel costs are deducted currently for income tax purposes, the deferral of the under-recovery for regulatory accounting would create a temporary difference and a credit-balance ADIT would be recorded. The related tax deduction would essentially provide cost-free financing for a portion of the fuel cost under-recovery. The ADIT is a source of non-investor supplied cost-free capital. Such ADIT is not being deducted from the under-recovered fuel balances in Account 1823144 in AEP Ohio's carrying cost calculations. If the ADIT balance related to the Company's FAC under-recovery balances is not considered, or deducted somewhere else, such as in rate base, ratepayers would be over-paying carrying costs by paying for carrying costs on the portion of the Deferred Fuel balance that has been financed by tax savings, i.e., on the portion not financed with investor-supplied capital. Unless the ADIT related to the under-recovered fuel balances is being recognized somewhere else in the ratemaking process, the pre-tax WACC should be getting applied to an Under-recovered fuel balances that is net of the related credit-balance ADIT, not to the gross Under-recovered balance.

The following exhibit provides an illustrative example of how AEP Ohio has applied the monthly carrying cost rates for debt and equity to the under-recovered fuel balances in Account 1823144 without any offset for related credit-balance ADIT, and an illustration of how that directly related ADIT would finance a portion of the fuel cost under-recovery, and thus reduce the carrying charges[42]:

[41] Ohio Power's 2010 FERC Form 1, at pages 276-277, line 6, for example, shows ADIT-Other (Account 283) related to Deferred Fuel of $109.2 million at January 1, 2010 and $177.1 million at December 31, 2010. Page 450.1 of OP's 2010 FERC Form 1, shows a deduction to pretax book income of $193.9 million for Deferred Fuel Costs. The credit balance ADIT in Account 283 on OP's books represents non-investor supplied cost-free capital that is financing a portion of OP's Deferred Fuel balance.

[42] For illustrative purposes, a simple calculation is presented using round numbers for under-recovered balances and a 40% combined federal and state income tax rate.

Exhibit 7-70
Illustrative Example of How AEP Ohio is Applying the Monthly Pre-Tax Carrying Cost Rates for Debt and Equity to the Under-Recovered Fuel Balances in Account 1823144 and How Reflecting an Offset for Related Credit-Balance ADIT Would Affect the Carrying Cost Calculation

	Columbus Southern		Ohio Power	
Description	Without ADIT Offset	With ADIT Offset	Without ADIT Offset	With ADIT Offset
Monthly Debt Rate to be used	0.476%	0.476%	0.476%	0.476%
Monthly Equity Rate to be used	0.462%	0.462%	0.462%	0.462%
FAC Under-Recovery [1]	$ 50,000,000	$ 50,000,000	$ 400,000,000	$ 400,000,000
Illustative ADIT Offset [2]		$ (20,000,000)		$ (160,000,000)
Amount Being Financed by Investors		$ 30,000,000		$ 240,000,000
Balance for Carrying Costs	$ 50,000,000	$ 30,000,000	$ 400,000,000	$ 240,000,000
Monthly Debt Carrying Costs	$ 238,000	$ 142,800	$ 1,904,000	$ 1,142,400
Monthly Equity Carrying Costs	$ 231,000	$ 138,600	$ 1,848,000	$ 1,108,800
Total Monthly Carrying Costs	$ 469,000	$ 281,400	$ 3,752,000	$ 2,251,200
Difference from Failing to Recognize ADIT Financing:				
Monthly	$ 187,600		$ 1,500,800	
Annual [3]	$ 2,251,200		$ 18,009,600	

Notes
[1] Simple rounded numbers used for illustrative purposes
[2] Computed for illustative purposes at a 40% combined federal and state income tax rate
[3] For illustrative puposes, annual amount is monthly amount x 12

AEP Ohio believes its carrying cost calculations to apply the gross-of-tax WACC to the under-recovered FAC balances in Account 1823144 (without any recognition of the fact that financing for a portion of the Deferred Fuel balances has provided by income tax savings reflected in the related credit-balance ADIT, Account 283) have been fully consistent with the Company's presentation and the authorization received from the Commission in Case Nos. 08-917 and 08-918, originally in the March 18, 2009 Opinion and Order at page 23, and subsequent on rehearing.

Larkin reviewed AEP Ohio's calculations of the carrying charges on the Deferred Fuel balance and found them to be consistent with AEP Ohio's understanding of the it authorization received from the Commission in Case Nos. 08-917 and 08-918. Larkin also selectively verified the postings of the calculated carrying charge amounts for debt and equity to the deferral account for CSP and OP. No exceptions were noted.

We recommend that AEP Ohio and the other parties to the case re-examine whether the Commission-authorized gross-of-tax WACC for debt and common equity capital should be applied to what such investors are actually financing of the fuel cost under-recovery balances, which would appear to be the Deferred Fuel amounts recorded in Account 182.3 less the directly related credit-balance ADIT for Deferred Fuel recorded in Account 283.

Active Management

LA-2010-44 asked whether AEP Ohio engaged in "active management" during the review period January through December 2010, and if so, to identify, quantify and provide the accounting

documentation for each such transaction during that period. In addition, LA-2010-44 asked AEP Ohio to fully explain the reasoning and estimated economic benefit that was anticipated for each transaction. In response, AEP Ohio stated:

> *No, the Company does not engage in "active management" as defined by the auditor to be "the practice of flattening one's position on a frequent (daily) basis to align coal commitments with power sales outlook."*

Emission Allowances

AEP Ohio provided documentation related to accounting detail associated with costs and revenues, purchases and sales of emission allowances, and monthly emission allowance inventory in response to LA-2010-49 through LA-2010-50.

LA-2010-49 requested the detailed general ledger pages for each account that contains costs and/or revenues that are included in the FAC filings. In response, AEP Ohio referred to the FAC workbooks that were provided in the response to LA-2010-43.

LA-2010-50 requested detailed general ledger pages for all purchases and sales of emission allowances ("EA") and for gains or losses realized on such purchases and sales of EAs. In response, AEP Ohio stated that the requested detail regarding EAs is not reflected in the general ledger. The Company referred to the response to EVA-1-36 for a schedule of emission allowance purchases, sales as well as related gains and losses for both CSP and OPCO. The following table summarizes for CSP the emission allowance purchases, sales, and gains and losses that occurred during the January through December 2010 review period:

Exhibit 7-71
CSP Emission Allowance Activity

Columbus Southern Company

	January-10		February-10		March-10		April-10		May-10		June-10	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2												
Sales					748	$34,210						
Gains		(196)				$34,406						
Losses												
Purchases												
Seasonal NOx												
Sales												
Gains												
Losses												
Purchases												
Annual NOx												
Sales												
Gains												
Losses												
Purchases												

	July-10		August-10		September-10		October-10		November-10		December-10	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2												
Sales											30,487	$9,714,999
Gains												$3,688,616
Losses												
Purchases											40,685	$9,818,035
Seasonal NOx												
Sales												
Gains												
Losses												
Purchases											366	$183,000
Annual NOx												
Sales												
Gains												
Losses												
Purchases											599	$539,100

The table below summarizes for OPCO, the emission allowances purchases, sales and gains and losses that occurred during the January through December 2010 review period:

Exhibit 7-72
OPCO Emission Allowance Activity

Ohio Power Company

	January-10		February-10		March-10		April-10		May-10		June-10	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2												
Sales					5,734	$129,792						
Gains		(228)				$130,020						
Losses												
Purchases												
Seasonal NOx												
Sales							1,050	$34,000			1,750	$67,750
Gains								$22,107				$40,329
Losses												
Purchases			63	$4,095								
Annual NOx												
Sales	200	$148,000			300	$167,250	1,350	$516,250			800	$301,000
Gains		$145,930				$163,712		$507,050				$294,012
Losses												
Purchases			260	$176,800								

	July-10		August-10		September-10		October-10		November-10		December-10	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2												
Sales											105,539	$6,770,404
Gains												$6,541,971
Losses												$785,221
Purchases			2,658	$29,238							81,682	$17,043,339
Seasonal NOx												
Sales					500	$23,750	2,595	$154,790	1,949	$110,023		
Gains						$16,456		$116,182		$75,921		
Losses												
Purchases											80	$2,400
Annual NOx												
Sales	400	$186,000	500	$185,000	500	$155,000			706	$368,290		
Gains		$180,750		$179,642		$145,439				$363,021		$10,528
Losses												
Purchases											260	$83,200

LA-2010-51 requested CSP's and OPCO's monthly emission allowance inventory (quantity of allowances and cost) and to show how it was allocated between native and non-native customers. In response, AEP Ohio stated that the Companies do not allocate EA inventory between native and non-native load customers.

AEP Ohio's response to LA-2010-51 also included attachments which reflected CSP's and OPCO's monthly EA inventory balances during 2010. The table below summarizes for CSP the monthly EA month ending inventory balances for each month of the January through December 2010 review period:

Exhibit 7-73
CSP Emission Allowance Inventory

[redacted]

The table below summarizes for OPCO, the monthly EA inventory balances for each month of the January through December 2010 review period:

Exhibit 7-74
OPCO Emission Allowance Inventory

[redacted]

Changes To Fuel, Purchased Power Procurement And Emission Allowance Procurement

Documentation related to the review of changes to fuel, purchased power procurement and emission allowance procurement during the period January through December 2010 includes AEP Ohio's responses to LA-2010-53 and LA-2010-54.

LA-2010-53 asked the Companies' to list and describe all organizational changes to the Companies' Fuel, Purchased Power Procurement and Emission Allowance Procurement during the review period. In response, AEP Ohio stated that with respect to organizational changes to the Companies' Fuel, Emissions and Logistics during the review period, to refer to Attachments 1 through 3 from LA-2010-53. In addition, AEP Ohio stated that there were minor organizational changes to the purchased power procurement organization, but all employees responsible for purchase power procurement still work in AEP Commercial Operations Group during the January through December 2010 review period.

LA-2010-54 requested information similar to LA-2010-53, although from a procedural versus organizational standpoint. In response to LA-2010-54, AEP Ohio stated that there were no procedural, policy or accounting changes related to the Fuel and Emission Allowance Procurement. However, there was a process change to Purchased Power Procurement, which related to a change in the software used in 2010 for power scheduling in PJM.

Internal Audits

LA-2010-57 requested that the Companies' provide a listing and copies of any and all internal audit reports related to fuel procurement, synfuel, coal trading, fuel inventory management, purchased power, emission allowances, accounting for FAC-includable costs, portfolio optimization, energy sales, PJM charges and revenues, fuel and purchased power invoices, PJM invoices, allocation of PJM revenues and costs to Ohio retail load customers, allocation of other FAC includable costs and revenues to Ohio retail load customers, and/or other FAC related subject matter for the review period.

In response, AEP Ohio provided six internal audit reports, which were issued at various points during 2010. The following indicates the areas that were the subject of the internal audits, along with a summary of recommendations for each area:

1. 2009 Coal Pile Inventories(report issued January 29, 2010)

The purpose of this internal audit was to:

- Review the System Power Plants' spring and fall coal inventory reports for completeness and propriety.
- Assess the reasonableness of the book inventory at the time of the survey, which is compared to physical inventory results to determine the coal inventory adjustment.
- Determine whether the coal inventory adjustments reported by Power Plants were calculated accurately and in compliance with AEP System Accounting Bulletin No. 4, which requires recording 100% of the difference between the physical inventory and book inventory. Another physical inventory must be conducted within six months if the difference is greater than +/- 2%.
- Determine that plants with a variance of +/- 2% investigated the variances and addressed any issues discovered.
- Verify that the accounting entries recording financial adjustments were reasonable and complete.
- Observe the inventory volume and density measurement activities at three plants to evaluate compliance with AEP Circular Letter CI-O-CL-0084.

According to the report, Audit Services detected errors, which resulted in both overstatements and understatements of coal inventory. These errors included:

Two plants, which were unspecified in the internal audit report, miscalculated book inventory at the time of the physical inventory survey. The first such error occurred when one of the Companies plants utilized the inventory information from the wrong report in the fuel accounting system, which resulted in an overstatement of 40,500 tons. Audit services indicated that since AEP Ohio implemented the [redacted] system on May 1, 2009, this error appeared to be an isolated incident and management was informed. The second error occurred when the unspecified plant miscalculated the surveyed inventory, which resulted in a minor overstatement

of 250 tons. Each plant issued a revised coal inventory report prior to year end to correct these errors.

Management detected the following two additional errors: (1) the Civil Lab incorrectly entered density values on Tanners Creek's spring 2009 inventory report, which resulted in an understatement of inventory of 36,129 tons; and (2) the Civil Lab incorrectly entered a volume of 631.837 cubic feet instead of 631,837 cubic feet on Glen Lynn's fall 2008 inventory report, which resulted in an understatement of inventory by 25,122 tons.

Audit Services stated that the Civil Lab's review process is designed to detect these types of errors, but failed in both instances to do so. Management was made aware of these issues and had advised the Civil Lab to be more thorough going forward. The Civil Lab and the plant issued revised coal inventory reports and the ensuing inventory adjustments were booked in the fall of 2009.

Audit Services concluded that the coal pile inventory results and resulting adjustment were properly reflected, in all material respects as of December 31, 2009.

2. *New Source Revenue ("NSR") Consent Decree Process & Controls*

(report issued February 10, 2010)

The purpose of this internal audit was to perform an internal control design review to ensure controls over the NSR Consent Decree process are adequately designed to verify the completeness, accuracy and reasonableness of the following:

- Implemented models (short and long term)
- Model inputs
- Model outputs

Another objective of this internal audit was to test the effectiveness of controls over the NSR Consent Decree process to ensure that such controls are in place and operating effectively in order for AEP to optimize gross margin results within the constraints of the annual NOx emission cap.

The scope of this internal audit included the following sub-processes for the period January through December 2009:

- Daily short-term NSR Consent Decree sub-process
- Weekly long-term NSR Consent Decree sub-process

For each area of review identified above, in its "Review Scorecard", Audit Services indicated the designation "well-controlled" under the category "Conclusion Classification". Well-controlled was defined as "Controls are appropriately designed and are operating effectively to manage risks. Control issues may exist, but are minor".

3. *Controls over Billing and Recording Payments Under the AEP Ohio Ormet Power Agreement (report issued April 5, 2010)*

The objective of this internal audit was to assess the adequacy and effectiveness of the internal controls over the Ormet/AEP Ohio billing process and to determine AEP's compliance with the power agreement.

- The scope of this internal audit included the following:
- To review the preparation of and accounting for the invoices to Ormet for the year 2009 in compliance with the final order including the 2009 true-up that was issued in February 2010.
- To review the accuracy of the Metered Energy Billing Determinants in kWh for the invoices to Ormet.
- To review the accounting for the FAC prior to September 17, 2009 and the Economic Development Rider ("EDR") subsequent to September 18, 2009.
- To track the Maximum Discount and Maximum Delta Revenue that ratepayers will be expected to pay through the EDR and deferral of up to $12 million of potential unrecovered cost differential applicable to 2010 and 2011 with carrying costs.
- To track the London Metals Exchange price of aluminum used for determining the billing rate for 2010 through 2018.

Audit Services Review Scorecard indicated the designation "well-controlled" for the second, third and fifth scope areas noted above. However, the Review Scorecard indicated that "improvements in controls needed" for the first and fourth scope items noted above. Specifically, Audit Services noted the following five findings as well as the associated risk and proposed solutions:

Finding #1 – Reconciliation of Customer Accounting System ("MACSS") with Ormet Special Billing Spreadsheet

- Issue: The accounts receivable balance ("A/R") maintained within the MACSS is not periodically reconciled to the balance maintained by the Special Billing group, which is the source of the billings to Ormet. A difference totaling approximately $1.6 million was discovered, but was subsequently identified and resolved.
- Risk: Transactions recorded for the special billing arrangement could be inaccurate.
- Resolution: The Special Billing group should reconcile the balances reflected on the special billing spreadsheet with the amounts reflected in the MACSS on a monthly basis and any differences should be identified, investigated and resolved prior to the bill being issued. This section also states that the billing specialist and the customer account representative were unable to determine the cause of a remaining net imbalance of $4,500, but based on recent settlement activity and immateriality of the net amount due to AEP (i.e., the $4,500), Audit Services adjusted this imbalance off.

Finding #2 – True-up Charges Not Posted to Customer Accounting System (MACSS)

- Issue: Although the 2009 true-up charges were properly included on the summary folder in the January billing, they were not entered into MACSS. Not entering these amounts

resulted in revenues and A/R balances being understated by $50,781 in the Companies accounting records.

- Risk: AEP accounting records are incomplete.
- Resolution: The monthly spreadsheet was changed to highlight an area on the spreadsheet billing for normal monthly billing as well as annual true-up billing when applicable. In addition, the billing specialist will post the MACSS entries from this spreadsheet on a monthly basis.

Finding #3 – Remittance Posted in the Customer Accounting System (MACSS) Incorrectly

- Issue: Emailing amounts to be posted to the operating company's accounts is a separate manual process that creates opportunities for errors. The January remittance of the December 2009 Ormet billing was not posted to MACSS operating company accounts correctly. Ormet remits a single payment and that payment must be credited to two AEP Ohio accounts in MACSS (CSP and OPCO). The billing specialist communicates the amounts to be posted to the operating company accounts via an email to Remittance Processing.
- Risk: Incorrect accounting entries could be posted causing an over/under position in revenues and A/R balances in the individual operating company's accounting records.
- Resolution: Since the monthly billing identifies the amounts to be posted to each operating company, a copy of the approved bill is now sent to Remittance Processing to be utilized for posting to MACSS once the billed amounts are remitted.

Finding #4 – Communication and Monitoring of Billing Agreement Components and Customer Activity

- Issue: A formal process of communicating the information necessary to assure the accuracy and completeness of the billing and responsibilities for monitoring the billing accuracy have not been established. The calculation of the Ormet bill is impacted by numerous factors, including Ormet's employment level, past due amounts, the cumulative monthly discount, etc. Many of these items are reported to the special billing group in an inconsistent and informal manner. This includes face-to-face as well as telephone conversations, emails and voicemails. This inconsistency and informality could result in miscommunication of key information that impacts billing.
- Risk: Miscommunications of key billing factors could result in inaccurate bills being sent to the customer.
- Resolution: The following changes were made to assure the accuracy and completeness of the communication of key billing factors and the appropriate review of bills prior to issuance:
    - The customer account representative sends an email to the billing specialist stating that he/she has reviewed the current month's bill and approves for issuance to Ormet.
    - Ormet's filings with the PUCO of their employment level as well as other contract constraints are sent by Ormet's human resources representative to AEP's

customer account representative, who forwards those communications to the billing specialist to be used in determining the amount to be billed.

- The customer account representative verifies that the payments are received on time and for the right amount.
- The billing specialist verifies that the previous month's payments are complete and applied correctly to the AEP Ohio accounts.

Finding #5 – Documentation of the Recalculation of the Ormet Bill

- Issue: The accuracy of the spreadsheet that calculates the Ormet bill is not being verified quarterly as required by Company policy. Because of the complexity and magnitude of the calculations contained in the Ormet billing spreadsheet, it is considered a "high risk" manual billing. The Customer Services and Marketing Department requires that the customer account representative independently calculate the billing at least once each quarter to assure that the spreadsheet used to create the bill continues to generate accurate results. The documentation of this verification is required to be placed into the Account Data and Management ("ADAM") repository. This verification was not being performed correctly by the customer account representative who incorrectly understood that the Ormet rates were programmed into the MACSS and that his comparison of the Ormet billings spreadsheet to MACSS was an independent calculation, when the spreadsheet is used to populate MACSS.
- Risk: The spreadsheet used to prepare the billing could be intentionally or unintentionally changed, resulting in inaccurate results that are not detected timely.
- Resolution: The customer account representative maintains a separate secured copy of the billing spreadsheet and recalculates the bill one month each quarter. Any discrepancies are investigated and resolved. The final results are documented and placed into the ADAM repository.

4. System Integration Agreement ("SIA") Process, Controls and Compliance Review (report issued April 16, 2010)

The objectives of this internal audit was to ensure controls are adequately designed to identify realized costs/benefits and properly assign or allocate these costs/benefits to the AEP East or West Zones based on the provisions of the SIA.

The scope of this internal audit considered all provisions of the SIA and specifically focused on the following articles and service schedules:

- Article IX – Assignment of Costs and Benefits of Coordinated Operations
- Article X – Billing Procedures
- Service Schedule A2 – Allocation of Capacity Costs
- Service Schedule A3 – Purchased Power Costs
- Service Schedule B2 – System Capacity Exchanges
- Service Schedule C2 – System Energy Exchanges

- Service Schedule D2 – Allocation of Trading and Marketing Activity Costs
- Service Schedule D3 – Allocation of Trading and Marketing Realizations

Audit Services Review Scorecard indicated the designation "improvements in controls needed" for the review of the SIA. Specifically, Audit Services noted the following four findings related to the SIA as well as the associated risk and proposed solutions

Finding #1 – Produce a Comprehensive Summary of SIA Revenues and Costs

- Issue: A monthly summary of costs and revenues shared between the AEP East and West Zones arising from the SIA agreement are contained in the AEP East Interchange Power Statement ("IPS"), the summaries of which are sufficient to meet settlement needs under the provision of the SIA. However, SIA revenues and costs are not presented in a transparent and comprehensive manner that is understandable to a typical user because the IPS is complex and facilitates settlement of activity within each respective zone. Improving the presentation will assure that results are sufficiently and properly reviewed as well as reducing the risk that results are not properly reported.
- Risk: The financial impact to operating companies resulting from the application of the SIA is not transparent. As a result, there is an increased risk that results may not be properly recorded and reported.
- Resolution: The AEP East and West IPS will be enhanced to clearly cross-reference the applicable SIA service schedules to improve the presentation of the monthly SIA revenues and costs.

Finding #2 – Removal of SPP Network Integration Transmission Service ("NITS") Charges/Costs from Service Schedule D3

- Issue: The AEP West Zone trading and marketing realizations have been improperly reduced by SPP NITS during the April 2006 to December 2009 time period. Specifically, the SPP NITS charges/costs are primarily related to serving native load customers rather than off-system load customers. Inclusion of a small portion of these SPP transmission charges/costs is warranted if it directly relates to an off-system load customer in Service Schedule D3, but should be excluded if it relates to serving on-system load customers.
- Risk: The Company may not be in compliance with SIA Service Schedule D3.
- Resolution: The Company determined that the SPP NITS charges/costs were not used to make off-system sales for the April 2006 to December 2009 time period. The Company decided to exclude these costs and recorded a $362,000 estimated one-time adjustment in March 2010 for the entire time period. The impact of the adjustment resulted in a positive benefit of $362,000 to the AEP West Zone, while it was a negative cost to the AEP East Zone for the same amount. On a going forward basis, the SPP NITS charges/costs will be excluded from the calculation of trading and marketing realizations in SIA Service Schedule D3.

Finding #3 – Formally Document and Approve SIA Interpretations

- Issue: SIA interpretations made by the Company have not always been formally documented and approved.

- Risk: The Company may not be able to clearly demonstrate compliance with SIA Service Schedules A3, D2 and D3.
- Resolution: An SIA Technical Committee will be formed by the Company. SIA interpretations made by the Company will be formally documented, reviewed, and approved by the SIA Technical Center.

Finding #4 – Formal Monthly Reconciliation Process

- Issue: There is not a formal monthly reconciliation process in place to ensure new realized or non-recurring realized business activity recorded in the general ledger is considered for inclusion in SIA Service Schedule D. A formal monthly reconciliation process will reduce the Company's risk of miscommunication or human error that could result in a potential misapplication of the SIA.
- Risk: New or non-recurring realized business activity may be incorrectly excluded from Service Schedule D.
- Resolution: On a monthly basis, the Commodity and Energy Accounting team formally reconciles a defined set of recurring journal entries against the realized SIA Service Schedule D results produced by the Power Settlements team. This reconciliation process will be enhanced to identify and document why new realized or non-recurring realized business activity is unclear, then it will be discussed, resolved and documented by the SIA Technical Committee.

5. Review of Controls over Consumables Management Process (report issued October 7, 2010)

The objectives of this internal audit were to:

- Identify and evaluate the control processes over the forecasting and procurement process for consumables.
- Identify and evaluate the controls to determine appropriate inventory levels and to plan for adequate storage to secure and protect the consumables.
- Identify and evaluate the accounting controls for (1) receipts and delivery, (2) consumption, (3) inventory on hand, and (4) journal entry and closing process.

The scope of this internal audit included the following for lime, limestone, trona and urea: Forecasting and Procurement, Receiving, Consumption, Inventory, Accounting and Payments.

Audit Services Review Scorecard indicated the designation "well-controlled" for all but the Inventory and Accounting scope areas identified above. The conclusion for these two areas was "well-controlled but minor improvements needed". Specifically, Audit Services noted the following finding for these two scope areas as well as the associated risk and proposed solutions:

Finding #1 – Book to Physical Inventory is not performed at Lakin Urea hub

- Issue: Lakin is the permanent hub for urea and has only one dome which holds 8,000 tons. Barges tied to the Lakin dock provide additional storage. Physical inventory measurements are not possible inside the dome because the shape and the density of the stored material is unknown. In addition, the dome has not been cleaned out, allowing for

an inventory adjustment in over a year. Because the product is inside the dome, it cannot be surveyed like coal. The best guess at the amount in the dome is measured by using a plumb bob, the basis function of which is to ensure that the dome is not overfilled. However, depending on whether or not material is being reclaimed from the dome, the measurement is not very accurate.

- Risk: Because of imprecision in the measurement process for receipts into, and shipments out of Lakin, variances between book and physical inventory values could accumulate over time without being detected, causing the book value of inventory to be misstated.
- Proposed Resolution: A formal process should be implemented to review the amount of inventory on the books and analyze that amount for reasonableness based on known data such as vendor and Lakin weight measurements for shipments and the variances between them, weight measurements for trucks leaving Lakin, and dome measurements based on the plumb bob. Perpetual inventory should be adjusted at least annually if this analysis indicates significant book to physical differences.

6. Review of Control for Coal Procurement Processes Supported by [redacted] (report issued October 7, 2010)

The objectives of this internal audit were to:

- Verify that [redacted] meets the requirements of each applicable business process.
- Perform an internal control design assessment to ensure the system, processes, and controls are adequately designed to mitigate operational risks and achieve compliance with Sarbanes-Oxley financial reporting control requirements.
- Test the business process controls for operating effectiveness.

The scope of this internal audit was to review coal procurement processes supported by the [redacted] system including the following:

- Coal Contract/Counterparty Set-up
- Coal Logistics
- Coal Receipt and Quality Analysis
- Coal Consumption
- Coal Inventory Adjustments
- Coal Payment
- Accounting
- [redacted] Application Controls: Security, Interface and System Configuration

Audit Services Review Scorecard indicated the designation "well-controlled" or "well-controlled but minor improvements needed" for all but scope area 2 identified above. Specifically, Audit

Services noted the following four findings related to scope areas 1, 2 and 8 as well as the associated risk and proposed solutions:

Finding #1 – Review and Approval of Transportation and Fuel Surcharge Rate Escalation

- Issue: The Fuel Contract Administration group uses Excel spreadsheets to update transportation and fuel surcharge rates for existing contracts. The calculated rates are entered into [redacted] and are used for payment purposes. These rates are not reviewed for accuracy and are not approved by Fuel Contract Administration management.
- Risk: Calculated transportation and fuel surcharge rates may not be accurate. Payments utilizing these rates may result in inaccurate payments to suppliers.
- Resolution: The Fuel Contract Administration Manager has implemented a procedure to review and approve the transportation and fuel surcharge rates prior to the rates being entered into [redacted].

Finding #2 – User Access to [redacted]

- Issue: Ninety-eight users had the "Read Only" user access role in [redacted], which granted those users the ability to update data in the Shipment module. Users in this role could verify a shipment, change shipment status, create and delete routing information and change the quantity (tons) received. An IT security token was allowing access through a function that AEP did not use in [redacted].
- Risk: Users with inappropriate access could make unauthorized changes to the shipment area, which may result in inaccurate coal inventory levels reported in the financial statements.
- Resolution: IT has updated the security token to remove update privileges from the "Read Only" role in [redacted].

Finding #3 – User Access to Contracts Online

- Issue: As a result of an IT server change that inadvertently removed the appropriate security set-ups, all AEP employees had access to Contracts Online. This allowed any AEP employee to view sensitive information, such as contract prices and vendor banking information. However, no Code of Conduct issues were noted during the review.
- Risk: Unauthorized users may be able to exploit, copy, disclose, alter or destroy sensitive information. Inappropriate access to contract information could create noncompliance with FERC Standards of Conduct. In addition, unauthorized access to sensitive vendor data could cause damage to the Company's reputation, as well as legal liability resulting from vendor damages.
- Resolution: The Fuel IT Support group has reinstated the assigned security groups that restrict access to Contracts Online to only those users with a legitimate business need.

Finding #4 – User Access to Transportation Rate Escalation Spreadsheets

- Issue: Forty-two users had inappropriate update access to the transportation contract rate escalation spreadsheets. These spreadsheets were not password protected. This occurred when an employee who recently retired in connection with the voluntary severance

program moved a file from his personal network drive to a shared drive to allow file access to a replacement employee. The Fuel Contract Administration Manager was not aware of this action.

- Risk: Users with inappropriate access can modify the spreadsheets intentionally or accidentally, which can lead to inaccurate price calculation.
- Resolution: The Fuel Contract Administration group has secured the transportation rate models by applying password protection to the rate escalation spreadsheets.

AEP River Transportation Division

The AEP-owned barge company, called AEP River Transportation Division (RTD) is owned by Indiana and Michigan Power Company (IMPC), a subsidiary company of AEP. Barge freight services are provided by RTD to OPCo (its affiliate) and other AEP operating companies which receive coal deliveries via river transportation under the Barge Transportation Agreement.

Per the May 1986 Barge Transportation Agreement, RTD provides barge transportation services to the AEP operating subsidiaries that have coal plants located on the Kanawha, Green and Ohio Rivers, including Ohio Power Company (OPCo), Appalachian Power Company (APCo), and AEP Generating Company (AEPGC). RTD has operated barges, tugboats and other facilities for the transportation of coal on the Kanawha, Green and Ohio Rivers and other navigable waterways to transport coal to APCO, OPCO, AEPGC and IMPC since September 4, 1973. The generating stations owned by these AEP operating companies require large quantities of coal, which can be delivered to such stations in river barges.

Article V of the May 1986 Agreement provides that the RTD transportation services are to be priced as follows:

ARTICLE V

PRICE

The Division shall charge to each Shipper, and each Shipper shall pay to the Division, the costs of any transportation services performed by the Division for such Shipper. Such costs shall consist of all charges and expenses directly attributable to the performance of such service, a fair and equitable allocation of other charges and expenses of the Division (taking into account the transportation services performed by the Division for I&MECo), a provision for taxes at the combined normal tax and surtax rate applicable to corporations under Section 11 or any successor section of the Internal Revenue Code of 1954, as in effect from time to time, and an amount equal to 9.21% per annum of I&MECo's net investment in the Division. The determination of the 9.21% composite rate is shown in Appendix B. The Division will use the 9.21% composite after tax rate of return on its net investment until such time as it receives approval from the Public Service Commission of West Virginia and/or The Virginia State Corporation Commission, if necessary, to adjust the return on common equity on January 1 of each calendar year to the rate of return on common equity determined and allowed by the FERC in the most recent wholesale rate proceeding involving I&MECo. In the absence of a FERC order during the calendar year preceding each January 1, the rate of return

on common equity would be that authorized by the Public Service Commission of Indiana in an I&MECo retail electric rate proceeding, during the calendar year preceding such January 1, otherwise the existing rate of return continues until the next January 1. For purposes of this Agreement, I&MECo's net investment in the Division during any period shall be understood to consist of its investment in real and personal property and an amount equal to 1/8 of the aggregate operation, maintenance, rental and general expenses of the Division for each annual period, plus prepayments and deferred expenses at the end of such period. If for any period the aggregate charges of the Division for transportation services performed do not equal the aggregate costs of performing such services, a prospective adjustment in rates will be made. A review of the need for such prospective adjustments shall be undertaken at least annually.

Demurrage and standby charges shall be assessed as provided in Appendix A hereto.

The Barge Demurrage Charges and Towboat Standby Charges, provided as Appendix A to the Barge Transportation Agreement is dated as effective March 1, 1978.

The SEC Release No. 35-24039 dated March 4, 1986, Order Authorizing the Rendition of Associated and Nonassociated Transportation Services, indicates that the primary purpose of the RTD is to move coal for the operating companies of the AEP System at the most reasonable price.

Pages 2-5 of that SEC Release address the subject of cost recovery as follows:

The basic principle used to determine barge rates is that revenues should equal costs. Since 1973, this principle has been adhered to on total cumulative revenues for the period 1973 to 1984 of approximately $260.5 million. The River Transportation Division's rates have been based on a detailed cost of service analysis, following normal transportation industry practice, based on a zone rate system where each river movement bears an equitable share of total costs. The zone rate structure, as a whole, is reasonable and free of undue discrimination.

The zone rate system was designed and established so that projected revenues would be expected to cover costs. Zone rates are set prospectively in such an amount that the expected revenues will be sufficient to recover projected costs for the next period. These expenses include (1) direct expenses from each river movement, (2) an allocation of all other expenses, net of credited revenues from providing services to nonassociates and (3) provisions for taxes. The variance for each zone (deficit or surplus of revenues over expenses by zone) at the end of each calendar year is carried over to the next year and added to or subtracted from the projected costs to be recovered by the rates set to recover projected costs. The review to adjust rates is undertaken at least once a year, although an adjustment for significant cost shocks (i.e. fuel oil price changes, tax changes, wage escalations) are made as they occur and would not wait for the annual adjustment process.

Specific barge rates are determined by zone. Currently there are four zones, each zone being treated as a cost center. Direct charges such as labor, fuel and rents are assigned to each cost center on a projected basis. Overhead costs such as supervisory salaries and expenses, general office operations and other costs are proportionately allocated to the four cost centers in the same proportion as direct expenses. Revenues from all services provided to nonassociates are first credited to reduce overhead costs, and then applied to direct charges in I&M's Federal Energy Regulatory Commission ("FERC")

Account 151. I&M proposes by this application-declaration to include a provision for taxes based on or measured by income and an amount for the cost of capital of its net investment in the River Transportation Division (including working capital requirements), and to allocate such costs to zones on the same basis as overhead. A cost per ton-mile in each zone is determined by dividing projected total zone costs by projected total ton-miles moved within each zone. A barge rate for any specific move within a zone is the product of: (1) cost per ton-mile, (2) the number of adjusted miles for the movement (actual miles adjusted for down time), and (3) the number of net tones moved. In general, movements within each zone share similar characteristics, and are considered to be different from movements in other zones. These rates were reviewed before November 1, 1985 to determine what adjustment to rates, if any, were needed to adjust revenues to equal costs. I&M proposes to enter into a Barge Transportation Agreement with any Applicant requiring barge transportation services incorporating the barging rates as described, and entitling the Applicant to a service priority over any nonassociated company. Rates for nonassociated service will be at the highest practicable level, based on market conditions.

I&M proposes that the cost of capital on its net investment in the River Transportation Division be established at 9.21% per annum, which rate was approved in orders of the Corporation Commission of Virginia and the West Virginia Public Service Commission in 1981 and 1984, respectively, and which I&M proposes to begin applying after approval by this Commission. It represents a weighted average cost of capital based on I&M's capitalization ratio as of September 1, 1973, when the original transportation assets were acquired. The cost of long-term debt and preferred stock are the effective rates of the most recent long-term debt and preferred stock issues by I&M prior to September 1, 1973. The return on common equity is the return ordered by FERC on March 18, 1980, in I&M's general rate proceeding. I&M proposes to use the 9.21% composite rate until such time as state Commissions authorize, if necessary, an adjustment of the return on common equity on January 1 of each calendar year to the rate of return on common equity determined and allowed by FERC in the most recent wholesale rate proceeding involving I&M. In the absence of a FERC order during the calendar year preceding each January 1, it is proposed that the rate of return on common equity would be that authorized by the Public Service Commission of Indiana in an I&M retail electric rate proceeding during the calendar year preceding such January 1, otherwise the existing rate of return continues until the next January 1.

The costing procedures for barge rates were provided in response to LA-2010-66, in Confidential Attachment 1 to that response. [redacted]:

[redacted]

[redacted]

The confidential Actualization file was provided with the response to LA-2010-2-117.

The RTD's 2010 Rate Matrix, which provides the affiliated coal barging rates for OPCo based on the 2010 budget, was provided in the Confidential Attachment 1 to LA-2010-67. This lists the barging rates for each OPCo plant from each potential load-out area to the plant. OPCo plants that are supplied with coal by the RTD include Amos, Cardinal, Kammer, Mitchell, Muskingum River, Sporn, and Gavin.

A listing of all operating leases for captive barges was provided with the response to LA-2010-74. Copies of the five largest operating leases based upon annual cost in 2009 and 2010 to OPCo were provided in the Confidential Attachments to EVA-4-11 from the initial FAC audit covering calendar year 2009, as referenced in the response to LA-2010-76. Those lease and charter

agreements list OPCo as Charterer for 40 barges. The agreements provide that the lessor is the owner of the vessels. Section 8(a) (provided at EVA-4-11, Confidential Attachment 2, page 16 of 65from the initial FAC audit) provides as follows concerning maintenance and repairs:

> *SECTION 8. MAINTENANCE AND REPAIR OF VESSELS, REPLACEMENTS, ALTERATIONS, MODIFICATIONS.*
>
> *(a) The Charterer shall pay all costs, expenses, fees and charges incurred in connection with the use and operation of the Vessels during the Term. The Charterer shall at all times during the Term, at its own cost and expense, maintain and preserve each Vessel in accordance with good commercial maintenance practices for Vessels of the same type and service owned by companies of similar size and financial standing and having similar operations and cargoes, so that such Vessel shall be (1) insofar as due diligence can make her so, tight, staunch, strong and well and sufficiently tackled, appareled, furnished, equipped and in every respect seaworthy; (2) in satisfactory operating condition, ordinary wear and tear excepted, and in satisfactory repair and working order consistent with accepted industry practice; (3) in compliance with all laws, regulations, requirements or rules; (4) maintained and repaired in compliance with all Manufacturer's recommended procedures and, if none, consistent with accepted industry practice; (5) in compliance with all applicable insurance requirements; and (6) maintained at a standard of maintenance not less than the highest standard of maintenance performed on similar Vessels owned or chartered by the Charterer. The Charterer shall maintain complete and accurate maintenance records with respect to each Vessel, and will allow the Owner and its agents and representatives reasonable access to review, inspect and make extracts of such records in accordance with the terms hereof. The Vessels shall be drydocked by the Charterer at its sole cost and expense whenever necessary to maintain or preserve such Vessels in accordance with the provisions of this Charter Agreement.*

The response to LA-2010-75 indicates there are no operating leases between OPCo and River Operations for OPCO-owned barges.

The affiliated freight rate true ups for the five quarters starting with the fourth quarter of 2009 for OPCo were provided in Confidential Attachment 1 to LA-2010-68. That information is summarized in the following table:

Exhibit 7-75
River Operations, Summary of OPCO Quarterly Actualizations

[redacted]

For 2010, I&M had approximately [redacted] in revenue from OPCo related to the RTD. Costs and expenses were [redacted], offset by [redacted] for third party gains, less I&M's return on investment of approximately [redacted]. RTD also delivers urea to OPCo. For 2010 RTD shipped both coal and urea to OPCO plants. The 2010 quantities included urea tonnage of approximately [redacted] and coal tonnage of [redacted]. The net cost (based on RTD's Costs and Expenses, less the Third Party Gain, plus RTD's Return on Investment) for OPCo for 2010 was approximately [redacted]. For the [redacted] tons of urea and coal delivered, this is an average cost of approximately [redacted] per ton. In comparison, the average cost per ton for the fourth quarter of 2009 was [redacted], as shown in the above table.

AEP's response to LA-2010-2-118 provides the following explanation as to how the RTD amounts are reflected in OPCo's quarterly FAC filings:

> *The adjustments detailed in the attachment to response LA-2010-68 are posted in the general ledger to account 1510001 for the respective plants' coal inventories (or account 1540012 for urea barging cost adjustments). These amounts would then effect the average weighted cost of the individual inventories. As coal is consumed from each of these inventories, the 5010001 expense would then be effected (or account 5020002 for urea consumption). Accounts 5010001 and 5020002 are picked up in the fuel costs each month and would then be reflected in the quarterly FAC filings.*

AEP changed its presentation in 2010 of RTD Administrative Expenses in the Barge Operations Income Statement in 2010 to show less line item detail. For 2010, the Barge Operations Income Statement shows costs for AEP Administrative Charges and Other Administration Expense.

Exhibit 7-76
River Operations, Administrative Expenses

Intercompany barge optimization reports (cross charter reports) are utilized by RTD, and are provided in response to LA-2010-72 for December 2009 and January through December 2010. These reports show, by month, the barge days associated with Captive chartered to Commercial and Commercial chartered to Captive, as well as the monthly amounts of Commercial Expense/Captive Revenue and Captive Expense/Commercial Revenue. For 2010 the total amounts of Commercial Expense/Captive Revenue and Captive Expense/Commercial Revenue were The balance between these two amounts reflects the RTD operating plan to optimize combined fleet performance and not have cross-subsidies to either the captive or commercial side of the barge transportation business.

The RTD's Barge Operations Income Statements and Balance Sheets for Captive Operations for December 2009 and each month of 2010 were provided in Confidential Attachments 1 through 4 to LA-2010-69. Consolidated financial statement information for captive operations in 2010 were provided in the confidential attachment of LA-2010-2-120. LA-2010-2-120 also provided the pre-consolidation financial statement information for captive operations business segments in 2010 and the consolidating entries and adjustments for 2010 captive operations.

The RTD's "Actual Net Investment Base & Cost of Capital Billing Adder" for 2009 and 2010 was provided in Confidential Attachments 1 through 3 to LA-2010-70.

The Investment Base consists of a Working Capital Requirement that is based on RTD's Expenses, less Sub-lease Revenues, plus a prior period Over-Collection, plus Prepayments and Materials and Supplies, less Other Current Liabilities and Accruals. The result of these items is an amount of "Net Expenses" which is multiplied by 0.125 (i.e., by 1/8th) to derive a "Working Capital Requirement."

To the Working Capital Requirement are added Real Property and Personal Property taxes (based on a 13-month average of Net Book Value). The addition of these items results in an Investment Base, which is multiplied by a "Before Tax" rate of return of % to derive an Actual Return on Investment. The derivation of the % "Rate of Return on Assets" that applied for 2008 is shown on LA-2010-70 Confidential Attachment 1, page 4 of 6. It is based upon a capitalization consisting of Long Term Debt, Preferred Stock and Common Stock. The Annual Cost rate used for Common Equity of % was specified in Note D to be "*No more than the rate ordered by Indiana 11/12/93 in Case No. 39314.*" The Before-Tax rate of return reflects a gross-up for federal income taxes at a 35% tax rate.

Calculations for 2010 were provided in LA-2010-70 Confidential Attachment 3. On page 5 of 9 of Attachment 3, this also shows that the Annual Cost rate for Common Equity was %.

Note D on that page states this to be "*No more than the rate ordered by Indiana 03-04-09 in Case No. 43306.*"

The derivation of the net investment base components reflect AEP's implementation of certain recommendations made in conjunction with the 2009 audit. In the RTD "Investment Base" calculations, RTD is now applying the 1/8 to what appears to be operating expenses. As described in the 2009 audit, RTD had previously been applying the 1/8th to Balance Sheet accounts.

It appears that the way the RTD charges to the AEP captive operations are set up with the billing and a subsequent true-up (actualization), the operating companies, including OPCo, will essentially be paying the RTD for all of its costs, including the return component. Given this set-up, there does not appear to be much risk, if any, that RTD will not collect its cost of service (including the return component) from the AEP captive operating utilities that use RTD for transportation services. While some return on investment would appear to be warranted since RTD has a net investment in assets that are used to provide service, we would question whether the Return on Common Equity (especially the [redacted]% ROE that was applied in 2009) is appropriate and commensurate with the risk of this operation.

AEP's response to LA-2010-2-121 Confidential Attachment 1 addresses how AEP has addressed the recommendations concerning the RTD made in the 2009 audit report.

With respect to 2009 Financial Audit Recommendations 6a, 6e, 6f and 6j, AEP modified the RTD investment base calculation to remove balance sheet items from the 1/8th O&M cash working capital formula and has reflected those in the RTD investment base on a 13-month average basis. Additionally, AEP has calculated a 13-month average Accumulated Deferred Income Tax (ADIT) balance and applied that in deriving the RTD investment base.

With respect to 2009 Financial Audit Recommendation 6b, AEP Ohio asserts that the RTD agreement provides a procedure for updating the RTD cost of capital and Return on Equity. AEP has not addressed, however, why an ROE that has been set in a FERC order or by a state commission (such as Indiana) for a utility would be appropriate for RTD, when RTD is functioning as a fully cost reimbursed operation with annual true-ups, and, consequently, the level of risk to RTD would seem to be lower than for other utility operations.

With respect to 2009 Financial Audit Recommendation 6g, AEP Ohio had no objection to the recommendation that the RTD other administration expenses and AEP administrative charges should be reviewed in detail. AEP responded to discovery concerning the detail of these charges that was requested by the auditors.

With respect to 2009 Financial Audit Recommendations 6c and 6d, AEP agreed with the recommended modifications to correct the Working Cash component of the RTD investment base for 2008 and 2009, and credit the applicable operating companies, including OPCo, as a result of those changes. In the course of making those corrections, RTD identified net undercollections, resulting in additional charges to RTD's customers of $165,421. AEP Ohio's response to LA-2010-2-121 Confidential Attachment 1, page 3, indicates that both the corrections for 2008/2009 and the 2010 true up will be recorded by RTD in March 2011.

In response to 2009 Financial Audit Recommendations 6h and 6i, additional explanations were provided of the ADIT amounts on RTD's books, and relate to typical items such as timing

differences for depreciation (book versus tax), pensions and other post retirement benefits, and RTD's deferred revenues and expenses (i.e., its over/under billings).

The Company's response to LA-2010-2-122 provided detailed calculations showing how the RTD operating expenses and other operating expenses were used to allocate items such as the third party benefit and return on investment to OPCo for the four quarters comprising 2010.

LA-2010-3-138-4 asked AEP: "Has the Ohio PUC allowed either CSP or Ohio Power to use a 1/8th O&M calculation for cash working capital in any distribution rate cases from 2000 to the present?"

AEP's confidential response stated that: [redacted]

The following table shows the estimated annual revenue requirement to OPCO from the RTD's Working Capital Requirement, derived from information provided in LA-2010-70:

Exhibit 7-77
Estimated Annual Revenue Requirement to OPCO from RTD Working Capital Requirement

[redacted]

The above table shows the total amount of annual revenue requirement on the RTD Working Capital component of the RTD investment base, and the estimated portion of this that becomes a cost of OPCO for 2009 and 2010. Additionally, the following table shows how much of the total annual RTD revenue requirement for the RTD investment base relates to the RTD Working Capital component:

Exhibit 7-78
Portion of Total Annual Cost for RTD Investment Base Comprised by RTD Working Capital Requirement

[redacted]

The use of a 1/8th O&M calculation for determining a working capital component of investment base has been controversial. It assumes there is a net lag between the collection of revenue and the payment of cash expenses of approximately 45 days (365 / 8 = 45.625 days). The validity of this assumption should be tested via a lead-lag study. AEP should be required to analyze the

receipt of revenue and the payment of cash expenses for RTD captive operations, similar to a lead-lag study.

The use of a 1/8 formula for computing cash working capital has been discredited for a number of reasons, including because it would always produce a positive cash working capital allowance, even in situations where funds were being supplied to the service provider through operations. Many of the AEP operating utilities have conducted lead-lag studies. It appears questionable that the RTD would be incapable of having an appropriate lead-lag study analysis of its cash receipts and expenditures as the basis for a cash working capital component of the RTD "Investment Base." An appropriately conducted lead-lag study analysis would also tend to be more reliable than the 1/8 formula assumption currently being used by RTD.

RTD compares rates for coal tonnage between AEP and commercial customers based on mileage. Per the confidential attachment provided with LA-2010-77, [redacted]

EVA provided us with barge transportation information from competitive providers Ingram and Crounse for the transportation of coal, lime and limestone for another electric utility, which had been publicly filed with the Kentucky Public Service Commission. We were unable to make an "apples to apples" comparison of the cost of that river barge transportation with the costs being incurred by OPCo for RTD barge transportation.

LA-2010-2-123 asked whether the RTD or AEP or OPCO had information with respect to barge transportation rates charged by competitive carriers such as Crounse or Ingram. The Company's response indicates that:

> *During the last half of 2010 Crounse moved 368,152 tons from the Cook Coal Terminal to the Gavin Plant at a rate of $7.85 per ton. AEP required delivery of as many coal tons as possible during the 4th quarter of 2010. River Operations utilized all available equipment but needed assistance from a third party. One of the primary factors in the decision process of buying third party freight developed because River Operations was moving empty barges a considerable distance to relocate to Cook Coal Terminal. Crounse had a similar temporary problem but they were moving empties many miles to the upper Ohio River. The purchase worked for both companies and allowed River Operations to focus on the Upper Ohio River area and still have tons moved from Cook to Gavin.*

As explained in the response to LA-2010-02-126, OPCO and AEP do not issue RFPs for barge transportation as this service is provided by the RTD. The RTD fulfills all of AEP's barging needs, other than the occasional transaction, such as the one noted above, as described in response to LA-2010-2-123.

As identified in the response to LA-2010-2-125 total demurrage revenue recognized in 2010 for RTD was [redacted] OPCO's portion of that was [redacted]. Per LA-2010-2-124 demurrage is billed according to contract terms and is reported as affiliated or outside revenue by RTD based on the identity of the customer.

Based on our review of RTD information to date, we believe there may be a need to revise, prospectively, the way the RTD Net Investment Base and Cost of Capital Billing Adder that is used to determine RTD charges to OPCo is derived.

Based on our review of RTD information to date, we have the following recommendations in the Recommendations section below.

AEP should be required to analyze the receipt of revenue and the payment of cash expenses for RTD captive operations, similar to a lead-lag study, and to present such information to support its assumption that RTD has a significant Cash Working Capital requirement. If adequate supporting information is not provided to substantiate that RTD has a significant Cash Working Capital requirement and the amount of that requirement using lead-lag study analysis of cash receipts and cash payments, the RTD Working Capital component of the RTD investment base should be removed from the cost charged by RTD to OPCo from January 1, 2011 forward.

AEP should address why an ROE that has been set in a FERC order or by a state commission (such as Indiana) for a utility would be appropriate for RTD, when RTD is functioning as a fully cost reimbursed operation with annual true-ups, and, consequently, the level of risk to RTD would seem to be lower than for other utility operations.