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Case No. 12-3133-EL-FAC
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1 INTRODUCTION

Under Senate Bill 221, utilities were required to provide consumers with a standard service offer (SSO) consisting of either a market rate offer (MRO) or an electric security plant (ESP). On March 18, 2009, the Public Utilities Commission of Ohio (PUCO) approved an ESP for the Columbus Southern Power Company (CSP) and the Ohio Power Company (OPCo). The ESP, which included a fuel adjustment clause (FAC), was for a three-year period ending December 31, 2011. At the end of 2011, CSP merged into OPCo. A second ESP (ESP2) was approved in February 2012 (after some iteration) for a period starting January 1, 2012 running through December 31, 2014. Under ESP2, the FAC continues on an unmerged basis and that an Alternative Energy Rider (AER) be implemented for each Company. The PUCO also required a series of auctions so that OPCo could transition to a competitive market. The first auction would be 10 percent, energy only. By June 1, 2014, 60 percent of OPCo's SSO energy requirements were to be supplied via auction. By January 1, 2015, all of OPCo's SSO energy requirements would be supplied via auction. Under the FAC, 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.

The PUCO solicited proposals to conduct both management/performance and financial audits of the FAC and AER recovery mechanisms for the years 2012, 2013, and 2014. In addition, the PUCO wanted support for the final reconciliation and true-up of the FAC following its termination. To achieve these goals, the PUCO defined two audits. The first audit (Audit I) was to cover the years 2012 and 2013 for both the FAC and AER. The second audit (AUDIT 2) was to cover the FAC and AER for 2014 as well as the reconciliation and true up of the FAC.

Following a competitive solicitation, 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 and provide reconciliation support. This first audit covered 2012 and 2013 was completed in 2014. This is the second audit which covers 2014 for the FAC and AER. It could not include a reconciliation of the deferred fuel balance because there are many outstanding issues that affect the deferred fuel balance amount.

[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"

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.
- 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 order to mitigate the impact of the ESP on customers, the PUCO limited 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

In January 2011, AEP filed an application to continue the ESP past 2011. In December 2011, the PUCO modified and approved a September 2011 agreement. Under the September 2011 agreement, AEP would have transitioned to a market-based generation rate structure over a four and a half year period between January 2012 and May 2016. In February 2012, the PUCO revoked the ESP and directed AEP to file a modified ESP application.

In March 2012, AEP-Ohio filed a modified ESP application which provided for AEP-Ohio to separate its generation assets from its distribution and transmission assets and provided for a transition period through 2014. The PUCO approved a modified ESP in August of 2012 which provides for the transition to a fully competitive market by June 1, 2015.

The balance in the FAC under-recovery accounts as the beginning and end of each audit years are summarized in Exhibit 1-2. A filing has been made and the accrued amounts are being recovered. The amounts are without any of the proposed adjustments for the prior audit periods.

Exhibit 1-2
Balance in FAC Accrual Accounts

	12/31/2014	12/31/2013	12/31/20112
Fuel Adjustment Clause (FAC)	$4,720,589	$13,116,786	-$12,504,934
Phase In Recovery Rider (PIRR)	$37,038,440	$492,390,964	$573,519,809
Total	$41,759,029	$41,759,029	$41,759,029

One of the primary objectives of the current audit had been to reconcile AEP's accrual amount. Since the recommendations from the prior audit, which included significant adjustments to the FAC, have not been addressed, a reconciliation is not possible.

Opinion and Order

In May 2014, the Opinion and Order from Cases No. 10-268-EL-FAC, No. 10-269-EL-FAC, and 11-281-EL-FAC was issued. These cases were the FAC audits for 2010 and 2011. The Opinion and Order with limited exceptions adopted all of the auditors' recommendations from the 2010 and 2011 audit reports. The recommendations by case are provided below with the current status. Due to the timing of the order, many of the auditors' recommendations were not complied with in 2012 and 2013. Therefore, the auditors are not finding fault with the Company with respect to the recommendations requiring studies or policy changes. The auditors are, simply providing a follow-up status report.

Cases No. 10-268-EL-FAC and 10-269-EL-EFC

Management Audit Recommendations - 2010

1. 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.

   Status: AEP Ohio reduced the inventory at [redacted] in 2011 to normal levels.

2. 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.

   Status: A study was not provided to the auditor for review. As discussed in this audit report, in 2014 AEPGR used a policy of increased spot purchases to reduce the risk of over-commitment.

3. 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.

   Status: A revised approach was not provided to the auditor for review.

4. 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.

   Status: The manual was not revised. For 2014, a new manual was prepared and provided to AEPGR to follow during the period in which it served as an agent for OPCo.

5. 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.

   Status: AEPSC did not provide documentation regarding actions taken to improve coal quality compliance.

6. 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.

   Status: EVA did not find that AEPSC worked to minimize the costs associated with the closure of the Conesville Coal Preparation Plant. EVA specifically found that the decision to extend the [redacted], coal supply agreement prior to marketing the Conesville Coal Preparation Plant was ill-advised.

7. 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.

   Status: The documents have been provided.

8. 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.

   Status: The allocation of solar obligations is being performed correctly.

Financial Audit Recommendations - 2010

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

   Status: AEP has complied with this recommendation.

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

   Status: The Commission adopted this recommendation. AEP complied with this recommendation upon the Commission's approval of the AER in September 2012 and for which the Company employed starting in October 2012. In order to be in compliance with the Commission's Opinion and Order, the Company should identify and separate the REC values from the energy and capacity value of its renewable energy purchases for the 2010 review period.

3. 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.

   Status: The Commission adopted this recommendation. AEP complied with this recommendation upon the Commission's approval of the AER in September 2012 and for which the Company employed starting in October 2012. In order to be in compliance with the Commission's Opinion and Order, the Company should show how REC costs incurred by CSP and OP were separately identified and excluded from the 12/31/2010 FAC deferral.

4. AEP should be assigning appropriate values to its Renewables inventory, including its non-Ohio, non solar REC inventory.

   Status: The Commission adopted this recommendation. AEP complied with this recommendation upon the Commission's approval of the AER in September 2012 and for which the Company employed starting in October 2012. However, to be in compliance with the Commission's Opinion and Order, the Company should assign appropriate values to its Renewables inventory for the 2010 review period.

5. 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.

   Status: The Commission adopted this recommendation for the 2010 review period. To Larkin's knowledge, this lead lag study has not yet been conducted. In addition, it should be noted that Larkin made a similar recommendation for the 2012 and 2013 review periods.

6. 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.

   Status: The Commission did not adopt this recommendation.

7. 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.

   Status: The Commission did not adopt this recommendation.

8. 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.

   Status: The Commission did not adopt this recommendation.

Case No. 11-281-EL-FAC

Management Audit Recommendations - 2011

1. EVA recommends that prior to any future negotiations with [redacted], AEPSC develop a coal procurement strategy that allows it to conduct a competitive solicitation for high sulfur coal and that the results of that solicitation, if favorable, be used in the negotiation. EVA further recommends that any future justification memorandum contain the results of the solicitation combined with a fulsome disclosure and analysis of comparable indexes. Finally, as necessary, AEPSC should reach out to third parties to assist it in the development and implementation of a repricing strategy to improve the quality of the results as third parties may be more aware of re-opener negotiation strategies and relevant non-AEP transactions. If the FAC continues, EVA recommends that the strategy be provided to the next management/performance auditor for review.

   Status: EVA was not provided a strategy to review. EVA found significant problems with the reopener in 2012 and recommended an adjustment in FAC recovery in the audit report of 2012 performance. The recommendation is outstanding. AEPSC improved its market price discovery in 2013.

2. EVA recommends that if the FAC does not continue that the next management/ performance audit determine if there should be any credit to the under-recovery due to the shifting of the low cost tons from the [redacted] contract out of period.

   Status: The FAC was continued

3. EVA recommends that the fuel procurement manual be revised to contain more specificity. Based upon AEPSC's 2011 performance, EVA specifically recommends that AEPSC develop policies with respect to the following:

   a. Procedures for addressing the chronic non-compliance with contract coal specifications under many of its coal supply agreements,

   b. The basic items that should be included in all justification memorandums including firm indications of market price, market indexes that are representative of the products being purchased, and full disclosure to management as to the value of the transaction relative to market.

   c. The quality that should be used to evaluate coal bids from the chronic non-performers.

   d. The exceptions when AEPSC is not required to solicit bids for procurements.

If the FAC continues, EVA recommends that the revisions be done in time for review by the next management/performance auditor.

Status: The manual was not revised. As noted above, OPCo provided a manual for AEPGR to follow during the period in which AEPGR was serving as Agent.

4. EVA recommends that any payments made to [redacted] for shortfalls beginning in 2013 through the remaining term of the FAC not be recoverable through the FAC.

Status: EVA has recommended payments made to [redacted] in 2012 and beyond not be recoverable through the FAC. These recommendations are outstanding.

5. EVA recommends that any proceeds received from the sale of CCPP assets be applied to the FAC under-recovery.

Status: AEPSC explained to the auditors' satisfaction that there we no net proceeds from the sale of the Conesville Coal Preparation Plant.

6. EVA recommends that AEPSC be directed to develop a strategy for addressing the [redacted] contract issues and that the strategy should consider a full range of options. If the situation has not been resolved in 2012 and the FAC continues, EVA recommends that the strategy be available for review by the next management/performance auditor.

Status: A strategy was not provided to EVA in 2013 to review. The contract was bought out at the end of 2014. The terms were not provided for review.

Financial Audit Recommendations - 2011

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

Status: The Commission adopted this recommendation. AEP complied with this recommendation upon the Commission's approval of the AER in September 2012 and for which the Company employed starting in October 2012. In order to be in compliance with the Commission's Opinion and Order, the Company should identify and separate the REC values from the energy and capacity value of its renewable energy purchases for the 2011 review period. It should be noted that this recommendation also applies to the January through September 2012 period.

2. AEP should show in detail how REC costs incurred by CSP and OPCO in 2011 have been separately identified and excluded from the 12/31/2011 FAC deferral for each company, CSP and OPCO.

Status: The Commission adopted this recommendation. AEP complied with this recommendation upon the Commission's approval of the AER in September 2012 and for which the Company employed starting in October 2012. In order to be in compliance with the Commission's Opinion and Order, the Company should show how REC costs incurred by CSP and OP were separately identified and excluded from the 12/31/2011 FAC deferral. It should be noted that this recommendation also applies to the January through September 2012 period.

3. AEP should be assigning appropriate values to its Renewables inventory, including its non-Ohio, non-solar REC inventory.

   Status: The Commission adopted this recommendation. AEP complied with this recommendation upon the Commission's approval of the AER in September 2012 and for which the Company employed starting in October 2012. However, to be in compliance with the Commission's Opinion and Order, the Company should assign appropriate values to its Renewables inventory for the 2010 review period. It should be noted that this recommendation also applies to the January through September 2012 period.

4. 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.

   Status: The Commission adopted this recommendation for the 2011 review period. To Larkin's knowledge, this lead lag study has not yet been conducted. In addition, it should be noted that Larkin made a similar recommendation for the 2012 and 2013 review periods.

5. 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.

   Status: The Commission did not adopt this recommendation.

6. 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.

   Status: The Commission did not adopt this recommendation.

7. On January 23, 2012 the Commission issued an Opinion and Order in Case Nos. 09-872-EL-FAC and 09-873-EL-FAC, and on April 11, 2012 issued an Entry on Rehearing in those

dockets which provided clarification of AEP Ohio's obligations as they affect crediting OPCO's FAC under-recovery. AEP Ohio's crediting of those clarified amounts against OPCO's FAC under-recovery should be reviewed in the next audit.

Status: The Commission adopted this recommendation. Larkin requested that the Company provide documentation which substantiates that the credits were booked in accordance with the Commission's Orders. In its confidential response to LA-2014-9-001, [redacted]

[redacted]

[redacted]

8. AEP Ohio should be required to explain fully the derivation of, and the purpose for, the "Transfer Losses", including what those costs are for and why these items are reasonable costs to be included in the FAC.

Status: The Commission adopted this recommendation. Upon Larkin's request that OPCo explain fully the "Transfer Losses", in its confidential response to LA-2014-9-002, [redacted]

9. AEP Ohio may want to question the costs billed to CSP for trucking coal from Killen to Stuart for the reasons explained in the 2011 DP&L audit report

Status: The Commission adopted this recommendation. Larkin's inquired as to whether the Company had investigated the costs billed to CSP for trucking coal from Killen to Stuart. In its confidential response to LA-2014-9-003, OPCo, [redacted]

[redacted]

10. Larkin recommends that the $9,579 difference between the December estimate and actual for Account No. 5550046 as it relates to [redacted] be removed from the 2011 FAC.

    Status: This difference was due to timing and the Company accounted for this transaction in January 2012. The Commission stated that no further action was required.

11. Larkin recommends that AEP Ohio determine and assign a salvage value to the CCPP for the purposes of the depreciation calculations.

    Status: The Commission adopted this recommendation. To date, it does not appear that the Company has determined and assigned a salvage value to the CCPP for the purpose of the depreciation calculations.

12. Larkin recommends that should AEP Ohio sell the CCPP, the proceeds from the sale should be credited against the December 31, 2011 under-recovered FAC balance.

    Status: The Commission directed that this issue be addressed in the next audit cycle. The Company did not flow the net proceeds from the sale of the CCPP, which occurred in April 2013, through the FAC.

Audit Of The FAC and AER

The 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). The AER audit will follow the guidance provided for this work in Attachments 3 and 4 of this RFP. The audits will also cover any other specific items identified by the PUCO or Staff.

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 October 21, 2015. EVA and/or Larkin conducted interviews with the individuals in the positions listed in Exhibit 1-3 mostly during the week of October 19th 2015. In addition to those listed, Mr. Jim Sorrels, Manager of Regulatory Analysis and Case, attended all the interviews in Columbus. Several follow-up calls were held with the listed personnel as well as others.

Exhibit 1-3
List Of Interviews

No.	Topic	Department	Participants
1	Ohio Regulatory/FAC Reporting	Ohio Regulatory/FAC Reporting	Andrea Moore; John Pulsinelli; Tim Dooley; Mike Giardina; Mark Gundlefinger; Jay Godfrey; Joe Karrasch; Scott Mertz, Jim Sorrels; Megan Pratt
2	Fuel Accounting	Fuel Accounting	Tim Dooley; Jennifer Fischer; Andrea Moore, John Pulsinelli, Jim Sorrels; Doreen Hohl; Megan Pratt
3	Environmental Compliance	Environmental Compliance	John Hendricks; John McManus; Tim Dooley; Brian Rupp; Janine White, Jim Sorrels; Megan Pratt
4	Purchased Power	Purchased Power	Julianne Lloyd; Tim Dooley; Scott Mertz; Mark Leskowitz, Anthony Bender, Jim Sorrels; Megan Pratt
5	Consumables, Fuel Oil, Biofuels, and Coal	Procurement	Jim Henry; Kim Chilcote; Jim Sorrels; Megan Pratt; Ben Duckworth; Mike Ward
6	Natural Gas, Consumables, Fuel Oil, Biofuels, and Coal	Procurement	Jim Henry; Megan Pratt; Ben Duckworth; Nita Spracklen; Clint Stutler
7	Internal Audits	Internal Audits	Rod Burnham; Tim Dooley; Megan Pratt
8	Gavin Plant Visit	Gavin Plant Visit	Brian Rupp; Janine White; Robert Jessee; Nick Tipple; Dave Caldwell; Megan Pratt

This audit report contains findings for fuel, emission allowances, and AER through 2014 and the Auction Phase-In Rider ("APIR") and Fixed Cost Rider ("FCR") through May 2015.

FAC Audit

Major 2014 Management Audit Findings – General

1. With Corporate Separation, AEPGR acted as agent for Ohio Power in the procurement activities for Ohio Power customers. The procurement responsibility for the Mitchell station was transferred to Kentucky Power. With [redacted], the Ohio Power coal supply agreements were assigned to AEPGR or Kentucky Power.

[redacted] As a result, AEPGR manages [redacted] of its plants; AEPSC manages [redacted]

3. Also as part of the Corporate Separation, AEPGR [redacted] to provide barging services to the AEPGR plants. These contracts were [redacted] in December 2013 but not provided to the auditor to review as part of the 2013 audit. The tonnage amounts included in the [redacted] are in excess of the recent [redacted] requirements of the plants. According to AEPGR, the tonnage amounts were for planning purposes only.

4. The management team for AEPGR included the prior head of AEPSC fuel procurement as well as key staff members.

5. AEPGR indicated it chose not to transfer some of the systems that had been used by AEPSC to manage and monitor fuel procurement activities.

6. Ohio Power named AEPGR as the Fuel Agent for 2014 due to the partial recovery of fuel costs through the FAC. To that end, Ohio Power provided a manual detailing the Fuel

.Agent Requirements. The dates on the cover page of the manual are October 1, 2014 through December 31, 2014.

[redacted]The [redacted] station were not available for a considerable portion of the year. Plant personnel indicated that the problems were related to a lack of maintenance personnel and funding. AEPGR's explanation in EVA-2014-3-9 was that “[redacted]

8. AEPGR indicated it “has since stressed to all of its plants the importance of [redacted] and following requirements of coal supply agreements to avoid having a similar issue going forward.”

9. Coal generation accounted for 88 percent of AEPGR generation in 2014.

10. AEPGR purchased about 13.0 million tons of coal in 2014. This was slightly lower than 2013 purchases. According to AEPGR, the average cost of coal in 2014 was [redacted] per MMBtu[2] which is a slight improvement over the [redacted] average cost in 2013.

11. Compared to EIA 923 filings for the other three Ohio utilities for which data are available, AEPGR had the [redacted] cost of coal. This was due to many legacy procurement decisions in 2012 and 2013 as well as the decision to draw down plant inventories in 2013 which left AEPGR exposed to the spot market during the unexpected polar vortex which increased coal burn and the need to buy high-priced coal for immediate delivery.

12. In addition, the railroads in 2014 had less than optimal performance which created delivery problems to the [redacted] plant. AEPGR was able to maintain an adequate coal supply by buying barge coal and then trucking the coal to the plant.

13. AEPGR purchased over [redacted] percent of its coal requirements in 2014 from [redacted] percent of AEPGR's purchases in 2014.

14. AEPGR expanded its use of Illinois Basin coals in 2014 with substantial purchases from [redacted]. Illinois Basin coal still only accounted for about [redacted] percent of total purchases and [redacted] percent of purchases for [redacted].

15. Due to the decline in coal demand and prior issues related to over-commitment, AEPGR increased the use of spot purchases to manage plant inventories.

[2] AEPGR does not include transportation costs for all the coal purchased from the Powder River Basin. EVA added [redacted] per ton to these purchase costs to estimate the delivered prices. The transportation rate is based upon the costs used by AEPGR to evaluate bids of Powder River Basin coal.

16. AEPGR operated under revised inventory targets in 2014. While the inventory targets for the plants on the retirement list (Kammer, Muskingum River, and Picway) stayed at [redacted] days, the inventory targets for Conesville 4, Conesville 5&6, and Gavin were [redacted]

17. Inventory performance varied by plant but generally began 2014 at below target levels and ended 2014 at high levels.

18. AEPGR entered into a [redacted] 2014 in which [redacted] until no later than [redacted], 2014 for AEPGR [redacted]. This arrangement was entered into [redacted].

19. AEPGR made a number of changes to its procurement practices in 2014. [redacted] formal solicitation was conducted in 2014. The balance of the procurements were largely made through email RFP's, phone RFP's, and direct negotiations. Except for the [redacted], AEPGR extended the opportunity to bid to a limited number of selected buyers. This change was not consistent the Fuel Agent Requirements manual which mandated the more formal approach to RFP's.

20. In total, AEPGR entered into [redacted] spot coal purchases for 2014 deliveries. Only [redacted] of the purchases were directly from the January solicitation which was sent to approximately [redacted]. [redacted] was effectively an extension of [redacted] purchases from the January solicitation.

21. A comparison of contemporaneous purchases made by AEPGR to purchases made by other utilities show that AEPGR on occasion paid made for comparable coals.

22. AEPSC was able to buy some higher sulfur coals for [redacted] during the audit period and maintain environmental compliance.

23. Almost all of the coal consumed by [redacted] in 2014 was [redacted].

24. In [redacted], AEPSC entered into a [redacted] contract with [redacted] for Muskingum River beginning in [redacted]. [redacted]. AEPGR did not [redacted].

25. In 2014, AEPGR [redacted].

26. AEPGR bought the inventory on the ground at [redacted] in December 2014 as part of [redacted] at the end of 2014. As part of the [redacted].

27. AEPGR declined to provide information on [redacted] which was effective 2015, or information on any other 2015 [redacted].

28. AEPGR purchased 28.6 MMBtu of natural gas at an average price of $[redacted] per MMBtu. The vast majority ([redacted] percent) was for the Waterford combined-cycle plant which was base loaded for [redacted] year in a row. The gas is purchased on a [redacted] basis.

Management Audit Recommendations

1. EVA recommends that it be made clear for any future regulatory actions that the fuel commitments made in 2014 for 2015 and beyond have not be subject to a prudency review.
2. EVA recommends the payments made to [redacted] should not be recoverable through the FAC.
3. EVA recommends that the [redacted] as well as the market premium [redacted] (consistent with the outstanding recommendation from the prior audit) should not be recoverable through the FAC.
4. EVA recommends that the jurisdictional revenue received from [redacted] flow through the FAC consistent with the recommendation from the prior audit.

2014 Financial Audit Findings

1. On December 31, 2013, corporate separation occurred and as a result, the transfer of AEP Ohio's generating assets to a new competitive affiliate, AEP Generation Resources ("AEPGR") became effective on January 1, 2014.
2. Pursuant to corporate separation, effective January 1, 2014, AEPGR and not OPCo, operated plants that had previously been run by AEP Ohio.
3. On November 13, 2013, the Commission issued an Opinion and Order in Case No. 12-3254-EL-UNC that approved and modified the Company's application to establish a Competitive Bidding Process and authorized the Company to unbundle the FAC and establish the Auction Phase-In Rider ("APIR") and Fixed Cost Rider ("FCR")
4. The APIR and FCR continued throughout the term of the ESP II which ended on May 31, 2015.
5. On September 1, 2015, AEP Ohio submitted its final FAC, which reflected actual data from January through May 2015 and the elimination of the forecast component.
6. In the September 1, 2015 final APIR and FCR filing, the beginning over-recovery balance of $27.315 million was added to the net under-recovery balance for the period January through May 2015, for an ending balance over-recovery of $2.453 million.
7. In 2014, AEPGR supplied energy to OPCo for its retail load under the Power Supply Agreement ("PSA").
8. The Commission directed that AEP Ohio transition to a competitive retail marketplace for generation through an auction process. The initial auction reflects an energy auction of 10% delayed until April 1, 2014. Subsequently, on June 1, 2014, now delayed until November 1, 2014, 60% of the Company's SSO energy load will provided by auction and

100% of OPCO SSO requirements will be supplied through auction beginning January 1, 2015.

9. For the quarterly FAC and APIR filings, the Company has used kWh sales as the basis for differentiating the quarterly FAC rates for Ohio Power and CSP.
10. After the merger of Ohio Power and CSP, AEP it can no longer separately identify FAC includable costs applicable to their respective areas, i.e., similar to the breakouts that were used prior to the merger.
11. There were no fuel amounts deferred during the audit period that affected the recorded fuel cost.
12. Pursuant to an internal audit that related to a review of the [redacted].

[redacted] Pursuant to an internal audit that related to [redacted]

14. [redacted].

15. Pursuant to an internal audit that related to [redacted].
16. [redacted] related to the [redacted] was recorded in Account 5010031on December 31, 2014. The costs associated with the [redacted] was [redacted] associated with terminating the contract and [redacted] associated with [redacted]. All of the expense associated with the [redacted] was borne by AEPGR and was not included in the APIR per the response to LA-2014-3-008.
17. As it relates to [redacted], in November 2014, AEPGR accrued the amount of [redacted], or which approximately 11.85%, or [redacted] flowed via the PSA to the APIR. In addition, in December 2014, AEPGR accrued another [redacted], of which 14.59%, or [redacted] flowed via the PSA to the APIR. The Company stated that these amounts were the only [redacted] that was charged to the PSA and recovered by the APIR.
18. During 2014, the Company included [redacted] of [redacted] capacity charges in the FAC and/or FCR.
19. During the period January through May 2015, the Company included [redacted] of [redacted] capacity charges in the FCR. Beginning in the period January through May 2015, the [redacted] capacity charges are now recorded in Account 5550122.

20. During 2014, the Company included [redacted] of [redacted] demand charges in the FAC and/or FCR.
21. During the period January through May 2015, the Company included [redacted] of [redacted] charges in the FCR.
22. For 2014 and through May of 2015, the Company's FAC, APIR and FCR did not include carrying charges.
23. The Company recorded three coal inventory adjustments in the spring, fall and winter of 2014 that related to the physical inventory surveys that were performed at [redacted]. The spring and fall 2014 inventory adjustments involved overages between the quantity of coal tonnage observed during physical inventory surveys and what was recorded on the books. These adjustments resulted in decreases to fuel expense of [redacted] and [redacted], respectively. The winter inventory adjustment was due to an error noted subsequent to the fall survey which led to a correcting entry of 1,570 tons, the result of which increased fuel expense by [redacted].
24. The [redacted] during 2014 resulting in [redacted] of the coal shipments to [redacted] per the response to LA-2014-4-003.
25. The Company receives a license fee from [redacted] for the use of its property pursuant to a [redacted] under which the coal being delivered to [redacted], which [redacted], and [redacted]. There is no reduction to the cost of [redacted] under this arrangement.
26. During 2014, AEPGR recorded [redacted].
27. During 2014 the Company recorded barge transportation costs [redacted].
28. Upon the transfer of Ohio Power's generating assets to AEPGR, AEPGR entered into a new [redacted].
29. A comparison of charges for demurrage under the previous arrangement versus the [redacted] the demurrage rates charged to AEPGR in 2014 were [redacted].

[redacted] The total costs related to barging services received by AEPGR in 2014 [redacted]

AER Audit

Management Audit Findings

1. It appears based on its filing, OPCo complied with its RPS obligation in 2014.

2. OPCo complied with its renewable energy requirement primarily through three major long-term renewable power purchase agreements which it supplemented with purchases of qualifying renewable energy credits.
3. The Alternative Energy Rider (AER) commenced in October 2012 at which time the renewable energy credit (REC) cost recovery was transferred to this rider.
4. OPCo continued to use a methodology to separate the REC values from the bundled prices under the three long-term contracts based upon residual accounting. The cost of the energy and the capacity are deducted from the total cost of renewable power purchases to yield the REC value. An alternative methodology could be to use the market price for REC's and keep the balance of the price in the FAC. This issue disappears with the end of the FAC
5. Due to an increase in the PJM capacity costs, the financial impacts of the residual accounting approach are less.

Management Audit Recommendations

None

Financial Audit Findings

1. During the renewables related interview that was conducted on October 19, 2015, the Company stated that a forward-looking estimate was accrued through December 2014 for purposes of separating the non-solar and non-Ohio non-solar RECs and that a true-up of these amounts was calculated in January 2015. In addition, the Company stated that a similar true-up for 2013 was calculated in April 2014.
2. In January 2015, the Company made a true-up adjustment to inventory to reflect the new 2014 solar benchmark of [redacted] RECs needed for compliance, which increased REC inventory by [redacted] units and which resulted in the unit cost changing from [redacted] per REC to [redacted] per REC. The actual inventory adjustment of [redacted] RECs reflects [redacted] for total value and unit cost.
3. In January 2015, the Company made an inventory adjustment to reflect the new non-solar benchmark of [redacted] RECs needed for compliance, which increased REC inventory by [redacted] units and which resulted in the unit cost changing from [redacted] per unit for non-solar non-Ohio REC inventory and [redacted] per unit for non-solar Ohio RECs to a combined non-solar REC inventory per unit cost of [redacted] in accordance with SB 310. The actual inventory adjustment of [redacted] RECs reflects [redacted] for total value and unit cost.
4. In April 2014, the Company made a true-up adjustment that related to a change in the estimate used for 2014 consumption.
5. In periods up to October 2012, the Company had been keeping inventories of REC quantities and cost for its Solar RECs, and maintaining an inventory of non-Solar RECs at zero cost. Commencing in October 2012, the Company began assigning a cost to the non-Solar REC inventories. The Company maintained monthly REC inventories during 2014 with quantities and cost for each type of REC that it tracks.

6. The zero value OPCo has assigned to its non-Ohio non-solar REC inventory during periods prior to October 2012 had been questioned in prior audits, in which it was recommended that a reasonable value for the REC should be assigned. The procedure that AEP began employing in October 2012 and continued using in 2014 assigns a cost to RECs based on a residual method based on subtracting from the total cost of the renewable energy purchases values for (1) capacity and (2) energy. The residual amount is the cost assigned to the REC component of the purchase.
7. As of December 31, 2014, the Company's REC inventory costs were:
   a) Solar RECs: [redacted]
   b) Non-Solar, Non-Ohio RECs: [redacted]
   c) Non-Solar Ohio RECs: [redacted]
8. To determine the capacity cost of solar and non-solar renewable purchases under its residual method, the Company used PJM RPM auction prices of $27.73/MW-day for the period January through May 2014 and $125.99/MW-day for June through December 2014.
9. In Case No. 10-2929-EL-UNC, the Company presented extensive testimony of why the PJM RPM auction prices for capacity were unreasonably low and should not be applied for determining a capacity cost for AEP Ohio.
10. In Case No. 10-2929-EL-UNC, the Commission addressed capacity cost for the Company and determined that a capacity cost of $188.88/MW-day was fair and reasonable.
11. Use of a higher price for the capacity component of renewable purchases would result in a lower cost being assigned to the REC value and less cost being included in Rider AER and a higher cost amount for renewables (for renewables capacity) being included in the FAC and/or APIR.
12. For the quarterly AER filings, the kWh information is used only for rate design. Ultimately, actual AER revenues are reconciled with actual AER includable costs.

Financial Audit Recommendations

1. Larkin concurs with EVA's recommendation that the retail share of [redacted] of the license fee revenue received from [redacted] be credited to the FAC and/or APIR mechanism.
2. For purposes of determining the capacity cost of renewables purchases for the 2014 audit period the capacity cost of $188.88/MW-day that the Commission determined in Case No. 10-2929-EL-UNC $188.88 was fair and reasonable should be used.
3. For 2014, FAC/APIR and AER results should be recalculated accordingly to reflect the application of the $188.88/MW-day capacity charge that the Commission determined in Case No. 10-2929-EL-UNC was fair and reasonable.

Audit Outline

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

- Section 2 AEPGR Background
- Section 3 Fuel Procurement Audit

- Section 4 Environmental Audit
- Section 5 Performance Audit
- Section 6 Financial Audit
- Section 7 AER Audit

2 AEP OHIO BACKGROUND

Background on Ohio Power Company and AEP Generation Resources

On October 31, 2012, American Electric Power Service Corporation (AEPSC) on behalf of its affiliates, Ohio Power Company (Ohio Power) and AEP Generation Resources Inc. AEPGR filed an application pursuant to section 203 of the Federal Power Act (FPA) requesting Commission authorization for an internal corporate reorganization that would result in the separation of Ohio Power's generation and power marketing businesses from its transmission and distribution businesses.

This transfer was required under the second Electricity Security Plan (ESP) in which Ohio Power agreed to separate its generating assets from its distribution business. To comply with this requirement, AEP could either sell Ohio Power's generation, similar to what Duke Energy Ohio did, or it could transfer the generation to an affiliate. Efforts to sell the assets had not been successful forcing the Corporate Separation. The assets may ultimately be sold to a third party although the timing is unclear. In early 2015, AEP retained Goldman, Sachs & Co. to explore disposition options for AEPGR.

Effective December 31, 2013, Ohio Power transferred approximately 11,200 megawatts of Ohio Power-owned generation to AEPGR. AEP Ohio's two-thirds ownership of John E. Amos Plant Unit 3 (867 MW) was transferred to Appalachian Power and 50 percent of Mitchell Plant (816.5 MW) and operating control was transferred to Kentucky Power.[3] Following the transfers and expected retirements through 2015, including the Philip Sporn station in West Virginia, AEPGR expects to own about 8,000 MW. AEPGR will bid into the PJM market, and Ohio Power will purchase electricity from PJM, from 2014 moving forward.

The power plants in which AEPGR had ownership shares during the audit period are listed in Exhibit 2-1.

[3] The other 50 percent was sold to Wheeling Power. The Wheeling Power sale did not close until 2015.

Exhibit 2-1
AEP Generation Resources Capacity

Power Plant Name	Operator	Owned Capacity (MW)	Operating Ownership (%)	Prime Mover	Fuel Type
Cardinal 1	AEP Generation Resources	600.0	100.0	Steam Turbine	Coal
Conesville 4	AEP Generation Resources	366.3	43.5	Steam Turbine	Coal
Conesville 5&6	AEP Generation Resources	888.0	100.0	Steam Turbine	Coal
Darby	AEP Generation Resources	507.0	100.0	Gas Turbine	Natural Gas
Gen J M Gavin	AEP Generation Resources	2,598.0	100.0	Steam Turbine	Coal
J.M. Stuart	Dayton Power and Light Co.	600.1	26.0	Steam Turbine	Coal
J.M. Stuart IC	Dayton Power and Light Co.	2.3	26.0	Internal Combustion	Distillate Fuel Oil
Kammer 1-3	AEP Generation Resources	630.0	100.0	Steam Turbine	Coal
Mitchell	Kentucky Power	816.5	50.0	Steam Turbine	Coal
Muskingum River	AEP Generation Resources	1,425.0	100.0	Steam Turbine	Coal
Philip Sporn 2&4	Appalachian Power	305.0	50.0	Steam Turbine	Coal
Picway 5	AEP Generation Resources	100.0	100.0	Steam Turbine	Coal
Racine	AEP Generation Resources	47.4	100.0	Hydraulic Turbine	Water
W.H. Zimmer	Duke Energy Corp	341.4	25.4	Steam Turbine	Coal
Walter C. Beckjord 6	Duke Energy Corp	58.0	12.5	Steam Turbine	Coal
Waterford Energy Facility	AEP Generation Resources	850.0	100.0	Combined Cycle	Natural Gas
TOTAL		10,135			
AEPGR		8,012			

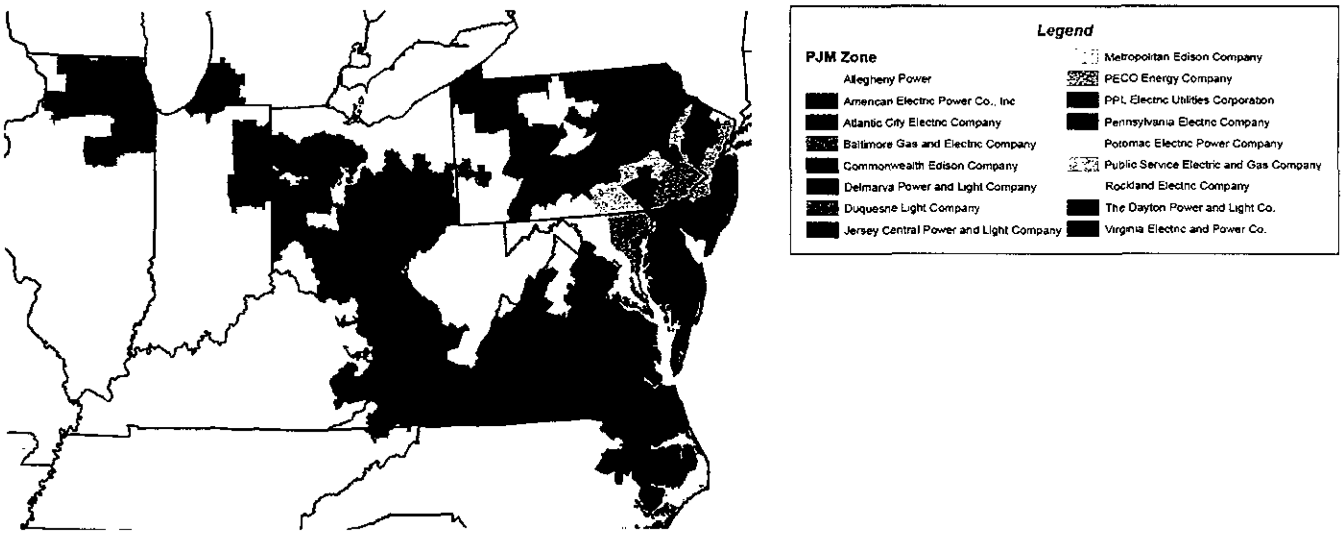
Source: Form 1 and EVA

Part and parcel with these changes were the termination of the Interconnection Agreement between Ohio Power, Appalachian Power, Indiana Michigan Power, Kentucky Power and AEPSC which had defined how the member companies shared the costs of their generation plants and the termination of the Interim Allowance Agreement that provided for the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement.

In addition, responsibility for fuel procurement for the former OPCo units was transferred from American Electric Power Service Company (AEPSC) to AEPGR. Effective January 1, 2014, AEPGR has had the sole responsibility and scope of discussions between AEPSC and AEPGR regarding fuel supply management were limited. A number of functions continue to be provided by AEPSC personnel through a joint services agreement.

AEP belongs to the Regional Transmission Organization (RTO) 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 RTO, 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. While significant generation will be acquired through the proscribed auctions, AEPGR will sell generation through PJM and Ohio Power will use PJM to balance its generation requirements.

Exhibit 2-2
PJM Interconnection Zones



Generation by AEPGR owned plants in 2014 is summarized in Exhibit 2-3. In 2014, 90.9 percent of AEPGR's electricity generation came from coal. About 78 percent of generation came from from plants operated by AEGPS. Waterford had another strong year. It was the third year in a row with a capacity factor in excess of 50 percent. Peak generation occurred in 2012 when the capacity factor was over 65 percent.

Exhibit 2-3
AEPGR Generation by Plant, 2014 (MWH)

Plant	Operator	Fuel Type	Generation*	Percent of Total
Cardinal 1	AEP Generation Resources	Coal	4,473,391,000	10.3%
Conesville 4	AEP Generation Resources	Coal	1,736,283,000	4.0%
Conesville 5&6	AEP Generation Resources	Coal	3,795,706,000	8.7%
Darby	AEP Generation Resources	Natural Gas	31,837,000	0.1%
Gen J M Gavin	AEP Generation Resources	Coal	15,710,692,000	36.2%
J.M. Stuart	Dayton Power and Light Co.	Coal	2,626,610,000	6.0%
J.M. Stuart IC	Dayton Power and Light Co.	Distillate Fuel Oil	116,200	0.0%
Kammer 1-3	AEP Generation Resources	Coal	1,013,683,000	2.3%
Mitchell	Kentucky Power	Coal	4,228,154,000	9.7%
Muskingum River	AEP Generation Resources	Coal	3,224,778,000	7.4%
Philip Sporn 2&4	Appalachian Power	Coal	810,808,000	1.9%
Picway 5	AEP Generation Resources	Coal	-	0.0%
Racine	AEP Generation Resources	Water	251,322	0.0%
W.H. Zimmer	Duke Energy Corp	Coal	1,713,171,000	3.9%
Walter C. Beckjord 6	Duke Energy Corp	Coal	133,768,000	0.3%
Waterford Energy Facility	AEP Generation Resources	Natural Gas	3,924,872,000	9.0%
TOTAL			**43,424,120,522**	**100.0%**
TOTAL AEPGR-Operated			**33,911,493,322**	**78.1%**
Coal			**39,467,160,200**	**90.9%**
AEPGR-Operated Coal			**29,954,533,000**	**88.3%**

Source: Form 1 and EVA

Coal Plants

This section provides background information on the five coal plants operated by AEPGR plus Cardinal.[4]

Cardinal

The Cardinal plant is located on the Ohio River, at mile marker 76.6. Cardinal consists of three units. Unit 1 is owned by AEPGR: 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 designed. An extended outage in 2012 was necessary to modify the scrubber. An aerial view is provided in Exhibit 2-4. AEPSC buys coal for the entire station but the contracts are now independent. This plant receives coal by barge and truck.

Exhibit 2-4
Cardinal Plant

Recent plant operating statistics for Cardinal 1are provided in Exhibit 2-5. Cardinal 1 generation fell by almost 70 percent in 2012 due to the scrubber-related outage. Generation began to return to normal levels in 2013, operating at [redacted] percent capacity factor and producing [redacted] GWh. Generation in 2014 was lower largely due to reduced dispatch because of lower natural gas prices.

[4] Kentucky Power became the operator of the Mitchell power plant effective January 1, 2014 and is therefore not included among the discussion of plants operated by AEPGR.

Exhibit 2-5
Historical Operating Statistics at Cardinal 1[5]

[redacted]

Conesville

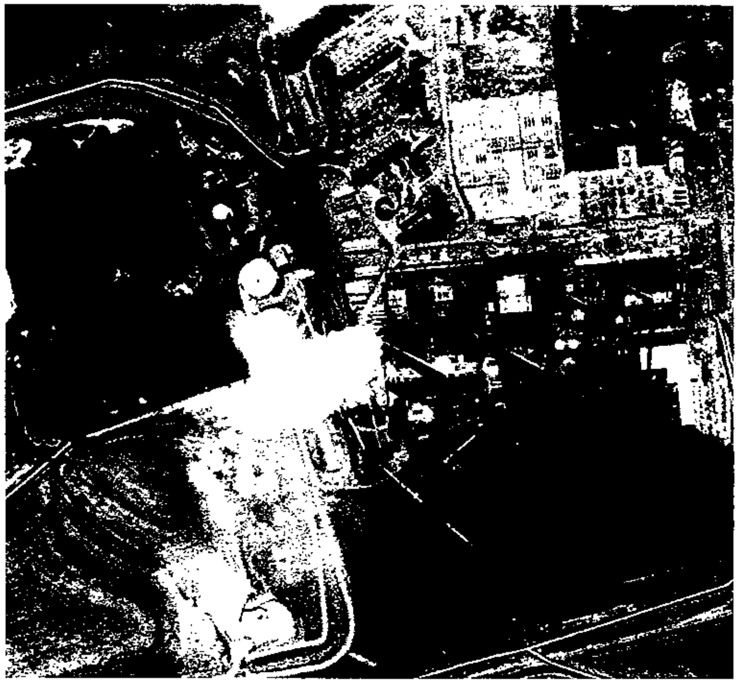
The Conesville station consisted of six units with a total generating capacity of 1,745 MW. All of the units except Conesville 4 were 100 percent owned by AEP. Conesville 4 is jointly owned by Dayton Power & Light (16.5%) and Duke Energy Ohio (40%) which sold its share to Dynegy in 2015.

Conesville 1 & 2 were retired in 2005. Conesville 3 was retired in 2012. Conesville 4 was retrofitted with a scrubber in 2009. This scrubber was a jet bubbling reactor design which AEP deployed at a number of plants. AEP encountered numerous problems with this technology which it determined to be a result of fundamental design deficiencies. Beginning in September 2012 and continuing through March 2013, problems with the scrubber at Conesville 4 forced the unit out of operation. Conesville 5 and 6 were built with scrubbers and these scrubbers were upgraded in 2009 to comply with a New Source Review settlement. [redacted]

As can be seen in Exhibit 2-6, Conesville 5 & 6 share a stack. Coal to this station is delivered by truck and rail[6]. The Conesville Coal Preparation Plant, which was originally built to wash locally produced trucked coal, was closed in January 2012 and sold to [redacted] in 2013. The plant was operated for a short period in 2013 under AEP's permits with contract personnel to prepare washed coal for testing at Conesville 5 & 6. AEP had no involvement of the preparation plant during the audit period.

[5] Operating Statistics for the plants are obtained from a variety of sources including filings to EIA and the Company.
[6] Technically, the rail delivered coal has to be trucked a short distance to the power plant.

Exhibit 2-6
Aerial View of Conesville Plant



Recent plant operating statistics for Conesville 4 and Conesville 5&6 are provided in Exhibit 2-7. Note Conesville 3 is included with Conesville 4 data until its retirement in 2012. Generation at Conesville 4 had been fairly flat from 2010 through 2013. Generation increased significantly in 2014 although the capacity factor was [redacted] percent. Generation at Conesville 5 & 6 declined significantly in 2012 with a slight rebound in 2013. Generation in 2014 improved again still.

Exhibit 2-7
Conesville Operating Statistics

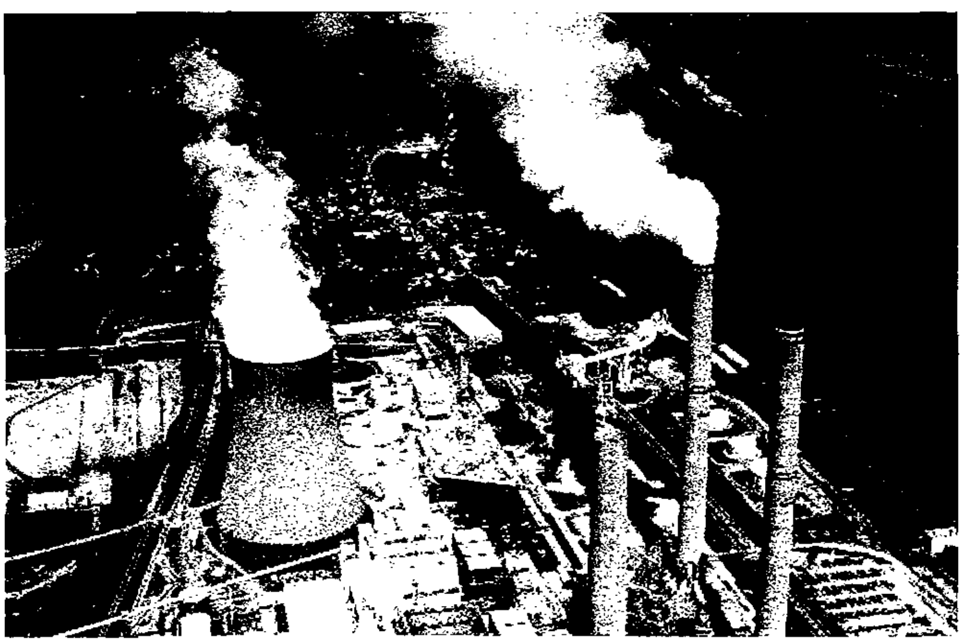
[redacted]

[redacted]

Gavin

The Gavin station consists of two units with a total generating capacity of 2,640 MW. These units were retrofitted 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 2-8) is currently delivered by barge.

Exhibit 2-8
Aerial View of the Gavin Plant



Gavin has two samplers connected to the barge unloaders. During much of 2014, one or both samplers were unavailable. The reasons provided by the plant was lack of resources (money and people). AEPGR supplement the explanation in EVA-2014-3-9. "Upon discovering the sampler issue, the plant contacted the manufacturer of the sampling equipment and scheduled an appointment to inspect the equipment (the manufacturer was backed up with other appointments at this time). After inspecting the equipment, the manufacturer determined that replacement parts were needed and had to be ordered, which again extended the time the sampler was out of service. Once the parts arrived, the manufacturer came back to the plant and made the necessary repairs."

Under the coal supply agreements, it is the responsibility of the Buyer to obtain a sample which then determines quality for payment purposes. While the contracts provide contingencies when the sampler is not available, the expectation is that samplers will be available most of the time.

Recent plant operating statistics are provided in Exhibit 2-9. Generation in both 2012 and 2013 was down compared with 2011. This is AEPGR's largest station and before 2013 consistently burned more than seven million tons per year. In 2013 and 2014 the unit burned 6.5 and 6.3 million tons respectively and ran at an operating capacity factor of [redacted] percent. As shown above, Gavin accounted for [redacted] percent of AEPGR's 2014 generation.

Exhibit 2-9
Gavin Operating Statistics

[redacted]

Kammer

The Kammer station consisted of three 210 MW coal-fired power plants. Kammer's boilers were cyclones and as such required a lower fusion coal, consistent with the fusion content of the high sulfur coal they were designed to burn. Compliance with clean air regulations had been a challenge for Kammer because low sulfur bituminous coals typically have a high ash fusion temperature. An aerial view of the plant is provided in Exhibit 2-10.

Exhibit 2-10
Aerial View of Kammer Plant

The Kammer units were not retrofitted with advanced pollution control equipment. All three units at Kammer were retired in 2015. Operating statistics for 2014 and the four prior years provided in Exhibit 2-11. Utilization of this plant was very low in 2013 and 2014.

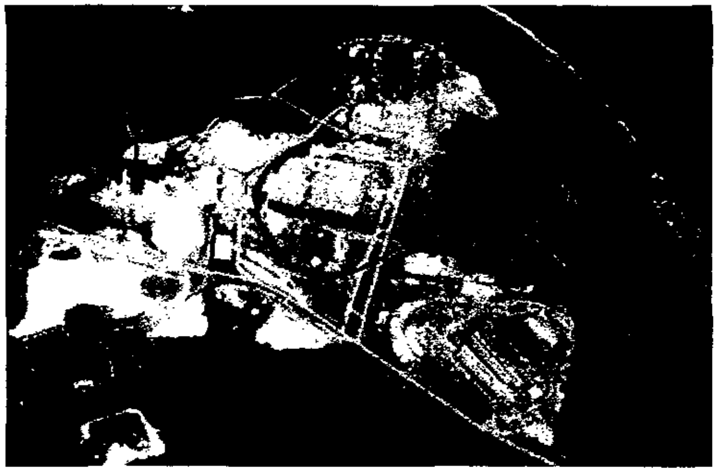
Exhibit 2-11
Operational Statistics for Kammer

[redacted]

Muskingum River

The Muskingum River plant was located in Beverly, Ohio. Muskingum River consisted of five units. The four smallest units were wet bottom boilers which required a lower ash fusion coal. Unit 5, the newest and largest boiler, was a dry bottom supercritical unit which could burn higher ash fusion coals. An aerial view is provided in Exhibit 2-12. This plant received coal by rail, as the Muskingum River is not navigable for barge deliveries. Coal could also be delivered by truck when necessary. None of the units were retrofit with scrubbers; Unit 5 was retrofitted with an SCR. All units at Muskingum River were retired in 2015.

Exhibit 2-12
Muskingum River Plant



Operating statistics for 2014 and the four prior years provided in Exhibit 2-13. As a result of the polar vortex in early 2014, burn was higher than had been expected as the station was needed to meet system requirements.

Exhibit 2-13
Historical Operating Statistics at Muskingum River

[redacted]

Picway

Picway was AEP Ohio's smallest coal plant. (Exhibit 2-14) Coal was delivered to this station by rail or truck. This plant was not equipped with any advanced pollution control equipment.

Exhibit 2-14
Aerial View of Picway Plant

[redacted]

Recent plant operating statistics are provided in Exhibit 2-15. No generation was reported for 2014.

Exhibit 2-15
Picway Operating Statistics

[redacted]

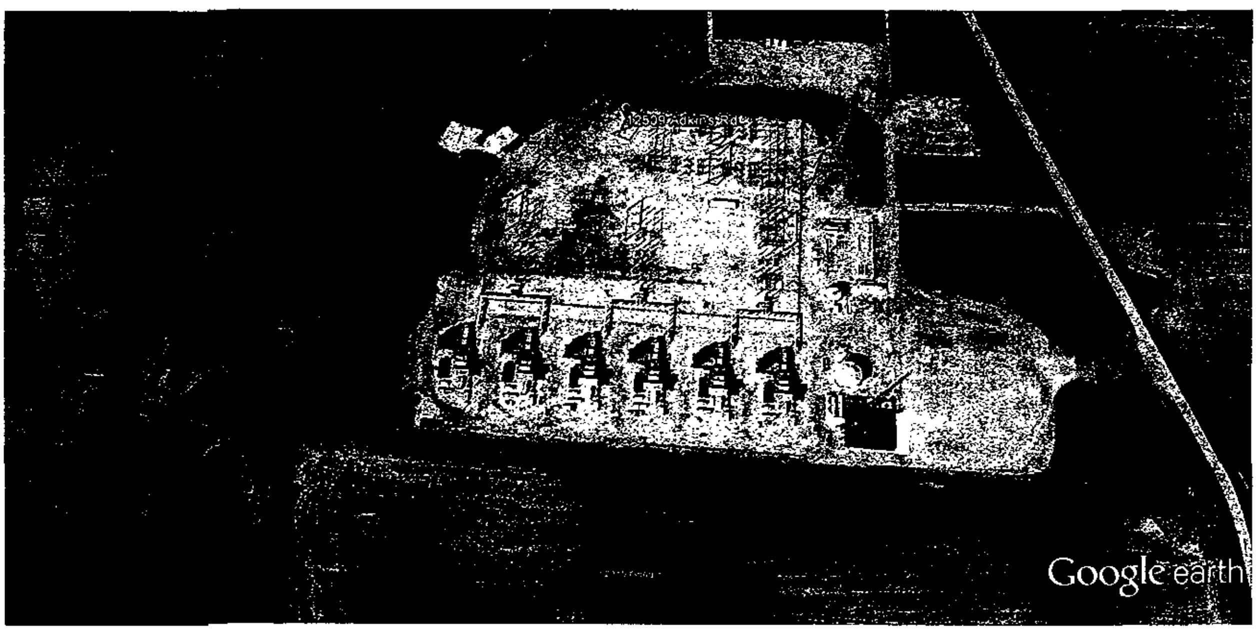
Natural Gas Plants

Darby

The Darby plant, located approximately 20 miles southwest of Columbus, Ohio, is a natural gas, simple cycle power plant with a nominal generating capacity of 480 MW. The plant began commercial operation in 2001. Columbus Southern Power purchased the plant from DPL Energy in 2007. At the time, AEP's CEO Michael Morris stated that AEP's "forecasts indicate that the growing electricity needs of (its) customers in our eastern seven states' footprint will soon be beyond the capabilities of our existing fleet of power plants." AEP's strategy was to acquire "(n)atural gas-fired merchant plants like Darby … that have a purchase price well below the cost to build a new, comparable plant." As a simply cycle plant, Darby was purchased to meet customer demand during peak periods.

An aerial view of the Darby plant is provided in Exhibit 2-16. The plant consists of six GE frame 7EA simple cycle combustion turbines and a fuel oil storage tank. Distillate fuel oil is a secondary fuel supply.

Exhibit 2-16
Aerial View of Darby Plant



Recent plant operating statistics for Darby are provided in Exhibit 2-17. The capacity factor in 2014 was [redacted] percent. Its highest capacity factor was achieved in 2012 at [redacted] percent.

Exhibit 2-17
Darby Operating Statistics

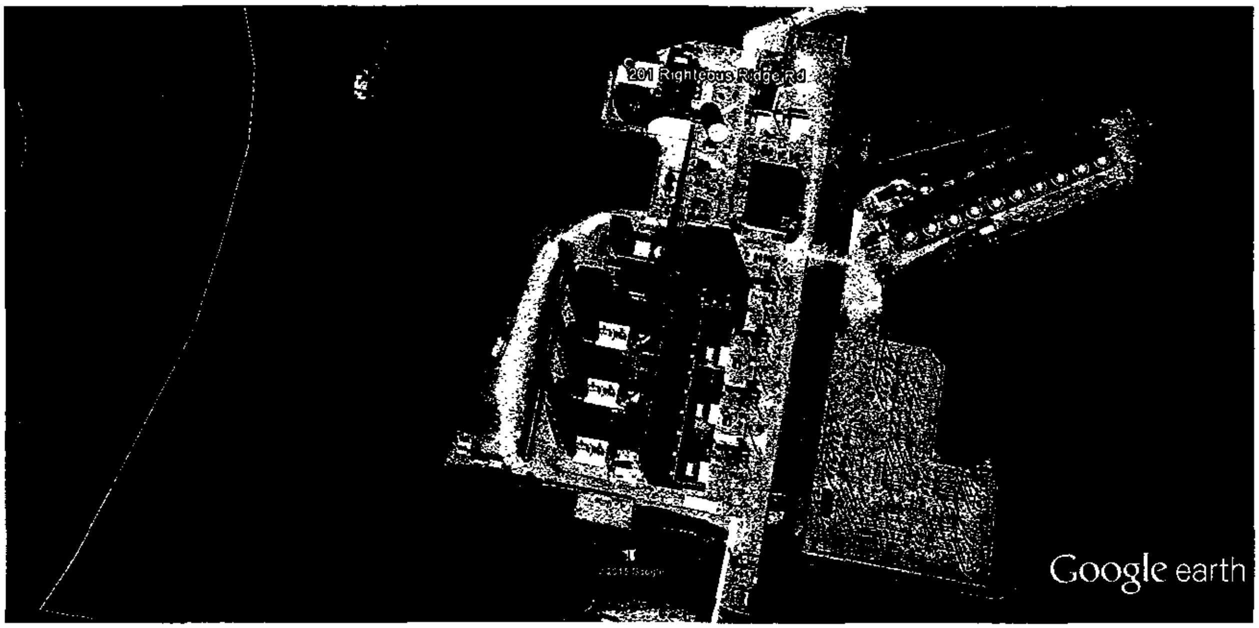
[redacted]

Waterford Energy Center

The Waterford Energy Center is a natural-gas fired, combined cycle power plant located in Waterford, OH which is in the southeastern part of the state. The plant, which was built by Public Service Enterprise Group (PSEG), started operations in 2003. It was purchased by Columbus Southern Power in 2005. At the time of its purchase, the expectation is that it would not "operate for long periods of time because of significantly higher natural gas prices". According to AEP, the primary motivations for the acquisition were to help insure AEP could meet the 15 percent reserve margin required by PJM and to provide generation "on days of high electricity demand."

The facility's power train consists of three GE 7FA gas-fired combustion turbines, three heat recovery steam generators, and one steam turbine. Inlet air cooling equipment and duct burners were installed to increase the facility's electric output and SCR's were installed to reduce NOx emissions. An aerial view of the Waterford plant is provided in Exhibit 2-18.

Exhibit 2-18
Aerial View of Waterford Energy Plant



Recent plant operating statistics for Waterford are provided in Exhibit 2-19. Waterford has been a baseload generator for the last three years. Its highest capacity factor was achieved in 2012 at over [redacted] percent.

Exhibit 2-19
Waterford Operating Statistics

[redacted]

3 FUEL PROCUREMENT AUDIT

The fuel supply arrangements for AEPGR consist of commercial purchases comprised of long-term, short-term, and spot purchases.

2014 Coal Procurement Performance

Coal purchases in 2014 by plant and contract type for AEPGR are summarized in Exhibit 3-1. The average price was [redacted] per MMBtu.

Exhibit 3-1
AEPGR Coal Purchases, 2014

[redacted]

Source: AEPGR[7]

There is considerable variation in the delivered price by plant with [redacted] having the lowest delivered prices and [redacted] the highest. The difference in the average delivered price between [redacted] (which should have similar delivered prices) reflects [redacted]

AEPGR's delivered coal costs on a dollars per MMBtu basis are compared to the 923 data for the other Ohio utilities for which data are publicly available in Exhibit 3-2.[8] AEPGR's coal costs compare unfavorably with the coal purchase expenses of the other Ohio utilities. According to the 923 data, AEPGR had the highest delivered costs in 2014. This comparison is indicative of performance but not dispositive as the utilities vary with respect to quality requirements and transportation.

[7] The exhibit was compiled from AEPGR provided data with one change. When not provided, EVA [redacted] per ton transportation costs for the Powder River Basin coal.
[8] FirstEnergy does not report its fuel purchase costs of Form 923.

Exhibit 3-2
Ohio Utility Coal Purchase Costs, 2014

[redacted]

Source: AEPGR and Form 923 for the other Ohio utilities.

Some additional detail about the 2014 purchases by the other Ohio utilities is provided on Exhibit 3-3. AEPGR paid significantly more for both its contract and spot purchases. The higher contract prices reflect primarily the above market contracts with [redacted] that have been discussed in the prior audit report. The above market prices for spot purchases reflect the premium paid by AEPGR for its spot purchases during the first half of the year.

Exhibit 3-3
Ohio Utility Coal Purchase Details, 2014

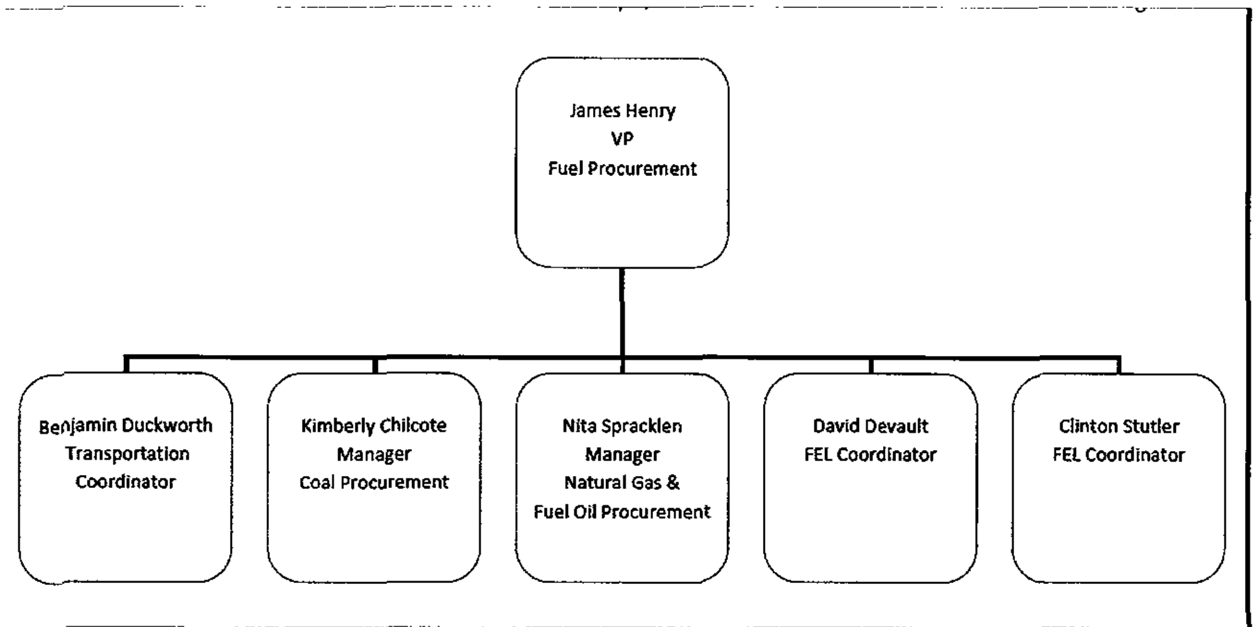
[redacted]

Source: AEP and Form 923 for the other Ohio utilities

Management And Organization

As noted above, following Corporate Separation fuel supply for the AEPGR plants is handled by AEPGR. The fuel supply organization within AEPGR is shown in Exhibit 3-4.

Exhibit 3-4
Organization Chart for AEPGR Fuel Procurement



Policies And Procedures

Given that 2014 is a transition year for fuel procurement for the AEPGR generating assets in that a portion of their fuel costs were recovered through the FAC. For the transition year, AEPGR was named as the Fuel Agent for Ohio Power during this period. As part of that role, Ohio Power drafted the Ohio Power Fuel Agent Requirements Manual with which it expected the Fuel Agent to comply. While the cover page of the manual states the dates to be October 1, through December 31st of 2014 (suggesting the manual was not prepared until then), the introduction to the manual is clear that it is intended to apply to all fuel procurement during 2014.

The organization of the manual is similar to the prior AEPSC fuel procurement manual although customized for its stated purchase. The sections of the manual are as follows:

[redacted]

[redacted]

The manual is consistent with standard utility procurement practices and is not consistent with some of AEPGR's practices in 2014. For example, the manual states "[redacted] As discussed below, AEPGR performed [redacted]. The remaining procurements were [redacted]

The manual provides a lengthy discussion of when an emergency procurement is necessary. Only in emergency procurement are the standard RFP requirements waived. [redacted]. To state the obvious, there was ample time to solicit the market for February once the January procurement was made and if the coal was not needed, AEPGR would not have been under any obligation to purchase it. Ditto for April.

Also, the justifications for the emergency procurements did not comply with the manual which states [redacted]

Finally, given [redacted]

Inventory Management

The Fuel Agent Requirements states that the "Agent's primary objective of fuel procurement is 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 and managed by the Agent with due consideration of coal supply disruption risks." With respect to the actions that should be taken if the actual inventory levels diverge from targets, "an appropriate course of action shall be implemented shall be implemented by the Agent."

The inventory targets in effect during the audit period along with the targets for the prior audit period are provided in Exhibit 3-5. The inventory targets for the plants on the retirement list (i.e., Kammer, Muskingum River, and Picway) remained at [redacted] days. The inventory targets for Cardinal 1, Conesville 5&6, and Gavin were reduced. No reason was provided for the reduction although not a surprise. It is EVA's experience that merchant plants do maintain lower inventory levels because they do not have the regulatory exposure to having inadequate coal supplies on hand to meet demand. The question is whether the reduction was premature.

Exhibit 3-5
Inventory Targets

[redacted]

As a result of the inventory levels going into 2014 being below historical levels and in some cases below target, AEPGR was not prepared to meet Q1 burn levels without a significant level of hasty procurements.

End of year inventory by year and plant is shown Exhibit 3-6. Inventory was up by almost [redacted] percent even with the [redacted] ton drop at Kammer and the [redacted] ton drop at Picway due to their pending retirements. The largest increase was at [redacted] followed by [redacted]).

Exhibit 3-6
End of Year Inventory Levels by Plant

[redacted]

The inventory levels by month and plant compared to inventory capacity and the inventory targets are shown in Exhibit 3-7. Performance varied considerably by plant. Overall inventory management appears to have been a challenge in 2014. With the non-retiring plants all below target levels for most of the year. Of particular concern, were the low inventory levels at the beginning of the year, the high inventory levels at [redacted] during the last quarter of 2014, and the growth in inventory levels at [redacted]

Exhibit 3-7
Inventory Levels at the AEPGR Plants (Tons)

[redacted]

[redacted]

[redacted]

At [redacted], the full inventory capacity was consumed in reached in mid-October 2014 as a result of a plant force majeure. [redacted] Rather AEPGR entered into a [redacted]

As discussed in the prior audit, EVA believes that AEPSC had been imprudent by not addressing the over-commitment [redacted] when it extended its agreement with [redacted] through 2015 and that related costs should not be recoverable. EVA disagrees with the characterization that

9 [redacted]

AEPGR had to take the coal upon the cessation of the force majeure event at the rate of [redacted]. Many contracts including many AEPGR contracts are amended to modify delivery dates. Regardless and consistent with prior recommendations, EVA recommends any costs associated with [redacted] should not flow through the FAC.

In Exhibit 3-8, inventory levels at AEPGR-operated plants are compared to actual and normal industry levels of East North Central utilities based upon EVA's proprietary stockpile report.[10] In the first quarter of 2014, utility inventory levels at the East North Central utilities declined due to cold weather and railroad delivery issues. Inventory rebuild programs combined with lower natural gas prices caused inventory levels to grow in the second half of the year. AEPGR inventory levels [redacted] than the industry averages.

Exhibit 3-8
AEPGR Inventory Days Versus East North Central

[redacted]

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

[10] 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.

minus two percent be investigated. [redacted]

The information provided on the physical inventory survey adjustments at AEPGR-operated plants are summarized for 2014 in Exhibit 3-9. [redacted]. Most of the survey results indicated that the [redacted].

Exhibit 3-9
Physical Inventory Survey Adjustments, 2014

[redacted]

Based upon the 2.0 percent threshold in AEP System Accounting Bulletin No. 4, investigations [redacted]

Internal Audits

[redacted]

11 [redacted]\.

12 [redacted]

Coal Procurement

In 2014, AEPGR purchased approximately 13 million tons of coal for five plants. As AEPGR is separate from AEPSC, the solicitations be in writing or over the phone were specific to AEPGR's requirements. As a result and to the extent that suppliers have a location or quality advantage to anyone of AEPGR's plants, AEPGR's lost the advantage of an open non-destination specific solicitation.

Coal Procurement Strategy

AEPGR's strategy is to layer in coal commitments to minimize market exposure at any one time. The recent volatility in coal burn has resulted in AEPGR and other utilities increasing the use of spot procurements in order to avoid over-commitment. AEPGR had a larger open position than its predecessor going into 2014 and, as a result, paid more for coal in 2014 because of the higher than expected burn in the first half of the year. Other consumers have taken different approaches such as increased volume optionality in their contracts, fixed volume contracts with flexible terms, requirements contracts and higher stockpiles. AEPGR has almost no volume optionality in its contracts and has reduced rather than increased its stockpile target. AEPGR inherited one fixed volume contracts with a flexible term and one contract with volume optionality and negotiated two short-term requirements contracts. The balance of the contracts are for fixed volumes and fixed terms.

Coal Solicitation

Prior to Corporate Separation, AEPSC monitored its coal position overall and by plant and supplier through an internally developed model which monitored actual and target inventory levels, actual and projected burn, and spot and contract commitments. AEPSC typically bought through formal solicitations. A request-for-proposal ("RFP") was issued, generally by AEPSC without naming which plants require coals. The RFP requested bids for a wide range of coals and gave bidders the option to bid for spot and/or multi-year contract business. The results from the RFP process helped to determine whether to buy coal on a spot or contract basis and for what term.

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

Since Corporate Separation, AEPGR has moved away from the historical practices in two important respects. It only conducted one formal solicitation in 2014. The balance of the purchases were made through email or phone solicitations with limited counter-parties or direct negotiation with single counter-parties. Also, AEPGR does not appear to have purchased OTC coal for its commodity needs.

AEPGR conducted one formal coal solicitations in 2014 (January) and multiple e-mail and phone solicitations.

January 14, 2014 RFP

The January 14th RFP solicited both spot (Q2-Q4 2014) and term offers (3-5 years) for two coal qualities. The primary difference in the two coal qualities was with respect to Btu. Bids for Specification A, which had a minimum Btu/lb of 11,800, were solicited either on a delivered basis to Conesville or FOB Mine. Bids for Specification B, which had a minimum Btu/lb of 11,000, were solicited on an FOB barge basis. The desired quantities were not indicated.

The bidders list produced by AEGPR included about 100 companies. Bids were received from [redacted] companies. Several companies provided multiple bids.

[redacted] were made from the RFP. The purchases [redacted]. The quality-adjusted delivered prices in the justification memorandum differ from the spreadsheet analysis provided by AEPGR in response to EVA-2014-1-8 although the rankings remained the same. The rationale for purchasing coal for [redacted] was the desire to keep plant inventory levels at or below target amounts.

The [redacted] in Exhibit 3-10. All of the agreements provide for quality adjustments for [redacted]. [redacted] of the agreements provide for [redacted] adjustments. [redacted] agreement has a [redacted] EVA frowns upon [redacted] Therefore, under certain circumstances a [redacted]. Further, it is EVA's experience that [redacted].

Exhibit 3-10
Purchases from the January 14th 2014 RFP

[redacted]

There may have also been purchases for 2015 and beyond. AEPGR declined to provide any information with respect to those purchases.

Procurement Administration

AEPGR indicated it had not to take all the contract administration tools as part of the Corporate Separation, choosing instead to create their own. The lack of systems may have been the reason why [redacted] escaped appropriate attention.

EVA identified the problem when it reviewed the coal quality sheets. As shown in Exhibit 3-11, [redacted] half-month periods had identical coal quality for [redacted] contract. EVA believed this was a typographical error as from EVA's experience it would be impossible for the results over [redacted] to be the same. It turned out the results were the same because the [redacted]. Following the contract for when the [redacted][13] The duration of this problem is unacceptable for many reasons but primarily because the sample determines the payment to the supplier. In this particular case, the average Btu of the applied sample is [redacted] That being said, if a supplier knew its coal was not being sampled, it may affect the quality of the coal that is shipped making the calculated average quality not reliable.

Exhibit 3-11
Example Quality Analysis for Contract Coal to [redacted]

[redacted]

Spot Coal Procurements

AEPGR purchased significant volumes under spot coal procurements in 2014. This is in sharp contrast to spot procurements in 2013 when little coal was purchased because demand was lower

[13] Under the [redacted], the precise language is as follows: [redacted]

than expectations. Further, most of the spot coal purchased in 2013 was for Mitchell, a plant which is not considered in this audit with the change in operating company to Kentucky Power at the end of 2013. The spot agreements are listed by supplier in Exhibit 3-12.

Exhibit 3-12
Spot Coal Agreements

[redacted]

As previously discussed, spot agreements are one vehicle for managing coal inventories although they are not without cost or problems. The cost of relying on spot purchases alone to manage inventory levels is that exposes the utility to greater price volatility because the chances are when it needs coal others need coal as well. This can be clearly seen at [redacted] in 2014.

As shown in Exhibit 3-13, spot purchases at [redacted] were significantly higher in February through May than the balance of the year. This was primarily due to three factors. Burn was higher due to the polar vortex. Inventory going into the year was very low. The procurement strategy was to keep contract commitments low in order to manage inventory levels. Weather-related delays occurred under a number of contracts.

Exhibit 3-13
[redacted] Purchases by Month (Tons)

[redacted]

As the polar vortex affected most of the country, other consumers also needed coal which caused prices to rise. Spot coal prices during February through May were substantially above contract coal prices as shown in Exhibit 3-14. Given the quantity of spot coal purchased during this period, the incremental cost of coal to [redacted] was substantial.[14]

Exhibit 3-14
Average Price by Purchase Type and Month ($/MMBtu)

[redacted]

14 [redacted].

Another problem with heavy reliance on the spot market is the administrative cost associated with the multiple procurements. As shown above, there were [redacted] spot procurements during the audit period. All of these procurements, except for the [redacted] resulting from the January RPF plus [redacted] which was essentially an extension of [redacted], were purchased via email or phone solicitation or through negotiated agreements including emergency and distress purchases. These procurements are not only time consuming but by limiting the potential suppliers which is a necessity in a phone solicitation, the likelihood the buyer is not receiving the lowest cost coal available in the market is significantly increased.

A quick review of Kentucky-regulated coal purchases[15] produced several examples of this. For example, in June, Kentucky Power purchased barge coal for its Mitchell station. The specifics of this purchase are compared to a contemporaneous purchase by AEPGR of similar quality coal in Exhibit 3-15.

Exhibit 3-15
Comparison of AEPGR Spot Purchase to Market Spot Purchase

[redacted]

The quality and quantity are similar. The Trafigura price to Kentucky Power is [redacted] per ton lower. The [redacted] purchase was made from a phone solicitation. [redacted]. This result should not be surprising to AEPGR. There is almost always a range in bid prices which is why broad solicitations are encouraged. So the fact that when AEPGR selects a limited number of parties to participate there is a distinct possibility that the lowest cost coal may not be included in the process.

Contract Overview

AEPGR was a party to [redacted] long-term coal supply agreements in 2014. The agreements, which are listed in Exhibit 3-16, combined accounted for [redacted] tons.

[15] Regulated utilities in Kentucky are required to file all of their fuel purchase agreements.

Exhibit 3-16
AEPGR Coal Contracts

[redacted]

2014 Performance

Deliveries under the [redacted] contracts in 2014 were about [redacted] million tons which was about [redacted] million tons below the contract levels as shown in Exhibit 3-17. The largest shortfall was over the [redacted] tons not shipped under the [redacted]. [redacted]

Exhibit 3-17
AEPGR Contract Tonnage Performance, 2014

[redacted]

Source: Commitments EVA-2014-1-14, Deliveries EVA-2014-1-15

Individual Contract Performance

Performance in 2014 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 suspension specifications for Btu, SO_2 and/or ash.

[redacted]

The [redacted] contract is for [redacted] years. The contract provided that the first [redacted] were to be at an [redacted]; the balance was to be at the [redacted]. AEPGR also has a [redacted]

In 2014, the contract was amended [redacted] times. Amendments [redacted] were administrative addressing contractually-allowed price adjustments. According to the justification for [redacted], to address the [redacted] under the contract, the parties [redacted]. The amendment defines [redacted] is provided in Exhibit 3-18.

Exhibit 3-18

[redacted]

[redacted]

Shipments under the [redacted] in 2014 are summarized in Exhibit 3-19. In [redacted] periods, the average Btu content was [redacted]. Overall, the quality was [redacted] and [redacted].

---

16 [redacted]

Exhibit 3-19
Shipments Under [redacted] Contract, 2014

[redacted]

As noted above, the [redacted] were out of service [redacted]. The contract provided for the [redacted]. As the average quality for the [redacted]

Deliveries were about [redacted] contract levels. The rate of delivery was closer to [redacted] for [redacted] of the year versus about [redacted]. It appears that the amendment [redacted].

[redacted]

The initial [redacted] contract was signed in [redacted] tons per month of [redacted] for [redacted]. The initial contract ran through [redacted]. Subsequent amendments [redacted] tons per month and extended the contract to [redacted]. This contract has been [redacted]

[redacted]. The prior management/performance audit provides a full discussion of the issues related to this contract.

In 2014, AEPGR reached an agreement [redacted]. EVA was provided very limited information on [redacted].[17] In 2014, [redacted] was amended [redacted]. Amendment [redacted] was administrative addressing contractually-allowed price adjustments. Amendment [redacted], dated [redacted], provided that if the [redacted] According to the amendment, [redacted]

It is clear [redacted]. EVA recommends no portion of the [redacted]

2014 Performance

Shipments under the [redacted] in 2014 are summarized in Exhibit 3-20.

17 [redacted]

Exhibit 3-20
Shipments Under [redacted] Contract, 2014

[redacted]

[redacted]

In [redacted], AEPSC and [redacted] entered into a complex contract for [redacted]. 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 [redacted]. There are multiple quality specifications, some of which vary by year. Part of the coal comprised the [redacted] portion of the [redacted]. The pricing is complex because prices for segments get reset starting for [redacted] which also affect annual tonnage nomination options. In addition to the [redacted] devoted to the Contract Price and Annual Tonnage Determination, the contract also includes by reference an [redacted].

2014 Performance

The [redacted] contract was amended [redacted] in 2014. The first amendment which was finalized on [redacted] stemmed from [redacted]

[redacted]. The amendment provided for the addition of the [redacted] mines as Alternate Production Sources and [redacted]. If [redacted]. Amendment [redacted] also allowed AEPGR [redacted]

The [redacted] amendment addressed a number of matters. [redacted] of AEPGR [redacted] AEGPR. Amendment [redacted] formally acknowledged that [redacted] by AEPGR [redacted], [redacted]. Amendment [redacted] addressed how the 2013 shortfall [redacted][18] [redacted]

Shipments under the [redacted] agreement in 2014 are summarized in Exhibit 3-21. Deliveries in 2013 were [redacted]. Most of the coal was [redacted] and there were [redacted] which were [redacted]s and [redacted]. There was no quality for [redacted]. The shipments of Specification B coal also had occasional [redacted]. There was no quality for [redacted] for this coal. [redacted] was used to determine the [redacted].

[18] AEPGR would not share the details of this [redacted] as it only applied [redacted] beginning in 2015.

Exhibit 3-21
Shipments Under [redacted] Agreement, 2014

[redacted]

[redacted]

In [redacted], AEPSC entered into an [redacted] agreement with [redacted]. The basic terms of the contract are summarized in Exhibit 3-22. This contract obligates AEPGR to buy its [redacted] from [redacted] but does not [redacted]. AEPGR has to buy [redacted]. As such it provided considerable flexibility to AEPGR and addresses the uncertain and volatile burn at [redacted].

Exhibit 3-22
Overview of [redacted] Agreement

[redacted]

The agreement was amended [redacted] in 2014 to provide the Q2 2014 nomination. With this nomination, the total tonnage under this agreement turned out to be just [redacted] tons as shown in Exhibit 3-23.

Exhibit 3-23
Tonnage Under [redacted] Agreement

[redacted]

2014 Performance

Shipments under this agreement in 2014 are summarized in Exhibit 3-24. The quality of the deliveries was consistent with the contract specifications.

Exhibit 3-24
Shipments Under [redacted] Agreement, 2014

[redacted]

[redacted]

In [redacted], AEPSC entered into [redacted]ents with [redacted] that collectively provide the basis for the [redacted]. The interest [redacted]. In order to qualify for the [redacted]. As a result, in order to [redacted] AEPGR must [redacted]d.

[redacted], were assigned to AEPGR effective 1/1/2014.

Under the [redacted], AEPGR [redacted] provides for AEPGR to [redacted] provides for the [redacted]

Under the [redacted], AEPGR receives what is referred to as a [redacted], is summarized in Exhibit 3-25. In the deal summary prepared for management, AEP noted that it believes the [redacted]

Exhibit 3-25

[redacted]

[redacted]

AEPGR indicated it would not be flowing any of [redacted] through the FAC. The reason provided is that "FAC ratepayers will realize a net benefit without cost through this arrangement because the savings in the cost of [redacted] by AEPGR Company as a result of the [redacted] will be reflected in the FAC via [redacted]." AEPSC also notes that the "decisions to [redacted] were made over a period of several months in the [redacted]. Many corporate business units were involved in this process including: Fuels Emission & Logistics, Corporate Accounting, AEP Legal, AEP Regulatory and AEPGR Company." To the best of the auditor's knowledge, AEPSC did not ask for or receive an opinion from the Commission or Staff regarding the appropriate accounting treatment.

Fundamentally, EVA believes that the only reason [redacted] burns substantial quantities of coal, which were purchased on the behalf of jurisdictional customers. In other words, the asset (i.e., the coal) during the audit period effectively [redacted] Therefore, [redacted] received are inextricably tied to AEPGR's ability to lever this asset into [redacted]. With respect to the specific justification regarding [redacted] savings noted by AEPSC in its response to EVA-2012/13-3-8 that it included "no value for [redacted]" in its deal value because [redacted] will not be certifying that the required [redacted] have in fact been realized. In fact, EVA is aware of situations where utilities have decided to [redacted] because of higher operating costs and lower plant availability. Absent a clear demonstration of total savings, EVA is not convinced by AEPSC's arguments.

Finally, it is not at all clear that customers are not adversely affected in their cost of fuel. In the deal package, AEPSC notes that following a test burn at [redacted], the [redacted] yielded acceptable results "[redacted]". This exclusion suggests that [redacted]

[redacted]. After the end of the FAC, this is no longer an issue. Prior to the end of the FAC, having the fee not flow through the FAC reduces the incentive to minimize fuel costs at the plant.

EVA recommended an adjustment to the FAC of [redacted] in 2013. EVA is recommending that jurisdictional customers receive a full pro-rata share of the [redacted].

[redacted]

In [redacted] entered into a [redacted] for the supply of [redacted]. In addition, the agreement gives [redacted] each year provided such option is exercised no later than [redacted] prior to the commencement of [redacted]. The mine is located [redacted]. In [redacted], the agreement was d[redacted] decided it best to each company having a stand-alone agreement. The new agreement was given the [redacted].

The contract was amended [redacted] in 2014. Both amendments were price escalations.

Shipments in 2014 under the [redacted] are summarized in Exhibit 3-26. Shipments were about [redacted] contract levels. [redacted] was not in compliance with the SO_2 specifications for [redacted].

Exhibit 3-26
Shipments Under [redacted], 2014

[redacted]

The initial contract with [redacted] was signed in [redacted] and provided for [redacted]. [redacted], AEPSC could elect to [redacted]

[redacted]. The specifications are described in Exhibit 3-27.

Exhibit 3-27

[redacted]

Subsequent amendments [redacted]. In [redacted], AEPSC amended the contract to [redacted].

[redacted], AEPSC agreed to extend the [redacted] wanted the assurance of future volumes for its own planning purposes. AEPSC agreed to extend the agreement [redacted] at an annual rate of [redacted] tons per year. The key terms of the amendment are as follows:

- The price for [redacted]. According to AEPSC, this pricing structure produced an [redacted].[19]
- The price for the remaining years will be set by [redacted].

EVA reviewed the justification and concluded that AEPSC was ill-advised in extending the [redacted] agreement in the manner it did for the following reasons:

- AEPSC had a huge problem at [redacted] because the plant dispatch was impaired due to the current high price of [redacted]. EVA believed that the availability of business at [redacted] provided some ability for negotiation on the [redacted] terms either with [redacted][20] or perhaps a third party that could have provided a comprehensive solution.
- [redacted], AEPSC made the decision\ [redacted]. Given the significant costs associated with [redacted], AEPSC would have been well advised to [redacted] EVA was told that AEPSC did not start [redacted]
- [redacted], it had become clear that AEPSC had on numerous occasions purchased more coal that it ultimately [redacted]

[19] When parties make offers like this it should be a signal of their financial fragility. In exchange for [redacted] in the first half of the year, they are reducing their realizations in the second half of the year [redacted].

[20] AEPSC argues that using [redacted] would have been more expensive because these units do not need [redacted]. As AEPSC did not explore how a global settlement would have worked, there is no basis for EVA to agree with AEP. Renegotiating [redacted] to include additional tons for [redacted] could have been based upon alternative coals, not the coals moving to [redacted] Further, there are procedures in place to accommodate the transfer of coal purchases from the [redacted].

[redacted] AEPSC provided no reasons to enter into this commitment with [redacted] at this time when its own forecast (that was contained in the justification package) showed that the [redacted] would leave little open position through [redacted], thereby taking away the margin necessary to insure the plant was not over-committed.

- By [redacted], it was clear in the market that significant coal-fired generation would be retiring thereby creating excess coal supply.
- [redacted] performance was suggesting its financial fragility. To its credit, AEPSC had supported [redacted] through difficult times. AEPSC gave [redacted] price relief in 2009 and 2010. AEPSC agreed to defer repayment in [redacted]. AEPSC agreed to allow [redacted] to ship tonnage shortfalls [redacted]. At some point, AEPSC needs to consider whether continued support is consistent with the interest of its customers.

Given these findings, EVA recommended the following:

- Any contract buy-down payments to [redacted] not be recoverable through the FAC
- Any proceeds from the [redacted] be applied to the FAC under-recovery whenever the [redacted] or in whatever form it occurs.

In the relevant Opinion and Order (Case No. 10-268-El-EFC et al), the Commission did not prospectively rule on this issue other than stating should there be such payments they be addressed in the audit period in which they occur. To date, the audit reports which quantified these payments have not been addressed.

In 2014, the [redacted] contract was amended [redacted]. The [redacted] amendment provided for a change in the shipment schedule. The [redacted] amendment established pricing for 2014.

2014 Performance

Shipments in 2014 under the [redacted] are summarized in Exhibit 3-28. Shipments were [redacted].

Exhibit 3-28
Shipments Under [redacted], 2014

[redacted]

In [redacted], AEPSC entered into [redacted] with shipments beginning in [redacted]. The contract provided for deliveries of 250,000 tons [redacted] and [redacted] tons each year thereafter. An amended in [redacted] extended the contract to [redacted] to make up for shortfalls dating back to [redacted].

The [redacted] was amended [redacted] in 2014, [redacted] administrative in nature.

2014 Performance

Shipments under this contract in 2014 are shown in Exhibit 3-29. Contract shipments exceeded contract obligations by about [redacted]. With one minor exception, the shipped quality was [redacted].

Exhibit 3-29
Shipments Under [redacted], 2014

[redacted]

[redacted]

AEPGR Company entered into agreement [redacted] in [redacted]. The terms of the agreement are summarized in Exhibit 3-30.

Exhibit 3-30
[redacted]

[redacted]

As noted in the prior audit, this agreement was [redacted]. Rather, according to AEPSC, the Seller approached Buyer about entering into this agreement with AEPGR as well as another agreement with AEPGR. It is highly unusual and not industry practice to enter into an agreement [redacted]. Another unusual aspect of this agreement is the [redacted]. AEPSC's own justification analysis, summarized in Exhibit 3-33, showed a loss compared to market of [redacted]. Market is defined as the [redacted]. It was only in the [redacted] of the contract, did it become net favorable to market.

Exhibit 3-31
AEPSC Analysis of [redacted]

[redacted]

The calculations of the [redacted] and [redacted] costs are shown in Exhibit 3-32.

Exhibit 3-32
Derivation of [redacted] Contract versus Market Price

[redacted]

In the prior audit, EVA recommended that AEPSC's allowed fuel cost recovery in [redacted] be reduced by [redacted] to align costs and benefits of the contract for jurisdictional customers. EVA also recommended a similar adjustment in [redacted]. These recommendations have not yet been decided by the PUCO.

In [redacted], the agreement was assigned to AEPGR. In addition it was amended [redacted] in 2014.[21] [redacted] of the amendments [redacted] provided for changes in sourcing. [redacted] provided for a change in quantity and sourcing as well as an agreement that [redacted] and a [redacted] provided for the [redacted]. In addition on [redacted], AEPGR gave timely notice that it [redacted].

Not included in the amendments was documentation of [redacted] to [redacted] in 2014. It is not clear why [redacted] was not in an amendment or otherwise disclosed to the auditors. The auditors only became aware of the [redacted] when the company representatives were asked about whether the shortfall in [redacted] contract shipments extended into [redacted]. EVA believes this transaction should have been disclosed if not in an amendment then certainly in response to EVA's date request EVA-2014-1-6 which asked for a description of all contract disputes in 2014.[22] Finally, in the cover letter for all data requests EVA requests documents that the auditors "may have failed to ask for ... that would be helpful to" the performance of the audit. This lack of disclosure is a significant concern not only with respect to the [redacted] but it raises questions as to what other information was not provided because of a failure to specifically request it or the Company's decision not to provide.

Shipments under the [redacted] in 2014 are summarized in Exhibit 3-33.

[21] Change Orders [redacted] were never executed.
[22] AEPGR provided a non-response to this DR, stating none of the contracts were in arbitration or litigation. The DR asked more generally about disputes of which this is clearly one.

Exhibit 3-33
Shipments Under [redacted], 2014

[redacted]

With [redacted] exceptions, deliveries [redacted] In addition, the shipments volumes in all months were [redacted] monthly contract tonnage. AEPGR indicated that it closely monitored shipment quality and quantities. The quantify shortfall was due to both parties. In some cases, [redacted] did not have the coal. In other cases, AEPGR could not accept delivery [redacted].

An even bigger problem for AEPGR was language that was included in the standard terms and conditions which provided for [redacted]. This language most likely originated when AEP had purchased Enron's London trading desk.[23] [redacted] In the [redacted] case, since the contract was [redacted], had it been [redacted] AEPGR, AEPGR would have [redacted]. Given the contract price was on average about [redacted], AEPGR would have owed [redacted]

---

[23] Traders want this language because it allows them to use [redacted]. This provision is not appropriate for regulated utilities. The industry standard for regulated utilities is [redacted]

[redacted]. Based upon the actual shipments of [redacted] could have been over [redacted].

AEPGR indicated an awareness of this exposure. As a result, it was careful in its dealings with [redacted] to manage this. Ultimately the parties negotiated a [redacted]. The basis for this [redacted] is provided in Exhibit 3-34. EVA reviewed the [redacted] and concurs that it was reasonable particularly in the context of the contract language.

Exhibit 3-34
Support for [redacted]

[redacted]

That being said, since EVA found the original contract imprudent, it believes that jurisdictional customers should have no obligation for any share of this payment. Further, jurisdictional customers should not be paying the full contract amount for the reasons discussed above and in the prior audit. EVA recommends that in addition to the amount of the [redacted] be deducted from the allowed fuel recovery bringing the total to [redacted] Alternatively, if the PUCO consider the entire agreement imprudent, given AEPGR's [redacted] strategy to purchase coal for [redacted] on a spot basis, the adjustment to fuel recovery should be [redacted].

Transportation Review

Coal is generally offered to AEPSC FOB barge or FOB railcar and it is the responsibility of AEPSC to arrange for transportation.

Barge transportation had been handled exclusively by AEP River Operations, which is a wholly-owned subsidiary of Indiana Michigan Power. For the period beginning [redacted], barging was handled under [redacted] that were negotiated in [redacted]. The [redacted] were not disclosed in the prior audit. A summary of the [redacted] is provided in Exhibit 3-35.

Exhibit 3-35
New Barge Agreements [redacted]

[redacted]

The terms and conditions in [redacted]. With respect to price, [redacted] percent of the price is [redacted]. The balance of the price is adjusted by changes in [redacted] and changes in [redacted].

The basic terms of the barging agreement are not consistent with a typical [redacted]. There is no discussion of scheduling, such as how the parties will keep each other informed as to expected quantities for each quarter or month. The tonnage numbers are odd for two reasons. First, they are very specific which is unusual, [redacted] Second, the volumes for [redacted] did not make sense at the time the agreements were negotiated given the [redacted] burn levels. In [redacted] burned less than [redacted]. If the plant operated at the same level for [redacted] and the [redacted], the barging requirements would be less than [redacted] tons or [redacted] what the commitment was for. In [redacted], [redacted] burned [redacted] tons with most of the coal being delivered by rail. The commitment level for barging is in excess of what the barging requirements could have been expected. Also, the term of the agreements for [redacted] do not reflect [redacted] which was well known at the time. Finally, some standard commercial terms are missing, such as a discussion of [redacted] or [redacted] in the event the [redacted].[24]

AEPGR did not [redacted] for barging as generators typically do. Rather the [redacted]. AEPGR indicated no justification was prepared and AEPGR felt it had appropriately [redacted] for the respective moves. The rates [redacted] but ultimately the purpose of [redacted] is to [redacted]. EVA agrees a [redacted] during a transition period made sense. It is not clear [redacted] would have been needed for this purpose.

AEPGR is a party to multiple rail contracts under which the rail coal is delivered. The contracts are listed in Exhibit 3-36.

[24] AEPGR indicated that the [redacted], rather they were included [redacted]. There was nothing in the agreements indicating this was the case.

Exhibit 3-36
Rail Contracts

[redacted]

The [redacted] plants which receive the majority of their coal by rail are [redacted]. The [redacted] contract for [redacted] was amended [redacted] times during the audit period. [redacted] of the amendments added additional origins. [redacted] amendment extended the term through [redacted][25] and established [redacted]. [redacted] and provided limited sourcing and [redacted] for the additional tonnage. The [redacted] contract was amended to run through [redacted].

Other Fuel Procurement

AEPSC also acquires natural gas for Darby and Waterford. Darby is a peaking plant used primarily during May to October. [redacted]. Waterford is a combined-cycle plant which is dispatched on an economic basis. Gas purchases in 2014 are summarized by month on Exhibit 3-37.

Exhibit 3-37
Natural Gas Purchases

[redacted]

[25] As noted in the discussion on barging, an expiration date [redacted] is appropriate for [redacted].

AEPGR indicated that it purchases its gas monthly for base periods and day to day for other requirements. At this point, AEPGR indicated it sees no reason to enter into term agreements for gas. AEPGR continues to monitor the market in the event factors warrant a change in this position.

AEPGR also purchases fuel oil for flame stabilization and start up. Purchases are relatively low and the agreements are for requirements. A [redacted] for oil was conducted in [redacted] for all of its requirements.

1.

4 ENVIRONMENTAL PERFORMANCE

Environmental Requirements

AEPGR coal plants are subject to air emission regulations through both state and federal programs. Throughout the audit period, these coal plants were required to comply with EPA's Clean Air Interstate Rule (CAIR).[26]

Under the Clean Air Interstate Rule (CAIR), power plants must surrender emission allowances each year to cover their annual emissions of both sulfur dioxide (SO_2) and nitrogen oxides (NOx) as well as surrender additional allowances for their NOx emissions during the five-month ozone season (seasonal NOx). Each plant was initially given an allocation of SO_2, annual NOx and seasonal NOx at no cost under an EPA distribution formula and is permitted to trade allowances (e.g. sell surplus, purchase to meet target) that can be used to meet their compliance requirement.

AEP has a stated policy on 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. AEPGR was a party to the Interim Allowance Agreement (Modification 1) that provided the framework for the allocation of SO_2 purchases and sales among the AEP companies. The Interim Allowance Agreement ended at the end of 2013 and, therefore, was noting effect throughout the audit periods. Seasonal and Annual NOx allowances are managed separately by AEP.

AEP-Ohio and [redacted] are parties to a NOx allowance agreement that was originally issued in 2004 and modified in November 2010. This agreement ended in 2013

AEPGR emissions for 2014 are shown in Exhibit 4-1.

[26] Clean Air Interstate Rule (CAIR) was initially vacated but then reinstated pending an appropriate replacement rule. To replace CAIR, EPA signed the Cross State Air Pollution Rule (CSAPR) on July 6, 2011 which placed limits on state-wide emissions of NO_X and SO_2 beginning in 2012. However, CSAPR was challenged on a number of grounds before being stayed by the court on December 30, 2011, two days prior to its effective date. In a subsequent decision, the US Court of Appeals vacated CSAPR and returned to the CAIR program limitations. EPA appealed this decision to the US Supreme Court and US Supreme Court reversed the US Court of Appeals. CSAPR went into effect January 1, 2015.

Exhibit 4-1
AEPGR Emissions, 2014

Plant	SO2 Tons	Seasonal NOx Tons	Annual NOx Tons
Beckjord 6	2,865	108	358
Cardinal 1	3,456	337	1,014
Conesville	6,048	3,847	10,659
Darby	-	-	23
Gavin	37,271	4,410	10,249
Kammer	15,003	1,063	2,883
Lawrenceburg	8	119	242
Mitchell	2,237	739	1,701
Muskingum River	49,576	1,028	2,673
Sporn 2,4, 5	6,048	415	1,248
Stuart	2,707	762	1,833
Waterford	8	74	149
Zimmer	4,014	1,031	2,623
Total	**129,241**	**13,933**	**35,655**

Source: EVA-2014-1-028

These emission levels are below the plant emission allocations for each year of the audit period because of the large prior investments in post combustion controls. As shown in Exhibit 4-2, AEPGR has ownership interests in 13 coal units with flue gas desulfurization controls to reduce SO_2 emissions (Cardinal #1, Conesville #4-6, Gavin #1-2, Mitchell #1-2, Stuart #1-4 and Zimmer #1). All of the remaining AEPGR coal plants without scrubbers were planned to retire because of the costs associated with complying with the new EPA Mercury and Air Toxics Standard (MATS).

A similar story exists for the current NOx requirements. AEPGR units also over-complied with their seasonal and annual NOx allocations during the audit period because of their large investment in post combustion selective catalytic reduction (SCR) controls. With the pending coal unit retirements, AEPGR will be left with only two units (Conesville #5-6) without the advanced SCR controls. [redacted]

Exhibit 4-2
Status Of Environmental Retrofits On AEPGR Units

		SCR		FGD		
Power Plant Name	Unit	Installation Date	Installation Status	Installation Date	Installation Status	Retired
Cardinal	1	2003	Complete	2008	Complete	
Conesville	3	-	Not Plannned	-	Not Planned	Yes
Conesville	4	2009	Complete	2009	Complete	
Conesville	5	-	Not Plannned	2006 Upgrade	Complete	
Conesville	6	-	Not Plannned	2006 Upgrade	Complete	
Darby	1-6	-	Not Plannned	-	Not Planned	
Gen J M Gavin	1	2001	Complete	1995	Complete	
Gen J M Gavin	2	2001	Complete	1995	Complete	
J.M. Stuart	1	2004	Complete	2008	Complete	
J.M. Stuart	2	2004	Complete	2008	Complete	
J.M. Stuart	3	2004	Complete	2008	Complete	
J.M. Stuart	4	2004	Complete	2008	Complete	
Kammer	1	-	Not Plannned	-	Not Planned	Yes
Kammer	2	-	Not Plannned	-	Not Planned	Yes
Kammer	3	-	Not Plannned	-	Not Planned	Yes
Mitchell	1	2007	Complete	2007	Complete	
Mitchell	2	2007	Complete	2007	Complete	
Muskingum River	1	-	Not Plannned	-	Not Planned	Yes
Muskingum River	2	-	Not Plannned	-	Not Planned	Yes
Muskingum River	3	-	Not Plannned	-	Not Planned	Yes
Muskingum River	4	-	Not Plannned	-	Not Planned	Yes
Muskingum River	5	2005	Complete	-	Not Planned	Yes
Philip Sporn	2	-	Not Plannned	-	Not Planned	Yes
Philip Sporn	4	-	Not Plannned	-	Not Planned	Yes
Philip Sporn	5	-	Not Plannned	-	Not Planned	Yes
Picway	5	-	Not Plannned	-	Not Planned	Yes
W.H. Zimmer	1	2004	Complete	1991	Complete	
Walter C. Beckjord	6	-	Not Plannned	-	Not Planned	Yes
Waterford Energy Facility	1	2002	Complete	-	Not Applicable	
Waterford Energy Facility	2	2002	Complete	-	Not Applicable	
Waterford Energy Facility	3	2002	Complete	-	Not Applicable	

Emission banks for AEPGR were transferred from AEPSC at the lower of cost or market. With the reinstatement of the Cross States Air Pollution Rule (CSAPR) effective January 1, 2015, CSAPR allowances were allocated according to the rule and CAIR allowances were cancelled for 2015 going forward. Title IV SO_2 allowances continue to be required. AEPGR provided information on the status of the Title IV and CAIR NOx allowance banks as of the end of 2014. This information is summarized in Exhibit 4-3. [redacted] No information was provided on the CSAPR banks.

Exhibit 4-3
End of Year AEPGR Emission Allowance Banks

[redacted]

AEPGR reported limited sales and purchases of allowances in 2014. The [redacted]. It is summarized in Exhibit 4-4 and explained in Section 6. Most of the dollars are related to [redacted].

Exhibit 4-4
Allowance Activity During Audit Period (Tons)

[redacted]

Environmental Reagents

The cost of environmental reagents is recovered in the FAC. A schedule of reagent requirements by plant is provided in Exhibit 4-5.

Exhibit 4-5
Reagent Requirements By Plant

	Lime	Limestone	Hydrated Lime	Trona	Urea
Cardinal 1		x	X	X	X
Conesville 4		X	X	X	X
Conesville 5&6	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. AEPGR uses hydrated lime for water treatment with the limestone scrubbers.

The trona is used for SO_3 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 [redacted]. Pricing is based upon the [redacted]. The material is delivered [redacted]

AEPGR has multiple consumable contracts in place. These contracts are summarized in Exhibit 4-6.

Exhibit 4-6
Consumable Contracts

[redacted]

The only activity on these contracts for 2014 deliveries were administrative. AEPGR had to make a spot purchase of limestone in April for Conesville because of ice cover on the lakes prevented LaFarge from resuming their shipments in 2014 and Conesville needed an emergency procurement. AEPGR also made two test purchases: lime slurry for a test at Conesville 4 and 400 tons EnProv Trona for a test at Gavin.

5 POWER PLANT PERFORMANCE

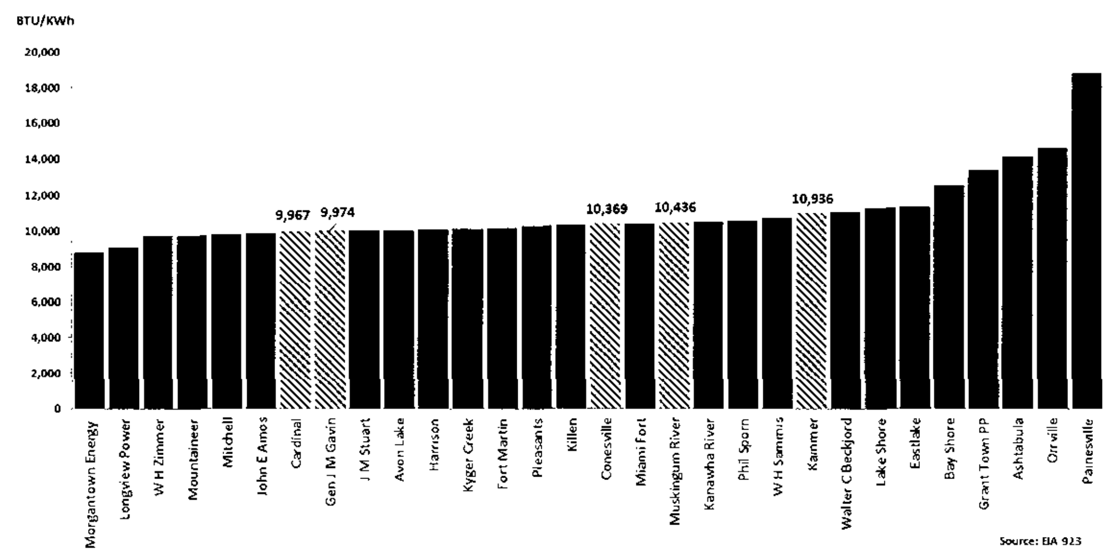
Benchmarking

AEPGR operates five coal-fired power plants. AEPGR'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.

2014 Performance

The heat rates for the AEPGR plants compared to the heat rates for the other coal-fired plants in Ohio and West Virginia is provided for 2014 in Exhibit 5-1.[27] The data used to generate these figures are from the Department of Energy.[28] The AEPGR plants are highlighted. In 2014, Cardinal and Gavin were in the top 10 based upon heat rates. Conesville and Muskingum River were in the middle of the pack. Kammer's heat rate was slightly higher.

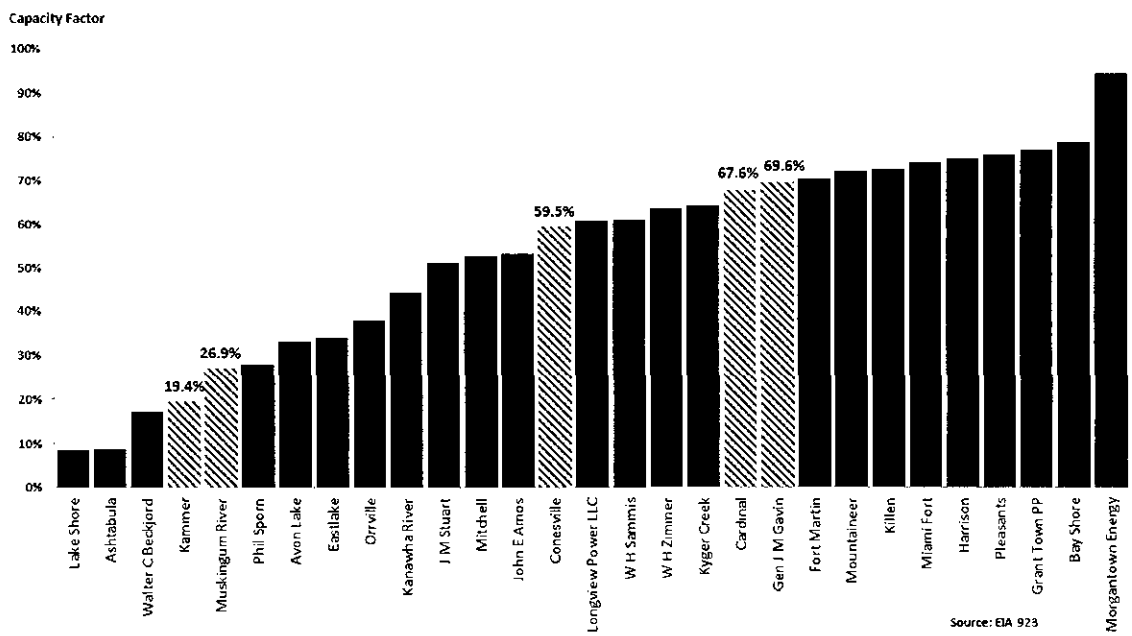
Exhibit 5-1
Coal-Fired Power Plant Heat Rates.[29] 2014



[27] Longview is not included.
[28] All of the data (AEP and other plants) come from 2014 EIA-923 (generation and MMBtu) and EIA-860 (capacity). Picway data are not reported to EIA.
[29] The heat rates are calculated based upon generation and MMBtu consumption from EIA 923.

The capacity factors for the same units for 2014 are provided in Exhibit 5-2. Not surprisingly, the ranks were similar with Gavin and Cardinal having the highest capacity factor of the AEPGR plants. The relative ranking with respect to capacity factor was not as good with nine plants having better capacity factors. Conesville's capacity factor was better in 2014. Muskingum with high cost coal, the extended start-up programs at Kammer and Muskingum , and the Kammer operating strategy adversely affected the capacity factor for these plants.[30]

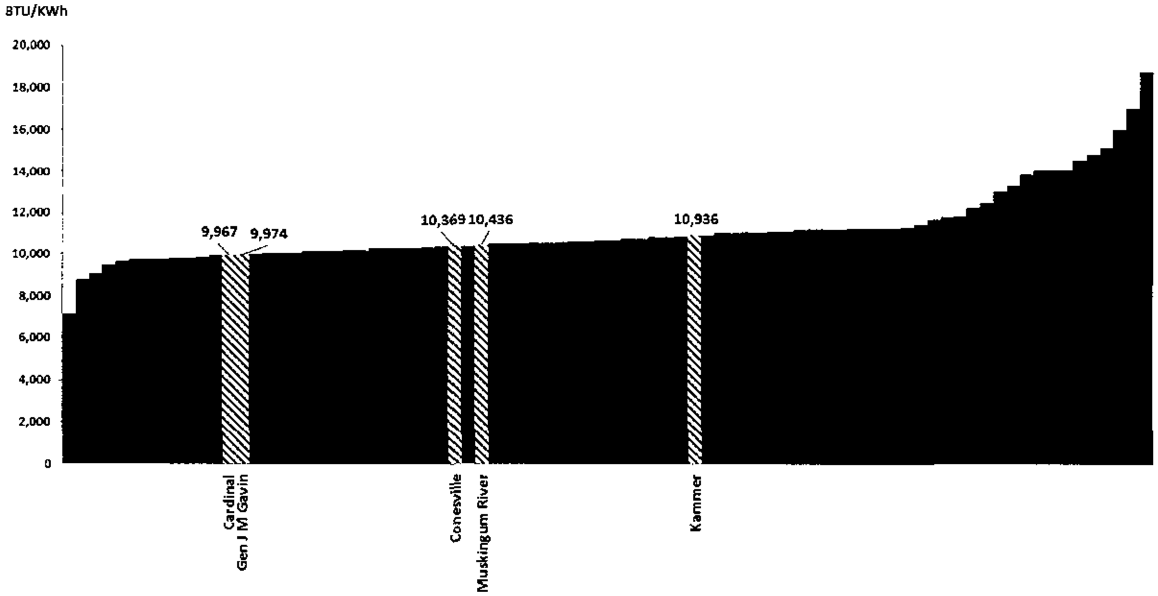
Exhibit 5-2
Coal-Fired Power Plant Capacity Factors 2014



The AEPGR plants are also benchmarked against the coal-fired PJM plants. AEPGR generation will be bid into PJM and therefore its competitive position with respect to the other PJM will determine its dispatch. Exhibit 5-3 provides the heat rates for all PJM coal-fired plants in 2014. AEPGR plants fall in the top 20 percent indicating their relative competitiveness assuming competitively priced fuel.

[30] In 2010, AEP had put a number of units into "extended startup" status for nine non-peak months of the year including Picway 5, Muskingum 4, and Sporn 4. In addition, Sporn 5 was put into permanent extended startup. Kammer started to operate in a "substitute operation" mode, in which only two units are operated at one time.

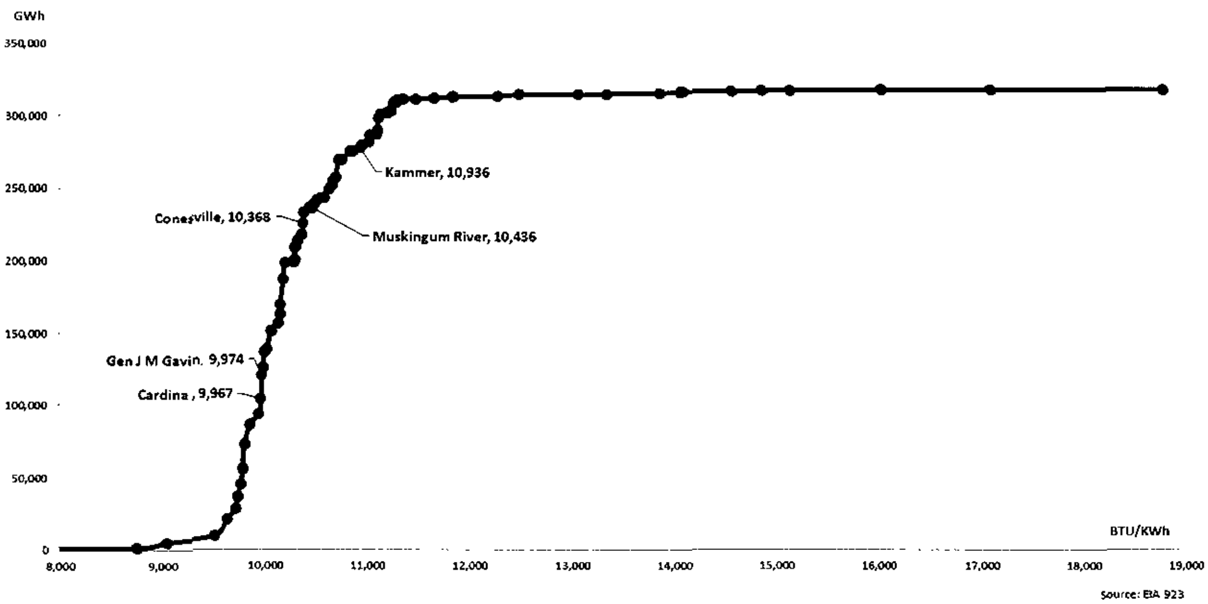
Exhibit 5-3
PJM Coal-Fired Power Plant Heat Rates 2014



The relative heat rate rankings for the AEPGR units with respect to total generation are provided on Exhibit 5-4 for 2014. This graph is a better measure of the competitiveness of the AEPGR units.

In this presentation, the same two units are on the lower part of the curve. The biggest difference between the presentations is with respect to Conesville and Kammer. Within the PJM system, Kammer looks to be a marginal unit although as explained above this also reflects its delayed start-up and operating strategy. Conesville and Muskingum are fairly close to each other.

Exhibit 5-4
PJM Coal-Fired Power Plant Cumulative Generation by Heat Rate, 2014



6 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
- Transition from FAC to the APIR and FCR
- First Quarter 2014
- Second Quarter 2014
- Third Quarter 2014
- Fourth Quarter 2014
- First Quarter 2015
- Second Quarter 2015
- Final APIR and FCR Filing
- Minimum Review Requirements
- 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, APIR and FCR Filings, Supporting Workpapers and Documentation
- [redacted] Generating Station
- [redacted] Demand Charges
- Audit Trail for Reconciling Adjustments
- Renewable Energy Resources
- Carrying Costs on Deferred Fuel Balances
- Active Management
- [redacted] and Related Revenue
- Emission Allowances
- Changes to Fuel, Purchased Power Procurement and Emission Allowance Procurement
- Internal Audits
- AEP River Operations

Certificate Of Accountability Of Independent Auditors

To: Ohio Power Company

We have examined the quarterly FAC, APIR and FCR filings of Ohio Power Company ("OPCo" or "Company") for the year ended December 31, 2014, which support the calculation of the Fuel Adjustment Clause ("FAC") rates for the three month period January through March 2014 and the Auction Phase-In Rider ("APIR") and Fixed Cost Rider ("FCR") rates for the period April through December 2014 and January through May 2015. In addition, we have examined the quarterly Alternative Energy Rider ("AER") filings which support the calculations of the Alternative Energy Rider for the period January through December 2014. We have also examined OPCo's final reconciliation and true-up of the FAC, as well as the FCR and APIR for the period of January through May 2015. 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 OPCo's compliance with specific requirements.

The quarterly FAC, APIR, FCR and AER filings are the responsibility of the Company's management. Our responsibility is to express an opinion as to OPCo's fair determination of the FAC, APIR and FCR rates for January through December 31, 2014 calculated with those quarterly filings, which include the Reconciliation Adjustments for the period July 2013 through December 2014 that were reflected by OPCo through the Company's quarterly FAC and APIR filings, and to express an opinion as to OPCo's fair determination of the Rider AER rates for January through December 2014, that were reflected by OPCo through the Company's quarterly AER Filings.

In our opinion, except for the error corrections and other concerns noted in this report, OPCo has determined, in all material respects, (1) the FAC rates for the three-month period January through March 2014; (2) the APIR and FCR rates for the nine-month period April through December 2014; and (3) the APIR and FCR rates for the five-month period January through May 2015 in accordance with its proposed procedures and its interpretation of what should be includable in the FAC rates.

In our opinion, except for the concerns noted in this report, OPCo has determined, in all material respects, the AER rates for the 12-month period January through December 2014 in accordance with its proposed procedure, and its interpretation of what should be includable in the AER rates.