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REPORT OF THE MANAGEMENT/PERFORMANCE AND FINANCIAL AUDIT OF THE FUEL AND PURCHASED POWER RIDER OF THE DAYTON POWER AND LIGHT COMPANY (14-0117-EL-FAC)

August 21, 2014

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1 EXECUTIVE SUMMARY

The Dayton Power and Light Company (DP&L) is a public utility as defined in Section 4905.02, Revised Code, and, as such, is subject to the jurisdiction of the Public Utilities Commission of Ohio (PUCO). Under an approved stipulation, DP&L's rates were set pursuant to a rate stabilization plan (RSP) from January 1, 2006 through December 31, 2008 (RSP Stipulation). Under the RSP, DP&L's fuel rate was fixed and included in the base retail generation rates.

On October 10, 2008, DP&L filed an application for a standard service offer (SSO) in the form of an electric security plan (ESP), pursuant to Section 4928.143, Revised Code. A stipulation (the ESP Stipulation), approved by the PUCO (the ESP Order), extended the DP&L rate plan through December 31, 2012 (subsequently extended by a year) and allowed DP&L among other things to implement a by-passable fuel recovery rider to recover jurisdictional fuel and purchased power costs consistent with the provisions of Senate Bill 221. DP&L is required to make quarterly filings related to its fuel and purchased power costs and have its costs subject to an annual audit by an independent third-party or PUCO Staff.

A second ESP (ESP2) for DP&L was approved on September 4, 2013 in Case No. 12-426-EL-SSO et al for the period beginning January 1, 2014 and ending May 31, 2017. According to the PUCO website, "(d)uring the term of the ESP, DP&L will conduct an auction for 10 percent of its standard service offer load for the period of Jan. 1, 2014 to Dec. 31, 2014; 40 percent for the period of Jan. 1, 2015 to Dec. 31, 2015; and 70 percent for the period of Jan. 1, 2016 to May 31, 2017. At the end of the ESP, the company is expected to have divested all of its generation assets. DP&L will establish a service stability rider (SSR) in order for it to provide a stable standard service offer as it divests its generation assets during the term of the ESP. The SSR will collect $330 million from Jan. 1, 2014, through Dec. 31, 2016. DP&L will have the option to seek future approval from the PUCO for a five month extension not to exceed $45.8 million."

Several parties filed for rehearing and on March 19, 2014 the PUCO determined that DP&L's phase-in to full competitive pricing for SSO generation requirements should be accelerated. The PUCO based its ruling upon DP&L's February 25, 2014 supplemental filing in a separate proceeding (Case No 13-2420-EL-UNC) that addressed the company's proposal to transfer or sell its generating assets. In that supplemental filing, DP&L indicated that the company and "its indirect parent, The AES Corporation (AES), have recently begun to evaluate the transfer of DP&L's generation assets to an unaffiliated third party through a potential sale. A sale to a third party could occur as early as 2014." The PUCO, therefore, determined that the competitive bid process (CBP) should account for 60 percent of load beginning January 1, 2015 (up from 40 percent); and, 100 percent of load beginning January 1, 2016 (up from 70 percent). Also, the PUCO determined on rehearing that the deadline for the company to divest its generation should be no later than January 1, 2016.

Following this ruling, several parties again filed for reconsideration. DP&L asserted that the acceleration of the CBP would cause the company to lose substantial revenue and would jeopardize its financial integrity. DP&L stated that the PUCO based its decision to accelerate the CBP schedule on the belief that DP&L could transfer its generation assets sooner than previously indicated. DP&L asked that the original CBP schedule and asset divestiture dates be reinstated.

On June 4, 2014, the PUCO issued an order on rehearing that addressed various issues, including the CBP schedule and the divestiture date. The PUCO concluded that the accelerated CBP schedule is not practicable or that the CBP schedule jeopardizes DP&L's financial integrity. With regard to the divestiture date, the PUCO acknowledged that there are "terms and conditions in certain bonds that significantly impede upon [DP&L's] ability to transfer its generation assets to an affiliate before September 1, 2016, and, due to adverse market conditions, DP&L will not have sufficient cash flow to refinance the bonds before 2017. Therefore, the PUCO set a modified deadline of January 1, 2017 for the asset transfer.

With respect to the fuel cost recovery, the new ESP provides for a FUEL Rider through 2014. The FUEL Rider is based upon a least cost stacking methodology for jurisdictional customers consistent with the prior ESP with the exception that the DPLER load is now excluded. With respect to fuel-related Optimization Gains, DP&L did not ask for nor receive a continuation of the Optimization program in the new ESP. With respect to the AER which continues, the PUCO "established that the company's AER will be trued-up quarterly, as opposed to annually, to more accurately align costs with revenues." The PUCO denied the company's proposal to recover costs for the Yankee Solar Generating Facility on a nonbypassable basis, noting the facility should be included in the company's asset divestiture plan but also held that DP&L was not barred from recovering the cost of the past energy resources used to serve SSO load.

DP&L continues to be required to make quarterly filings related to its fuel and purchase power costs and have its costs subject to an annual audit by an independent third-party or PUCO Staff.

The PUCO solicited proposals for the performance of the FUEL Rider and AER audits of the years 2013 and 2014. Energy Ventures Analysis, Inc. (EVA) and its subcontractor, Larkin & Associates PLLC (Larkin) (collectively, the EVA Team) were selected by the PUCO to perform the desired management/performance and financial audits. EVA and Larkin had previously performed the audits of 2010, 2011, and 2012.

A Stipulation and Recommendation (2011 FUEL Rider Stipulation) was entered into by the parties relative to issues raised regarding DP&L's FUEL Rider for the audit period January 1, 2011 through December 31, 2011 on December 5, 2012. The Stipulation was approved by the PUCO by entry on January 23, 2013. No Stipulation and Rider was entered into following the issues raised regarding DP&L's FUEL Rider for the audit period January 1, 2012 through December 31, 2012. A hearing was held December 9-10, 2013. To date, no decision has been issued.

FUEL Rider Background

DP&L's fuel adjustment clause, the FUEL Rider, is the mechanism that is being used to recover DP&L's prudently incurred fuel and purchased power. The FERC accounts included in the FUEL Rider are as follows:

- Accounts 411.8 and 411.9 (Gains and Losses from Disposition of Allowance) – the gains or losses from the sale of allowances.
- Account 421 – Miscellaneous Non-Operating Income.
- Account 426 – the realized loss on purchased power.
- Account 456 – for gains and losses on coal sales and heating oil derivatives.
- Account 501 (Fuel) – the cost of fuel and transportation for generating electricity.
- Account 509 (Allowances) – the cost of emission allowances related to emissions of sulfur dioxide (SO_2) and nitrous oxide (NOx).
- 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 565 – transmission costs associated with certain purchased power. (No fuel-related charges were made from this account in calendar year 2010.)

Audit of the FUEL Rider

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 audit period includes the actual cost for the Rider FAC for the months January 1, 2013 through December 31, 2013. The audits should follow the guidelines in Section L of Appendix D and Section M of Appendix E to former Chapter 4901:1-11, O.A.C.

Audit Approach

EVA and Larkin conducted this audit through a combination of document review, interrogatories, site visits and interviews. EVA and Larkin visited the Killen power plant on June 13, 2014. EVA and/or Larkin conducted interviews with the individuals in the positions listed in Exhibit 1-1 during the week of June 11-12, 2014. DP&L regulatory staff and PUCO Staff also attended most interviews.

Exhibit 1-1. Interviews Conducted

No.	Department	Participants
1	Accounting and Support for Fuel Riders and AER Filings	[redacted]
2	Commercial Operations/Coal Procurement	
3	Commercial Structuring - RECs, Biomass, Biodiesel	
4	Risk Management	
5	Treasury - Counter-Party Risk	
6	Regulatory Operations/Fuel Rider, AER	
7	Commercial Structuring - Forecasting	
8	Generation/CCD/Environmental	
9	Commercial Operations/Coal Procurement	
10	Internal Audit/Physical Coal Inventory	
11	Killen Plant Visit	

Outstanding Management Audit Recommendations

As noted above, the prior audit issues have not been resolved. The outstanding recommendations are as follows:

1. The FUEL Rider should be adjusted to reflect the costs associated with the 2010 imprudent decisions related to DP&L's failure to exercise a competitive supply option and DP&L's purchase of excessive [redacted] contracts, both for 2012 delivery. This includes both the direct costs and the related optimization values in Optimizations 2012-B, 2012-C, 2012-D, and 2012-I. Larkin has estimated the adjustment to be [redacted].
2. The FUEL Rider should be adjusted to delete the optimization values associated with Optimizations 2012-A, 2012-H, 2012-J, and 2012-K. Larkin has estimated this adjustment to be [redacted].
3. DP&L should develop a fuel supply strategy that [redacted].
4. DP&L should develop guidelines for coal sales to affiliate companies.
5. DP&L should review whether it needs [redacted] given the changes to the natural gas market and that this review be available for review by the next management/performance auditor.

EVA asked DP&L to provide a status report on Recommendations #3, #4, and #5. In its response, DP&L correctly noted that the PUCO had not "ruled" on these recommendations and therefore was not required to perform any of the requested studies.

With respect to Recommendation #3, DP&L disputed this finding and chose not to perform any analysis absent a Commission order to do so.

With respect to Recommendation #4, DP&L indicated that neither it nor AES has a Code of Conduct that explicitly addresses affiliate transactions. DP&L noted that FERC rules would require a FERC filing and approval prior to the effectiveness of any purchase or sale of *power* between DP&L and an affiliate." (emphasis added) EVA believes that FERC's requirements with respect to power support EVA's position with respect to fuel. As one of the specific questions DP&L now is required to consider [redacted], the importance of a Code of Conduct applying to affiliate transactions increased.

With respect to Recommendation #5, DP&L conducted a cost benefit analysis of moving from [redacted].

Major Management Audit Findings

1. In 2013, DP&L purchased 6.9 million tons of coal at an average delivered price of $51.13 or $2.19 per MMBtu which is about a 15 percent lower than 2012 prices of $60.05 per ton or $2.55 per MMBtu. The dramatic reduction in costs is due to a number of factors including the fact that total purchases of [redacted], DP&L increased the use of lower quality (lower cost) coals at Killen, and DP&L [redacted].
2. Recovery of Optimization Gains ended in 2012. As a result, the improvement in 2013 fuel costs was even greater than recorded in the Form 923 filings as there were no adders to the prices related to optimization gains.
3. DP&L generation increased by 17 percent overall with DP&L plant-operated generation up by nine percent. The large increase was due to Zimmer and Stuart Unit 3, both of which performed poorly in 2012. Coal accounts for over 99 percent of DP&L generation. About 47 percent of its coal-fired generation comes from DP&L-operated plants.
4. DP&L's coal purchase costs as reported to the Energy Information Administration (EIA) on Form 923 are competitive with other Ohio and nearby utilities for which data are available.
5. The average delivered price of coal to the Killen and Stuart Stations are competitive with the average delivered cost to 11 utility plants which receive coal by barge that are equipped with scrubbers, burn high sulfur coals, and that are proximate to Killen and Stuart.

6. DP&L fuel procurement organization was trimmed during 2013. In addition, the scope of the manager of the fuel's group was expanded to include non-DP&L fuel procurement activities. Fifty percent of his time is now charged to other AES procurement activities.

7. DP&L conducted four RFP's in 2013 generally consistent with its revised guidelines. DP&L considered all coals whether they were consistent with the boxed specifications and evaluated option values. From the January 2013 RFP, DP&L made Q2 and Q3 purchases [redacted] tons. From the March 2013 RFP, DP&L purchased [redacted]. From the April 2013 RFP, DP&L purchased [redacted] tons for each [redacted]. From the November 2013 RFP, DP&L purchased [redacted] suppliers for 2014.

8. DP&L stopped the preparation of its standard recommendations memorandum with the November 2013 RFP. DP&L indicated the change was to standardize the process within AES. The new format does not provide the same level of detail or adequate information about the RFP process.

9. The Credit Risk Management Policy was modified in 2013. With respect to coal, the 35 percent cap on supply by a single producer was eliminated. It was replaced with a fairly complex process which considers [redacted] There are no apparent limits on how much of DP&L's supply can come from a single supplier as the prior policies had done The credit results are not incorporated into the ultimate purchase recommendations other than to say whether the suppliers were approved.

10. The purchases made in 2013 combined with the prior purchases result in a very concentrated supply with the top [redacted] accounting for about [redacted] of 2013 purchases and the top [redacted] accounting for about [redacted].

11. The inventory levels at both Killen and Stuart ended the year at below 30 days of maximum burn.

12. Physical inventories were conducted in 2013 at Killen and Stuart. The differences between book inventory and physical inventory at both Killen and Stuart were within the tolerances and did not require follow-up.

13. In 2013, DP&L finalized four agreements with [redacted] related to the production of Refined Coal at the Stuart Station. The interest in Refined Coal is related to the tax credit under Section 45 of the Internal Revenue Code (Code). In order to qualify for the tax credit, the Refined Coal must be purchased from an unrelated party. The four agreements are [redacted]. None of the net revenues DP&L received related to the Section

45 plant were flowed through the FUEL Rider. Personnel at the Stuart Station are still evaluating whether the use of Refined Coal has an adverse impact on plant operations.

14. DP&L sold coal under one of its contracts to [redacted]. The jurisdictional share of the profit made from this sale flowed through the FUEL Rider.
15. AES initiated a sale process of the DP&L generating assets. None of the fuel procurement personnel are under a program to incent their continued service until the sale process is complete.

Management Audit Recommendations

1. The proceeds DP&L received in 2013 related to the consumption of Refined Coal by jurisdictional customers should flow through the FUEL Rider.
2. The jurisdictional share of proceeds DP&L receives in 2014 related to proceeds from the resale of coal should flow through the FUEL Rider.
3. DP&L should revise its credit policy with regard to coal procurement to restore limits with respect to the share of supply by producer.
4. For all procurements in 2014, DP&L should prepare comprehensive recommendations which incorporate compliance with the credit policy.
5. DP&L should consider whether a program to incent fuel procurement personnel to remain with the utility through the term of the ESP is appropriate given the importance of this function to the operation of the plants.

Financial Audit Findings

1. DP&L's Fuel Rider deferral (i.e., the 2013 undercollection) has been impacted by customer supplier switching that has occurred. Larkin reviewed a schedule provided in response to LA-2013-79 that reflected statistical data for the 2013 review period. This schedule indicated that over the course of 2013, DP&L [redacted] customers across its various billing categories (residential, secondary, etc.), and that DPLER and other suppliers customer bases increased by [redacted], respectively.
2. In preparing its Fuel Rider sales forecasts for its quarterly Fuel Rider filings affecting 2013, DP&L reflected the impact of known customer supplier switching.
3. Pursuant to Additional Commitment B in the Stipulation and Recommendation dated December 5, 2012, DP&L created and used a trend line analysis for forecasting and validating its sales forecasts, including the impact of customer switching. DP&L stated that due to seasonality and other factors, monthly forecasts will vary and as such, a simple trend line analysis will not be reflective of a seasonal quarter
4. DP&L now incorporates customer switching into its forecast by observing the known level of switching at the time the forecast is created then projects incremental switching to be consistent with the rate observed in recent months.

5. DP&L's deferral amounts by account totaled [redacted] as of December 31, 2013.
6. DP&L has reasonable procedures in place to account for and collect plant fuel burn related information.
7. Based on the results of physical inventories, DP&L made adjustments to its coal inventory balances at the Stuart and Killen Stations during 2013.
8. The adjustment related to Stuart increased coal inventory (and reduced Fuel expense) by $62,825 which reflects DP&L ownership share and the adjustment to Killen reduced coal inventory (and increased Fuel expense) by $575,152, which reflected DP&L's ownership share.
9. The coal inventory adjustments at Stuart [redacted] and Killen [redacted] were the subject of a physical inventory overseen by AES's Internal Audit Group. The Internal Audit group recommended that Company management continue with its daily review and analysis of the Coal Movement Verification Process, which identifies outliers [redacted] between vendor scale readings on coal shipments received versus the amounts ordered by each generation station (see additional discussion below). DP&L management agreed with the IA group's recommendation and stated in its Action Plan that DP&L will continue to perform a daily review of coal inventory movement to ensure that any variances are identified, investigated and remedied in a timely manner.
10. Pursuant to the Coal Movement Verification Process, for Killen Station, approximately [redacted] of barges had a deviation of 100 tons or more and such deviations were bidirectional. In the case of Stuart Station, approximately [redacted] of barges had a deviation of 100 tons or more. Nearly all of the coal left in barges at Stuart Station was reclaimed by the station while performing its barge cleaning process.
11. DP&L transferred 3,474 tons of [redacted] coal from Killen to Stuart in March 2013 which resulted in a $3,357 gain for Stuart. This transaction was posted to the general ledger in April 2013. DP&L confirmed that this gain flowed through the Fuel Rider.
12. The joint owners' share of the gains and losses associated with the coal transfers were billed to them, so there was no impact of the joint owners' share of the gains and losses on the Fuel Rider.
13. DP&L is appropriately accounting for the cost of demurrage as part of the transportation cost of delivering coal to the generating plants. For 2013, DP&L had demurrage costs of $[redacted].
14. As described in the response to LA-2013-41, DP&L has taken various actions in 2013 throughout the year in efforts to mitigate demurrage costs.
15. In conforming with Item No. 9 from the Stipulation and Recommendation dated October 5, 2011 from the 2011 review, DP&L prepared explanations for differences between forecast and actual Fuel Rider revenues and between forecast and actual Fuel Rider costs in 2013.
16. Larkin reviewed DP&L's audit trail for Fuel Rider includable costs, focusing on the test month of July 2013 and also selectively verified actual cost contained in DP&L's Reconciliation Adjustments (RAs) to supporting documentation. We conclude that

DP&L has maintained adequate audit trail documentation for 2013 and for its Reconciliation Adjustments.

17. Pursuant to Section J of the Optimization Provisions from the Stipulation and Recommendation dated December 5, 2012, in which DP&L agreed to cease charging back 75% of any fuel optimization transactions to the Fuel Rider, DP&L confirmed that there were no costs related to 2013 Optimizations included in DP&L's Fuel Rider for any months of 2013.

18. DP&L made deferred fuel entries during the months of January and February 2013 to true-up the fuel deferral adjustment for December 2012 which contained a portion for System Optimization. The net effect was a $1,139 increase to the deferred fuel balance.

19. DP&L made adjustments during the months of January, February and March 2013 to true up system optimizations that DP&L had claimed for 2012. These 2012 optimization true-up adjustments that DP&L recorded in 2013 resulted in [redacted] in the deferred fuel balance. The Company stated that the values associated with these true-ups, which occurred in early 2013, were reflected in a schedule that DP&L provided to EVA and Larkin subsequent to the hearing associated with the 2012 review period.

20. Larkin verified that the [redacted] was recorded in 2013 by DP&L for true-ups of optimizations that had been claimed by DP&L in 2012, but the documentation provided by DP&L did not specifically show how the [redacted] related to each of the 2012 optimizations. During a follow-up conference call, DP&L stated that the 2012 optimization true-ups were embedded in a schedule that DP&L had provided after the Commission's hearing concerning the 2012 Fuel Rider, but are not specifically identified.

21. Hutchings Unit 4 was retired on June 1, 2013. In addition, DP&L has no remaining capacity obligation with PJM and per an agreement between DP&L and the U.S. Environmental Protection Agency ("EPA"), the remaining Hutchings units could not be operated on coal after September 30, 2013. The last coal delivery at Hutchings via rail occurred in 2011.

22. DP&L stated that while no final decision has been made as to Refuel or Repower Hutchings Units 3, 5, or 6, it is expected that those units will be deactivated on June 1, 2015.

23. The Company stated that the Hutchings coal inventory of 15,337 tons with a cost of $1,335,495 was not disposed of. However, none of this coal was burned during any month of 2013 nor was any of the related cost at plant shutdown charged to the Fuel Rider.

24. Hutchings related costs included in the Fuel Rider in 2013 totaled $156,390.

25. DP&L uses a year-to-date "calendar" analysis of residential, DPLER and wholesale sales to calculate the allocation factor related to emission allowance sales on a year-to-date basis each month. An allocation schedule is provided by the Accounting Department to calculate the allocation factors in order to determine the jurisdictional share of emission allowance sales.

26. Larkin reviewed a sampling of customer billing information to test whether DP&L had accurately applied the Fuel Rider rates. No exceptions were noted.

27. LA-2013-44 asked the Company to provide the following information: "For purchases of power recorded in July 2013 that are included in the Fuel Rider, please provide the related invoices, and paid cash voucher or cash payment receipt." The Company provided [redacted]. DP&L provided further support for its purchased power costs with a reconciliation schedule for its PJM settlements. From this additional documentation, Larkin was able to tie out the July 2013 power purchases from PJM to the amounts included in the Fuel Rider. Other than some immaterial variances, no exceptions were noted.

28. On February 27, 2014, DP&L purchased 2,500 NOx allowances, including 404 allowances needed to meet the 2013 compliance requirement. The jurisdictional share of the estimated costs of the 404 allowances was flowed through the fuel rider in 2013.

29. On February 18, 2013, DP&L entered into four separate contract agreements with [redacted], including a (1) Refined Coal Sales Agreement; (2) Feedstock Supply Agreement; (3) Lease Agreement; and (4) Site Services Agreement.

[redacted]

31. In a Letter Agreement from [redacted] to DP&L dated August 27, 2013, [redacted] making an investment in the refined coal project which would allow production of refined coal to resume at Stuart.

[redacted]

33. DP&L provided documentation related to the sale of coal to [redacted], as well as the 2013 accruals and accounting analysis reflecting all postings to FERC Account 456099.

34. DP&L stated that the coal sales to [redacted] were not included in the Fuel Rider during 2013.

[1] DP&L stated that the "Fuel Recovery 2010" documents represent the Company's general ledger.

[redacted]DP&L provided a supplemental schedule to LA-2013-2-2, which provided, by month, a breakout of the [redacted] coal sales revenue and monthly lease revenue during 2013[redacted]

36. The application of the wholesale and DPLER allocation factors to the [redacted] resulted in DP&L Fuel Rider revenue of [redacted].

37. DP&L did not have quarterly AER filings for the 2013 review period. Rather, during 2013, DP&L's AER rates for January through July were $0.0006405 per kWh (per Second Revised Sheet No. G26) that was approved in Case No. 10-89-EL-RDR and $0.0017847 per kWh (per Third Revised Sheet No. G26) that was approved in Case No. 13-1200-EL-RDR that became applicable with the first billing unit in August 2013 and continued for the remainder of 2013.

38. For 2013, DP&L reported REC expense of $2,518,684 and compliance administrative expense of $306,705 in DP&L's May 1, 2014 filing in Case No. 14-806-EL-RDR, Schedule 2, for a total expense of $2,825,389. Compared with 2013 AER revenue of $4,812,517, DP&L had an over recovery of $1,987,128.

39. For 2013, DP&L calculated $209,722 AER carrying costs, using a cost of debt of 5.86%, which had been approved by the Commission in Case No. 10-89-EL-RDR. Other than some minor rounding differences in May and November 2013, Larkin's recalculations of DP&L's AER carrying charges for 2013 were without exception.

40. As demonstrated in the above Exhibit 6-7 and in the details provided in DP&L's confidential response to LA-2013-104, DP&L met each of the 2013 Renewable Benchmarks established by Ohio SB 221.

41. DP&L maintains appropriate REC inventories, at weighted average cost, which is updated monthly, for each type of REC.

    (1) Non-Ohio, Non-Solar RECs,

    (2) Non-Ohio Solar RECs,

    (3) Ohio Non-Solar RECs, and

    (4) Ohio Solar RECs.

42. A concern had been identified with respect to DP&L's 2013 renewables administrative compliance cost, which, based on the information provided through July 28, 2014, appeared to be highly disproportional to the respective REC expense for DP&L and DPLER, each of which have similar renewables compliance requirements to meet, which are based on load. However, DP&L's subsequent explanations state that the only month in which costs were allocated was January 2013, and there was only a total of $3,054 in Administrative costs that month of which 41% was allocated to DP&L based on its baseline REC requirements relative to DPLER's. The other costs assigned to DP&L reflected actual hours of work done for DP&L from February through December 2013 when RECs for DP&L were separately acquired.

43. On August 15, 2014, DP&L provided a correction for 2014 renewables administrative cost, which allocates 42 percent of PJM GATS invoices and internal staff costs to

DPLER, based on DPLER's three-year adjusted baseline. This correction, which DP&L stated that it is recording in August 2014, reduces DP&L's AER costs by $14,259 plus $334 of interest for a total reduction to DP&L's AER costs of $14,593.

Financial Audit Recommendations

1. Larkin recommends that the revenues associated with the sales of coal to [redacted] and related lease payments, which totaled [redacted] on a DP&L retail basis, should flow through the Fuel Rider.
2. The correction to DP&L's renewables administration cost described in Finding No. 43, to reduce DP&L's AER includable costs by $14,259 plus $334 of interest, for a total of $14,593, should be made.

Audit Review

A draft of the audit report was provided to the Company for review. The auditors appreciated the Company's efforts and every issue raised by the Company was addressed. The Company in its comments noted that it did not verify every number in the report and reserved its rights regarding any future process with respect to the report. If additional issues concerning the report that have not been identified to date are subsequently raised by the Company, the auditors reserve the opportunity to respond.

Audit Outline

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

- Section 2 DP&L Background
- Section 3 Fuel Procurement Audit
- Section 4 Plant Performance
- Section 5 Financial Audit
- Section 6 AER Audit

2 DP&L BACKGROUND

Overview

Following approvals by the Federal Energy Regulatory Commission ("FERC"), the PUCO, and others, the AES Corporation completed its purchase of DPL Inc., owner of DP&L, in November 2011. In 2012, AES recorded a goodwill impairment charge of approximately $1.82 billion for DPL. AES noted in both its 2012 10-K filing that it had "not realized the anticipated benefits and cost savings of the DPL acquisition, and DPL continues to face business and regulatory challenges."

AES is a global power company which was incorporated in Delaware in 1981. As of the end of 2013, AES owns and/or operates a diversified generation portfolio of approximately 37,150 MW world-wide. As a percentage of installed capacity, coal and natural gas account for 30 and 36 percent and 35 percent, respectively; oil, diesel and petroleum coke comprise five percent. The balance is renewables, primarily hydro, wind and solar..

AES has two integrated utilities in North America, Indianapolis Power and Light (IPL), which it owns through IPALCO Enterprises, Inc. (IPALCO), the parent holding company of IPL and The Dayton Power and Light Company (DP&L), which it owns through DPL Inc. (DPL), the parent company of DP&L. IPL generates, transmits, distributes and sells electricity to approximately 470,000 customers in the city of Indianapolis and neighboring areas within the state of Indiana. DP&L generates, transmits, distributes and sells electricity to more than 500,000 customers in a 6,000 square mile area of West Central Ohio.

DP&L wholly and commonly owns 12 power generating facilities with a total capacity of 3,251 megawatts (2,829 MW of coal and 422 MW of other capacity). Exhibit 2-1 lists the facilities; Exhibit 2-2 displays their locations.

DP&L's coal capacity will decline as DP&L has announced its plans to retire Hutchings and the co-owners of Beckjord 6 have informed PJM of their intention to retire this unit by June 1, 2015. In addition, subject to regulatory approvals, DP&L agreed to sell its 31 percent stake in East Bend to Duke Energy Kentucky, leaving Duke Energy Kentucky the sole owner of this station. The reported sales price for DP&L's 31 percent of the 600 MW unit was $12.4 million plus the assumption of certain liabilities and closing adjustments.

Additionally, as part of an Electric Security Plan (ESP) approved in September 2013, DP&L is required to separate its generation assets by 2017. DP&L has stated the book value of its generating assets as approximately $1.58 billion. As of mid-2014, after marketing these assets, AES has announced that rather than sell the generating assets to an unaffiliated third party, it will instead transfer 2,897 – the majority of the fleet – to an affiliate of DPL by January 1, 2017 in order to comply with the ESP. AES noted in its press release that "(i)n light of the potential recovery of power prices, as well as PJM capacity prices, AES believes that this business has additional value that can be captured by continuing to own and operate these generating assets."

Exhibit 2-1. DP&L Wholly- and Commonly-Owned Power Generation Facilities

Coal Generating Assets

Utility	Plant Name	Units	Location	Ownership %	Capacity Total (MW)	Capacity DP&L Share (MW)	Fuel Type
Dayton P&L	O.H. Hutchings	1-6	Miamisburg, OH	100%	365	365	Coal
Dayton P&L	J.M. Stuart	1-4	Aberdeen, OH	35%	2,308	808	Coal
Dayton P&L	Killen	2	Wrightsville, OH	67%	600	402	Coal
Columbus	Conesville	4	Conesville, OH	17%	780	129	Coal
Duke Energy	East Bend	2	Rabbit Hash, KY	31%	600	186	Coal
Duke Energy Ohio	Miami Fort	7,8	North Bend, OH	36%	1,018	366	Coal
Duke Energy Ohio	W.C. Beckjord	6	New Richmond,	50%	414	207	Coal
Duke Energy Ohio	Zimmer	1	Moscow, OH	28%	1301	366	Coal

Other Fossil-Fueled Generating Assets

Utility	Plant Name	Units	Location	Ownership %	Capacity Total (MW)	Capacity DP&L Share (MW)	Fuel Type
Dayton P&L	O.H.	7	Miamisburg, OH	100%	23	23	NG
Dayton P&L	JM Stuart	1-4	Aberdeen, OH	35%	8.8	3	DFO
Dayton P&L	Killen	1	Manchester, OH	67%	18	12	DFO
Dayton P&L	Frank M Tait	1-3	Moraine, OH	100%	256	256	NG
Dayton P&L	Frank M Tait	1-4	Moraine, OH	100%	10	10	DFO
Dayton P&L	Monument	1-5	Dayton, OH	100%	12	12	DFO
Dayton P&L	Sidney	1-5	Sidney, OH	100%	12	12	DFO
Dayton P&L	Yankee Street	1-7	Centerville, OH	100%	94	94	NG

Source: EIA-860 Data

DP&L belongs to the regional transmission organization PJM Interconnection (PJM) which is part of the Eastern Interconnection grid operating an electric transmission system serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Among the primary purposes of PJM are to dispatch electric generating plants on a lowest cost basis, thereby reducing the electric costs for all members of the pool, to coordinate regional planning to ensure reliability to the region in which it operates, and to operate markets for capacity, energy, demand response products and ancillary services. Exhibit 2-3 provides a map of PJM.

Exhibit 2-2. Location of DP&L Power Generation Facilities[12]

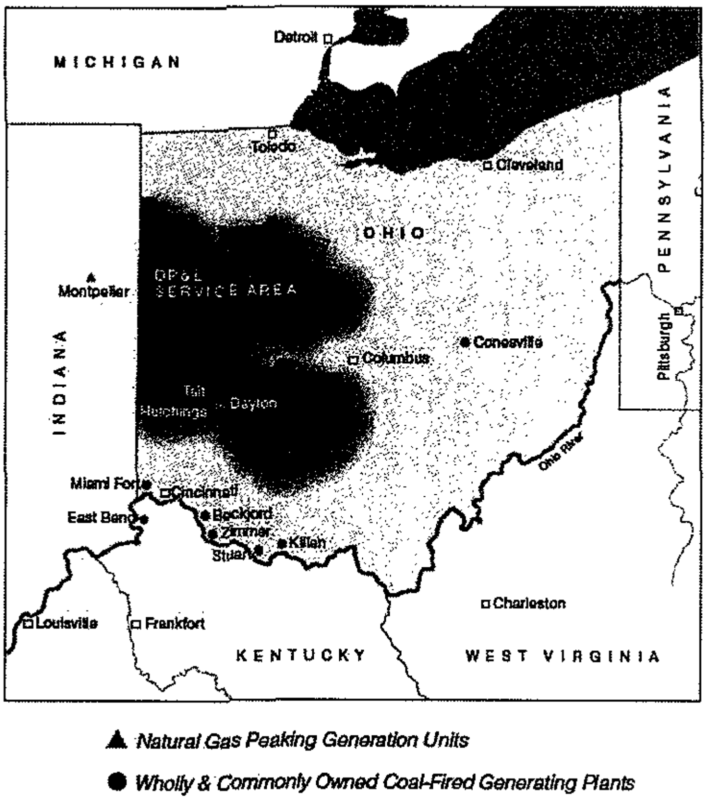
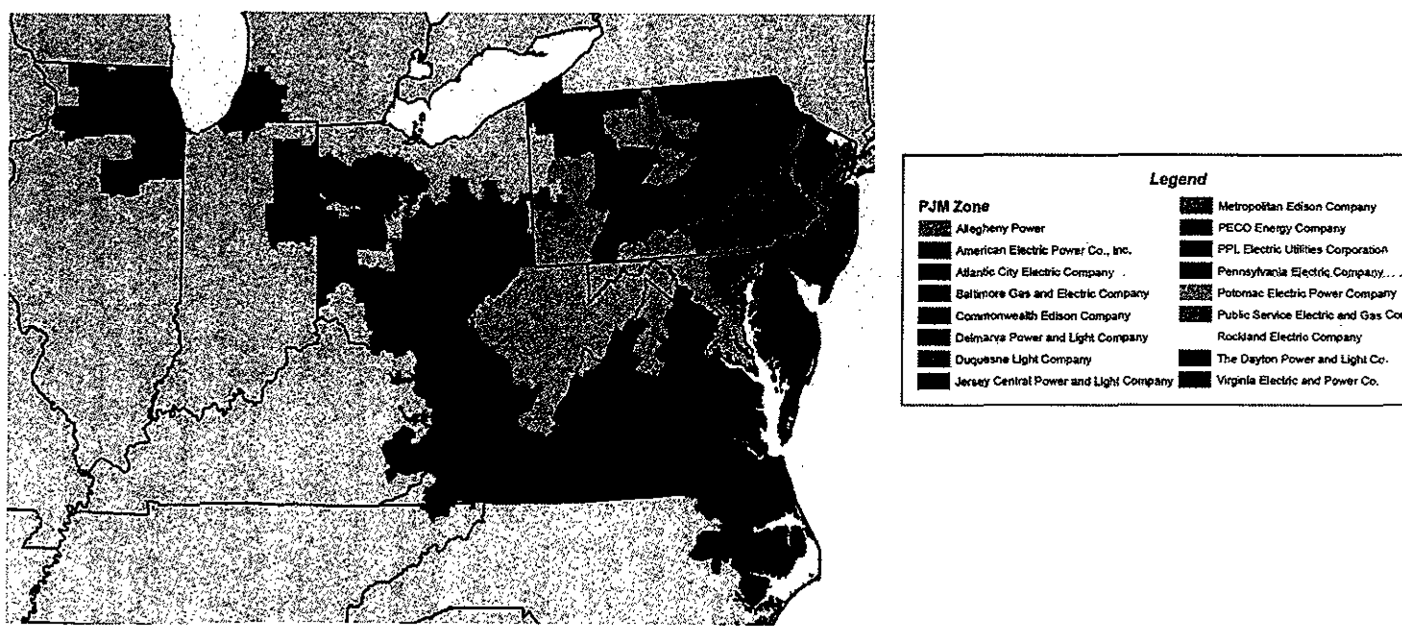


Exhibit 2-3. PJM Interconnection Zones



DP&L's share of generation by plant in 2013 is summarized in Exhibit 2-4. Coal accounts for 99.7 percent of DP&L generation. About 47 percent of its coal-fired generation comes from DP&L-operated plants.

Exhibit 2-4. DP&L 2013 Generation by Plant (GWH)

Plant Name	Coal	Gas	Oil	Total 2013	Total 2012	% Change
Conesville 4	536.2	-	-	536.2	431.5	24%
East Bend	1,165.7	-	-	1,165.7	977.3	19%
Frank M. Tait CT 1-3	-	20.8	-	20.8	53.3	-61%
Frank M. Tait IC	-	-	0.1	0.1	0.1	-6%
J.M. Stuart	4,654.8	-	-	4,654.8	3,964.8	17%
J.M. Stuart IC	-	-	0.1	0.1	0.1	-13%
Killen CT	-	0.2	-	0.2	0.1	125%
Killen	2,281.2	-	-	2,281.2	2,317.7	-2%
Miami Fort 7/8	2,788.4	-	-	2,788.4	2,574.0	8%
Monument IC	-	-	0.1	0.1	0.1	-34%
O.H. Hutchings	-	-	-	-	45.4	-100%
O.H. Hutchings CT	-	-	-	-	0.1	-100%
Sidney IC	-	-	0.1	0.1	0.1	-9%
W.H. Zimmer	2,641.7	-	-	2,641.7	1,358.0	95%
W.C Beckjord 6	726.9	-	-	726.9	922.6	-21%
Yankee CT	-	-	0.8	0.8	0.7	10%
TOTAL	**14,795.0**	**21.0**	**1.2**	**14,817.2**	**12,646.1**	**17%**

Source: Form 1

Generation year on year grew by 17 percent overall but nine percent for DP&L operated plants. The disproportionate increase was due to Zimmer and Stuart both of which had much better years in 2013. DP&L generation from the coal units rose from 12.5 TWh in 2012 to 14.8 TWh in 2013

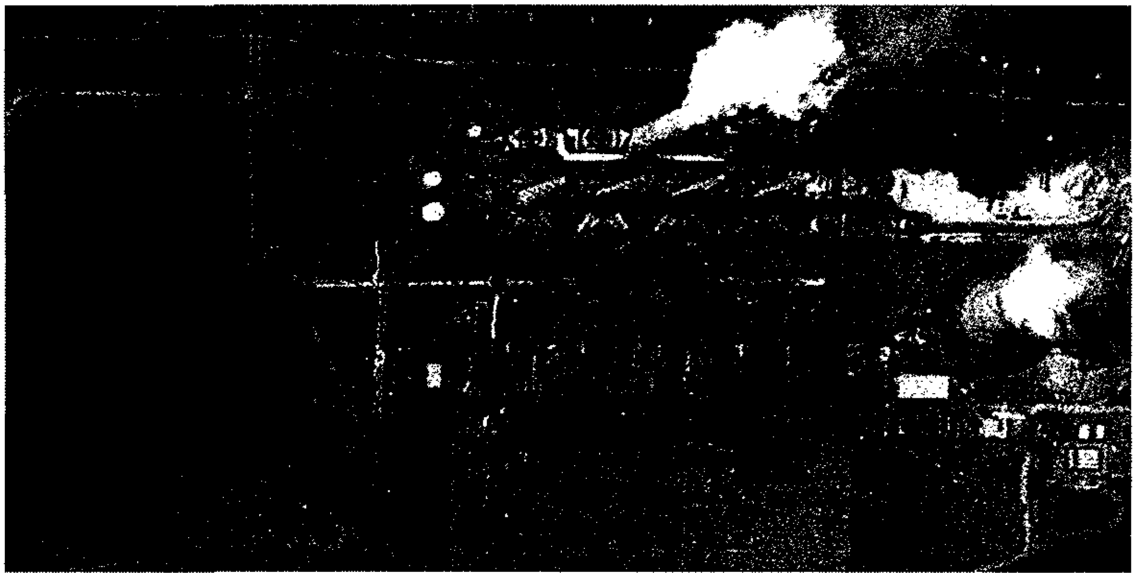
Coal Plants

This section provides background information on the three coal plants operated by DP&L. These are the only coal plants for which DP&L has responsibility for coal procurement.

J. M. Stuart

The Stuart Station consists of four units with a total generating capacity of 2,308 MW. The retrofits of flue gas desulfurization units on all four units were completed in 2008. As can be seen in Exhibit 2-5, the four units now share a common stack. All coal to this station is delivered by barge.

Exhibit 2-5. Aerial View of Stuart Plant



Recent plant operating statistics are provided in Exhibit 2-6. Generation in 2013 was higher than in 2012, although was still below the plants typical historical operation.

Prior to the retrofitting of the scrubbers, the Stuart Station burned low sulfur coal in order to meet its 3.16 pound of SO_2 per MMBtu SIP limit. The coal originated primarily in Central Appalachia. The retrofit of the scrubbers has allowed higher sulfur coal. The scrubbers are designed for coals with an SO_2 content up to 7.22 pounds per MMBtu. However, given the design of the boilers, DP&L did not assume a complete switch to higher sulfur coals because of concerns over slagging and fouling. DP&L has been very successful [redacted]

Exhibit 2-6. J.M. Stuart Operating Statistics

Plant	Units	Location	Ownership %	Total MW	Utility Share
JM Stuart	1-4	Adams, OH	35	2,308	808

	2013	2012	2011	2010	2009
Generation (MWh)	13,314,057	11,509,341	13,739,923	13,461,635	15,323,885
Consumption					
Coal (tons)	5,780,295	5,007,218	6,267,696	5,931,182	6,749,846
Oil (barrels)	59,041	78,048	82,762	76,409	55,259
Capacity Factor	65.9%	56.9%	68.0%	66.6%	75.8%
Heat Rate (Btu/kWh)	9,927	9,906	9,942	9,950	9,800

[redacted]

[redacted]

DP&L entered into multiple agreements with [redacted] during 2013 related to the installation of a Refined Coal plant at Stuart. The interest in Refined Coal is related to the tax credit under Section 45 of the Internal Revenue Code ("Code"). Refined Coal is coal which has been treated in a manner which provides for a 40 percent reduction in emissions of nitrogen oxide (NOx) and at least 20 percent of the emissions of either sulfur dioxide (SO_2) or mercury when the coal is burned as compared to emission when burning the coal without treatment. In order to qualify for the tax credit, the refined coal must be purchased from an unrelated party. As a result, in order for [redacted] to qualify for the tax credit, DP&L [redacted]

Killen

The Killen Station consists of one 600 MW coal-fired power plant. The station was designed for two units, but only one unit (Killen 2) was built. The unit was subject to the original New Source Performance Standard of 1.2 pounds SO_2 per MMBtu which the utility chose to comply with through the use of low sulfur compliance coal. A scrubber was retrofit on the Killen Station in 2007. An aerial view of the plant is provided in Exhibit 2-7. All of the coal consumed by Killen is delivered by barge. Killen has converted almost completely to high sulfur Illinois Basin coal, which sells at a significant discount to the Central Appalachian coal for which it was designed. The single boiler at Killen is substantially larger than the boilers at Stuart. Due to its size, Killen's boiler is capable of accommodating the higher sulfur and lower-fusion Illinois Basin coals with fewer operational challenges than Stuart. After significant testing, the plant will now accept lower quality coals for up to [redacted] of its supply.

Killen retains a small amount low sulfur Central Appalachian coal, which allows the plant a larger degree of flexibility during start-up after maintenance outages. The low sulfur coal has two applications, both related to the scrubber operations. After an extended maintenance outage, the chemical reaction in the jet bubbling reactor (JBR) must be initiated before it reaches a level sufficient to remove SO_2 from high sulfur coal. Killen has a short (one hour) air permit, requiring the plant to meet a lower level of emissions during start-up which is more difficult with high sulfur coal. DP&L believes the plant start-up with the low sulfur coal is a better strategy for enabling the JBR reaction to reach the level needed to effectively scrub the higher sulfur coal to comply with the air permit.

Exhibit 2-7. Aerial View of Killen Plant

The second use of low sulfur coal is when issues arise with the scrubber which may compromise its operation, but are not sufficiently problematic to require complete shut-down. During this time the plant may burn low sulfur coal in order to slow the chemical reaction in the JBR down and make repairs, while the unit remains in service.

Recent plant operating statistics are provided in Exhibit 2-8. The plant has operated below 70 percent capacity factor in each of the last two years. Coal burn historically was about 1.8 million tons per year. In 2012 and 2013, coal burn was at approximately 1.6 million tons.

Exhibit 2-8. Historical Operational Statistics for Killen

Plant	Units	Location	Ownership %	Total MW	Utility Share
Killen	2	Adams, OH	67	600	402

	2013	2012	2011	2010	2009
Generation (MWh)	3,442,966	3,605,364	3,872,867	4,052,724	4,268,653
Consumption					
Coal (tons)	1,578,242	1,610,257	1,740,912	1,811,732	1,864,977
Oil (barrels)	23,286	21,985	18,838	14,926	18,935
Capacity Factor	65.5%	68.6%	73.7%	77.1%	81.2%
Heat Rate (Btu/kWh)	10,214	10,489	10,296	10,296	9,787

O.H. Hutchings

DP&L's smallest station is the Hutchings 365 MW power plant which consists of six small units. An aerial view is provided in Exhibit 2-9. This plant receives coal by truck or rail. The plant has not been retrofitted with scrubbers.

Exhibit 2-9. O.H. Hutchings Plant

Recent plant operating statistics are provided in Exhibit 2-10. Though the plant is scheduled for retirement in June 2015, it is effectively out of service.

Exhibit 2-10. Historical Operating Statistics at O.H. Hutchings

Plant	Unit	Location	Ownership %	Capacity	DPL Share
O.H. Hutchings	1-6	Miamisburg, OH	100%	365	365

	2013	2012	2011	2010	2009	2008
Generation (MWh)	0	45,392	75,542	170,961	91,477	374,407
Consumption (tons,mcf)						
Coal	0	27,745	43,170	94,264	50,479	191,077
Natural Gas	0	31,310	56,641	102,907	77,851	188,147
Capacity Factor	0%	1%	2%	5%	3%	11%
Heat Rate (Btu/kWh)	0	16,006	14,841	14,398	14,526	13,147

According to AES' 2013 first quarter 10-Q filing, "as a result of existing and expected environmental regulations, including MATS, DP&L … notified PJM that it plans to retire the six coal-fired units aggregating approximately 360 MW at its wholly-owned Hutchings Generation Station." DP&L noted that "Hutchings Unit 4 is currently out of service with damage to its turbine and will be retired by June 2013. DP&L plans to retire Hutchings

Units 1, 2, 3, 5 and 6 by June 2015." [redacted]

Asset Sale

AES started a sale process for DP&L generating assets as required in the current ESP. Ultimately when the plants are sold, the responsibility for fuel procurement will go with the plants. If the assets are transferred to a non-regulated affiliate of DP&L as AEP and First Energy have done, the asset holding entity will have the responsibility for fuel procurement. Absent a change in the law or a modification to the ESP, the role for fuel procurement for the DP&L plants is short-lived. EVA understands there are no programs to incent fuel procurement personnel to remain with the utility as long as this function is required. From a regulatory perspective, staff retention through 2014 is extremely important and EVA believes such a program should be considered.

3 FUEL PROCUREMENT AUDIT

Overview

In 2013, DP&L purchased 6.9 million tons of coal at an average delivered price of $51.13 per ton or $2.19; per MMBtu. (Exhibit 3-1) No coal was purchased for Hutchings during the audit period. According to DP&L's classification, 52 percent of purchases were on a spot basis. Average prices declined year over year by about 15 percent. The decline in price is attributed to the change in mix as less than one percent of its coal purchases were from Central Appalachia in 2013 versus 8.3 percent in 2012, increased use of lower quality (lower-priced) coals, and a soft coal market.

Exhibit 3-1. *DP&L Coal Purchases, 2013*

	Contract					Spot					Total				
	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu
Stuart	2,408,050	11,910	2.4	$ 52.49	$ 2.20	2,972,413	11,598	2.8	$ 50.87	$ 2.19	5,380,463	11,738	2.6	$ 51.59	$ 2.20
Killen	899,175	11,665	2.6	$ 51.75	$ 2.22	651,812	11,226	3.2	$ 46.40	$ 2.07	1,550,987	11,481	2.8	$ 49.50	$ 2.16
Total	3,307,225	11,844	2.5	$ 52.29	$ 2.21	3,624,225	11,531	2.8	$ 50.06	$ 2.17	6,931,450	11,680	2.7	$ 51.13	$ 2.19

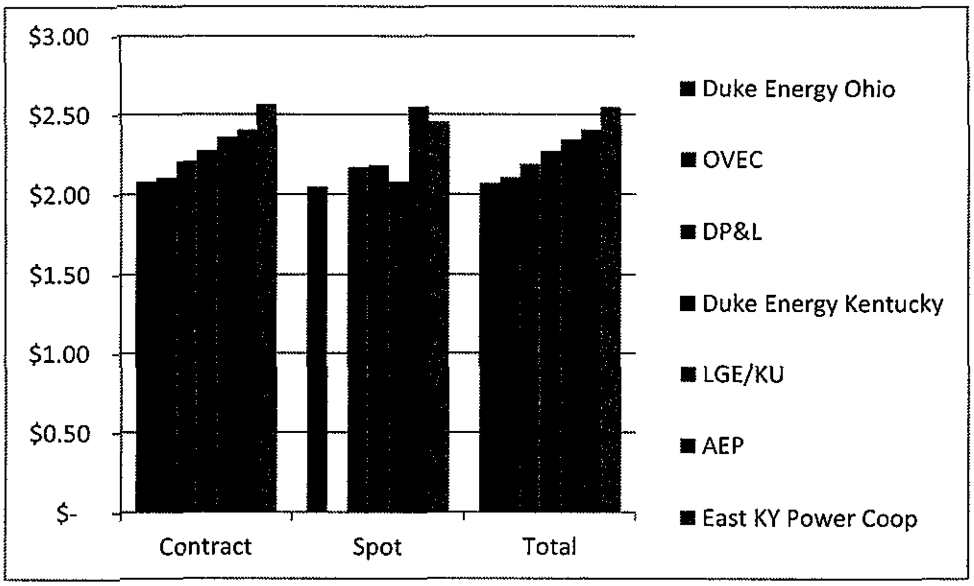
Source: Form 923.

The improvement in fuel costs is actually under-stated as the actual fuels costs in 2013 do not include optimization-related adjustments that had been adders to the fuel price until the program ended in 2012.

DP&L's delivered coal costs on a dollars per MMBtu basis are compared to the other Ohio and nearby utilities for which data are publicly available in Exhibit 3-2. DP&L had the third lowest costs of the seven utilities included in this comparison. Exhibit 3-3 provides some additional details about each utility's purchases. Some of the differences are explained by location, legacy contracts, the average quality of the purchases, and the contract/spot mix.

Another relevant metric for DP&L is how the delivered prices to Stuart and Killen compare to the delivered prices to other plants located nearby on the river which are equipped with scrubbers and/or burn high sulfur coal. Of the 11 plants shown in Exhibit 3-4, Killen and Stuart are the fifth and sixth lowest cost plants. This is a dramatic improvement over 2012 for both with Killen having been the eighth highest cost in 2012 and Stuart the most expensive in 2012. Also provided on the exhibit is the average sulfur content of the purchases at each plant. All of the plants have an average sulfur content of three to four percent and the correlation between sulfur and price is not strong. Other factors influencing average cost are contract vintages, spot/contract mix and plant locations.

Exhibit 3-2. Ohio and Nearby Utility Coal Purchase Costs, 2013 ($/MMBtu)



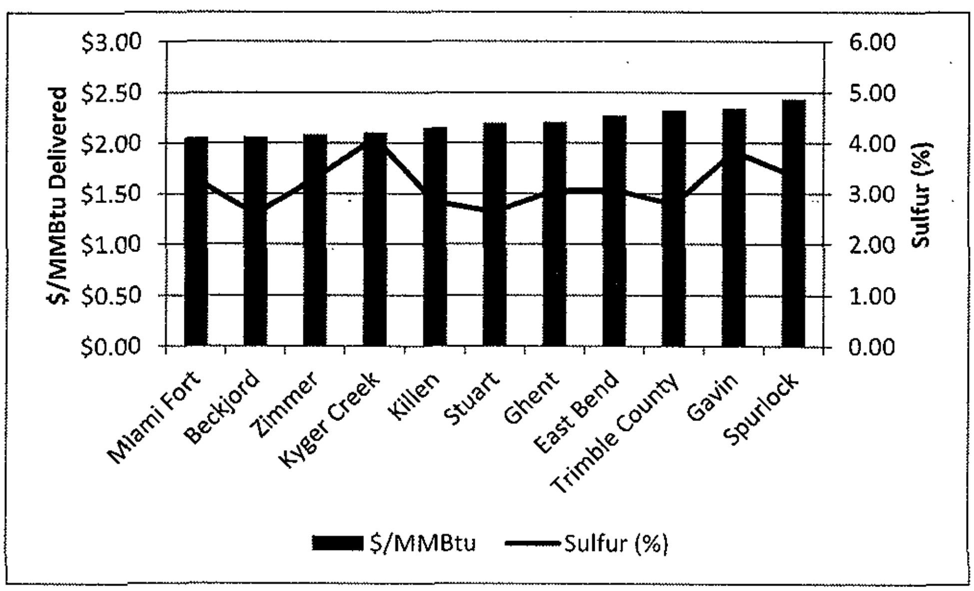
Source: Form 923.

Exhibit 3-3. Coal Purchase Details for Other Ohio and Nearby Utilities, 2013

	Contract					Spot					Total				
	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu
Duke Energy Ohio	5,480,642	12,061	3.4	50.2	$ 2.08	3,245,872	11,517	2.9	47.1	$ 2.05	8,726,514	11,859	3.2	49.0	$ 2.07
OVEC	2,129,595	12,218	4.1	51.4	$ 2.10	-	-	-	-	-	2,129,595	12,218	4.1	51.4	$ 2.10
DP&L	**3,307,225**	**11,844**	**2.5**	**52.3**	**$ 2.21**	**3,624,225**	**11,531**	**2.8**	**50.1**	**$ 2.17**	**6,931,450**	**11,680**	**2.7**	**51.1**	**$ 2.19**
Duke Energy Kentucky	1,657,999	11,376	3.1	51.8	$ 2.27	83,222	12,317	3.1	53.8	$ 2.18	1,741,221	11,421	3.1	51.8	$ 2.27
LGE/KU	14,796,620	11,400	3.1	53.8	$ 2.36	965,367	10,414	1.8	43.3	$ 2.08	15,761,987	11,340	3.1	53.1	$ 2.34
AEP Generation Resources	13,132,170	12,255	3.4	59.0	$ 2.41	149,180	12,063	2.1	61.6	$ 2.55	13,281,350	12,253	3.4	59.0	$ 2.41
East Kentucky Power Coop	3,812,900	11,374	3.2	58.4	$ 2.57	749,704	11,410	2.6	56.1	$ 2.46	4,562,604	11,380	3.1	58.0	$ 2.55

Source: Form 923.

Exhibit 3-4. Delivered Prices to Proximate River Plants, 2013



Background on DP&L's Coal Supply

The retrofitting of scrubbers on Killen and Stuart continues to dramatically change the type of coal purchased by the utility. In 2007, DP&L purchased almost exclusively Central Appalachia coal. In 2013, less than one percent of purchases originated in Central Appalachia. DP&L indicated it maintains a small stockpile of Central Appalachian coal at Killen for use in bringing unit on line after extended outages.

The current coal specifications which are contained in DP&L's standard operating procedure (SOP) for coal procurement are shown in Exhibit 3-5 for Killen and Stuart and Exhibit 3-6 for Hutchings. The specifications, which DP&L sometimes refers to as its boxed specifications, were not revised in 2013. DP&L indicated it no longer restricts bids to these limits.

Exhibit 3-5. Killen and Stuart Coal Specifications

[redacted]

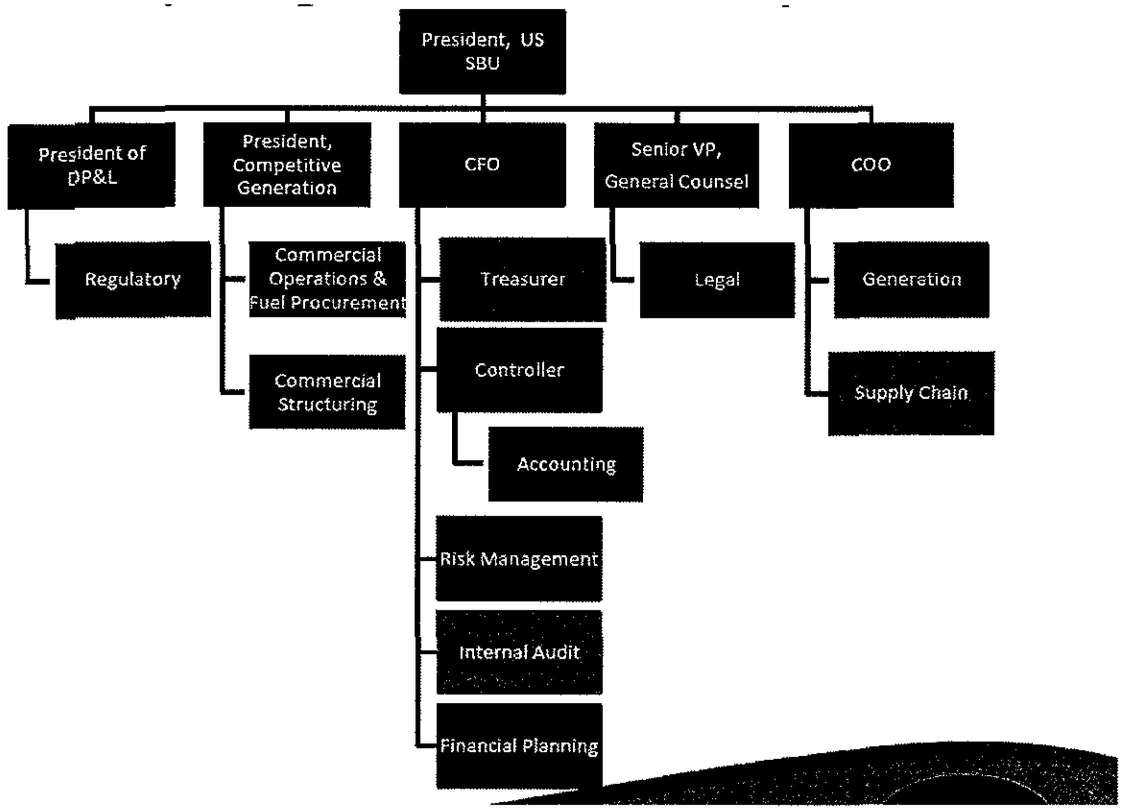
Exhibit 3-6. Hutchings Coal Specifications

[redacted]

Management and Organization

There were a number of organizational changes within DP&L during 2013 as a result of AES incorporating DP&L into its U.S. Strategic Business Unit. As a result, some of the changes related to the transfer of certain functions to Indianapolis. In addition, AES centralized U.S. coal procurement (excluding Indianapolis Power and Light (IPL) procurement) in Dayton. The current SBU organization is shown in Exhibit 3-7.

Exhibit 3-7. U.S. Strategic Business Unit Organization Chart



The organization of the fuel procurement team is provided in Exhibit 3-8. The fuel procurement team is responsible for procurement of commodities and transportation services for the fossil fuel generating stations operated by the Company. The functions performed by this group encompass the following:

- planning and budgeting functions,
- solicitation and evaluation of proposals for fuel and transportation contracts,
- selection and qualification of suppliers and shippers,
- contract negotiation,
- administration and enforcement, and
- operations support.

Exhibit 3-8. Fuel Procurement Team

[redacted]

This team has a stated goal of creating value for DP&L's customers and shareholders by contracting and delivering commodities that are compatible with the company's equipment and achieving the reliability of supply at the most economical value per megawatt hour generated.

DP&L personnel are now responsible for the procurement of fuel for other AES North American assets excluding IPL.

Policies and Procedures

DP&L has documented its fuel procurement policies and procedures in what it referred to as its Standard Operating Procedures or SOP's. There are seven separate SOP's related to fuel. These SOP's, listed below, are very detailed.

- Coal and Limestone Procurement
- Coal, Limestone, Fuel Oil, Gypsum Scheduling
- Coal Quality Control
- Coal Supply Chain Disruption
- Coal Inventory
- Fuel Oil Inventory and Quality Control

- Fuel Consumption Estimate and Position Management

Coal and Limestone Procurement SOP

DP&L revised its Coal and Limestone Procurement SOP most recently in January 2013. In May 2013, DP&L changed its credit policy with respect to coal suppliers. Before the change, there was a 35 percent cap on how much coal an individual company could supply. There is now a fairly complicated evaluation process to determine what amount (tons and percent) of coal an individual party can supply based upon their qualified production not the share of supply purchased by DP&L. The revision appears to have been motivated by DP&L's desire to purchase tons for each of 2014 and 2015 following the April 2013 RFP. The April 30th credit review notes (emphasis added):

[redacted]

DP&L elected to purchase one million tons per year which increased [redacted] supply to [redacted] in 2014 [redacted] in 2015 as shown in Exhibit 3-9.

Exhibit 3-9. [redacted] Share of Total Purchases

[redacted]

As noted above, the new policy focuses on the share of a supplier's qualified production it can ship not on the concentration of suppliers with respect to DP&L's purchases. While a secondary concern may be being too large a customer for a single supplier, the primary risk concern is being over–reliant on a single producer. It is industry standard risk management to have a diversified supplier base where possible. This revision which appears to have been motivated by a desire not to be in violation of its own credit policy does not appear to have any analytical justification.

EVA has several specific comments related to the credit analysis as well:

- The credit review limits its scope to the Illinois Basin. DP&L has regularly purchased coal from Northern Appalachia and based upon the RFP [redacted].

- The credit methodology does not address traders which have and are likely to continue to be sources of supply. In 2013, DP&L purchased Illinois Basin coals through [redacted].
- The credit analysis was incorrectly applied for [redacted] credit rating from S&P.[2] No credit rating for [redacted]. Had the [redacted] credit rating been considered, the tonnage that could be purchased from [redacted] would have been lower.

Despite the importance of the risk evaluation and the requirement that the Credit Manager or Risk Management Committee must approve each procurement (per the Risk Management Policy), there is no mention of the credit/risk evaluation in the recommendation memorandum.

DP&L issued four formal coal RFPs in 2013.[3] In addition to the four coal RFPs, DP&L completed 10 distress coal purchases and three spot purchases. All of the distress purchases were with [redacted][4] coal for Killen. As shown in Exhibit 3-10, the purchases were for single barges and at prices that are at a discount to the market.

Exhibit 3-10. Distress Coal Purchases in 2013

[redacted]

All of the spot purchases were with [redacted] following a September 12, 2014 email and broker solicitation. DP&L indicated it was soliciting the market in part to [redacted]. DP&L indicated it was not obligated through either prior Stipulations or its Standard Operating Procedures to conduct a formal solicitation because the requirement was for the following calendar quarter. DP&L informed the various parties it contacted about its potential need for [redacted]

[2] SNL Report, June 3, 2013 "S&P affirmed [redacted] corporate credit rating".
[3] DP&L produced results from three RFP's conducted in 2014. They have not been reviewed as part of this audit as they were not performed during the audit period.
[4] This coal has been [redacted].

Exhibit 3-11. September 2014 Spot Coal Purchases

PO	Supplier	Tons	Volume Opton	Btu/lb	#SO2/ MMBtu	Plant	$/Ton Delivery Pt	$/MMBtu Del'd	SO2 Penalty ($/Ton)
[redacted]									

Following a review of DP&L's RFP practices, each of the four RFP's is reviewed below.

2013 RFP Practices

DP&L's RFP process generally remained the same in 2013. With respect to the amount of coal to purchase, DP&L ties purchases to [redacted]. DP&L uses its [redacted].

A complete RFP package is sent to a large list of prospective suppliers. RFP announcements are also sent to the coal periodicals.

The RFP package contains a description of the procurement, the bid form, and a draft contract for the potential suppliers to comment upon.

Coals are evaluated using the [redacted].

As part of each procurement, DP&L historically prepared a procurement summary. Starting with the November 2013 procurement, DP&L modified the procurement summary to be more in line with other AES procurement. The procurement summary (which is intended to replace the recommendation) consists of two pages and a new form. The two pages are mostly boiler plate information about [redacted] along with a summary of the purchases. The new form seeks responses to the following questions.

[redacted]

[redacted]

- [redacted]

While the questions if answered thoroughly are not bad, most of the [redacted]"

EVA does not find this form to be particularly suitable to utility procurement efforts given the broad nature of most of the questions and the limited responses provided. This may be acceptable to AES after 2014 until the plants are sold but for the duration of the ESP, EVA recommends a more thorough package that contains at a minimum a summary of the RFP (what was solicited), a summary of the bids received and a summary of DP&L's evaluation (both fuel and credit), and a review of the implications of each award on each supplier's position with respect to overall DP&L requirements.

January 11, 2013

DP&L issued a RFP for up to 250,000 tons per quarter for the second, third, and fourth quarters of 2014 [redacted]

[redacted]

Exhibit 3-12. Contracts Resulting from January 11, 2013 RFP

PO	Supplier	Tons	Volume Opton	Btu/lb	#SO2/ MMBtu	Plant	$/Ton Delivery Pt	$/MMBtu Del'd	SO2 Penalty ($/Ton)
[redacted]									

The offered [redacted], was assigned to Killen.

March 26, 2013

DP&L issued a RFP for up to 250,000 for the third and fourth quarters of 2013 [redacted] The resulting contracts from the RFP are summarized in Exhibit 3-13.

Exhibit 3-13. Contracts Resulting from March 26, 2013 RFP

PO	Supplier	Tons	Volume Opton	Btu/lb	#SO2/ MMBtu	Plant	$/Ton Delivery Pt	$/MMBtu Del'd	SO2 Penalty ($/Ton)
[redacted]									

The lower quality [redacted].

April 9, 2013

DP&L issued an RFP for 2014 and 2015 based [redacted]. The RFP requested bids of up to 1.0 million tons per year.

[redacted]

[redacted]

Exhibit 3-14. Contracts Resulting from April 9, 2013 RFP

PO	Supplier	Year	Killen	Stuart	Volume Opton	Btu/lb	#SO2/ MMBtu	$/Ton Delivery Pt	$/MMBtu Del'd	SO2 Penalty ($/Ton)
[redacted]										

As noted above, EVA saw no consideration of supplier concentration in DP&L's analysis.

November 15, 2013

DP&L issued a RFP for its open coal requirement for first quarter 2014. The RFP indicated that offers for the remaining three quarters of 2014 would also be considered. [redacted].

The traditional recommendation memorandum was not provided for this RFP. As discussed above, DP&L substituted a different format beginning with this RFP. EVA found the replacement to be inadequate. Again, there was no discussion of supplier concentration with these awards.

Exhibit 3-15. Contracts Resulting from November 15, 2013 RFP

PO	Supplier	Quarter	Tons	Volume Opton	Btu/lb	#SO2/ MMBtu	Plant	$/Ton Delivery Pt	$/MMBtu Del'd	SO2 Penalty ($/Ton)
[redacted]										

Coal Inventory SOP

The Coal Inventory SOP explains the responsibilities for inventory management, the basis for the establishment of inventory minimums, the inventory minimums, and the tons constituting the base inventory levels. DP&L has established a "normal minimum" [redacted] at each station. The days are based upon the operating inventory (i.e., the inventory on the ground and in transit exclusive of the base) divided by the full burn rate. DP&L does not include a target inventory level for each station in its SOP.

An inventory of coal is maintained to manage fluctuations in fuel consumption and delivery. Common causes of fluctuations in inventory are:

- Seasonal Variation in burn
- Planned/Unplanned maintenance
- Delivery schedule based on seasonal and supplier variation
- Lock and unloader outages
- Overall supply conditions in the market

Two groups oversee inventory decisions; one group establishes inventory goals while the other approves them. The membership of each group is as follows:

Establish Inventory Goals

- Managing Dir., Commercial Operations
- Plant Mangers
- CD/CCD co-owners (if applicable)

Approve Inventory Goal

- Vice President, Commercial Operations
- Sr. Vice President of Generation & Marketing

Stuart Coal Inventory

Stuart is a base-load plant that historically has run at high capacity factors throughout the year. In 2011, DP&L indicated that it believes the minimum inventory may be too little for Stuart given its size and the time required to replenish a depleted inventory given the longer haul from the Illinois Basin. The minimum inventory was not changed.

Inventory performance (as measured by end-of-month inventory) since December 2009 is provided on Exhibit 3-16. [redacted]

Exhibit 3-16. Monthly Coal Inventory for J.M. Stuart (DP&L Share)

[redacted]

Stuart's inventory days based upon maximum burn are displayed in Exhibit 3-17. [redacted].

Exhibit 3-17. Stuart Days of Inventory Based on Maximum Burn

[redacted]

Stuart's days of inventory compared to actual and normal stockpile days of Illinois Basin coal are shown in Exhibit 3-18. [redacted]

Exhibit 3-18. Days of Inventory Versus Normal Inventory

[redacted]

Killen Coal Inventory

Killen, like Stuart, is a base-load plant that historically runs at very high capacity factors. Killen unlike Stuart, has the ability to cycle, the burn forecasts for it are more sensitive to slight changes in the market.

Inventory performance in 2013 is displayed on Exhibit 3-19. DP&L drew down the Killen inventory at Killen over the last nine months of the year. [redacted]

[redacted]

[redacted]

Exhibit 3-19. Monthly Coal Inventory for Killen (DP&L Share)

[redacted]

Exhibit 3-20. Killen Days of Burn in Inventory Based on Maximum Burn

[redacted]

Hutchings Coal Inventory

DP&L operates Hutchings as a seasonal plant running more during peak winter and summer months. Hutchings was not operated in 2013.

Physical Inventory Adjustments

DP&L's procedures are documented in DP&L Business Practice Generation – 001 Coal Pile Inventory. There is also a procedure related to Internal Audit's role in the physical inventory process. (DP&L Business Practice 741) Neither procedure establishes a threshold amount which would trigger an investigation of the results. Per the 2010 FUEL Rider Stipulation, DP&L established thresholds that would trigger an investigation. The thresholds are eight percent of book and two percent of burn with a minimum of 5,000 tons.

The results from the physical inventory surveys of Stuart and Killen conducted in 2013 are summarized in Exhibit 3-21. Due to the deactivation of the Hutchings units and the de minimus coal on site, no physical survey of Hutchings was conducted in 2013.

Exhibit 3-21. Physical Inventory Results, 2013

[redacted]

The results from both surveys did not trigger any requirements for investigation.

Coal Procurement

In 2013, DP&L primarily bought high sulfur coal on both a contract and spot basis. Small amounts of low sulfur coal on a spot basis to meet its requirements.

Master Agreements

DP&L uses Master Agreements as the primary contractual document with suppliers. While the content of the Master Agreements vary somewhat between parties, the basic components of the Master Agreements are listed in Exhibit 3-22. As provided for in the Master Agreement, the details of each transaction are then documented in a Confirmation. The Confirmation also contains any deviations to the Master that apply for the particular transaction. The Master Agreements appear to work well for DP&L by significantly reducing the time and resources required to negotiate each purchase agreement.

Long-Term Contracts

As noted above, it is DP&L's practice to enter into master agreements with counter-parties and then use Confirmations for specific transactions. In 2013, DP&L was a party [redacted]. The confirmations are listed in Exhibit 3-23 with the contract identification and the base tonnage obligations in 2013 through

2018.[5] Each of the confirmations, along with contract performance, is reviewed below. Also reviewed is status of DP&L's bankruptcy claim related to the Patriot contract.

Exhibit 3-22. Components of the Master Agreements

Article	Sections
Transactions	Procedures
	Confirmations
	Representations
Term	Term and Survival Provisions
	Termination due to Operational Issues
Obligations	*Obligations for Purchase and Sale of Coal*
	Resale of Coal
	Scheduling
	Delivery
	Title and Indemnity
	Substitute Coal Sources
	Substitute Coal for Synfuel
	Taxes and Other Liabilities
Specifications	Specifications
	Unit Train or Truck Weighing
	Barge Weights
	Sampling and Analysis
	Representative Presence: Inspection
Quality Adjustments and Rejection Rights	Quality Adjustments
	Buyer's Rejection Rights
	Buyer's Suspension Rights
Settlement; Security	Billing and Payment
	Netting and Setoff
	Audit
	Reasonable Grounds for Insecurity
	Adequate Assurances
Force Majeure	Force Majeure
	Force Majeure: Definition
	Pro Rata Reductions
	Termination Rights
	Settlements and Capital Expenditures
Events of Default, Remedies, and	Events of Default
Limitations of Liability	Early Termination
	Early Termination Payment
	Remedies
	Damages Stipulation
	Expenses
	Limitation of Liability
Arbitration	
Miscellaneous	Successors and Assigns: Assignment
	Warranties
	Notices
	Confidentiality
	Governing Law
	Entire Agreement; Amendments; Interpretation
	Counterparts; Serverability; Survival
	Non-Waiver; Duty to Mitigate; Not Partnership or Third-Party Beneficiaries
	Administrator
	Definititions
Form of Transaction Confirmation	

[5] The subsequent commitments DP&L made in 2014 are not included or reviewed.

Exhibit 3-23. DP&L Contracts

[redacted]

As of the end of the audit period, DP&L had commitments for [redacted].

This contract position is much improved over prior years and reduces exposure to the short-term market which had been a primary concern in prior audits.

Alliance

In 2013, DP&L received coal under [redacted] with Alliance Coal[6]. [redacted] The basic terms [redacted] are provided in Exhibit 3-24.

Exhibit 3-24. Alliance Coal Contracts

[redacted]

Exhibit 3-25. Shipments under the Alliance Agreements by Purchase Order, 2013

[redacted]

6 [redacted].

Quality of shipments under the Alliance [redacted]

Exhibit 3-26. Quality of Shipments under Alliance Agreement 543011

[redacted]

*Shaded areas indicate non-compliance with Monthly Guarantees.

Quality of shipments under the Alliance [redacted]

Exhibit 3-27. Quality of Shipments under Alliance Agreement 543014

[redacted]

Exhibit 3-28. Quality of Shipments under Alliance Agreement 543015

[redacted]

DP&L entered into [redacted]

Exhibit 3-29. [redacted] Contracts with Alliance Coal [redacted]

[redacted]

Alpha Natural Resources

Since DP&L retrofitted its plants with scrubbers [redacted]

[redacted]

Exhibit 3-30. Alpha Coal Contract

[redacted]

Tonnage shipped under the Alpha Agreement 511014 is summarized in Exhibit 3-31.

Quality of shipments under the Alpha agreement is summarized in Exhibits 3-32. [redacted]

Exhibit 3-31. 2013 Shipments under the Alpha Agreement 511014

[redacted]

Exhibit 3-32. Quality of Shipments under Alpha Agreement 511014[7]

[redacted]

[redacted] The resulting contract is summarized in Exhibit 3-33.

[7] DP&L may be misreporting the quality of the [redacted] in the months of March through June.

Exhibit 3-33. 2013 Contract with Alpha for 2014 Delivery

[redacted]

American Coal

In 2013, DP&L received coal under four contracts with American Coal. The basic provisions of these contracts are summarized in Exhibit 3-34. DP&L had amended [redacted]

Exhibit 3-34. Contracts with American Coal

[redacted]

Tonnage shipped by contract and plant under the American Coal agreements are provided in Exhibit 3-35.

Exhibit 3-35. Shipments by American Coal by Contract, 2013

[redacted]

Quality of shipments under the American Coal agreement 501019 is summarized in Exhibits 3-36. [redacted]

Exhibit 3-36. Quality of Shipments under the American Coal Contract 501019

[redacted]

Quality of shipments under the American Coal agreement 501020 is summarized in Exhibits 3-37. As with [redacted]

Exhibit 3-37. Quality of Shipments under the American Coal Contract 501020

[redacted]

Quality of shipments under the American Coal agreements 501021 and 501022 is summarized in Exhibits 3-38. In both cases, there were shipments only in the month of January.

Exhibit 3-38. Quality of Shipments under the American Coal Contracts 501021 and 501022

[redacted]

In 2013, DP&L entered into [redacted] The basic terms of the agreement are summarized in Exhibit 3-39.

Exhibit 3-39. 2013 Contract with American Coal for 2014 and 2015 Delivery

[redacted]

[redacted]

In February 2013, DP&L entered into four agreements with [redacted] that collectively provide the basis for the installation of a Refined Coal facility at Stuart. The interest in refined coal is related to the tax credit parties can receive for Refined Coal under Section 45 of the Internal Revenue Code ("Code"). Refined Coal is coal which has been treated in a manner which provides for a 20 percent reduction in emissions of nitrogen oxide (NOx) and 40 percent reduction in the emissions of either sulfur dioxide (SO_2) or mercury. In order to qualify for the tax credit, the refined coal must be purchased from an unrelated party. As a result, in order to qualify for the tax credit, [redacted].

The four agreements are the Feedstock Supply Agreement, the Refined Coal Sales Agreement, Lease Agreement, and Site Services Agreement.

[redacted]

DP&L did not flow any of the revenue received from [redacted] through the FUEL Rider. EVA believes that jurisdictional customers are due their share of the proceeds. The only reason a Section 45 plant is located at Stuart is that Stuart burns substantial quantities of coal. To the extent this coal was purchased for jurisdictional customers, jurisdictional customers should get the benefit created by this procurement. In other words, the asset (i.e., the jurisdictional customer share of coal) during the audit period effectively belonged to them. Therefore, the fees received are inextricably tied to DP&L's ability to lever this asset into a Refined Coal agreement. While not suggesting customers are due a residual payment over the life of the project, EVA is recommending that during the remaining term of the FAC the jurisdictional share of proceeds should flow through the FUEL Rider.

The parties to the agreement have considerable discretion as to how they structured the payments other than the obligation to buy the Refined Coal from an un-related third party. For example, the agreements could have been structured to purchase the Refined Coal at a price below what the coal feedstock was purchased.

In EVA's interviews with DP&L, [redacted]

Finally, it is not at all clear that refined coal is good for Stuart. Other utilities which tried refined coal suspended the contract when it determined it was increasing outages and responsible for operating problems. Stuart management indicated they too were concerned and had initiated a program that would allow them to determine if there were adverse consequences. Refined Coal production commenced in May [redacted]

Foresight Energy

In 2013, DP&L received coal under four contracts with Foresight Energy. Foresight Energy is the operator for the Cline Group mines including Williamson. For all intents and purposes, Foresight Energy and Williamson Energy are the same company. All four of the contracts, which are summarized in Exhibit 3-40, [redacted].

Exhibit 3-40. Foresight Energy Contracts With Deliveries During 2013

[redacted]

Foresight's success derives in part from aggressive pricing of its Deer Run product. This coal is relatively low cost to produce if it can be sold on a partially-washed basis. As a partially washed coal, its Btu is lower, i.e., 10,800 Btu per pound, and its SO_2 higher, i.e., 6.5 pounds per MMBtu. This off-spec coal is [redacted]

Shipments by contract are shown below. (Exhibit 3-41) [redacted].

In addition to the contracts for delivery in 2013, DP&L entered into [redacted]. (Exhibit 3-42) [redacted]

[redacted]

Exhibit 3-41. Shipments of Foresight Energy Contract Coal in 2013

[redacted]

Exhibit 3-42. Long Term Contracts with Foresight

[redacted]

Knight Hawk

In 2013, DP&L received coal under one contract with Knight Hawk. The basic provisions of this contract are provided in Exhibit 3-43. [redacted].

Exhibit 3-43. Long Term Contracts with Knight Hawk

[redacted]

The quantity of the shipments under the Knight Hawk agreement is summarized in Exhibits 3-44 and 3-45.

Exhibit 3-44. Shipments under Knight Hawk Agreement 539003

[redacted]

Exhibit 3-45. Quality of Knight Hawk Shipments, 2013

[redacted]

[redacted].

Exhibit 3-46. Contracts Entered Into with Knight Hawk in 2012

[redacted]

Patriot

On July 9, 2012, Patriot Coal filed for bankruptcy protection under Chapter 11 of the Bankruptcy Code. As required, Patriot's filings included DP&L on the list of the 50 largest general unsecured claims against the debtor. [redacted]

[8] Ashland Coal was sold to Arch in 1997. Arch spun off certain assets into Magnum in 2005. Patriot acquired Magnum in 2008.

[redacted]

[redacted].

Given Patriot's emergence from bankruptcy in December 2013, DP&L was asked to update the status of these payments. DP&L's response was as follows:

> [redacted]
>
> [redacted]
>
> DP&L attempted to secure a seat on the unsecured creditors committee but was denied selection despite having a larger claim than other parties that were seated. DP&L intends to remain active in this bankruptcy in order to protect all of its substantive rights.[9]

Should any recovery be received, a provision should be made to insure jurisdictional dollars flow through to customers.

White Oak

In 2012, [redacted] In 2013 [redacted].[10] The basic provisions of these contracts are provided in Exhibit 3-47.

---

[9] Response to EVA-2013-1-15

[10] [redacted].

Exhibit 3-47. Contracts with White Oak Resources LLC

[redacted]

White Oak #1 is a new longwall mine in Hamilton County, Illinois being developed by a privately-owned company. At full production, the mine is expected to produce at an annual rate of about seven million tons. Alliance Resource Partners LP invested in this longwall mine in 2011 through various transactions, including an equity investment in White Oak. The reserves are sufficiently large to allow for the development of additional mines.

The mine development is behind schedule. [redacted]

Deliveries in 2013 are summarized on Exhibit 3-48. [redacted]

Exhibit 3-48. Shipments under White Oak Agreement 539003

[redacted]

The quality of the 2013 shipments is summarized in Exhibit 3-49. [redacted] As this coal is development coal, it is premature to judge what the typical delivered quality will be once the longwall is in operation.

[redacted]

Exhibit 3-49. Quality of Shipments under White Oak Agreement 575002

[redacted]

Williamson Energy

In 2013, DP&L received coal under a long-term contract with Williamson Energy. [redacted]

Exhibit 3-50. Overview of Williamson Long-Term Contract

[redacted]

Exhibit 3-51. Changes in Quality Specification in Amendment 2

[redacted]

[redacted]

The quantity of the shipments under the Williamson contract is summarized in Exhibits 3-52 and 3-53.

Exhibit 3-52. Shipments Under the Williamson Contract, 2013

[redacted]

Exhibit 3-53. Quality of Shipments Under the Williamson Contract, 2013

[redacted]

All of the Williamson coal [redacted]

Transportation

Most coal is delivered by barge. Hutchings previously received coal by rail and truck but no deliveries were made to it in 2013. The transportation agreements are reviewed in this section.

Barge

DP&L is a party to [redacted]

[redacted]

Rail

DP&L is party to a rail agreement with the [redacted].

Natural Gas Procurement

Overview

For DP&L, natural gas represents a very small portion of its fuel purchases – both in terms of volume and dollar cost. While only a small percentage of total fuel dollars spent on natural gas, it serves one primary use within the DP&L generating portfolio: meeting peak system load by generating from the Tait Gas Turbine facility.

Despite the small amount of gas used within the system, it is critical for DP&L to have a strong awareness of the U.S. natural gas market, as recent developments continue to push rapid change within the industry that will affect both the physical gas delivery system as well how gas is priced in the future.

Industry Background

Over the last six to seven years, the natural gas industry in the United States has changed dramatically. Rapid growth in unconventional gas development – primarily through the harnessing of shale gas– has greatly changed the landscape for both producers and consumers of natural gas. The critical nature of these changes demand action from primary stakeholders to ensure the appropriate allocation of capital for fuel procurement.

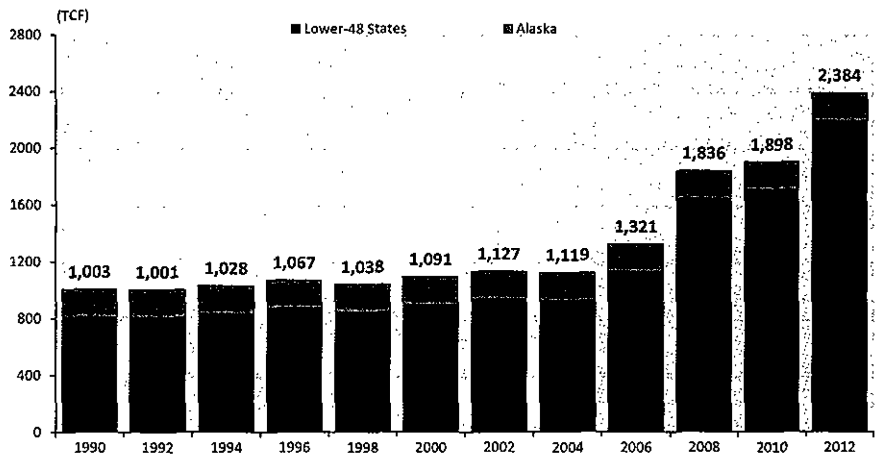
When looking at the shifts in natural gas over the last several years, there are three primary focus areas that will be critical to DP&L going forward:

- Discovery and rapid development of new natural gas supply sources, such as the Marcellus Shale
- Alteration of and additions to existing natural gas pipeline infrastructure to accommodate shifting supply base
- Impact of new supplies and infrastructure on natural gas prices and basis differentials

Natural Gas Supply

Every two years, the Potential Gas Committee -- a gathering of industry experts, geologists and other stakeholders -- release its estimates of how much natural gas exists in the reserve base of the United States. While the Committee does not comment on the economic viability of the development of these natural gas reserves, it does discuss the location and characteristics of how much gas is believed to be in the ground nationwide. Exhibit 3-54 shows the rapid change in this resource base over the last eight years.

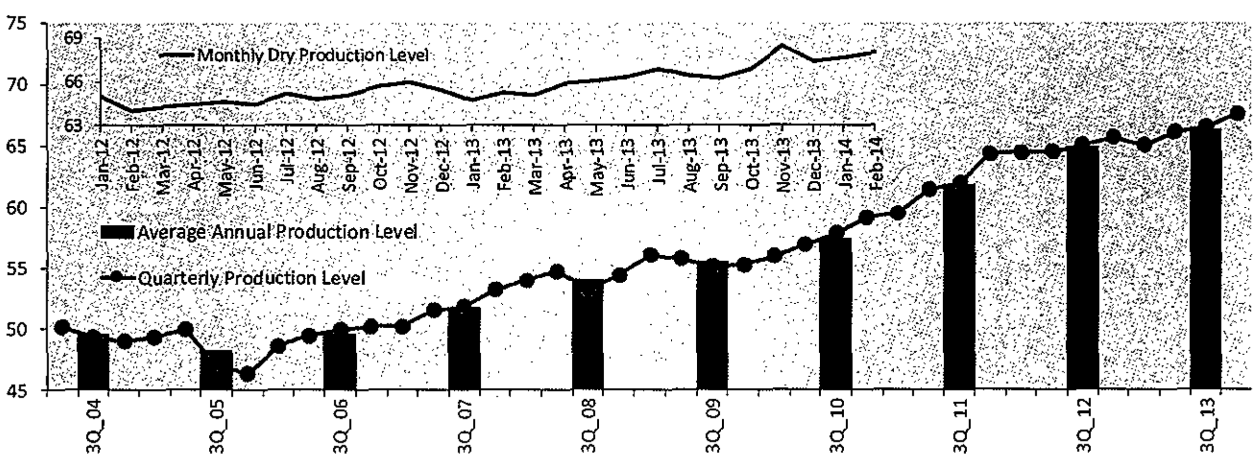
Exhibit 3-54. Potential Gas Committee Natural Gas Reserve Base Estimates



Source: Potential Gas Committee.

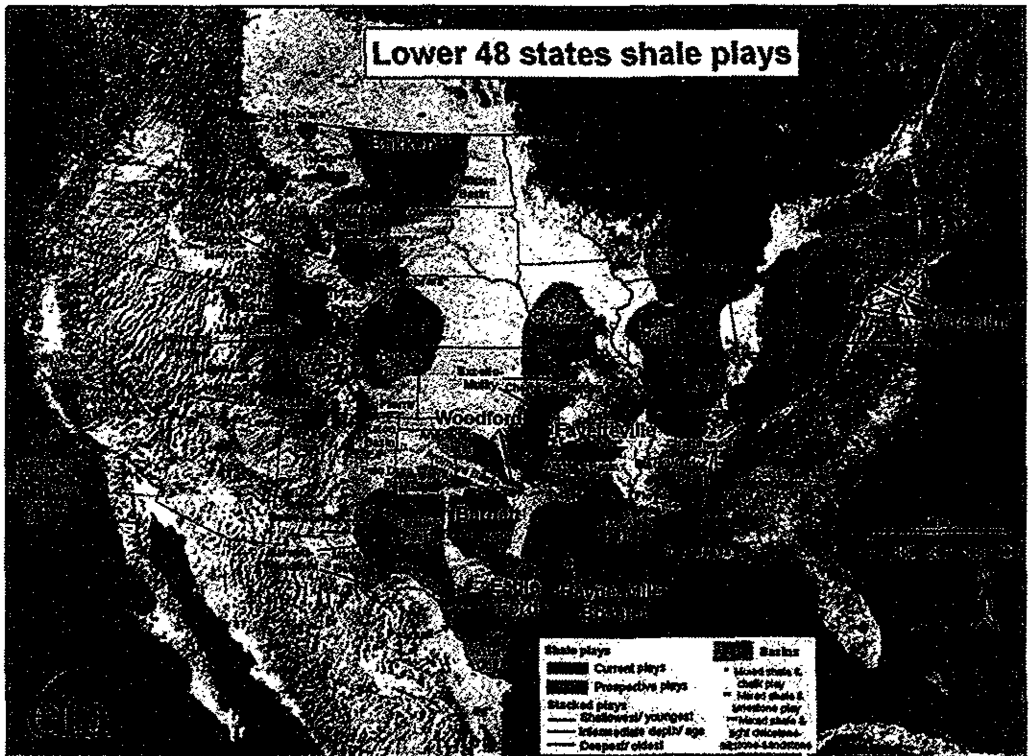
Exhibit 3-55 shows the rapid growth in Lower-48 Natural Gas production since 2004. Exhibit 3-56 shows the location of the shale plays accounting for this incremental production.

Exhibit 3-55. Lower-48 States Natural Gas Production (BCFD)



Note: Bars represent average annual production levels, while dots on the line graphs represent quarterly production levels.
Source: Lippman Consulting, EVA

Exhibit 3-56. Shale Gas Reserve Map from EIA



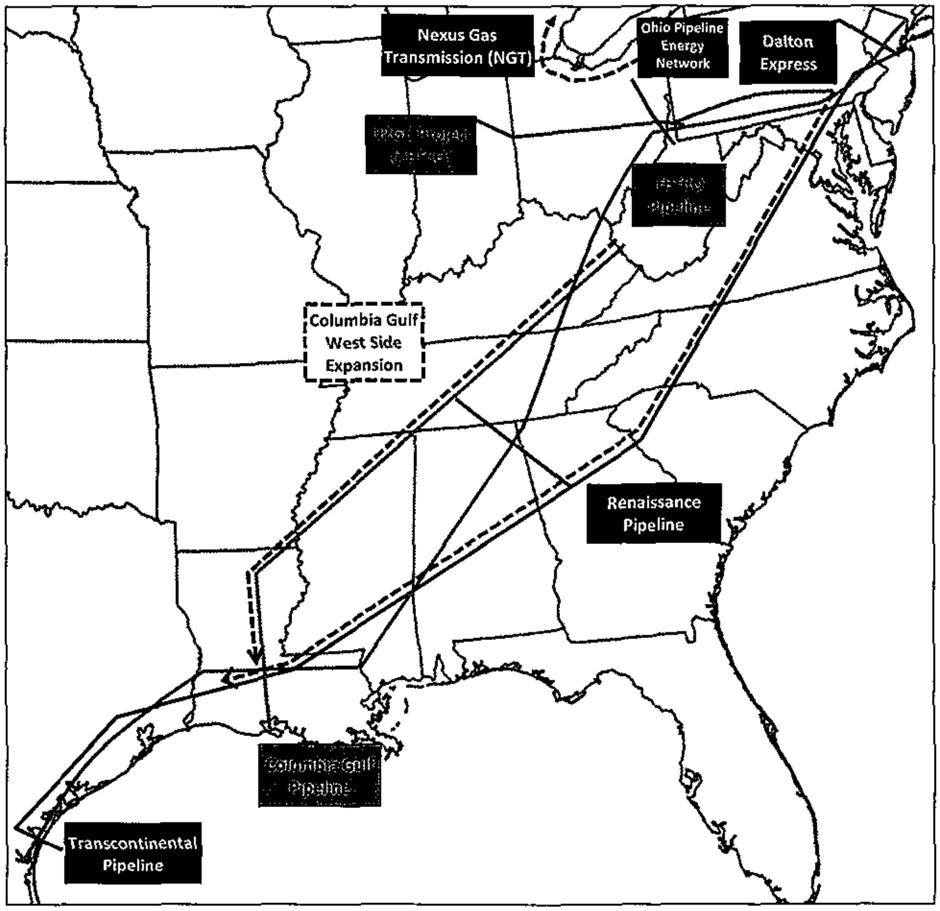
Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

The importance of the shale revolution to DP&L is twofold: first is the impact on natural gas pricing (which is discussed below). The second is the locational dynamics of this new supply. With much of the new supply coming online in the northeastern U.S. (i.e., Pennsylvania, West Virginia and Ohio), DP&L has increased proximity to an enormous volume of new shale gas reserves, greatly increasing its buying power within the region. This fact should permeate its pricing strategy as well as how it negotiates contracts with those pipelines that are able to service its facilities.

Natural Gas Infrastructure

In order to accommodate the recent shift in natural gas supply from the south / Gulf region to the Northeast, there are 57 completed or pending pipeline projects tasked with relieving the supply glut facing the core production areas of the Marcellus shale. Exhibit 3-57 shows an example of some of the larger projects that have taken place and will take place through 2014.

Exhibit 3-57. Major Northeast Pipeline Expansion Projects



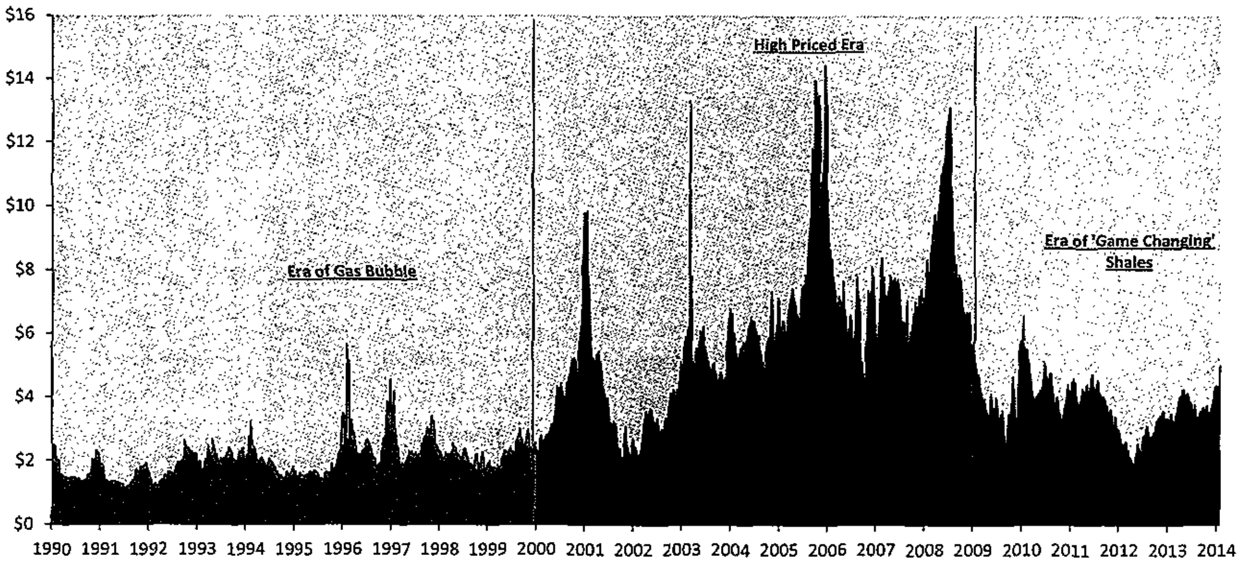
The implications of this new infrastructure are numerous and must be a critical input to any procurement strategy at DP&L. Some examples include:

- The creation of new pricing points and hubs – especially in the northeast. These include TETCO M2, Millennium South and the Leidy Hub. This provides greater trading liquidity in the region and offers greater pricing transparency
- Compression of basis differentials. The price differences between assorted regional pricing points will be reduced, thus reducing the delivered price of gas.
- Redirection and/or re-tasking of existing pipelines. Pipelines (such as the Rockies Express and Columbia Gulf) are looking to reverse direction to service Marcellus production.

Natural Gas Pricing

The net result of these large structural changes to the natural gas market has been a rapid decline in natural gas prices as shown in Exhibit 3-58. In 2012, prices hit lows not seen in close to a decade, dropping below $2.00/MMBtu in March/April. While prices were higher in 2013, they did not return to pre-shale levels. While it is yet to be seen how prices will evolve going forward, the industry consensus is that they will not return to historic highs. This "new era" of prices is a vital consideration to DP&L's natural gas procurement practices and, even more critically, its long term review of reliability and generation issues.

Exhibit 3-58. Henry Hub Natural Gas Price History



2013 Gas Purchase Review

In 2013, DP&L Energy purchased [redacted]. Natural gas volumes and charges by month are shown in Exhibit 3-59.[11]

Exhibit 3-59. DP&L Natural Gas Purchases

[redacted]

[11] Includes regulated and un-regulated purchases.

Upon review of the gas purchases, all prices paid and volumes purchased appeared to be prudent. Additionally, DP&L only conducted trades with counterparties with whom it has up-to-date master agreements.

Upon review of DP&L's pipeline charges, they also appeared prudent. [redacted].

Exhibit 3-60 shows a map of DP&L's key gas generating assets as well as the pipelines at that service them. The location of Tait, Yankee and Hutchings provides gas supply volume diversification options as well as direct paths from core supply sources to DP&L facilities.

Firm Capacity Recommendations in Prior Audit Report

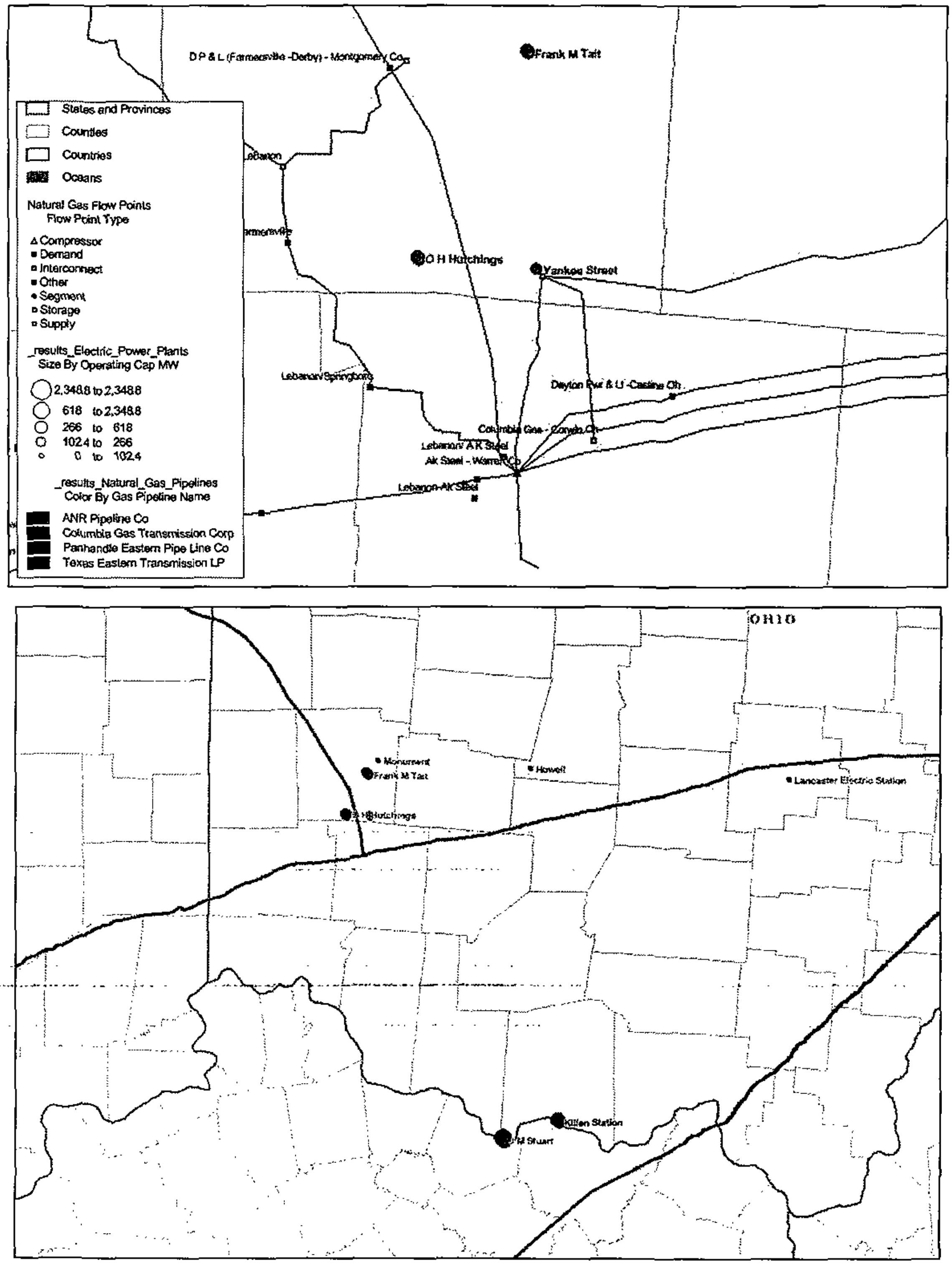
A recommendation in the report of the prior audit (Case No. 12-2881-EL-FAC) was made to review the DP&L's firm capacity agreements with [redacted]. The following was in last year's audit report:

[redacted]

[redacted]

[redacted]

Exhibit 3-60.   Key Gathering Assets and Pipelines



DP&L Firm Capacity Response Critique

In 2013, DP&L conducted a cost benefit analysis of moving from firm (FT) to interruptible (IT) contracts with [redacted]

4 PLANT PERFORMANCE

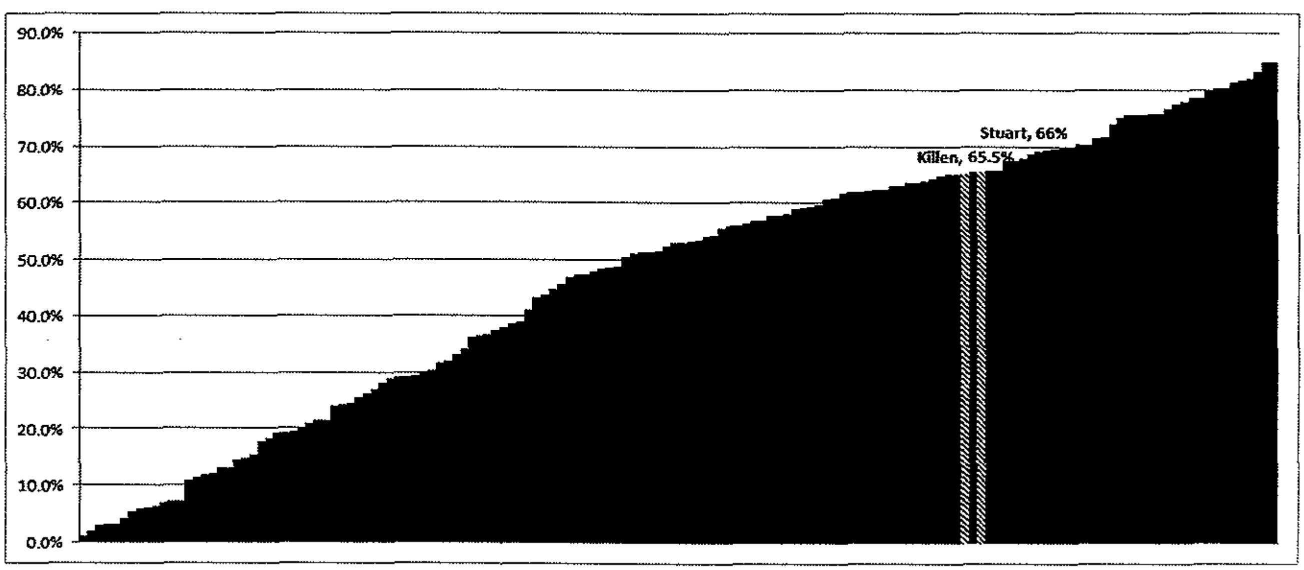
Benchmarking

The performance of the DP&L-operated coal plants can be measured against other coal-fired plants in the PJM Interconnection to determine how competitive these plants are at providing electricity to the power pool. This same comparison can be made to coal plants in Ohio and Kentucky which have similar fuel costs.

Two measures used to demonstrate plant performance are capacity factor and heat rate. Heat rate is the amount of energy used to generate one unit of electricity expressed in BTUs per kilowatt- hour. Capacity factor is the utilization rate of the plant or how many megawatt-hours were generated verses its potential generation. Capacity factor generally ties to the competitiveness of the plant.

The capacity factors of the three DP&L-operated plants compared to the other coal-fired plants in the PJM Interconnection are presented in Exhibit 4-1. Killen and Stuart are on the higher end of the curve, 65.5 percent and 66 percent, respectively. Hutchings did not operate in 2013.

Exhibit 4-1. PJM Coal-Fired Power Capacity Factors in 2013



Killen and Stuart have lower heat rates compared to their PJM competitors (Exhibit 4-2). A lower heat rate conveys that a plant will use less fuel to produce a unit of electricity, therefore the plants marginal cost to produce electricity is lower and able to sell electricity at a more competitive rate into the power pool.

Exhibit 4-2. PJM Coal-Fired Power Plant Heat Rates in 2013

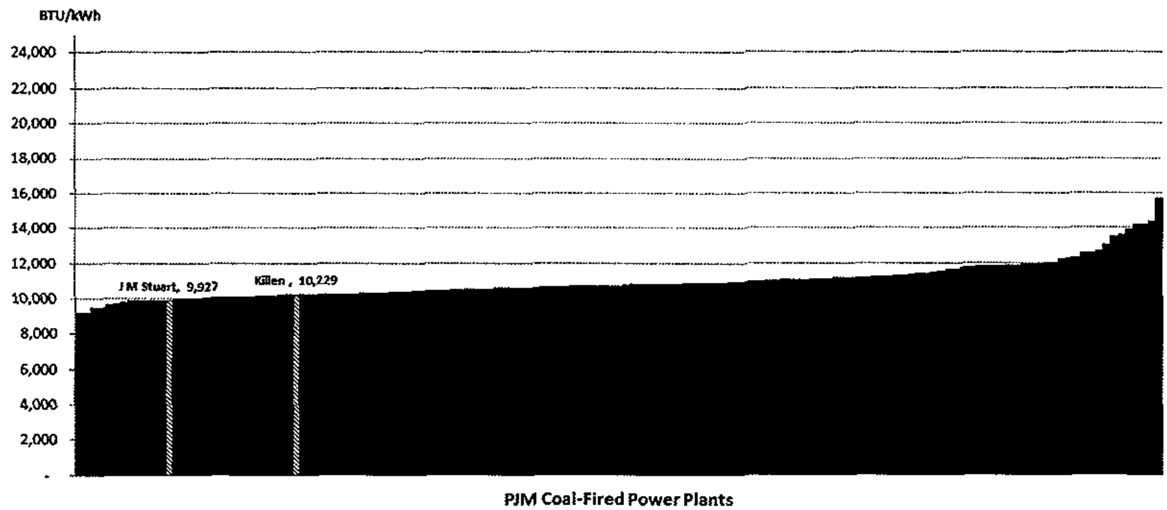
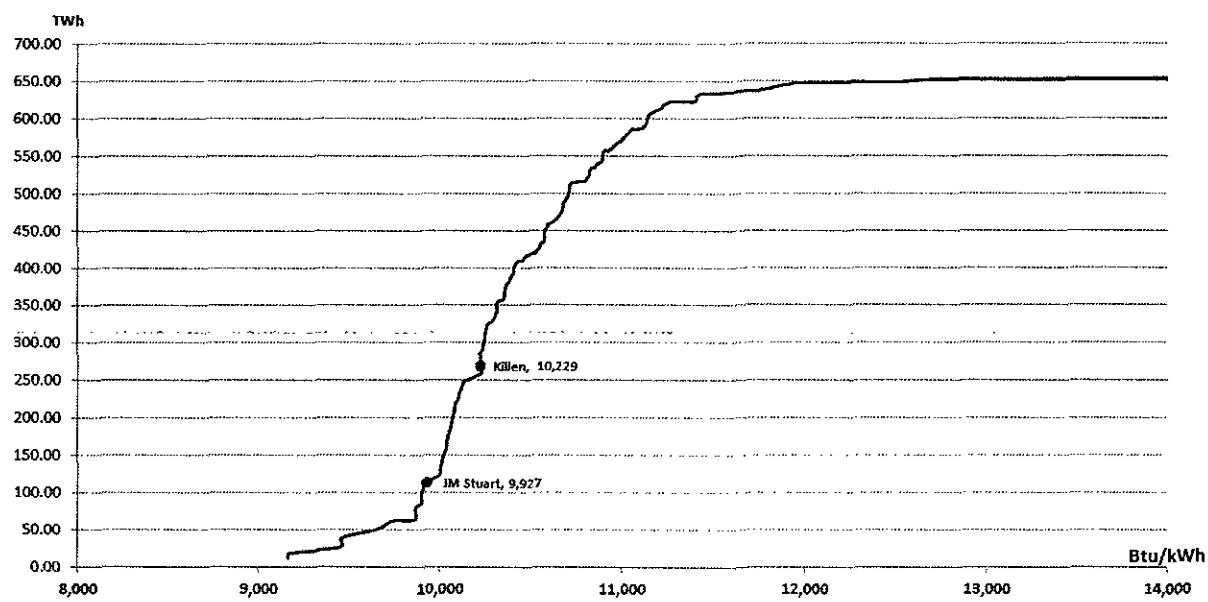


Exhibit 4-3 displays the cumulative 2013 generation of PJM coal-fired plants by heat rate. Stuart's heat rate puts it in the bottom half. Killen with a slightly higher heat rate is further up, though it is also on the front half of the dispatch curve.

Exhibit 4-3. PJM Coal-Fired Facilities Annual Cumulative Generation by Heat Rate, 2013



The comparisons with capacity factor and heat rate are provided with Kentucky and Ohio coal-fired plants respectively in Exhibits 4-4 and 4-5. Interestingly, the results are similar with the PJM population.

Exhibit 4-4. Ohio and Kentucky Coal-Fired Power Capacity Factors in 2013

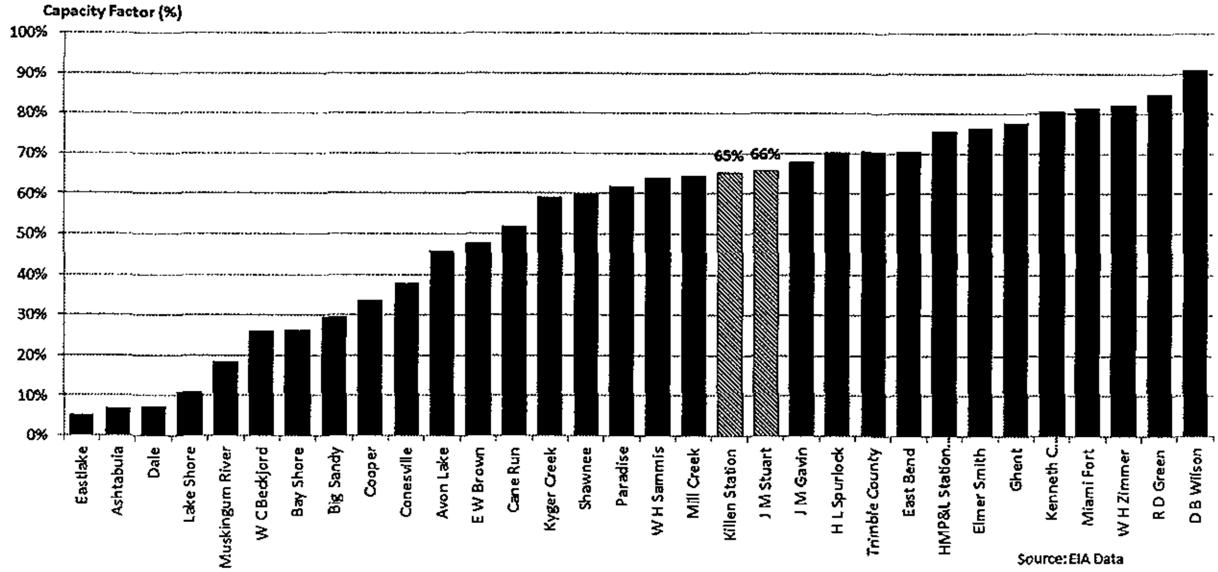
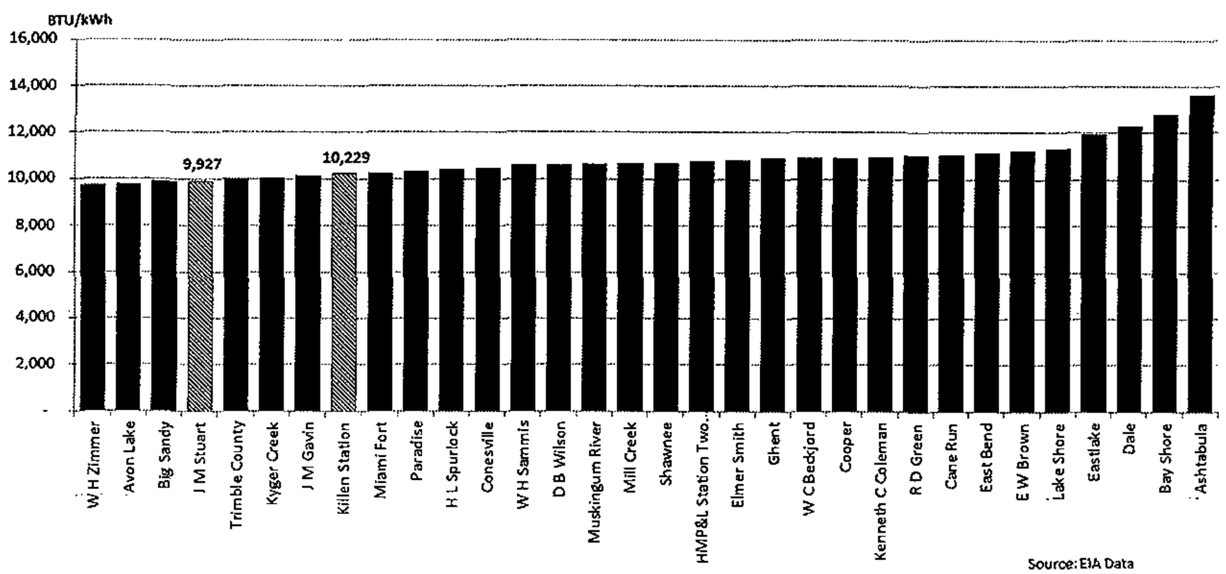


Exhibit 4-5. Ohio and Kentucky Coal-Fired Power Plant Heat Rates in 2013



5 FINANCIAL AUDIT OF THE FUEL ADJUSTMENT CLAUSE RIDER (FUEL RIDER) COMPONENT

Organization

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

- Certificate of Accountability of Independent Auditors
- Background
- Stipulation from Case No. 08-1094-EL-SSO
- Accounts Included in DP&L's FUEL Rider
- Quarterly FUEL Rider Filings
- FUEL Rider Deferrals
- Variances Between Forecasted and Actual Fuel Rider Revenues and Costs
- Potential for a Terminal Undercollected Balance
- Minimum Review Requirements
- Jointly Owned Generation
- Review Related to Coal Order Processing
- Fuel Ledger
- BTU Adjustments
- Freight and Barge Vouchers
- Fuel Analysis Reports
- Retroactive Escalations
- Review Related to Station Visitation and Coal Processing Procedure
- Coal Movement Verification Process
- Review Related to Coal Transfers Between Generating Stations
- Hutchings Generating Station
- Review Related to Fuel Supplies Owned or Controlled by the Company
- Review Related to Purchased Power

- Demurrage
- Review Related to Service Interruptions and Unscheduled Outages
- Audit Trail for FUEL Rider Filings, Supporting Workpapers and Documentation
- Reconciliation Adjustments Audit Trail
- System Optimization
- Accounting for Emission Allowances
- Application of FUEL Rider Rates to Customer Bills
- Changes to Fuel, Purchased Power Procurement and Emission Allowance Procurement
- General Ledger Detail and Audit Trail
- Customer Switching
- Internal Audits
- Section 45 Plant
- Memorandum of Findings and Recommendations

Background

On September 3, 2003, the Commission approved a stipulation extending DP&L's market development period to December 31, 2005, and provided for a rate stabilization plan ("RSP") from January 1, 2006 through December 31, 2008. Under the RSP, DP&L's Fuel rate was fixed and included in the base retail generation rates. DP&L filed an application with the Commission on October 10, 2008 for a standard service offer ("SSO") in the form of an electric security plan ("ESP") as Case No. 08-1094-EL-SSO et al. The application was supplemented on December 5, 2008. A Stipulation was subsequently filed with the Commission on February 24, 2009. (See discussion below) In the Commission's Opinion and Order dated June 24, 2009, the Commission authorized DP&L to implement a bypassable Fuel recovery rider ("FUEL Rider") to become effective January 1, 2010. The Commission also determined that the Stipulation would freeze distribution rates through December 31, 2012; would ensure rate certainty through December 31, 2012, with limited, specific exceptions; and requires DP&L to implement energy efficiency and peak demand reduction programs in consultation with an energy efficiency collaborative.

Stipulation From Case No. 08-1094-EL-SSO

Certain provisions of the FUEL Rider were addressed in a stipulation reached in Case No. 08-1094-EL-SSO et al.

Certificate Of Accountability Of Independent Auditors

To: The Dayton Power & Light Company

We have examined the quarterly FUEL Rider filings of The Dayton Power & Light Company ("DP&L") for the year ended December 31, 2013, which support the calculations of the Fuel Rider rates for the 12-month period January through December 2013. In addition, we have examined the quarterly Alternative Energy Rider ("AER") filings, which support the calculations of the Alternative Energy Rider for the 2013 period. 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 DP&L's compliance with specific requirements.

The FUEL Rider and AER filings are the responsibility of the Company's management. Our responsibility is to express an opinion as to DP&L's fair determination of the FUEL Rider rates for January through December 2013 calculated with those quarterly filings, which include the Reconciliation Adjustments for the period January through December 2013 that were reflected by DP&L through the Company's quarterly FUEL Rider filings, and to express an opinion as to DP&L's fair determination of the Rider AER rates for January through December 2013, that were reflected by DP&L through the Company's quarterly AER filings. We believe that our examination provides a reasonable basis for our opinion.

In our opinion, except for the recommended adjustments that are discussed in the Management Audit section of this report, DP&L has determined, in all material respects, the FUEL Rider rates for the 12-month period January through December 2013, including the Reconciliation Adjustments for the period January through December 2013 in accordance with its proposed procedures and its interpretation of what should be includable in the FUEL Rider rates.

In our opinion, except for the concerns noted in this report, DP&L has determined, in all material respects, the AER rates for January through December 2013 in accordance with its proposed procedure, and its interpretation of what should be includable in the AER rates.

This report is intended solely for use in Case No. 14-0115-EL-FAC at the Public Utilities Commission of Ohio ("PUCO").

Larkin & Associates PLLC

Larkin & Associates PLLC
Livonia, Michigan

The following passages are from the Stipulation and Recommendation in Case No. 08-1094-EL-SSO et al., dated February 24, 2009 at paragraphs 1 and 2:

> To assist in maintaining rate certainty, the parties agree to extend DP&L's current rate plan through December 31, 2012, except as expressly modified herein.
>
> DP&L will implement a bypassable Fuel recovery rider to recover retail fuel and purchased power costs, based on least cost fuel and purchased power being allocated to retail customers. To calculate the rider, jurisdictional emission allowance proceeds and twenty-five percent of jurisdictional coal sales gains will be netted against the fuel and purchased power costs. Retail customers for the purpose of this calculation include DP&L as well as DPL Energy Resource customers. The rider will initially be established at 1.97¢ per kWh, which amount will be subtracted from DP&L's residual generation rates. No later than November 1, 2009, DP&L will make a filing at the Commission to establish the fuel rider to become effective January 1, 2010. Thereafter, the Company shall file quarterly adjustments for recovery of the cost of fuel and purchased power. The Company's annual filing will be submitted during the first quarter of each year, beginning in 2011, and will be subject to due process, including audits and hearings (unless no signatory party objects to foregoing the hearing) for the twelve-month periods ending December 31, 2010 and 2011. The Company's annual filing shall include but not be limited to details substantiating all costs included in the fuel recovery rider during the prior calendar year so that Staff and interested parties can evaluate the methodology, account balances, forecasts, and substantiating support. Such audit shall be conducted by an independent third party auditor or Staff, at the Commission's discretion. If conducted by a third party: (a) the third party will be engaged by and report to staff; and (b) DP&L will fund the audit and may seek cost recovery through the fuel recovery rider. DP&L will withdraw its request for deferral of fuel costs for 2009-2010.

Accounts Included In DP&L's FUEL Rider

As stated in the Company's Application to Establish a FUEL Rider, DP&L has interpreted the Stipulation and Order in Case No. 08-1094-EL-SSO et al to allow for the inclusion of costs from the following FERC accounts and types of costs in its quarterly FUEL Rider filings:

> **Fuel Costs.** FERC Accounts 501 and 547 include the costs of fuel and transportation of fuel used for the generation of electricity. The majority of fuel handling costs at the plants are also recorded in Account 501. Gains and losses on fuel sales that are recorded into Account 456 and cleared through Account 501 were separately estimated as discussed below. The costs for disposal of fly ash are also recorded in FERC Account 501, but were excluded from the projected costs used to establish initial FUEL rates. The portion of the recorded costs for biomass and similar fuels that is higher than the equivalent cost of coal will be excluded from fuel calculations and recovered through the Alternative Energy

Rider; the portion of these costs up to the equivalent cost of coal will be included in the fuel calculations for recovery through the FUEL rates.

Purchased Power Costs and Related Transmission Not Otherwise Recovered. FERC Account 555 includes the cost of purchased power. FERC Account 565 includes electric transmission costs, including costs of transmission of power external to PJM to bring it to PJM (if any).

Emissions Allowances. FERC Account 509 records the costs of emission allowances. Currently this account includes sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") emission allowance costs. Future legislation may add other types of allowance costs that would also be recorded in this account for recovery.

Emission Fees. FERC Account 506 records the costs of emission fees, which are from the Ohio EPA. The Fuel Rider contains two separate components of emission fees, including (1) state emission fees related to DP&L withdrawing its application in Case No. 93-1000-EFR pursuant to paragraph 15 from the Stipulation and Recommendation dated October 5, 2011; and (2) ongoing monthly emission fees to date.

Gains and Losses. Gains and losses on purchased power are recorded in FERC Accounts 421 and 426. Gains and losses on the sale of coal and on the sale of heating oil futures used as a price hedge are recorded in FERC Account 456. Gains and losses on the sale of emission allowances are recorded in FERC Accounts 411.8 and 411.9. The net proceeds of optimization transactions, where there is a sale of coal or power and a replacement purchase, are based on the price of coal or power sold, net of the cost of the replacement coal or power.

Reconciliation Adjustment Initially Set to Zero. Within future Fuel Rider quarterly filings, the amounts under-recovered or over-recovered will be assessed or returned to customers over time through a reconciliation adjustment, which will also include a component to reflect carrying costs or benefits at DP&L's weighted average debt rate as last set in Case No. 08-1094-EL-SSO.

Quarterly FUEL Rider Filings

For the period 2013, DP&L made the following quarterly FUEL Rider filings:

Exhibit 5-1. Quarterly FUEL Rider Filings

Date Filed	Forecast Period Covered	Reconciliation Adjustment (Actual Period Covered)
October 31, 2012	December 2012 – February 2013	June – August 2012
January 31, 2013	March – May 2013	September – November 2012
April 30, 2013	June – August 2013	December 2012 – February 2013
July 31, 2013	September – November 2013	March – May 2013
November 1, 2013	December 2013 – February 2014	June – August 2013
May 1, 2014	June - August 2014[12]	September 2013 – May 2014

[12] The quarterly filing prior to this one, the forecasted period of which covered the period January through April 2014, only included 2013 actuals for September in the Reconciliation Adjustment on Schedule 2.

Larkin's review of DP&L's quarterly FUEL Rider filings covers the forecast periods encompassing calendar 2013. Our review also covers DP&L's calculations of the Reconciliation Adjustment (RA) components included within those quarterly FUEL Rider filings for the months of 2013. Larkin's review of DP&L's RA information included verification to actual recorded results on a test basis for the months of January through December 2013.

The following sections discuss DP&L's 2013 quarterly Fuel Rider filings by reproducing Schedules 1 and 2 as well as Workpaper 1 as Exhibits 5-2 through 5-17.

Quarterly FUEL Rider Filing – December 2012 through February 2013

Exhibit 5-2. Forecasted Quarterly Rate Summary, January through February 2013

THE DAYTON POWER AND LIGHT COMPANY
Case No. 11-5730-EL-FAC, 12-2881-EL-FAC
FUEL Rider
Forecasted Quarterly Rate Summary

Line No.	(A) Description	(B) Dec-12	(C) Jan-13	(D) Feb-13	(E) Total	(F) Source
1	Forecasted FUEL Costs	$40,140,541	$39,220,222	$32,425,010	$111,785,773	Workpaper 1, Line 14
2	Assigned to Off-System Sales	($13,930,041)	($13,093,841)	($10,144,311)	($37,168,194)	Workpaper 1, Line 15
3	Retail Costs	$26,210,500	$26,126,380	$22,280,699	$74,617,579	Line 1 + Line 2
4	Forecasted Generation Level Retail Sales	964,642,030	981,918,556	825,435,572	2,771,996,158	Workpaper 1, Line 17
5	Retail FUEL Rate before Reconciliation Adjustment $/kWh				$0.0269184	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				$0.0022612	Schedule 2, Line 7
7	Forecasted Retail FUEL Rate $/kWh				$0.0291796	Line 5 + Line 6

Line No.	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	Source
8	Distribution Line Loss Factors	1.00583	1.01732	1.04687	Line Loss Study 2009
9	**FUEL Rates $/kWh**	**$0.0293497**	**$0.0296850**	**$0.0305472**	Line 7 * Line 8

Schedule 1: This schedule reflects DP&L's estimates of the monthly fuel costs it expected to incur during the period December 2012 through February 2013[13]. As shown on lines 1-3 of Schedule 1, the categories included DP&L's forecasted fuel costs for December 2012 as well as January and February 2013, which totaled $111.786 million (column E), less amounts assigned to Off-System Sales which totaled $37.168 million, which resulted in forecasted net Retail Costs of $74.618 million. As shown on line 4 of Schedule 1, the Company included its forecasted Generation Level Retail Sales which totaled 2.772 billion kWh for the period December 2012, as well as January through February 2013. The Company then calculated its retail fuel rate before Reconciliation Adjustment of $0.0269184 per kWh by dividing the net Retail Costs of $74.618 million by the forecasted Generation Level Retail Sales as shown on line 5. The Company

[13] December 2012 is not within the 2013 audit period.

reflected a Reconciliation Adjustment for the period June through August 2012 (see Schedule 2 discussion below) of $0.0022612 per kWh on line 6. DP&L added its Reconciliation Adjustment to the $0.0269184 per kWh noted above to derive its forecasted retail fuel rate of $0.0291796 per kWh as shown on line 7 of Schedule 1. After applying the line loss factors of 1.00583, 1.01732 and 1.04687 cents per kWh for the High Voltage & Substation, Primary and Secondary & Residential voltage levels, the Company calculated fuel rates at the distribution level of $0.0293497, $0.0296850 and $0.0305472 cents per kWh as shown on line 9.

Exhibit 5-3. Reconciliation Adjustment – June through August 2012

THE DAYTON POWER AND LIGHT COMPANY
Case No. 11-5730-EL-FAC, 12-2881-EL-FAC
FUEL Rider
Reconciliation Adjustment (RA)

Line No.	(A) Description	(B) Jun-12	(C) Jul-12	(D) Aug-12	(E) Total	(F) Source
1	Actual FUEL Cost	$15,592,045	$21,768,348	$15,438,997	$52,799,390	Accounting Records
2	Actual Revenue Recovery	($15,205,774)	($18,708,648)	($18,129,984)	($52,044,406)	Accounting Records
3	Prior Reconciliation Under Recovery				$434,917	2012 Summer Quarter Reconciliation
4	Emission Fee Adjustment				$1,718,880	Accounting Records
5	Under (Over) Recovery				$2,908,782	Line 1 + Line 2 + Line 3 + Line 4
		Dec-12	Jan-13	Feb-13		
6	Forecasted Sales	485,107,815	458,125,149	343,159,984	1,286,392,948	
7	**Forecasted RA Rate $/kWh**				**$0.0022612**	Line 5 / Line 6

Schedule 2: Line 1 of Schedule 2 reflects DP&L's actual fuel costs that were incurred during June through August 2012, which totaled $52.799 million (column E). Line 2 of Schedule 2 reflects DP&L's actual revenues for the same period, which totaled $52.044 million. The difference between the Company's actual fuel costs and actual revenues, and the addition of the prior reconciliation under-recovery shown on line 3 as well as a $1.719 million adjustment which reflects the removal of Accounts 403 and 512 (see additional discussion below) shown on line 4, results in an under-recovery in the amount of $2.909 million, as shown on line 5. Line 6 of Schedule 2 reflects DP&L's forecasted sales for the period December 2012 through February 2013, which totals 1.286 billion kWh (column E). The Company derived its Reconciliation Adjustment of $0.0022612 per kWh (also shown on Schedule 1, line 6) by dividing the under-recovery of $2.909 million by its forecasted sales for the period December 2012 through February 2013.

Exhibit 5-4. Forecasted Quarterly Rate – Workpaper 1, December 2012 through February 2013

THE DAYTON POWER AND LIGHT COMPANY
Case No. 11-5730-EL-FAC, 12-2881-EL-FAC
FUEL Rider

Line No.	(A) Description	(B) Dec-12	(C) Jan-13	(D) Feb-13	(E) Total
	Forecasted Costs ($)[1]				
1	Steam Plant Generation (501)	$35,559,875	$33,767,070	$26,909,364	$96,236,309
2	Steam Plant Fuel Oil Consumed (501)	$1,060,130	$827,785	$1,150,906	$3,038,821
3	Steam Plant Fuel Handling (501)	$711,198	$1,013,012	$807,281	$2,531,491
4	Steam Plant Gas Consumed (501)	$0	$0	$0	$0
5	Coal Sales (456)	($870,920)	$0	$0	($870,920)
6	System Optimization	$253,887	$0	$0	$253,887
7	Heating Oil Realized Gains or Losses (456)	($8,544)	$0	$0	($8,544)
8	Allowances Consumed (509)	$0	$0	$0	$0
9	Cost of Fuel, Gas and Diesel Peakers (547)	$0	$0	$0	$0
10	Purchased Power (555)	$3,328,633	$3,546,584	$3,491,689	$10,366,907
11	Purchased Power Realized Gain/Losses (421 & 426)	$0	$0	$0	$0
12	Allowance Sales (411.8 & 411.9)	$0	$0	$0	$0
13	Emission Fees (506)	$106,282	$65,771	$65,771	$237,823
14	Total Costs	$40,140,541	$39,220,222	$32,425,010	$111,785,773
15	Assigned to Off-System Sales[1]	($13,930,041)	($13,093,841)	($10,144,311)	($37,168,194)
16	Retail Costs	$26,210,500	$26,126,380	$22,280,699	$74,617,579
17	Total Forecasted Generation Level Retail Sales[1]	964,642,030	981,918,556	825,435,572	2,771,996,158
18	Retail FUEL Rate $/kWh				$0.0269184
	Reconciliation Adjustment				
19	Under (Over) Recovery				$2,908,782
20	Forecasted RA Rate $/kWh				$0.0022612

Line No.	Line Loss Adjustment	Distribution Loss Factor[2]	Rate at Distribution Level
21	High Voltage & Substation	1.00583	$0.0293497
22	Primary	1.01732	$0.0296850
23	Secondary & Residential	1.04687	$0.0305472

Line No.	Standard Offer Metered Level Sales and Revenue Forecast	Winter FUEL Rider kWh	Winter FUEL Rider Revenue $
24	High Voltage & Substation	95,630,197	$2,806,718
25	Primary	17,101,233	$507,650
26	Secondary & Residential	1,120,299,369	$34,222,009
27	Total	1,233,030,799	$37,536,377

Notes: [1] Data from Corporate Model
[2] Distribution Loss Factors from 2009 Line Loss Study

Workpaper 1: Column A of this workpaper (lines 1-14) reflects a breakout of the categories of the forecasted costs that the Company has included in its Fuel Rider for the period December

2012 through February 2013. Columns B, C and D provide a breakout of the forecasted amounts associated with each expense category for December 2012 as well as January and February 2013, respectively, and which totals the $111.786 million shown on Schedule 1. Lines 15 through 18 of Workpaper 1 reflect the forecasted amounts shown on Schedule 1 for DP&L's off-system sales, retail costs, forecasted generation sales and retail fuel rate. Lines 19 and 20 of Workpaper 1 reflect the under-recovery of $2.909 million and the forecasted RA rate of $0.0022612 per kWh. Lines 21 through 23 of Workpaper 1 reflect the distribution line loss factors and forecasted fuel rates at the distribution level, which are shown on Schedule 1 at lines 8 and 9, respectively and were calculated by multiplying DP&L's forecasted retail fuel rate by each of the distribution line loss factors. Lines 24 through 26 of Workpaper 1 reflect a breakout of DP&L's standard offer metered level sales and revenue forecast. Specifically, Column D reflects forecasted kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels of 95.630 million kWh, 17.101 million kWh and 1.120 billion kWh, respectively. The Company's forecast totals 1.233 billion kWh as shown on line 27. Column E of Workpaper 1 reflects the Company's forecasted Fuel Rider revenue for each voltage level, which was calculated by multiplying the kWh associated with each of the voltage levels referenced above by the forecasted fuel rates at the distribution level. The Company's forecasted Fuel Rider totals $37.536 million as shown on line 27.

Quarterly FUEL Rider Filing – March through May 2013

Exhibit 5-5. Forecasted Quarterly Rate Summary, March through May 2013

THE DAYTON POWER AND LIGHT COMPANY
Case No. 11-5730-EL-FAC, 12-2881-EL-FAC
FUEL Rider
Forecasted Quarterly Rate Summary

Line No.	(A) Description	(B) Mar-13	(C) Apr-13	(D) May-13	(E) Total	(F) Source
1	Forecasted FUEL Costs	$30,987,115	$27,242,971	$34,380,832	$92,610,919	Workpaper 1, Line 14
2	Assigned to Off-System Sales	($6,992,602)	($6,335,242)	($12,757,058)	($26,084,902)	Workpaper 1, Line 15
3	Retail Costs	$23,994,513	$20,907,730	$21,623,774	$66,526,016	Line 1 + Line 2
4	Forecasted Generation Level Retail Sales	875,265,975	751,578,855	788,483,713	2,415,328,543	Workpaper 1, Line 17
5	Retail FUEL Rate before Reconciliation Adjustment $/kWh				$0.0275433	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				$0.0012112	Schedule 2, Line 8
7	Forecasted Retail FUEL Rate $/kWh				$0.0287545	Line 5 + Line 6

Line No.	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	
8	Distribution Line Loss Factors	1.00583	1.01732	1.04687	Line Loss Study 2009
9	**FUEL Rates $/kWh**	**$0.0289221**	**$0.0292525**	**$0.0301022**	Line 7 * Line 8

Schedule 1: This schedule reflects DP&L's estimates of the monthly fuel costs it expected to incur during the period March through May 2013. As shown on lines 1-3 of Schedule 1, the categories included DP&L's forecasted fuel costs for March, April and May, which totaled $92.611 million (column E), less amounts assigned to Off-System Sales which totaled $26.085

million, which resulted in forecasted net Retail Costs of $66.526 million. As shown on line 4 of Schedule 1, the Company included its forecasted Generation Level Retail Sales, which totaled 2.415 billion kWh for the period March through May 2013. The Company then calculated its retail fuel rate before Reconciliation Adjustment of $0.0275433 per kWh by dividing the net Retail Costs of $66.526 million by the forecasted Generation Level Retail Sales, as shown on line 5. The Company reflected a Reconciliation Adjustment for the period September through November 2012 (see Schedule 2 discussion below) of $0.0012112 per kWh on line 6. DP&L added its Reconciliation Adjustment to the $0.0275433 per kWh noted above to derive its forecasted retail fuel rate of $0.0287545 per kWh as shown on line 7 of Schedule 1. After applying the line loss factors of 1.00583, 1.01732 and 1.04687 cents per kWh for the High Voltage & Substation, Primary and Secondary & Residential voltage levels, the Company calculated fuel rates at the distribution level of $0.0289221, $0.0292525 and $0.0301022 cents per kWh as shown on line 9.

Exhibit 5-6. Reconciliation Adjustment – September through November 2012

THE DAYTON POWER AND LIGHT COMPANY
Case No. 11-5730-EL-FAC, 12-2881-EL-FAC
FUEL Rider
Reconciliation Adjustment (RA)

Line No.	(A) Description	(B) Sep-12	(C) Oct-12	(D) Nov-12	(E) Total	(F) Source
1	Actual FUEL Cost	$13,675,546	$12,800,065	$13,166,431	$39,642,042	Accounting Records
2	Actual Revenue Recovery	($16,741,588)	($11,885,974)	($13,707,048)	($42,334,610)	Accounting Records
3	Prior Reconciliation Under Recovery				$4,063,722	2012 Fall Quarter Reconciliation
4	Stipulation Adjustment				($2,000,000)	Case No. 11-5730-EL-FAC
5	Emission Fee Adjustment				$1,718,880	Accounting Records
6	Under (Over) Recovery				$1,090,034	Sum of Lines 1 thru 5
		Mar-13	Apr-13	May-13		
7	Forecasted Sales	369,524,572	266,990,844	263,422,307	899,937,723	
8	**Forecasted RA Rate $/kWh**				**$0.0012112**	Line 6 / Line 7

Schedule 2: Line 1 of Schedule 2 reflects DP&L's actual fuel costs that were incurred during September through November 2012, which totaled $39.642 million (column E). Line 2 of Schedule 2 reflects DP&L's actual revenues for the same period, which totaled $42.335 million. The difference between the Company's actual fuel costs and actual revenues, the addition of the prior reconciliation under-recovery shown on line 3 and the emission fee adjustment on line 5, and minus the $2.0 million stipulation adjustment agreed to in Case No. 11-5730-EL-FAC (see additional discussion below) on line 4, results in an under-recovery in the amount of $1.090 million, as shown on line 6. Line 7 of Schedule 2 reflects DP&L's forecasted sales for the period March through May 2013, which totals 899.938 million kWh (column E). The Company derived its Reconciliation Adjustment of $0.0012112 per kWh by dividing the under-recovery of $1,090 million by its forecasted sales for the period March through May 2013.

Exhibit 5-7. Forecasted Quarterly Rate – Workpaper 1, March through May 2013

THE DAYTON POWER AND LIGHT COMPANY
Case No. 11-5730-EL-FAC, 12-2881-EL-FAC
FUEL Rider

Line No.	(A) Description	(B) Mar-13	(C) Apr-13	(D) May-13	(E) Total
	Forecasted Costs ($)[1]				
1	Steam Plant Generation (501)	$25,480,323	$21,641,485	$28,889,066	$76,010,874
2	Steam Plant Fuel Oil Consumed (501)	$858,147	$1,206,747	$1,431,162	$3,496,056
3	Steam Plant Fuel Handling (501)	$509,606	$432,830	$577,781	$1,520,217
4	Steam Plant Gas Consumed (501)	$0	$0	$0	$0
5	Coal Sales (456)	$0	$0	$0	$0
6	System Optimization	$0	$0	$0	$0
7	Heating Oil Realized Gains or Losses (456)	($20,466)	($5,965)	($38,882)	($65,314)
8	Allowances Consumed (509)	$0	$0	$0	$0
9	Cost of Fuel, Gas and Diesel Peakers (547)	$0	$0	$81,663	$81,663
10	Purchased Power (555)	$4,053,222	$3,861,593	$3,333,759	$11,248,575
11	Purchased Power Realized Gain/Losses (421 & 426)	$0	$0	$0	$0
12	Allowance Sales (411.8 & 411.9)	$0	$0	$0	$0
13	Emission Fees (506)	$106,282	$106,282	$106,282	$318,846
14	Total Costs	$30,987,115	$27,242,971	$34,380,832	$92,610,919
15	Assigned to Off-System Sales[1]	($6,992,602)	($6,335,242)	($12,757,058)	($26,084,902)
16	Retail Costs	$23,994,513	$20,907,730	$21,623,774	$66,526,016
17	Total Forecasted Generation Level Retail Sales[1]	875,265,975	751,578,855	788,483,713	2,415,328,543
18	Retail FUEL Rate $/kWh				$0.0275433
	Reconciliation Adjustment				
19	Under (Over) Recovery				$1,090,034
20	Forecasted RA Rate $/kWh				$0.0012112

Line No.	Line Loss Adjustment	Distribution Loss Factor[2]	Rate at Distribution Level
21	High Voltage & Substation	1.00583	$0.0289221
22	Primary	1.01732	$0.0292525
23	Secondary & Residential	1.04687	$0.0301022

Line No.	Standard Offer Metered Level Sales and Revenue Forecast	Spring FUEL Rider kWh	Spring FUEL Rider Revenue $
24	High Voltage & Substation	113,797,075	$3,291,250
25	Primary	18,485,689	$540,753
26	Secondary & Residential	732,346,281	$22,045,234
27	Total	864,629,045	$25,877,237

Notes: [1] Data from Corporate Model
[2] Distribution Loss Factors from 2009 Line Loss Study

Workpaper 1: Column A of this workpaper (lines 1-14) reflects a breakout of the categories of the forecasted costs that the Company has included in its Fuel Rider for the period March through May 2013. Columns B, C and D provide a breakout of the forecasted amounts associated with each expense category for March, April and May 2013, respectively, and which totals the $92.611 million shown on Schedule 1. Lines 15 through 18 of Workpaper 1 reflect the forecasted amounts shown on Schedule 1 for DP&L's off-system sales, retail costs, forecasted generation sales and retail FUEL rate. Lines 19 and 20 of Workpaper 1 reflect the under-recovery of $1.090 million and the forecasted RA rate of $0.0012112 per kWh. Lines 21 through 23 of Workpaper 1 reflect the distribution line loss factors and forecasted fuel rates at the distribution level, which are shown on Schedule 1 at lines 8 and 9, respectively and were calculated by multiplying DP&L's forecasted retail fuel rate by each of the distribution line loss factors. Lines 24 through 26 of Workpaper 1 reflect a breakout of DP&L's standard offer metered level sales and revenue forecast. Specifically, Column D reflects forecasted kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels of 113.797 million kWh, 18.486 million kWh and 732.346 million kWh, respectively. The Company's forecast totals 864.629 million kWh as shown on line 27. Column E of Workpaper 1 reflects the Company's forecasted Fuel Rider revenue for each voltage level, which was calculated by multiplying the kWh associated with each of the voltage levels referenced above by the forecasted fuel rates at the distribution level. The Company's forecasted Fuel Rider totals $25.877 million as shown on line 27.

Quarterly FUEL Rider Filing – June through August 2013

Exhibit 5-8. Forecasted Quarterly Rate Summary, June through August 2013

FUEL Rider
Forecasted Quarterly Rate Summary

Line No.	(A) Description	(B) Jun-13	(C) Jul-13	(D) Aug-13	(E) Total	(F) Source
1	Forecasted FUEL Costs	$34,427,543	$37,576,706	$36,101,141	$108,105,390	Workpaper 1, Line 13
2	Assigned to Off-System Sales	($10,410,995)	($10,327,089)	($9,171,472)	($29,909,556)	Workpaper 1, Line 14
3	Retail Costs	$24,016,548	$27,249,617	$26,929,669	$78,195,834	Line 1 + Line 2
4	Forecasted Generation Level Retail Sales	881,050,016	990,159,453	985,012,397	2,856,221,866	Workpaper 1, Line 16
5	Retail FUEL Rate before Reconciliation Adjustment $/kWh				$0.0273774	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				$0.0009331	Schedule 2, Line 6
7	Forecasted Retail FUEL Rate $/kWh				$0.0283105	Line 5 + Line 6

Line No.	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	Source
8	Distribution Line Loss Factors	1.00583	1.01732	1.04687	Line Loss Study 2009
9	FUEL Rates $/kWh	**$0.0284756**	**$0.0288008**	**$0.0296374**	Line 7 * Line 8

Schedule 1: This schedule reflects DP&L's estimates of the monthly fuel costs it expected to incur during the period June through August 2013. As shown on lines 1-3 of Schedule 1, the categories included DP&L's forecasted fuel costs for June, July and August, which totaled $108.105 million (column E), less amounts assigned to Off-System Sales which totaled $29.910 million, which resulted in forecasted net Retail Costs of $78.196 million. As shown on line 4 of

Schedule 1, the Company included its forecasted Generation Level Retail Sales, which totaled 2.856 billion kWh for the period June through August 2013. The Company then calculated its retail fuel rate before Reconciliation Adjustment of $0.0273774 per kWh by dividing the net Retail Costs of $78.196 million by the forecasted Generation Level Retail Sales, as shown on line 5. The Company reflected a Reconciliation Adjustment for the period December 2012 through February 2013 (see Schedule 2 discussion below) of $0.0009331 per kWh on line 6. DP&L added its Reconciliation Adjustment to the $0.0273774 per kWh noted above to derive its forecasted retail fuel rate of $0.0283105 per kWh as shown on line 7 of Schedule 1. After applying the line loss factors of 1.00583, 1.01732 and 1.04687 cents per kWh for the High Voltage & Substation, Primary and Secondary & Residential voltage levels, the Company calculated fuel rates at the distribution level of $0.0284756, $0.0288008 and $0.0296374 cents per kWh as shown on line 9.

Exhibit 5-9. Reconciliation Adjustment – December 2012 through February 2013

THE DAYTON POWER AND LIGHT COMPANY
Case No. 11-5730-EL-FAC, 12-2881-EL-FAC
FUEL Rider
Reconciliation Adjustment (RA)

Line No.	(A) Description	(B) Dec-12	(C) Jan-13	(D) Feb-13	(E) Total	(F) Source
1	Actual FUEL Cost	$13,163,756	$15,359,908	$12,374,678	$40,898,341	Accounting Records
2	Actual Revenue Recovery	($12,302,738)	($15,554,887)	($14,913,314)	($42,770,938)	Accounting Records
3	Prior Reconciliation Under Recovery				$2,908,782	2013 Winter Quarter Reconciliation
4	Under (Over) Recovery				$1,036,185	Line 1 + Line 2 + Line 3
		Jun-13	Jul-13	Aug-13		
5	Forecasted Sales	344,133,299	416,453,400	349,900,536	1,110,487,235	
6	**Forecasted RA Rate $/kWh**				**$0.0009331**	Line 4 / Line 5

Schedule 2: Line 1 of Schedule 2 reflects DP&L's actual fuel costs that were incurred during December 2012 through February 2013, which totaled $40.898 million (column E). Line 2 of Schedule 2 reflects DP&L's actual revenues for the same period, which totaled $42.771 million. The difference between the Company's actual fuel costs and actual revenues, and the addition of the prior reconciliation under-recovery shown on line 3, results in an under-recovery in the amount of $1.036 million, as shown on line 4. Line 5 of Schedule 2 reflects DP&L's forecasted sales for the period June through August 2013, which total 1.110 billion kWh (column E). The Company derived its Reconciliation Adjustment of $0.0009331 per kWh by dividing the under-recovery of $1.036 million by its forecasted sales for the period June through August 2013.

Exhibit 5-10. Forecasted Quarterly Rate – Workpaper 1, June through August 2013

THE DAYTON POWER AND LIGHT COMPANY
Case No. 11-5730-EL-FAC, 12-2881-EL-FAC
FUEL Rider

Line No.	(A) Description	(B) Jun-13	(C) Jul-13	(D) Aug-13	(E) Total
	Forecasted Costs ($)[1]				
1	Steam Plant Generation (501)	27461711.9	$29,967,741	$29,102,428	$86,531,881
2	Steam Plant Fuel Oil Consumed (501)	$1,502,536	$1,301,082	$1,247,142	$4,050,760
3	Steam Plant Fuel Handling (501)	$823,851	$899,032	$873,073	$2,595,956
4	Steam Plant Gas Consumed (501)	$0	$0	$0	$0
5	Coal Sales (456)	$7,990	$0	$0	$7,990
6	Heating Oil Realized Gains or Losses (456)	$12,269	$11,990	$11,887	$36,146
7	Allowances Consumed (509)	$0	$0	$0	$0
8	Cost of Fuel, Gas and Diesel Peakers (547)	$680,996	$555,221	$34,848	$1,271,065
9	Purchased Power (555)	$3,872,419	$4,775,870	$4,765,992	$13,414,280
10	Purchased Power Realized Gain/Losses (421 & 426)	$0	$0	$0	$0
11	Allowance Sales (411.8 & 411.9)	$0	$0	$0	$0
12	Emission Fees (506)	$65,771	$65,771	$65,771	$197,312
13	Total Costs	$34,427,543	$37,576,706	$36,101,141	$108,105,390
14	Assigned to Off-System Sales[1]	($10,410,995)	($10,327,089)	($9,171,472)	($29,909,556)
15	Retail Costs	$24,016,548	$27,249,617	$26,929,669	$78,195,834
16	Total Forecasted Generation Level Retail Sales[1]	881,050,016	990,159,453	985,012,397	2,856,221,866
17	Retail FUEL Rate $/kWh				$0.0273774
	Reconciliation Adjustment				
18	Under (Over) Recovery				$1,036,185
19	Forecasted RA Rate $/kWh				$0.0009331

Line No.	Line Loss Adjustment	Distribution Loss Factor[2]	Rate at Distribution Level
20	High Voltage & Substation	1.00583	$0.0284756
21	Primary	1.01732	$0.0288008
22	Secondary & Residential	1.04687	$0.0296374

Line No.	Standard Offer Metered Level Sales and Revenue Forecast	Summer FUEL Rider kWh	Summer FUEL Rider Revenue $
23	High Voltage & Substation	122,190,847	$3,479,458
24	Primary	12,017,919	$346,126
25	Secondary & Residential	931,689,653	$27,612,859
26	Total	1,065,898,419	$31,438,442

Notes: [1] Data from Corporate Model
[2] Distribution Loss Factors from 2009 Line Loss Study

Workpaper 1: Column A of this workpaper (lines 1-13) reflects a breakout of the categories of the forecasted costs that the Company has included in its Fuel Rider for the period June through August 2013. Columns B, C and D provide a breakout of the forecasted amounts associated with each expense category for June, July and August 2013, respectively, and which totals the $108.105 million shown on Schedule 1. Lines 14 through 17 of Workpaper 1 reflect the forecasted amounts shown on Schedule 1 for DP&L's off-system sales, retail costs, forecasted generation sales and retail fuel rate. Lines 18 and 19 of Workpaper 1 reflect the under-recovery of $1.036 million and the forecasted RA rate of $0.0009331 per kWh. Lines 20 through 22 of Workpaper 1 reflect the distribution line loss factors and forecasted fuel rates at the distribution level, which are shown on Schedule 1 at lines 8 and 9, respectively and were calculated by multiplying DP&L's forecasted retail fuel rate by each of the distribution line loss factors. Lines 23 through 25 of Workpaper 1 reflect a breakout of DP&L's standard offer metered level sales and revenue forecast. Specifically, Column D reflects forecasted kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels of 122.191 million kWh, 12.018 million kWh and 931.69 million kWh, respectively. The Company's forecast totals 1.066 billion kWh as shown on line 26. Column E of Workpaper 1 reflects the Company's forecasted Fuel Rider revenue for each voltage level, which was calculated by multiplying the kWh associated with each of the voltage levels referenced above by the forecasted fuel rates at the distribution level. The Company's forecasted Fuel Rider totals $31.438 million as shown on line 26.

Quarterly FUEL Rider Filing – September through November 2013

Exhibit 5-11. Forecasted Quarterly Rate Summary, September through November 2013

THE DAYTON POWER AND LIGHT COMPANY
Case No. 11-5730-EL-FAC, 12-2881-EL-FAC
FUEL Rider
Forecasted Quarterly Rate Summary

Line No.	(A) Description	(B) Sep-13	(C) Oct-13	(D) Nov-13	(E) Total	(F) Source
1	Forecasted FUEL Costs	$32,808,495	$33,462,663	$34,062,819	$100,333,976	Workpaper 1, Line 13
2	Assigned to Off-System Sales	($11,950,428)	($14,134,299)	($13,441,464)	($39,526,191)	Workpaper 1, Line 14
3	Retail Costs	$20,858,066	$19,328,363	$20,621,355	$60,807,785	Line 1 + Line 2
4	Forecasted Generation Level Retail Sales	765,850,879	750,024,512	790,529,832	2,306,405,223	Workpaper 1, Line 16
5	Retail FUEL Rate before Reconciliation Adjustment $/kWh				$0.0263647	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				$0.0007826	Schedule 2, Line 6
7	Forecasted Retail FUEL Rate $/kWh				$0.0271473	Line 5 + Line 6

Line No.	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	Source
8	Distribution Line Loss Factors	1.00583	1.01732	1.04687	Line Loss Study 2009
9	**FUEL Rates $/kWh**	**$0.0273056**	**$0.0276175**	**$0.0284197**	Line 7 * Line 8

Schedule 1: This schedule reflects DP&L's estimates of the monthly fuel costs it expected to incur during the period September through November 2013. As shown on lines 1-3 of Schedule 1, the categories included DP&L's forecasted fuel costs for September, October and November, which totaled $100.334 million (column E), less amounts assigned to Off-System Sales which

totaled $39.526 million, which resulted in forecasted net Retail Costs of $60.808 million. As shown on line 4 of Schedule 1, the Company included its forecasted Generation Level Retail Sales which totaled 2.306 billion kWh for the period September through November 2013. The Company then calculated its retail fuel rate before Reconciliation Adjustment of $0.0263647 per kWh by dividing the net Retail Costs of $60.808 million by the forecasted Generation Level Retail Sales as shown on line 5. The Company reflected a Reconciliation Adjustment for the period March through May 2013 (see Schedule 2 discussion below) of $0.0007826 per kWh on line 6. DP&L added its Reconciliation Adjustment to the $0.0263647 per kWh noted above to derive its forecasted retail fuel rate of $0.0271473 per kWh as shown on line 7 of Schedule 1. After applying the line loss factors of 1.00583, 1.01732 and 1.04687 cents per kWh for the High Voltage & Substation, Primary and Secondary & Residential voltage levels, the Company calculated fuel rates at the distribution level of $0.0273056, $0.0276175 and $0.0284197 cents per kWh as shown on line 9.

Exhibit 5-12. Reconciliation Adjustment – March through May 2013

THE DAYTON POWER AND LIGHT COMPANY
Case No. 11-5730-EL-FAC, 12-2881-EL-FAC
FUEL Rider
Reconciliation Adjustment (RA)

Line No.	(A) Description	(B) Mar-13	(C) Apr-13	(D) May-13	(E) Total	(F) Source
1	Actual FUEL Cost	$12,637,934	$10,529,756	$9,896,243	$33,063,933	Accounting Records
2	Actual Revenue Recovery	($12,543,038)	($11,582,932)	($9,411,836)	($33,537,806)	Accounting Records
3	Prior Reconciliation Under Recovery				$1,090,034	2013 Spring Quarter Reconciliation
4	Under (Over) Recovery				$616,161	Line 1 + Line 2 + Line 3
		Sep-13	Oct-13	Nov-13		
5	Forecasted Sales	258,469,928	244,190,903	284,709,851	787,370,682	
6	**Forecasted RA Rate $/kWh**				**$0.0007826**	Line 4 / Line 5

Schedule 2: Line 1 of Schedule 2 reflects DP&L's actual fuel costs that were incurred during March through May 2013, which totaled $33.064 million (column E). Line 2 of Schedule 2 reflects DP&L's actual revenues for the same period, which totaled $33.538 million. The difference between the Company's actual fuel costs and actual revenues, and the addition of the prior reconciliation under-recovery shown on line 3, results in an under-recovery in the amount of $616,161, as shown on line 4. Line 5 of Schedule 2 reflects DP&L's forecasted sales for the period September through November 2013, which totals 787.371 million kWh (column E). The Company derived its Reconciliation Adjustment of $0.0007826 per kWh (also shown on Schedule 1, line 6) by dividing the under-recovery of $616,161 by its forecasted sales for the period September through November 2013.

Exhibit 5-13. Forecasted Quarterly Rate – Workpaper 1, September through November 2013

THE DAYTON POWER AND LIGHT COMPANY
Case No. 11-5730-EL-FAC, 12-2881-EL-FAC
FUEL Rider

Line No.	(A) Description	(B) Sep-13	(C) Oct-13	(D) Nov-13	(E) Total
	Forecasted Costs ($)[1]				
1	Steam Plant Generation (501)	$27,327,360	$29,082,218	$29,286,924	$85,696,503
2	Steam Plant Fuel Oil Consumed (501)	$1,472,863	$892,706	$1,177,266	$3,542,836
3	Steam Plant Fuel Handling (501)	$819,821	$872,467	$878,608	$2,570,895
4	Steam Plant Gas Consumed (501)	$0	$0	$0	$0
5	Coal Sales (456)	$0	$0	$0	$0
6	Heating Oil Realized Gains or Losses (456)	$3,906	$3,549	$16,823	$24,278
7	Allowances Consumed (509)	$0	$0	$0	$0
8	Cost of Fuel, Gas and Diesel Peakers (547)	$142,168	$0	$0	$142,168
9	Purchased Power (555)	$2,976,605	$2,545,952	$2,637,426	$8,159,984
10	Purchased Power Realized Gain/Losses (421 & 426)	$0	$0	$0	$0
11	Allowance Sales (411.8 & 411.9)	$0	$0	$0	$0
12	Emission Fees (506)	$65,771	$65,771	$65,771	$197,312
13	Total Costs	$32,808,495	$33,462,663	$34,062,819	$100,333,976
14	Assigned to Off-System Sales[1]	($11,950,428)	($14,134,299)	($13,441,464)	($39,526,191)
15	Retail Costs	$20,858,066	$19,328,363	$20,621,355	$60,807,785
16	Total Forecasted Generation Level Retail Sales[1]	765,850,879	750,024,512	790,529,832	2,306,405,223
17	Retail FUEL Rate $/kWh				$0.0263647

Line No.	Reconciliation Adjustment	
18	Under (Over) Recovery	$616,161
19	Forecasted RA Rate $/kWh	$0.0007826

Line No.	Line Loss Adjustment	Distribution Loss Factor[2]	Rate at Distribution Level
20	High Voltage & Substation	1.00583	$0.0273056
21	Primary	1.01732	$0.0276175
22	Secondary & Residential	1.04687	$0.0284197

Line No.	Standard Offer Metered Level Sales and Revenue Forecast	Fall FUEL Rider kWh	Fall FUEL Rider Revenue $
23	High Voltage & Substation	104,132,200	$2,843,392
24	Primary	10,339,157	$285,542
25	Secondary & Residential	642,021,607	$18,246,061
26	Total	756,492,964	$21,374,995

Notes: [1] Data from Corporate Model
[2] Distribution Loss Factors from 2009 Line Loss Study

Workpaper 1: Column A of this workpaper (lines 1-13) reflects a breakout of the categories of the forecasted costs that the Company has included in its Fuel Rider for the period September through November 2013. Columns B, C and D provide a breakout of the forecasted amounts associated with each expense category for September, October and November 2013, respectively, and which totals the $100.334 million shown on Schedule 1. Lines 14 through 17 of Workpaper 1 reflect the forecasted amounts shown on Schedule 1 for DP&L's off-system sales, retail costs, forecasted generation sales and retail fuel rate. Lines 18 and 19 of Workpaper 1 reflect the under-recovery of $616,161 and the forecasted RA rate of $0.0007826 per kWh. Lines 20 through 22 of Workpaper 1 reflect the distribution line loss factors and forecasted fuel rates at the distribution level, which are shown on Schedule 1 at lines 8 and 9, respectively and were calculated by multiplying DP&L's forecasted retail fuel rate by each of the distribution line loss factors. Lines 23 through 25 of Workpaper 1 reflect a breakout of DP&L's standard offer metered level sales and revenue forecast. Specifically, Column D reflects forecasted kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels of 104.132 million kWh, 10.339 million kWh and 642.022 million kWh, respectively. The Company's forecast totals 756.493 million kWh as shown on line 26. Column E of Workpaper 1 reflects the Company's forecasted Fuel Rider revenue for each voltage level, which was calculated by multiplying the kWh associated with each of the voltage levels referenced above by the forecasted fuel rates at the distribution level. The Company's forecasted Fuel Rider totals $21.375 million as shown on line 26.

Quarterly FUEL Rider Filing – December 2013

Exhibit 5-14. Forecasted Quarterly Rate Summary, December 2013

THE DAYTON POWER AND LIGHT COMPANY
Case No. 12-2881-EL-FAC
FUEL Rider
Forecasted Quarterly Rate Summary

Line No.	(A) Description	(B) Dec-13	(C) Jan-14	(D) Feb-14	(E) Total	(F) Source
1	Forecasted FUEL Costs	$32,928,319	$0	$0	$32,928,319	Workpaper 1, Line 13
2	Assigned to Off-System Sales	($9,160,624)	$0	$0	($9,160,624)	Workpaper 1, Line 14
3	Retail Costs	$23,767,695	$0	$0	$23,767,695	Line 1 + Line 2
4	Forecasted Generation Level Retail Sales	925,406,442	0	0	925,406,442	Workpaper 1, Line 16
5	Retail FUEL Rate before Reconciliation Adjustment $/kWh				$0.0256835	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				($0.0004917)	Schedule 2, Line 7
7	Forecasted Retail FUEL Rate $/kWh				$0.0251918	Line 5 + Line 6

Line No.	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	Source
8	Distribution Line Loss Factors	1.00583	1.01732	1.04687	Line Loss Study 2009
9	FUEL Rates $/kWh	**$0.0253387**	**$0.0256281**	**$0.0263725**	Line 7 * Line 8

Schedule 1: This schedule reflects DP&L's estimates of the monthly fuel costs it expected to incur during the period December 2013[14]. As shown on lines 1-3 of Schedule 1, the categories included DP&L's forecasted fuel costs for December 2013, which totaled $32.928 million

[14] January and February 2014 are not within the 2013 audit period.

(column E), less amounts assigned to Off-System Sales which totaled $9.161 million, which resulted in forecasted net Retail Costs of $23.768 million. As shown on line 4 of Schedule 1, the Company included its forecasted Generation Level Retail Sales which totaled 925.406 million kWh for the period December 2013. The Company then calculated its retail fuel rate before Reconciliation Adjustment of $0.0256835 per kWh by dividing the net Retail Costs of $23.768 million by the forecasted Generation Level Retail Sales as shown on line 4. The Company reflected a Reconciliation Adjustment for the period June through August 2013 (see Schedule 2 discussion below) of ($0.0004917) per kWh on line 6. DP&L added its Reconciliation Adjustment to the $0.0256835 per kWh noted above to derive its forecasted retail fuel rate of $0.0251918 per kWh as shown on line 7 of Schedule 1. After applying the line loss factors of 1.00583, 1.01732 and 1.04687 cents per kWh for the High Voltage & Substation, Primary and Secondary & Residential voltage levels, the Company calculated fuel rates at the distribution level of $0.0253387, $0.0256281 and $0.0263725 cents per kWh as shown on line 9.

Exhibit 5-15. Reconciliation Adjustment – June through August 2013

THE DAYTON POWER AND LIGHT COMPANY
Case No. 12-2881-EL-FAC
FUEL Rider
Reconciliation Adjustment (RA)

Line No.	(A) Description	(B) Jun-13	(C) Jul-13	(D) Aug-13	(E) Total	(F) Source
1	Actual FUEL Cost	$9,389,982	$11,618,922	$10,264,988	$31,273,892	Accounting Records
2	Actual Revenue Recovery	($9,600,250)	($11,912,883)	($11,399,983)	($32,913,116)	Accounting Records
3	Prior Reconciliation Under Recovery				$1,036,185	2013 Summer Quarter Reconciliation
4	Under (Over) Recovery				($603,039)	Line 1 + Line 2 + Line 3
5	1-Month's Under (Over) Recovery				($201,013)	Line 4 / 3
		Dec-13	Jan-14	Feb-14		
6	Forecasted Sales	408,787,139	0	0	408,787,139	
7	**Forecasted RA Rate $/kWh**				($0.0004917)	Line 5 / Line 6

Schedule 2: Line 1 of Schedule 2 reflects DP&L's actual fuel costs that were incurred during June through August 2013, which totaled $31.274 million (column E). Line 2 of Schedule 2 reflects DP&L's actual revenues for the same period, which totaled $32.913 million. The difference between the Company's actual fuel costs and actual revenues, and the addition of the prior reconciliation under-recovery shown on line 3, results in an over-recovery in the amount of $603,039, as shown on line 4. Line 5 reflects the 1-month's over-recovery of $201,013, which is derived by dividing the over recovery on line 4 by three months. Line 6 of Schedule 2 reflects DP&L's forecasted sales for the period December 2013, which totals 408.787 million kWh (column E). The Company derived its Reconciliation Adjustment of ($0.0004917) per kWh (also shown on Schedule 1, line 6) by dividing the 1-month's over-recovery of $201,013 by its forecasted sales for the December 2013 period.

Exhibit 5-16. Forecasted Quarterly Rate – Workpaper 1, December 2013

THE DAYTON POWER AND LIGHT COMPANY
Case No. 12-2881-EL-FAC
FUEL Rider

Line No.	(A) Description	(B) Dec-13	(C) Jan-14	(D) Feb-14	(E) Total
	Forecasted Costs ($)[1]				
1	Steam Plant Generation (501)	$27,653,230	$0	$0	$27,653,230
2	Steam Plant Fuel Oil Consumed (501)	$1,116,459	$0	$0	$1,116,459
3	Steam Plant Fuel Handling (501)	$829,597	$0	$0	$829,597
4	Steam Plant Gas Consumed (501)	$0	$0	$0	$0
5	Coal Sales (456)	$0	$0	$0	$0
6	Heating Oil Realized Gains or Losses (456)	$4,777	$0	$0	$4,777
7	Allowances Consumed (509)	$0	$0	$0	$0
8	Cost of Fuel, Gas and Diesel Peakers (547)	$0	$0	$0	$0
9	Purchased Power (555)	$3,258,486	$0	$0	$3,258,486
10	Purchased Power Realized Gain/Losses (421 & 426)	$0	$0	$0	$0
11	Allowance Sales (411.8 & 411.9)	$0	$0	$0	$0
12	Emission Fees (506)	$65,771	$0	$0	$65,771
13	Total Costs	$32,928,319	$0	$0	$32,928,319
14	Assigned to Off-System Sales[1]	($9,160,624)	$0	$0	($9,160,624)
15	Retail Costs	$23,767,695	$0	$0	$23,767,695
16	Total Forecasted Generation Level Retail Sales[1]	925,406,442	0	0	925,406,442
17	Retail FUEL Rate $/kWh				$0.0256835
	Reconciliation Adjustment				
18	Under (Over) Recovery				($201,013)
19	Forecasted RA Rate $/kWh				($0.0004917)

Line No.	Line Loss Adjustment	Distribution Loss Factor[2]	Rate at Distribution Level
20	High Voltage & Substation	1.00583	$0.0253387
21	Primary	1.01732	$0.0256281
22	Secondary & Residential	1.04687	$0.0263725

Line No.	Standard Offer Metered Level Sales and Revenue Forecast	Winter FUEL Rider kWh	Winter FUEL Rider Revenue $
23	High Voltage & Substation	32,270,443	$817,691
24	Primary	4,086,863	$104,739
25	Secondary & Residential	355,508,241	$9,375,641
26	Total	391,865,547	$10,298,071

Notes: [1] Data from Corporate Model
[2] Distribution Loss Factors from 2009 Line Loss Study

Workpaper 1: Column A of this workpaper (lines 1-13) reflects a breakout of the categories of the forecasted costs that the Company has included in its Fuel Rider for the period of December 2013. Column B provides a breakout of the forecasted amounts associated with each expense category for December 2013, and which totals the $32.928 million shown on Schedule 1. Lines

14 through 17 of Workpaper 1 reflect the forecasted amounts shown on Schedule 1 for DP&L's off-system sales, retail costs, forecasted generation sales and retail fuel rate. Lines 18 and 19 of Workpaper 1 reflect the over-recovery of ($201,013) and the forecasted RA rate of ($0.0004917) per kWh. Lines 20 through 22 of Workpaper 1 reflect the distribution line loss factors and forecasted fuel rates at the distribution level, which are shown on Schedule 1 at lines 8 and 9, respectively and were calculated by multiplying DP&L's forecasted retail fuel rate by each of the distribution line loss factors. Lines 23 through 25 of Workpaper 1 reflect a breakout of DP&L's standard offer metered level sales and revenue forecast. Specifically, Column D reflects forecasted kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels of 32.270 million kWh, 4.087 million kWh and 355.508 million kWh, respectively. The Company's forecast totals 391.866 million kWh as shown on line 26. Column E of Workpaper 1 reflects the Company's forecasted Fuel Rider revenue for each voltage level, which was calculated by multiplying the kWh associated with each of the voltage levels referenced above by the forecasted fuel rates at the distribution level. The Company's forecasted Fuel Rider totals $10.298 million as shown on line 26.

Quarterly FUEL Rider Filing – Showing Reconciliation Adjustment for September 2013 through August 2014

Exhibit 5-17. Reconciliation Adjustment – September 2013 through August 2014

Reconciliation Adjustment (RA)

Line No.	(A) Description	(B) Actual Fuel Costs	(C) Actual Revenue Recovery	(D) (Over)/Under (D) = (B) + (C)	(E) Carrying Costs	(F) Total (F) = (D) + (E)	(G) YTD[1]	(H) Source
1	Prior Period					$13,122	$13,122	Accounting Records
2	September-13	$8,978,305	($10,297,310)	($1,319,005)	$0	($1,319,005)	($1,305,884)	Accounting Records
3	October-13	$8,226,366	($8,298,782)	($72,416)	$0	($72,416)	($1,378,300)	Accounting Records
4	November-13	$8,672,253	($8,477,222)	$195,031	$0	$195,031	($1,183,269)	Accounting Records
5	December-13	$10,869,320	($9,490,321)	$1,378,999	$0	$1,378,999	$195,730	Accounting Records
6	January-14	$13,619,865	($11,057,984)	$2,561,880	$6,083	$2,567,963	$2,763,693	Accounting Records
7	February-14	$11,497,955	($10,927,437)	$570,518	$12,559	$583,077	$3,346,770	Accounting Records
8	March-14	$11,983,424	($9,037,325)	$2,946,100	$19,854	$2,965,953	$6,312,724	Accounting Records
9	April-14	$4,762,891	($4,480,526)	$282,365	$26,585	$308,950	$6,621,673	Corporate Forecast
10	May-14	$4,661,643	($4,303,605)	$358,038	$28,013	$386,051	$7,007,725	Corporate Forecast
11	June-14	$7,454,474	($7,454,474)	$0	$8,452	$8,452	$7,016,177	Corporate Forecast
12	July-14	$8,218,560	($8,218,560)	$0	$5,303	$5,303	$7,021,480	Corporate Forecast
13	August-14	$7,848,761	($7,848,761)	$0	$1,733	$1,733	$7,023,213	Corporate Forecast
14	(Over)/Under Recovery						$7,023,213	Line13
15	(Over)/Under Recovery Through May 2014						$7,007,725	Line 10
16	10% Quarterly Threshold						$2,352,179	(Sum of Column B, Lines 11 - 13) * 10%
17	Amount Exceeding Threshold						$4,655,545	Line 15 - Line 16
18	Total (Over)/Under Recovery						$2,367,668	Line 14 - Line 17
				Jun-14	Jul-14	Aug-14		
19	Forecasted Generation Level Sales			312,297,524	352,748,056	335,215,386	1,000,260,966	
20	**Forecasted RA Rate $/kWh**						$0.0023670	Line 18 / Line 19

[1] YTD = current month Total + previous month YTD total

Schedule 2: Column B of Schedule 2 reflects DP&L's actual fuel costs that were incurred during September 2013 through August 2014, which totaled $106.794 million. Column C of Schedule 2 reflects DP&L's actual revenues for the same period, which totaled $99.892 million. The difference between the Company's actual fuel costs and actual revenues results in an under-recovery in the amount of $6.902 million, as shown in column D. Column E reflects the carrying costs for the period of January through August 2014, which totals $108,582. The under-recovery for the period of September 2013 through August 2014, the addition of the prior reconciliation over-recovery shown on line 1, and the additions of the carrying costs for the January through August 2014 period, resulted in a YTD under-recovery of $7.023 million (column G, line 14). The YTD under-recovery through May 2014 of $7.008 million exceeded the 10% quarterly threshold of actual fuel cost for the period June through August 2014 of $2.352 million by $4.656 million. The difference between YTD under-recovery through August 2014 and the amount exceeding the quarterly actual fuel cost threshold resulted in a total under-recovery of $2.368 million. Line 19 of Schedule 2 reflects DP&L's forecasted generation level sales for the period June through August 2014, which totals 1.000 billion kWh (column G). The Company derived its Reconciliation Adjustment of $0.0023670 per kWh by dividing the total under-recovery of $2.368 million by its forecasted sales for the period June through August 2014.

FUEL Rider Deferrals

In its Opinion and Order dated June 24, 2009 regarding DP&L's October 10, 2008 application for a Electric Security Plan ("ESP"), in Case No. 08-1094-EL-SSO, the Commission approved an ESP and FUEL Rider for DP&L for a three-year period January 1, 2010 through December 31, 2012. In an Entry dated December 19, 2012, states:[15]

> Section 4928.141, Revised Code, provides that the rate plan of an electric distribution utility shall continue until a standard service offer is first authorized under Section 4928.142 or Section 4928.143, Revised Code. Similarly, Section 4928.143(C)(2)(b), Revised Code, directs that if a utility terminates an application for an ESP, the Commission will issue an order to continue the provisions, terms, and conditions of the utility's most recent standard service offer, along with any expected increases or decreases in fuel costs, until a subsequent offer is authorized.

On December 12, 2012, DP&L filed a revised application for an SSO pursuant to Section 4928.141 of the Revised Code, and which was for approval of a revised ESP in accordance with Section 4928.143 of the Revised Code[16]. In its Opinion and Order dated September 4, 2013 in Case No. 12-426-EL-SSO, the Commission approved DP&L's application for a second ESP for the period January 1, 2014 through May 31, 2017. In accordance with the referenced Opinion and Order as well as the Opinion and Order issued in Case No. 08-1094-EL-SSO, the Commission ordered two audits of the Fuel Rider and AER, with the first audit covering the period 2013 and the second audit covering 2014.

[15] Entry in Case No. 08-1094-EL-SSO, dated December 19, 2012, page 3.

[16] DP&L's revised application was filed to correct errors discovered in its initial ESP application, which was filed on October 5, 2012.

DP&L records its fuel deferrals in Account 1823000/2543000.

It should be noted that in the prior review periods 2010, 2011 and 2012, DP&L had filed an Annual Fuel Filing pursuant to the 2009 ESP Stipulation, which, as noted above, expired on December 31, 2012. However, DP&L has advised that the 2013 ESP Opinion and Order, which supersedes the 2009 ESP Stipulation, contains no requirement for an Annual Fuel Filing. Therefore, DP&L has not made such a filing for the 2013 review period. DP&L further stated that there is no loss of information since the prior annual filings were just a compilation of the quarterly filings made during the year, and such quarterly filings continued to be made throughout 2013.

The Company's responses to data requests LA-2013-49 and LA-2013-50 produced DP&L's Excel files and supporting workpapers for the FUEL Rider filings and RA adjustments.

Variances Between Forecasted and Actual Fuel Rider Revenues and Costs

During Larkin's review of DP&L's forecasted Fuel Rider revenues and expenses for the 2010 review period, Larkin concluded that understanding the reason(s) for why variances occur between forecasted and actual Fuel Rider revenues and expenses could lead to improvements in the accuracy of such future forecasts. As a result of that conclusion, Larkin made a recommendation which was incorporated into the Stipulation and Recommendation dated October 5, 2011. Specifically, Item No. 9 from the Stipulation states:

> The Parties agree that DP&L will "prepare explanations of differences between forecast and actual Fuel Rider revenues, and between forecast and actual Fuel Rider costs" in time for the review by the auditor for the 2011 Audit, and will provide these explanations to the Parties.
>
> (Footnote omitted)

Pursuant to confirming that DP&L was in compliance with this item from the 2011 Stipulation and Recommendation, Larkin asked the Company to provide a narrative which explains the variances between the forecasted and actual Fuel Rider revenues and expenses. In response, DP&L provided a summary of variances between forecasted and actual 2013 Fuel Rider revenues and expenses, which is replicated in 5-18 as well as a monthly schedule titled "2013 Fuel Variance Analysis" for each month January through December 2013.

Exhibit 5-18. Summary of Variances Between Forecast And Actual FUEL Rider Revenues and Costs during 2013

[redacted]

Each of the monthly Fuel Variance Analysis reports provided an explanation for the variances reflected for each respective month. For example, the variances noted in the January 2013 Fuel Variance Analysis is replicated in Exhibit 5-19 below.

Exhibit 5-19. Explanation of Variances Between Forecasted and Actual Fuel Rider Revenues and Costs for January 2013

[redacted]

During 2013, [redacted]. Because the Fuel Rider rate is bypassable, once customers switch to an alternative provider, they are no longer subject to paying rates

[17] Customers can opt to obtain transmission and generation services from a Certified Retail Electric Service (CRES) provider. CRES providers operating in DP&L's service territory include DP&L's affiliate DPLER and other non-affiliated providers.

established pursuant to the Fuel Rider. Consequently, customers who were DP&L retail jurisdictional customers during a period where an undercollection of Fuel costs occurred, but who have selected an alternative provider, avoid the obligation to make future payments for the Fuel Rider deferral (undercollection) that had occurred in periods when the customers had been DP&L retail jurisdictional customers subject to the Fuel Rider. Paying for the Fuel Rider undercollection thus becomes the responsibility of only the remaining DP&L retail jurisdictional customers who have not switched providers. Customer switching is discussed in more detail in a later section of this report

Potential for a Terminal Undercollected Balance

Data request LA-2013-59 asked the Company to provide the most current estimates and projections of the deferred Fuel Rider costs currently through to the end of the ESP term. This request also asked the Company to indicate DP&L's estimate of the collection period necessary to completely recover the deferred Fuel Rider costs after the ESP terms ends and to provide an estimate of the prospective surcharge and rate impact. In response, DP&L stated that providing estimates is not possible. DP&L also stated that systematic over- or under-collections were not built into the fuel recovery process, and therefore did not allow for an estimate of the balance as of the end of the ESP period. The Company's goal is to minimize any over or under-collections, and thus any end-of-period true-up effects on rates will be minimal and be necessary for a short period of time.

Minimum Review Requirements

As noted above, Larkin referred to the objectives and procedures outlined in Appendix E of former Chapter 4901:1-11 of the Ohio Administrative Code as guidance for the review requirements of this project. The purpose of the Uniform Financial Audit Program Standards and Specifications for the Electric Fuel Component is to provide uniform standards and specifications as guidelines for an independent auditing firm which conducts an EFC "financial audit"[18] pursuant to former section 4905.66(B)(2) of the Revised Code and former rule 4901:1-11-09 of the Administrative Code. The EFC "financial audit" program is only a guide for the auditor and should not be used to the exclusion of the auditor's initiative, imagination and thoroughness.

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

> The auditor's review shall include, but not be limited to, a review of:
>
> Purchasing procedures for Fuel procurement not under long-term contracts;
>
> Procedures for accounting for Fuel receipts, testing, and payments;
>
> Procedures for weighing, testing and reporting coal burned;

[18] As noted above, the review of DP&L's quarterly FUEL Rider filings were conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants.

Procedures for amortizing nuclear Fuel costs corresponding to nuclear generated energy;

Procedures for recording purchases and interchanges;

Procedures for accounting treatment of emission allowances; and

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

Larkin reviewed DP&L's response to data request LA-2013-1 for the Company's procedures for accounting for fuel receipts, testing of samples to ensure quality, and payments to vendors. DP&L provided several narratives from its Accounting Policies and Procedures Manual which discussed the various aspects of the Company's procedures with respect to fuel receipts, testing and payments to vendors. Each of these areas is discussed below.

Accounting for Coal Purchases, Consumption and Inventory

The Corporate Accounting Department oversees DP&L's coal accounting process. Information obtained from DP&L's three operated generation stations[19], the Risk Management/Commodity Settlement Department and fuel bills from Cincinnati Gas & Electric ("DUKE") and Columbus Southern Power ("AEP") is used to account for the Company's coal purchases. As it is responsible for covering the settlement of coal transactions, the Risk Management/Commodity Settlements Department forwards monthly coal transaction[20] data from the three generating stations to the Corporate Accounting Department. The Company records fuel inventory in FERC Account 151 by using a moving weighted average and expenses it based on monthly coal usage. Specific procedures are as follows:

[redacted]

[redacted]

[redacted]

[19] DP&L's operated generation stations include the O.H. Hutchings, J.M. Stuart and Killen generating stations.

[20] DP&L's coal transaction activity consists of coal purchases (recorded in FERC Acct 151), consumption (recorded in FERC Acct 501) as well as transfers or other relevant coal related information on a monthly basis.

[21] [redacted]

[redacted]

- [redacted].

Accounting for Gas Purchases, Consumption and Inventory

Corporate Accounting oversees DP&L's gas accounting process and information is obtained from the O.H. Hutchings generation station, the Risk Management/Commodity Settlements Department and monthly Vectren fuel bills. The Risk Management/Commodity Settlements Department addresses the settlement of peaker gas transactions, which consist of purchases, transportation, consumption, transfers and other relevant information related to peaker gas on a monthly basis. Corporate Accounting is tasked with the accounting associated with all peaker gas and O.H. Hutchings monthly gas usage. The peaker gas usage, including transportation demand fees, is charged to FERC Account 547 and O.H. Hutchings gas usage, including transportation demand fees, is charged to FERC Account 501. Specific procedures are as follows:

[redacted]

[22] CCD/CD refers to DP&L's partners at its jointly owned generating stations. CCD is comprised of Cincinnati Gas & Electric ("DUKE"), Columbus Southern Power ("AEP") and DP&L and CD is comprised of DUKE and DP&L. DP&L operates J.M Stuart on behalf of CCD and Killen on behalf of CD. AEP operates Conesville #4 on behalf of CCD and DUKE operates Beckjord #6 and Zimmer on behalf of CCD and East Bend and Miami Fort on behalf of CD.

[23] Gas Deal Entry System ("GDES") is an integrated, Fuel planning, procurement, logistics, inventory and cost accounting system used for peaker gas. GDES integrates information from pipelines, traders deals and multiple plants.

[redacted]

Accounting for Fuel Oil Purchases, Consumption and Inventory

Corporate Accounting oversees DP&L's fuel oil accounting process using information obtained from the generating stations, Risk Management/Commodity Settlements' FMS system, DP&L's Oracle system, copies of oil cash vouchers, as well as fuel bills from DUKE and AEP. Risk Management addresses the settlement of fuel oil purchases and Corporate Accounting accounts for all monthly fuel oil transactions, as well as the verifying, compiling and billing to DP&L's CCD/CD partners. The Company accounts for fuel inventory by using a moving weighted average and fuel oil is expensed on a monthly basis as it is consumed. Specific procedures are as follows:

[redacted]

Accounting for Coal Sales

Corporate Accounting oversees DP&L's coal sales accounting process by using information obtained from Risk Management/Commodity Settlements' FMS system as well as fuel bills from DUKE and AEP. Risk Management/Commodity Settlements addresses the settlement of coal sale transactions and forwards monthly Coal Sales Period Sales Profit/Loss Reports for DP&L operated generating stations to Corporate Accounting, which allocates the CCD/CD partners' share accordingly. Corporate Accounting is also tasked with compiling, billing and the accounting of coal sales gains or losses to and from the CCD/CD partners on a monthly basis. The Company records coal sales gains and losses by comparing the sales price to the cost of the coal sold and gains and losses are recorded when each transaction has been finalized and realized. Specific procedures are as follows:

[redacted]

[redacted]

Coal Pile Inventory

A physical coal pile inventory is taken annually on July 31. Central Services meets with each Station Manager and appoints a Station Inventory Representative. The One Project Coordinator[24] is chosen by the Vice President (or his designate) of Central Services from the field of Station Inventory Representatives.

Station Inventory Representatives are responsible for ensuring that all activities performed by the personnel and contractors are completed correctly and on time. Pursuant to this meeting these objectives, the Station Inventory Representative initiates a kick-off meeting, the purpose of which is to review the roles and responsibilities of all of the parties involved in the coal pile inventory process. The topics of this kick-off meeting include (1) contractor requested measurement locations; (2) additional grooming requests; (3) equipment needed to secure measurements in difficult to access locations; and (4) daily communication requirements. Once the aforementioned activities have been finalized, the Project Coordinator informs Internal Audit and Corporate Accounting of the schedule of activities at least ten work days prior to any on-site work.

The contractor submits the inventory report to each Station Inventory Representative. Once the report has been completed and reviewed and any necessary corrections made, it is then forwarded to the Station Manager for approval, and is then submitted to other areas of the Company. Specific procedures are as follows:

[redacted]

[24] The Project Coordinator is responsible for contacting and selecting contractors to determine density and volumetric values and producing the final coal inventory report.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted].

Each Station Inventory Representative is responsible for the inventory report at his/her respective station. Each of these reports must be developed under the following guidelines:

[redacted]

- [redacted]

The contractor's inventory reports shall include the following results:

[redacted]

[redacted]

[redacted]

[25] Density is valid if it is within the boundaries of the pile, above the base elevation of the pile, and below the theoretical maximum density from the sample's specific gravity.

[redacted]

The Station Inventory Representative issues the original draft of the contractor's report to Internal Audit and Corporate Accounting within two weeks after receiving all relevant information.

[redacted]

- [redacted]

All documentation related to the flyover, density and material balance is retained for a minimum of three years.

Coal Sales Billing

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]

When payment is received from the Counterparty:

[redacted]

[redacted]

[redacted]

- [redacted]

<u>Fuel Oil Payment</u>

[redacted]

[redacted]

[redacted]

When Settlements receives invoices in the fuel oil mailbox:

[redacted]

[redacted]

In the event the invoice data does match the manually entered data from the FMS into the EFOS and/or the pricing information:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

Coal and Limestone Payment

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
    - [redacted]
    - [redacted]
    - [redacted]
    - [redacted]

[redacted]

[redacted]

Larkin also reviewed the Company's procedures for weighing, testing and reporting coal burned per data request LA-2013-2.

DP&L does not have nuclear generation, so the provisions of E (4) do not apply.

[redacted]

[redacted]

[redacted]

[redacted][27].

[26] PJM sales estimates are trued-up in the following calendar month.

[27] A MISO settlement statement which lists any true-ups to sales and purchases is provided to the Accounting Department the following month.

[redacted]

Jointly Owned Generation

DP&L participates in seven jointly owned power plants, as described in the Company's response to LA-2013-4. The seven jointly owned power plants, and DP&L's ownership percentage as presented in AES Corporation's 2013 Form 10-K, are provided in Exhibit 5-20.

Exhibit 5-20. DP&L's Ownership Percentage of Jointly Owned Power Plants[28]

Plant	Co-owners	Operating Company	DP&L Ownership Percentage
J.M. Stuart	Duke; Columbus Southern Power ("AEP")	DP&L	35%
Conesville #4	Duke; Ohio Power	Ohio Power	17%
Beckjord #6	Duke; AEP	Duke	50%
Zimmer	Duke; AEP	Duke	28%
Killen	Duke	DP&L	67%
East Bend #2	Duke	Duke	31%
Miami Fort #7 & 8	Duke	Duke	36%

The Corporate Accounting Department oversees DP&L's CCD/CD fuel billing process. The Company obtains information from its operated generating stations, the Risk Management/Commodity Settlements Department as well as fuel bills received from DUKE and AEP.

DP&L accounts for fuel at jointly owned generation plants as follows. The same accounting methodology is used at all seven jointly owned power plants:

[redacted]

[28] The information shown in the table is correct as rounded. We note that the precise ownership of Zimmer is 28.1% and Conesville is 16.5%.

[redacted]

Larkin asked DP&L to identify any fuel amounts being deferred which affect the review period and to identify any such amounts by account and explain the reason for the deferral. In response to LA-2013-5, the Company provided a brief narrative on each of the FERC accounts that are included in the Fuel Rider and for which Larkin summarized in the section of this report titled: "Accounts Included in DP&L's Fuel Rider" in Chapter 6 on pages 5-6. The response to LA-2013-5 also included a summary of the Company's deferral amounts (by FERC account) as of December 31, 2013. This summary, which is reproduced in Exhibit 5-21, used the overall deferred balance as of December 31, 2012 as the starting point.

Exhibit 5-21. DP&L's Deferral Amounts by FERC Account as of December 31, 2013

[redacted]

Review Related to Coal Order Processing

According to the response to EVA-2013-1-3, DP&L does not use purchase requisitions or purchase orders for coal, natural gas or oil. Instead, an executed coal contract is used as authorization for DP&L to accept and pay for shipments of coal that meet the requirements of the contract until the contract obligations have been fulfilled. DP&L's response to data request EVA-2013-1-1 included copies of the coal contracts, which were reviewed by EVA. In addition, the Company purchases physical natural gas and oil for delivery to its generating stations at the prevailing market price. As part of this process, DP&L confirms that supplier invoices equal the market price and verifies that the quantity delivered is accurate.

To review the Company's processing of fuel invoices, Larkin obtained copies of cash vouchers and payment documentation for fuel purchases recorded in July 2013. This documentation was provided in the response to data request LA-2013-9.

The information provided in LA-2013-9 included an eight page summary of payment vouchers and invoices for the period July 2013. For each invoice listed on the summary pages, Larkin was able to trace the amount listed on the summary to the actual invoice. In addition, Larkin traced all of the invoices to general ledger account 151. No exceptions were noted.

Fuel Ledger

Data request LA-2013-10 requested DP&L's fuel ledgers for the period January through December 2013. In response, DP&L referred to the response to LA-2013-67, which requested that DP&L provide detailed general ledger pages for each of the following accounts: 151, 182.4, 254, 501, 456, 506, 509, 547, 555, 421, 426, 411.8 and 411.9 (see additional discussion below).

BTU Adjustments

Data request LA-2013-11 asked DP&L to provide documentation for Btu adjustments for fuel purchases recorded in July 2013 [redacted]

[redacted]

Pursuant to the narrative above, the responses to LA-2013-15 and LA-2013-25 refer to the response to LA-2013-11.

Freight And Barge Vouchers

Data request LA-2013-12 asked DP&L to provide freight cash vouchers for two days of coal receipts in July 2013 as well as copies of the portions of the corresponding coal received reports. In response, DP&L stated that it did not receive any coal via rail during any month in 2013.

In data request LA-2013-13, Larkin requested that DP&L provide two cash vouchers from each barge company for coal unloaded at Company plants during July 2013 as well as copies of the portions of the corresponding coal unloading reports and purchase orders. DP&L's barging services are provided [redacted] In response, DP&L provided

[29] Larkin modified the narrative to reference data requests related to the 2013 review period.

copies of invoices from [redacted], cash vouchers (which included data related to coal shipments received at the Killen and Stuart plants during July 2013) as well as a copy of the Barge Unloading Report (which details shipments of coal received in July 2013 for the Killen and Stuart plants). Upon reviewing and comparing the data listed on the documents provided, Larkin was able to trace the coal shipments detailed on the Barge Unloading Report to each of the cash vouchers and [redacted] invoices. No exceptions were noted.

Fuel Analysis Reports

Data request LA-2013-14 asked DP&L to provide the Company's procedures for preparing monthly fuel analysis reports. In its confidential response, the Company stated:

> [redacted]

DP&L has appropriate procedures in place for monitoring the quality of coal received.

Retroactive Escalations

DP&L has a coal supply agreement with [redacted]

Data request LA-2013-16 asked that DP&L identify all pending or approved retroactive escalations that affect fuel cost for the period January through December 2013 [redacted]

[redacted]

In terms of other retroactive escalations, the response to LA-2013-16 also stated that there are [redacted]

Specifically, the response to EVA-2013-1-15 stated that, [redacted]

Review Related To Station Visitation And Coal Processing Procedure

Larkin conducted an onsite field visit to DP&L's Killen Generation station on June 13, 2014. Document requests LA-2013-17 through LA-2013-42 relate to fulfilling the objectives of the station visit and the review of the Company's coal processing procedure from the receipt of coal to the disposition of fly ash.

A description of the Company's coal receiving procedures and controls for shortages, overages, and other discrepancies was provided in DP&L's confidential response to LA-2013-17, and is as follows:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

According to LA-2013-18, DP&L weighs the coal as received in the following manner:

For the Stuart and Killen plants:

[redacted]

[redacted]

[redacted]

- [redacted]

For the Hutchings plant:

[redacted]

- [redacted].

The Company resolves freight bill and car number discrepancies in the following manner:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted].

In its confidential response to LA-2013-19, the Company stated [redacted] The last coal delivery at Hutchings via rail occurred in 2011.

The procedures for how damaged cars are checked and who instigates claims for shortages are as follows:

[redacted]

[redacted]

- [redacted].

In a related question, LA-2013-34 requested a description of how freight bills, barge number and coal quantity and quality discrepancies are handled. Such discrepancies are handled in the following manner:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]

In response to data request LA-2013-35, DP&L described how damaged barges are checked and who instigates claims for shortages:

[redacted]

[redacted]

[redacted]

DP&L's response to LA-2013-21 described the Company's month-end cut-off procedures for coal deliveries and coal burn:

[redacted]

[redacted]

- [redacted].

A description of the Company's coal sampling procedures was provided in response to data request LA-2013-22 and are as follows:

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]

Scale calibration logs for the period January through July 2013 were requested in LA-2013-23. In response, DP&L provided conveyor calibration and feeder calibration records for the Killen and Stuart plants for the entire year. In the event coal scales are inoperable, the following procedures are performed:

- [redacted].

DP&L's procedures for handling coal from the stockpile to the firebox or boiler were requested with data request LA-2013-26. In response, DP&L provided three separate sets of documentation titled "DPL Business Practice" for the Hutchings, Killen and Stuart stations. Each set of these documents outlined a number of coal handling procedures that are performed by personnel at each of the referenced stations. The procedures are specific and detailed for each plant, and include references and helpful diagrams, such as the following diagram (from the Killen station coal handling procedures):

Exhibit 5-22. Diagram of Coal Barge Configuration and Coal Loading Specifications at the Stuart Station

[redacted]

An illustrative example of DP&L's detailed procedures for marking coal samples (from the Hutching Station's coal handling procedures, at page 6) is shown below:

Exhibit 5-23. Description of Coal Sample ID Number components

[redacted]

DP&L's procedures for taking physical inventories of coal are described in the response to LA-2013-27. DP&L's procedures for coal pile inventory are detailed and specific.

DP&L's coal handling and coal pile physical inventory procedure manuals are among the most detailed we have seen.

In addition to the working coal inventory, DP&L maintains a permanent or "base" coal inventory, which is recorded in a plant account and amortized.

In response to data request LA-2013-29, which requested accounting documentation for physical inventory and any related inventory adjustments recorded for the review period, including the general ledger, and fuel stock and consumption records, DP&L provided:

- Physical inventory worksheets for coal and oil
- FMS Period Posting Summary Reports
- FMS Upload Sheets for coal
- Month-end Fuel Oil Activity Reports
- Journal voucher for Fuel Oil Inventory adjustments
- General Ledgers for Accounts 151 (Fuel Inventory) and 501 (Fuel Consumption)

Larkin reviewed DP&L's records and was able to trace the amounts from the FMS Period Posting Summary Reports to the general ledger (Account 501 - Fuel Inventory). With respect to fuel oil, Larkin was able to trace the amounts from the workpapers and journal voucher to the general ledger (Account 501 – Fuel Consumption)

During Larkin's review of the aforementioned documents, it was noted that DP&L made two coal related physical inventory adjustments during the review period. One such adjustment related to the Stuart generation station while the other adjustment related to the Killen generation station. With respect to the inventory adjustment at Stuart, DP&L determined that the adjusted coal inventory totaled [redacted] tons versus a book coal inventory totaling [redacted] tons, which resulted in a physical inventory adjustment of [redacted] ([redacted]). A review of DP&L's inventory adjustment workpapers indicated that the Company allocated the [redacted] tons among Stuart Units 1 through 4 as summarized in Exhibit 5-24 below.

Exhibit 5-24. Summary of Physical Coal Inventory Adjustment at Stuart

[redacted]

As reflected in the Exhibit 5-24, Stuart's physical inventory exceeded its book value by [redacted] after applying DP&L's ownership percentage). As for the inventory adjustment related to Killen, DP&L determined that the adjusted coal inventory totaled [redacted]. The dollar impact of the Killen inventory adjustment is summarized in Exhibit 5-25 below.

Exhibit 5-25. Summary of Physical Coal Inventory Adjustment at Killen

[redacted]

As reflected in the Exhibit 5-25, Killen's physical inventory was [redacted]y [redacted] after applying DP&L's ownership percentage.

The Stuart and Killen inventory adjustments were the subject of an internal audit conducted by AES' Internal Audit group ("IA"), the report of which was issued on January 24, 2014[30]. The IA group classified the coal inventory variances discussed above as low risk. As discussed in Section III of the internal audit report, the IA group recommended that Company management continue with its daily review and analysis of the Coal Movement Verification Process, which identifies outliers [redacted] between vendor scale readings on coal shipments received versus the amounts ordered by each generation station (see additional discussion below). DP&L management agreed with the IA group's recommendation and stated in its Action Plan that DP&L will continue to perform a daily review of coal inventory movement to ensure that any variances are identified, investigated and remedied in a timely manner.

Coal Movement Verification Process

As it relates to the Coal Movement Verification Process ("CMVP"), Larkin requested that DP&L provide the CMVP related documents that pertained to 2013. In its confidential response to LA-2013-2-8, the Company provided copies of the following documentation: (1) Daily Fuels Activity Reports (Stuart); (2) Coal Handling Daily Reports (Stuart); and (3) [redacted] (Stuart and Killen).

In the referenced response, DP&L stated that as a percentage of total barges unloaded, there were relatively few instances during 2013 where a discrepancy [redacted] However, upon reviewing the documentation provided, Larkin noted that there were approximately two dozen pages of the [redacted], some of which are

[30] A copy of this internal audit report was provided in the response to EVA-2013-1-43.

multiple page reports that include various discrepancies of [redacted] between Stuart and Killen. In consideration of the large number of discrepancies noted on the 100 Ton Weight Difference Report, Larkin requested that DP&L explain and reconcile its statement above from the response to LA-2013-2-8. In response to Larkin's inquiry, DP&L stated:

> There are two dozen pages of reports because there is, approximately, a page for each month for two stations - in the case of Killen Station there are four months where there is only one barge that had a deviation of [redacted] and for Stuart Station there are a significant number of pages each month due to the additional documentation that they retained and provided. We noted in the response that the reports also list barges where the origin weight and station weight in FMS are the same - that is a deviation of 0, but contributes to the number of lines on each report. [redacted] However, nearly all of the coal left in barges at Stuart Station is reclaimed by the station in its barge cleaning process - the [redacted] Reports cannot account for those tons on a barge-by-barge basis. Many of the Stuart Station notes describe extremely wet barges or barges where coal cannot be removed from a box end with the station's continuous bucket unloader, but can be removed using a claim shell excavator in the barge cleaning operation.

DP&L further explained that many times, the deviation in tons is due to weather conditions when the coal was initially loaded, transported and held in harbors prior to being unloaded at the generating stations. This can result in a direct increase or decrease in the weight of the coal and can be further exacerbated by wet conditions. The Company provided the following narratives, which it describes as [redacted]

> Station Personnel
>
> [redacted]

Commercial Operations

[redacted]

The Company's response to LA-2013-30 describes the levels of review applicable to DP&L's plant operating statistics. The power plants develop Monthly Station Operating Reports, which are sent by each station's Engineering Department to various departments for cross-checking and reporting. The reports are also sent to the Middle Office, Fuels Department, and Accounting to verify the data used for accounting purposes.

Larkin requested copies of the generating station reports for the review period January through December 2013 that were sent to the Company's general office for incorporation into company statistics and workpapers sufficient to trace the reports to the statistics. DP&L's response to LA-2013-33 provided copies of Hutchings, Killen, and Stuart generating station reports for the period January through December 2013. Attachments to LA-2013-33 reflected the service hours, net heat rate, gross generation, net generation, and startups for each generating unit at the three plants. The attachments also reflect detailed daily and month-to-date information for each generating unit. For example, the monthly information for the Stuart generating station includes details on the following datasets.

Exhibit 5-26. Generating Unit Datasets Used In Stuart Station Monthly Operating Reports for 2013

[redacted]

DP&L has reasonable procedures in place to account for and collect plant fuel burn related information.

Data Request LA-2013-36 asked for the base coal inventory amounts at Stuart Station for both total plant and DP&L's share for 2012 and 2013 that shows any adjustments. In response, the Company provided the amounts shown in Exhibit 5-27 and stated that [redacted].

Exhibit 5-27. Base Coal Inventory at Stuart Station for 2012 and 2013

[redacted]

Review Related to Coal Transfers Between Generating Stations

Documentation related to the treatment of coal transfers between power plants was provided in response to LA-2013-37. The documentation provided related to the transfer of [redacted] from Killen to Stuart. The specifics of this transfer are discussed below.

[redacted] Coal Transfer

According to LA-2013-37, the transfer of the tons of [redacted] coal from Killen to based on a trade dating back to January 31, 2010, although delivery took place in March 2013. The components related to this transfer are summarized in Exhibit 5-28 below.

Exhibit 5-28. Summary of [redacted] Transfer from Killen to Stuart

[redacted]

As shown in Exhibit 5-28, this transfer resulted in a $3,357 gain to Stuart. Upon Larkin's request for supporting documentation for the recording of this gain, the Company provided a copy of the journal posting to the general ledger which reflects the credit for $3,357 to FERC Account 456 and Larkin confirmed that it was posted to the general ledger in April 2013. It was unclear whether the $3,357 gain flowed through the Fuel Rider and upon Larkin's inquiry, DP&L stated that the $3,357 gain was embedded in a larger gain for Stuart in the amount of $6,763, which was recorded in April 2013. Larkin reviewed the entries for FERC Account 456 in the Fuel Recovery Oracle Report for April 2013, and noted that the $6,763 gain for Stuart was reflected. Larkin confirmed that the $6,763 gain was also reflected in the monthly Excel workbook for April 2013 (provided in LA-2013-50), and thus, flowed through the Fuel Rider.

Hutchings Generating Station

As previously discussed, Hutchings Unit 4 has been retired and the Company has no remaining capacity obligation with PJM pursuant to an agreement between DP&L and the EPA. Specific to that agreement, the response to LA-2013-2-4 stated in part:

[redacted]

Data request LA-2013-2-4 also requested that DP&L show by month in 2013 how it disposed of the Hutchings coal inventory through the June 1, 2013 deactivation, including identifying the quantity and cost of the remaining coal at the plant when it was shut down. In response, the Company stated that the coal was not disposed of and referred to the response to LA-2013-2-3, which indicated that for each month of 2013, DP&L reported Hutchings coal inventory totaling 15,337 tons with an inventory cost of $1,335,495[31]. This response also indicated that none of this coal was burned during any month of 2013 nor was any of the related cost at plant shutdown charged to the Fuel Rider. Per the response to LA-2013-2-4, the Hutchings related costs that were included in the Fuel Rider during 2013 are reflected in the monthly workbooks provided in LA-2013-50. The exhibit below provides a summary of the 2013 Hutchings related costs that were included in the Fuel Rider.

Exhibit 5-29. Summary of Hutchings Related Costs in Fuel Rider in 2013

[redacted]

As shown in Exhibit 5-29, Hutchings related costs included in the Fuel Rider in 2013 totaled $156,390.

Review Related To Fuel Supplies Owned Or Controlled By The Company

DP&L's confidential response to data request LA-2013-43 stated that [redacted].

Review Related To Purchased Power

DP&L's response to LA-2013-44 provided documentation relating to the review of purchased power. Specifically, LA-2013-44 asked "For DPL, for purchases of power recorded in July 2013 that are included in the Fuel Rider, please provide the related invoices, and paid cash voucher or cash payment receipt". In its confidential response, the Company provided (1) [redacted]

[31] This information was also provided in response to EVA-1-19.

[redacted]. Larkin was able to trace the amounts from [redacted] to the general ledger and/or the RA workpapers provided with LA-2013-50 (see additional discussion below). As it relates to the [redacted], the Company provided the following narrative:

[redacted]

Through reviewing the "Fuel Clause Purchase Sale Summary – 7/1/2013 – PJM Summary" (PJM Reconciliation), Larkin was able to tie out the July 2013 power purchases from PJM to the amounts included in the FUEL Rider. Other than some immaterial variances, no exceptions were noted. DP&L also provided PJM reconciliation worksheets for the other 11 months of 2013 in the response to LA-2013-2-6.

With respect to system dispatch, Data Request LA-2013-45 inquired as to whether the dispatch related to the Company's generating units were under the control of PJM during the January through December 2013 review period. In its confidential response, DP&L stated that [redacted]

[32] DP&L stated that the "Fuel Recovery 2010" documents represent the Company's general ledger.

[redacted]

LA-2013-46 asked: "During the review period were any of the Company's generating units designated by PJM as "must run" for reliability or voltage control purposes? If so, please identify the units, hours, and cost/Mwh for each "must run" situation at the Company's generating units during this period." In its confidential response, DP&L stated that during the review period, there [redacted]

Exhibit 5-30. "Must Run" Generating Units For Stuart Diesels - November 2013

[redacted]

Demurrage

Demurrage, in general, relates to the delaying of a ship, barge, railway wagon, etc., caused by the charterer's failure to load, unload, etc., before the time of scheduled departure and to the extra charge required as compensation for such delay. DP&L incurs demurrage charges related to the barging of coal and other materials primarily to the Stuart and Killen plants it operates, which are located on the Ohio River within a few miles of each other and are served by barge delivery, when delays occur in the unloading of such barges. The Company stated in response to LA-2013-39 that [redacted].

Managing barge deliveries to minimize demurrage charges is one aspect of the overall least-cost management of fuel procurement. DP&L records demurrage charges as part of its cost for the transportation of coal. Demurrage costs are recorded into the coal inventory account (Account 151) and become part of the fuel cost for coal (Account 501) when the coal is burned.

According to the confidential response to LA-2013-38, during the 2013 review period, DP&L incurred net demurrage costs in a credit amount totaling [redacted] However, a footnote provided in that same response stated:

[redacted]

In response to Larkin's request that the Company explain and reconcile this discrepancy, DP&L stated:

[redacted]

Larkin reviewed the referenced section of the Ingram contract and noted where it states:

[redacted]

[redacted]:

Exhibit 5-31. Net Demurrage Charges For Years 2011 through 2013

[redacted]

It should be noted that the schedules provided in LA-2013-38 and LA-2013-40 (from which the amounts in Exhibit 5-31 were taken) represent total plant amounts and not solely DP&L's share.

DP&L provided additional explanations of how it weighs and evaluates the cost of incurring demurrage with other factors in managing its coal inventory and plant coal burn in its response to LA-2013-41:

[redacted]

[redacted]

When it is evaluating potential optimization trades, DP&L factors demurrage costs into its evaluation. DP&L's optimization cost evaluation Excel files include provisions for demurrage costs. However, during Larkin's review of the 2011 Fuel Rider, it was discovered that the Excel files used for Optimizations A through C from that review period were generated from an earlier version of the optimization model, which did not incorporate demurrage costs[33]. This led to Larkin's recommendation in the 2011 report that DP&L should continue to include the demurrage differences analysis in its evaluation of optimization trades. Larkin reviewed the Excel files for Optimizations A-M in the 2012 review period and confirmed that DP&L did incorporate demurrage costs in its evaluation of the 2012 optimizations. The results of DP&L's optimization trades in 2012 are addressed in additional detail in other sections of this report.

As described in the response to LA-2012-41, DP&L has taken various actions in 2012 throughout the year in efforts to mitigate demurrage costs.

Review Related to Service Interruptions and Unscheduled Outages

Documentation relating to the review of Service Interruptions and Unscheduled Outages includes DP&L's responses to data requests LA-2013-47 and LA-2013-48.

Exhibit 5-32 illustrates a few examples of the longest forced outages at DP&L's generating units during 2013 from DP&L's response to part 1 of LA-2013-48:

[33] Optimizations D-L from the 2011 review did incorporate demurrage costs.

Exhibit 5-32. Examples of Longest Forced Outages

[redacted]

Data request LA-2013-47 asked about customer power supply interruptions during the review period January through December 2013. In response, DP&L stated that none of its customers experienced an interruption as a result of a lack of power supply during the January through December 2013 review period. DP&L also stated that some of its customers have agreements with a Certified Retail Electric Service (CRES) provider or through a PJM-administered program for Curtailment Service Providers in which supply interruptions are permitted under the terms and conditions set forth in the related contracts and/or PJM procedures.

LA-2013-48 requested DP&L to identify instances during the review period in which the Company's generating units experienced unscheduled outages and to provide documentation concerning the following:

1. The cause(s) of the outage.
2. Steps taken by the Company to minimize the impacts of the unscheduled outage.
3. Efforts made to secure replacement power, if applicable.
4. The methodology employed to price the replacement power, if applicable.
5. The cost impacts resulting from the periods during which the unscheduled outage occurred.

In response to item 1, DP&L provided an Excel file titled "LA-2013-48 Part 1", which listed information relating to unscheduled outages at DP&L's generating units during the review period, including the unit name, event type, starting and ending dates of the outage, category name, code and a brief description of what caused the unscheduled outages. An example of this file was presented as Exhibit 5-32 above.

With respect to items 1 through 3, DP&L explained that the following three points need to be made before discussing the steps taken by the Company to minimize the impacts of the outages: (1) Jurisdictional customers are provided the least cost generation units, which means that jurisdictional customers receive the cost of DP&L's generating units to meet their needs beginning with the lowest cost unit; (2) DP&L is part of the PJM RTO and as such participates in the PJM energy market, which uses PJM's Security Constrained Economic Dispatch Model

("SCED") in order to dispatch and ensure that the least cost unit will be dispatched system wide to meet the next MW of load needed; and (3) DP&L's position is managed on a portfolio basis so that all available resources are considered when determining the impact of the unscheduled outages. The result is that DP&L's jurisdictional customers receive least cost supply stacking from the Company's generating units coupled with an efficient market for energy through participating in the PJM market.

DP&L explained further that in order to minimize the impacts of an unscheduled outage [redacted]

With respect to item 4, which requested the methodology employed to price the replacement power (if applicable), the Company stated:

> [redacted]

With respect to item 5, the cost impacts resulting from the periods during which the unscheduled outage occurred, DP&L stated that the cost impact to customers of each unscheduled outage depends on the retail position at the time of the outage and where the unit is in the supply stack. If the generator was not serving retail load on the day of the outage, there would be no cost impact to the retail customers. If the generator was serving retail load, the energy would be replaced by the most economical method available (i.e. either the next available resource in the supply stack or power purchases). On the day after the generator initially went offline, the remaining available resources would be stacked and the customers will use the least cost resources from DP&L's portfolio for that day.

Audit Trail for FUEL Rider Filings, Supporting Workpapers and Documentation

DP&L provided documentation relating to the audit trail for its Fuel Rider filings in its responses to data requests LA-2013-50 as well as LA-2013-52 through LA-2013-55.

Data request LA-2013-49 asked DP&L to provide electronically in Excel, all of the Company's quarterly Fuel Rider filings, which pertained to costs incurred or revenues recorded in the January through December 2013 review period. In response, DP&L provided Fuel Cost forecasts for January-February (from its October 2012 quarterly filing), March-May, June-August, September-November, and December 2013. DP&L also provided the related revenue class to tariff class conversions

LA-2013-50 asked for a complete set of supporting workpapers for all calculations in the FUEL Rider filings for the review period January through December 2013 and/or which pertained to costs incurred or revenues recorded in the review period. In response, DP&L provided monthly Excel workbooks which consisted of the following:

- The 2013 monthly actual Fuel Recovery calculations supporting the recorded journal entry
- Summary calculation for Fuel Recovery Derivative Gain Loss Adjustment
- Summary calculations for fuel cost adjustments from the Fuel Application
- Supporting workpapers for the summary sheets
- Monthly revenue to each tariff class

Specifically, on the first tab of the monthly Excel workbooks, the Company provided a narrative which stated in part:

> The purpose of this workbook is to calculate the over/under recovery of Fuel Costs, in accordance with the Fuel Rider stipulation, and to record the associated regulatory asset or liability.

The rest of this tab contained an overview which briefly described the contents of the Excel file which is comprised of Tabs .1 through .23. This overview included the following components:

Input Tabs – These tabs are linked to the various Calculation and Allocation tabs in order to generate the Fuel Rider Over/Under Recovery (Deferral or Liability).

Reconciliation Tab – There are two reconciliation tabs which are completed separately after all calculations have been finalized and journal entries recorded. The reconciliation tabs reconcile the Total Calculated Deferral from within this spreadsheet to the recorded Fuel Deferral in the General Ledger.

Allocation and Output Tabs – These tabs are where the retail costs are allocated between retail and DPLER, and billed and unbilled.

Summary Tabs – These tabs serve as the summaries of the dollars and MWhs in the Fuel Deferral. They summarize the information in Tabs .9 through .23 and are summarized by type of cost and plant as well as reflecting the retail/wholesale split.

Calculation Tabs – These tabs serve as the primary calculation tabs for the various expenses included in the Fuel Rider recovery calculation. Specifically, these tabs calculate the amount of expense to be allocated between retail (including DPLER) and wholesale costs for each unit within each plant.

In terms of the expense and revenue amounts that are reflected in the RA portion of DP&L's quarterly Fuel Rider filings (i.e. Schedule 2 from such filings), the primary tabs from the Excel file associated with these amounts are Tabs .5 through .7. Tab .7, which is titled "Summary $ Sheet", summarizes the total expenses that DP&L has included in its Fuel Rider after allocating such expenses between retail (including DPLER) and wholesale. The calculations from Tabs .9 through .20 flow through to Tab .7. The FERC accounts below (from Tab .7) represent the costs that DP&L has included in its Fuel Rider. The following list shows which tab from the Excel file relates to the FERC accounts listed below:

501 – Steam Plant Generation (Tab .9)

501 – Steam Plant Fuel Oil Consumed (Tab .10)

501 – Steam Plant Fuel Handling (Tab .11)

506 – Emission Fees (Tab .12)

456 – Coal Sales (Tab .14)

456 – Heating Oil Realized Gains or Losses (Tab .15)

509 – Allowances Consumed (Tab .16)

547 – Gas and Diesel Peakers of DP&L (Tab .17)

555 & 565 - Purchased Power (Tab .18)

421 – Purchased Power Realized Gain (Tab .19)

426 – Purchased Power Realized Losses (Tab .19)

411.8 & 411.9 – Allowance Sales (Tab .20)

In addition, Tabs .21, .22 and .23 represent fuel cost MWhs, gas and diesel peaker MWhs, and purchased power MWhs, respectively.

The DP&L retail and DPLER related costs on Tab .7 then flow through to Tab .6, which is titled "DP&L Allocation". This tab starts with the total combined retail and DPLER costs included in the FERC accounts referenced above. There is an allocation between DPLER and DP&L retail based on the ratio of DP&L's and DPLER's monthly MWh to the total billed monthly MWh, which are provided by the rates department. From there, the DP&L retail costs then flow through to Tab .5, which is titled "Allocation Spreadsheet". It is from this tab that the over/under recovery deferral is calculated by taking the difference between the DP&L retail costs and the billed monthly FUEL Rider revenues. The over/under recovery is then allocated between a billed and an unbilled deferral which is based on the ratio of DP&L's billed and unbilled monthly revenues and the billed deferral is flowed through to the Company's quarterly FUEL Rider filings.

DP&L also included additional supporting documentation in the form of a PDF file, which contains reproductions of journal entries and other support used in calculating the RAs. The first four pages of the PDF file referenced above relate to the monthly system optimization transactions. The remaining pages of the PDF are DP&L's support for the amounts reflected on the various tabs within the Excel file. These documents are labeled as Worksheets S-1 through

S-17. Of these documents, the primary support is from Worksheet S-12, which is titled "Fuel Recovery 2010 Oracle Report" and represents amounts recorded in the general ledger.

Larkin had selected July 2013 as its test month in terms of verifying the fuel related revenues and expenses that the Company included in the FUEL Rider. Specifically, data requests LA-2013-68, LA-2013-69 and LA-2013-72 requested that DP&L provide a complete audit trail from its quarterly FUEL Rider filings to the FUEL Rider workpapers and relevant general ledger accounts (and sub-accounts) for July 2013 actual RA fuel costs and revenues. In response, the Company provided detailed support from its internal accounting systems for the July 2013 revenues and expenses included in the FUEL Rider. Larkin was able to tie the amounts from this detail to the monthly Excel workbook for July 2013 (provided in LA-2013-50), which in turn was traced to the RA adjustment (for June, July and August 2013) in the quarterly FUEL Rider filing dated November 1, 2013 as well as the general ledger. Larkin also performed similar selective procedures for other months in the review period as well. As a result of the procedures described above, Larkin concluded that DP&L maintained adequate audit trail documentation for 2013.

LA-2013-51 asked whether DP&L engaged in "active management" of its fuel, purchased power, or emission allowance positions during the January through December 2013 review period, and if so, to identify, quantify and provide the related accounting documentation for each such "active management" transaction. In its confidential response, the Company stated:

[redacted]

Reconciliation Adjustments Audit Trail

As discussed previously, Larkin requested that DP&L provide a complete audit trail for all amounts in the RA portions in each of the Company's quarterly FUEL Rider filings. Specifically, the information requested by Larkin included the following:

<u>LA-2013-52</u>

- The accounting records and other documentation needed to trace each dollar amount in the RAs from the FUEL Rider filings to the fuel ledger, from the fuel ledger to the general ledger, and from the fuel ledger to the purchase orders and invoices.
- The complete documentation to trace the energy and system loss quantities in the Fuel Rider filings to the source documents.
- All journal entries, journal entry supporting documentation and workpapers related to recording RA adjustments in the Company's accounting records.
- Provide all calculations and supporting documentation related to computing RA adjustments in the Company's FUEL Rider workpapers.

LA-2013-53

- The accounting records and other documentation needed to trace each dollar amount in the RAs through the FUEL Rider filings to the general ledger, and from the general ledger to the purchase orders and invoices.
- The complete documentation to trace the purchased power costs in the FUEL Rider filings to the source documents.
- All journal entries, journal entry supporting documentation and workpapers related to recording purchased power costs in RA adjustments in the Company's accounting records.
- Provide all calculations and supporting documentation related to computing purchased power costs in RA adjustments in the Company's FUEL Rider workpapers.

The data requested in LA-2013-52 and LA-2013-53 was provided in LA-2013-50. In its responses to LA-2012-52 and LA-2012-53 (which were combined into a single response), DP&L discussed four adjustments that it made during the review period and which are summarized in Exhibit 5-33 below.

Exhibit 5-33. 2013 Adjustments to Fuel Rider

[redacted]

The Company provided schedules which showed how each of these adjustments was derived. With respect to the three system optimization related adjustments listed in the exhibit above, as discussed in further detail in the following section, beginning January 1, 2013, DP&L agreed to discontinue the charge-back of 75% of any fuel optimization transaction pursuant to the Stipulation and Recommendation date December 5, 2012. In its confidential response to LA-2013-78, the three system optimization related adjustments in the exhibit above were made to true-up system optimization transactions for all months of 2012.

Larkin requested informally that DP&L identify and provide a breakout of the specific 2012 system optimization transactions that the true-up adjustments [redacted] related to. In response to Larkin's inquiry, the Company scheduled a conference call which took place on August 6, 2014. During this call, DP&L stated that the values associated with these true ups were reflected in a schedule that it provided to EVA and Larkin on December 18, 2013 (subsequent to the hearing associated with the 2012 review period), and thus, were included in DP&L's 2012 optimization calculations. DP&L provided this schedule and the related supporting calculations for reference during the August 6, 2014 conference call. The Company stated that the values associated with its 2012 optimization true-ups (that DP&L recorded in 2013) were embedded in the figures on these schedules and are not explicitly reflected. As a result, Larkin was unable to specifically identify the trued-up amounts shown in Exhibit 5-33 to the individual 2012 optimizations.

As of the date of this report, the Commission has not issued an Opinion and Order as it relates to several system optimization transactions that EVA recommended for disallowance in the 2012 review period. DP&L stated that once the Commission issues its Opinion and Order in that proceeding, the 2012 system optimization values will be adjusted accordingly.

As noted above, the Company's supporting documentation for its 2013 RA adjustments were provided in LA-2013-50, in the monthly Excel workbooks, which are DP&L's source documentation for the amounts reflected in its quarterly FUEL Rider filings.

As noted previously, Larkin selected July 2013 as its test month for the 2013 FUEL Rider audit. As such, data requests LA-2013-68 and LA-2013-69 requested the Company to provide the following data:

<u>LA-2013-68</u>
A complete audit trail from (1) the Company's quarterly Fuel Rider filings to (2) the FUEL Rider workpapers, to (3) the general ledger balances for each of the general ledger accounts in which FUEL Rider includable costs are recorded as well as any other accounts used by DP&L for the July 2013 actual RA fuel costs.

<u>LA-2013-69</u>
A complete audit trail from (1) the Company's quarterly Fuel Rider filings to (2) the FUEL Rider workpapers, to (3) the general ledger balances and accounting records used by DP&L for the July 2013 actual RA fuel revenue.

As noted above, in the combined response to LA-2013-68 & 69, DP&L provided detailed support for the amounts reflected in the monthly Excel workbook for July 2013 (provided in LA-2013-50)[34].

System Optimization

In prior years dating back to the 2010 review period, and continuing through the 2012 review period, the Company has "optimized" its coal position in order to reduce the cost of fuel and obtain "sharing" profits from the optimization trades. A 75/25 DP&L/customer sharing ratio was provided for in the February 24, 2009 Stipulation in Case No. 08-1094-EL-SSO.

As part of the ESP Stipulation dated February 24, 2009 in Case No. 08-1094-EL-SSO and subsequently approved by the Commission in its Opinion and Order dated June 24, 2009, DP&L has implemented coal and coal/power optimizations which the Company states systematically lowers the fuel and purchased power costs and thus, results in reduced rates to its customers. Section 2 of the Stipulation (pages 3 and 4) states in part:

[34] Data requests LA-2013-70 and LA-2013-71 requested similar actual Fuel revenue and expense data for January 2013.

> DP&L will implement a bypassable fuel recovery rider to recover retail fuel and purchased power costs, based on least cost fuel and purchased power being allocated to retail customers. To calculate the rider, jurisdictional emission allowance proceeds and twenty-five percent of jurisdictional coal sales gains will be netted against the fuel and purchased power costs.

Pursuant to the ESP Stipulation, during the 2010, 2011 and 2012 review periods, DP&L had flowed the 75% charge-back associated with its optimization transactions through the Fuel Rider. Throughout the course of the fuel audits conducted by EVA and Larkin during the 2010, 2011 and 2012 review periods, system optimization has been a contentious issue. This contention culminated with the Stipulation and Recommendation dated December 5, 2012 where, at Paragraph J (pages 9 and 10), it states:

> Beginning January 1, 2013, and continuing until such time as the Commission issues an order approving a rate plan in Case No. 12-426-EL-SSO and continuing thereafter unless such approved rate plan specifies otherwise, DP&L will cease the charge-back of 75% of any fuel optimization transaction. It is recognized that DP&L may, in its business judgment, continue to engage in transactions that would be considered optimizations, but the jurisdictional share of any accounting gains and losses and changes in fuel cost would be reflected in rates without any optimization charge-back to customers.

Pursuant to the forgoing provision of the Stipulation and Recommendation dated December 5, 2012, Larkin asked DP&L to confirm that there are no costs related to system optimizations in the Fuel Rider in any months of 2013. In response to LA-2013-77, the Company stated:

> There were no costs related to 2013 Optimizations included in DP&L's Fuel Rider for any months of 2013.

In a related question, Larkin asked DP&L whether there were any adjustments, costs or credits to recorded fuel costs during 2013 that pertained to any prior year(s) Optimizations, and if so, to identify, quantify and explain each such adjustment and to provide the related journal entries. In its confidential response to LA-2013-78, DP&L stated in part:

> [redacted].

There were also adjustments made during the months of January, February and March to true up system optimization for all months in 2012. These adjustments resulted in an [redacted] increase in the deferred fuel balance[35].

The responses LA-2013-52/53 and LA-2013-78 included the detail associated with the fuel entries and adjustments discussed above. Upon reviewing the monthly Excel workbooks that were provided in LA-2013-50, Larkin confirmed that no system optimization transactions flowed through the Fuel Rider during 2013.

Accounting for Emission Allowances

DP&L provided documentation related to accounting detail associated with costs and revenues, purchases and sales of emission allowances, and monthly emission allowance inventory in the responses to LA-2013-56 through LA-2013-58.

Data request LA-2013-56 asked the Company to provide the detailed general ledger pages for each account that contains costs and/or revenues included in the FUEL Rider filings. In response, DP&L referred to its responses to data requests LA-2013-5 and LA-2013-67.

Data request LA-2013-57 requested detailed general ledger pages for all purchases and sales of emission allowances ("EA") and for gains or losses realized on such purchases and sales of EAs. In response, the Company referred to the response to LA-2013-67.

As it relates to the ratios used to determine emission allowance sales proceeds, Item No. 11 from the Stipulation and Recommendation dated October 6, 2011 stated:

> No later than December 31, 2011, DP&L will propose a method for periodically updating the ratio used to determine the jurisdictional share of emission allowance sales proceeds, and make its methodology available for review by the auditor, and DP&L will make this methodology available to the Parties.

Pursuant to this component of the 2011 Stipulation, data request LA-2013-66 asked the Company to explain fully and in detail the methodology developed for updating the ratios used to determine the jurisdictional share of emission allowance sales proceeds. In response, DP&L referred to allocation schedules that were provided in the response to LA-2013-65. The Company stated that these schedules, from which a 12-month rolling average is calculated, are used to derive the allocation factors to determine the jurisdictional share of emission allowance sales. Larkin compared the monthly allocation schedules to the monthly Excel workbooks provided in LA-2013-50 and confirmed that the allocation factors tied out between the two schedules. No exceptions were noted.

In terms of emission allowance purchases, sales and gains and losses flowing through the Fuel Rider, with the exception of April, which reflected a credit of $339 (DP&L retail portion was $125), there was no activity in FERC Accounts 411.8 and 411.9 during 2013. In a related data request, the Company's response to EVA-2013-1-29 stated:

[35] The three optimization related adjustments which total [redacted] are reflected in Exhibit 5-33 above.

[redacted]

Data request LA-2013-58 asked DP&L to provide its monthly emission allowance inventory (quantity of allowances and cost) and to show how it was allocated between native and non-native customers. In response, DP&L referred to its responses to LA-2013-65 and LA-2013-66, which show EA allocations between native and non-native customers.

DP&L's response to LA-2013-58 also included an attachment that reflected DP&L's monthly EA inventory balances. The exhibit below summarizes for DP&L the monthly EA inventory balances for each month of the January through December 2013 review period.

Exhibit 5-34. DP&L Emission Allowance Inventory

[redacted]

Larkin requested that DP&L provide documentation related to the purchase of annual NOx allowances in 2014 to meet the 2013 requirement including quantity, price, transaction dates, associated accounting (journal entries) and related invoices. In its confidential response to LA-2013-2-7, the Company provided an invoice from AEP Generation Resources, Inc. ("AEP") dated February 27, 2014, which indicated that DP&L [redacted]

[redacted], two emails from EPA Clean Air Markets Division that indicated the volume of NOx allowances purchases and the 2013 vintage as well as a "Transaction Confirmation" which reiterated the aforementioned quantity and cost as well as indicating that the purchased NOx allowances had a vintage of "2013 or earlier".

The response to LA-2013-2-7 stated that allowances for a particular month are treated as consumed based on the generation for that month and that the cost is the average unit price. As additional allowances are required to cover generation, the expensed cost is determined based on the weighted average unit price and the projected price of the additional allowances. In addition, the weighted average price will be adjusted based on actual costs incurred when future allowances are purchased. The Company further stated that as allowances are consumed, the expense flows through the Fuel Rider and are recorded in Account 509.

Larkin had also inquired as to whether an accrual for the 2014 NOx emission allowance purchases made for 2013 compliance was recorded for 2013, and whether the associated costs were included in the Fuel Rider in 2013. DP&L's informal response to Larkin's inquiry stated:

> In February 2014, we purchased [redacted] Of this amount [redacted] allowances were needed for 2013 compliance purposes and the rest are being held for 2014 compliance purposes or may be resold at some point. A total of [redacted] allowances were needed for December 2013.
>
> Because we estimate costs each month and true-up when actual costs are known, the December 2013 expense reflected in the fuel rider would be the jurisdictional share of the costs of [redacted] allowances that were in the portfolio at that time plus the estimated costs [redacted] each) of the additional 404 allowances that would be needed. The balance at the end of the year as shown on the "2013 DPL Fuel and Purchased Power Rider Analysis" worksheet which was provided to the auditors was [redacted] each at a balance of [redacted] ea.

Application of FUEL Rider Rates to Customer Bills

In order to verify that DP&L has included the correct FUEL Rider rates on its electric bills, Larkin reviewed a sample selection of monthly bills from the period July 2013, which were provided in the confidential response to data request LA-2013-74. This sample included eight customer billing statements with each reflecting a different billing rate. Larkin recalculated the FUEL Rider charges by multiplying the fuel rates for each rate type included in the sample by the meter usage indicated on each of the customer billing statements and then compared the results to each sampled customer's billing statement by the line item "Fuel Rdr". No exceptions were noted as reflected in Exhibit 6-37 below. Larkin then compared the results of its analysis to a summary sheet that was provided in LA-2013-74, and which contained calculations similar to those performed by Larkin. Again, no exceptions were noted.

Exhibit 5-35. Summary of Customer Bill Analysis

Tariff Class	Rate	Fuel Rate	Usage	Calculated Fuel Bill	Billed Amount	Difference
Residential	111	0.0296374	1,527	$ 45.26	$ 45.26	$ -
Residential Heat	141	0.0296374	2,123	$ 62.92	$ 62.92	$ -
Secondary	117	0.0296374	517	$ 15.32	$ 15.32	$ -
Primary	532	0.0288008	633,975	$ 18,258.99	$ 18,258.99	$ -
Primary Substation						$ -
High Voltage	531	0.0284756	41,910,011	$ 1,193,412.71	$ 1,193,412.71	$ -
Private Outdoor Lighting	25	0.0296374	75	$ 2.22	$ 2.22	$ -
School	162	0.0296374	84	$ 2.49	$ 2.49	$ -
Street Light	65	0.0296374	168	$ 4.98	$ 4.98	$ -
Source: LA-2013-74						

Changes To Fuel, Purchased Power Procurement And Emission Allowance Procurement

Documentation related to the review of changes to fuel, purchased power procurement and emission allowance procurement during the period January through December 2013 includes DP&L's responses to LA-2013-61 through LA-2013-66.

Data request LA-2013-61 asked the Company to list and describe all organizational changes to the Company's Fuel, Purchased Power Procurement and Emission Allowance Procurement during the review period. In response, DP&L listed five employees that are no longer with the Company, including three who left DP&L in 2013 and two who left in 2014. The five employees in question had worked in Commercial Operations, Competitive Market Services and Portfolio Strategy.

[redacted]

General Ledger Detail and Audit Trail

Data request LA-2013-67 requested general ledgers for the various FERC accounts which the Company has requested be included in the FUEL Rider. In response, DP&L provided the requested general ledger account sheets for January through December 2013.

As discussed above, data requests LA-2013-68 and LA-2013-69 asked DP&L to provide a complete audit trail from the Company's quarterly FUEL Rider filings to the FUEL Rider workpapers and to the general ledger balances for each of the accounts included in DP&L's Fuel Rider and any other accounts used by DP&L for July 2013 actual RA fuel costs and revenues. In its confidential response, DP&L provided the detailed support for July 2013, which agreed to the monthly data provided in the response to LA-2013-50 as well as the related general ledger FERC accounts.

Data requests LA-2013-70 and LA-2013-71 asked DP&L to provide the audit trail from the Company's quarterly FUEL Rider filings to the FUEL Rider workpapers to the general ledger balances for each of the accounts requested in LA-2013-67 and any other accounts used by DP&L for January 2013 actual RA fuel costs and revenues. In its confidential response, DP&L provided the detailed support for January 2013, which agreed to the monthly data provided in response to LA-2013-50 as well as the related general ledger accounts.

Data request LA-2013-72 asked the Company to provide the complete audit trail from the general ledgers for each account listed in LA-2013-67[36] to the invoices, journal entries and other documentation that supports the costs recorded in the general ledgers for each FUEL Rider includable account and sub-account. In response, DP&L referred to LA-2013-68 (previously discussed above) for the requested supporting documentation. Additional documentation, such as invoices, other journal entries, or any other supporting documentation, was requested and/or made available during EVA's and Larkin's onsite visit, June 11 through 13, 2014, as well as in responses to follow-up data requests.

Customer Switching

Since the 2010 review period, DP&L's retail load has been shifting to alternative suppliers, primarily to its affiliated supplier, DPLER. As a result of this "customer switching," customers who have switched to alternative suppliers could potentially avoid paying for any under-collections that have accumulated in the Fuel Rider during the time in which these customers were DP&L retail customers.

In order to mitigate the potential for this cost avoidance, Item No. 8 from the Stipulation and Recommendation dated October 6, 2011 stated in part:

> The Parties agree that DP&L will "incorporate its best estimate of the impacts of ongoing customer supplier switching into its Fuel Rider kWh sales forecasts."

[36] LA-2013-72 erroneously referenced LA-2023-66.

In data request LA-2013-80, Larkin asked the Company to explain fully and in detail how DP&L has incorporated this requirement from the October 6, 2011 Stipulation and Recommendation. In its confidential response, DP&L stated:

[redacted]

Data request LA-2013-79 asked DP&L provide statistics on 2013 customer switching by month and by tariff of those customers that switched from DP&L's jurisdictional service territory to another service provider including those customers that switched to DPLER. In its confidential response, DP&L provided statistical data by consumption and number of customers of customers that switched suppliers during 2013. Exhibit 5-36 provides a summary by month of those DP&L customers who switched to either DPLER or another alternative supplier during 2013.

Exhibit 5-36. Number of Customers who Switched to an Alternative Supplier in 2013

[redacted]

During the 2011 review period, Larkin had made the recommendation that DP&L (1) improve the accuracy of its forecast Fuel Rider rates; and (2) minimize the build-up of undercollections related to residential customer switching, use historical data to provide its own trend line analysis for residential customer switching when developing its Fuel Rider kWh sales forecasts.[37] In LA-2013-81, Larkin requested that DP&L provide the trend line analysis for residential customer switching pursuant to its recommendation. In response, the Company provided the requested trend analysis, which is replicated in Exhibits 5-37 and 5-38 below.

Exhibit 5-37. Trend Line Analysis Related to Residential Customer Switching (Actual Sales Billed per Month)

[redacted]

[37] This recommendation was adopted as Additional Commitment B at page 11 of the Stipulation and Recommendation dated December 5, 2012.

Exhibit 5-38. Trend Line Analysis Related to Residential Customer Switching (Percentage of Actual Sales Billed per Month)

[redacted]

DP&L stated that it uses the trend line analysis to forecast and validate its sales forecasts, but that because of seasonality and the factors noted in LA-2013-80 (as discussed above), monthly forecasts necessarily vary based on the season. As a result, a simple trend line analysis is not reflective of a seasonal quarter.

Findings:

1. In preparing its Fuel Rider sales forecasts for its quarterly Fuel Rider filings affecting 2013, DP&L reflected the impact of known customer supplier switching.
2. DP&L's Fuel Rider deferral (i.e., the 2013 undercollection) has been impacted by customer supplier switching that has occurred.
3. [redacted].

4. DP&L created and used a trend line analysis for forecasting and validating its sales forecasts, but due to seasonality and other factors, monthly forecasts will vary and as such, a simple trend line analysis will not be reflective of a seasonal quarter.

Internal Audits

Data request LA-2013-75 asked the Company to provide a listing of and copies of any and all internal audit reports related to fuel procurement, synfuel, coal trading, fuel inventory management, purchased power, emission allowances, accounting for Fuel Rider-includable costs, portfolio optimization, energy sales, PJM charges and revenues, fuel and purchased power invoices, PJM invoices, allocation of PJM revenues and costs to Ohio retail load customers, allocation of other Fuel Rider includable costs and revenues to Ohio retail load customers, and/or other Fuel Rider related subject matter for the review period. In its confidential response, DP&L referred to the confidential response to EVA-2013-1-43, which had requested any internal audits of fuel and purchased power that DP&L had conducted over the last five years. Of the internal audit reports provided in that response, three such reports pertained to the 2013 review period, each of which is discussed below.

DP&L Fuel Cost Recovery Audit

Pursuant to a recommendation from Larkin in the 2010 audit report, Item No. 13 from the Stipulation and Recommendation dated October 6, 2011 stated:

> The Parties agree that DP&L will internally audit its Fuel Rider processes and calculations during calendar year 2011 and, in the event there is a Fuel Rider thereafter, on a biennial basis.

Pursuant to the Stipulation and Recommendation, the Company conducted an internal audit of its Fuel Rider for the 2013 review period. This report for this internal audit, which is dated January 8, 2014, covered the period January 1, 2012 through October 31, 2013. The stated objectives of this internal audit were to evaluate and validate the accuracy of transactions related to the fuel cost recovery process, including the effectiveness of related controls and compliance with business policies and procedures. The Internal Audit ("IA") group stated that [redacted]

> [redacted]

DP&L Commodity Risk Management Audit

The IA group, at the request of DP&L management, conducted this internal audit which covered the period January 1 through August 31, 2013. The stated objectives of this internal audit were to evaluate and validate the accuracy of transactions related to the Commodity Risk Management process, including effectiveness of related controls and compliance with business policies and procedures. The report, which is dated November 4, 2013, included the following scope areas for this internal audit:

- Commodity transaction processes are in place to ensure trades are accurate, properly approved and in compliance with established policies and procedures.
- Commodity risk communications are made to the appropriate levels of management who are aware of activities and any violations, and that required communications to take place.
- Counterparty files are properly approved and risk analyses are performed and are in compliance with the Company's Credit Risk Management Policy.
- Segregation of duties exists between front, middle and back office functions.
- Controls over commodity trading activities, recordkeeping processes and financial reporting requirements are monitored for adherence to company policies and procedures.
- Reporting for transactions and related results are being completed accurately and on a timely basis, and are being distributed to and reviewed by the appropriate level of management.

Similar to the first internal audit discussed above, the IA group stated [redacted]

[redacted]

DP&L Coal Physical Inventory Audit

As discussed previously in this report, the IA group conducted an audit of coal physical inventory at the Stuart and Killen generating stations, which covered the period August 1, 2012 through July 31, 2013. The objective of this internal audit was to observe the third party coal physical inventory procedures and to test any inventory adjustments. The report, which is dated January 24, 2014, included the following scope areas for this internal audit:

- Observation of the coal inventory flyover at Stuart and Killen stations.
- Observation of the coal inventory drilling and density procedures at Stuart Station.
- Testing of the coal physical inventory reports prepared by SGS Minerals North America Inc. ("SGS") for the Stuart and Killen generating stations.
- Testing of the coal inventory adjustments booked in the General Ledger.

During its review of the Stuart and Killen physical coal inventories, the IA group concluded that the value of the physical coal inventory at Stuart exceeded the book balance by [redacted]. In addition, the value of the physical coal inventory at Killen was [redacted].

The IA group's recommendations to management and management's response and action plan are discussed in detail at page 5-49 of this report.

Section 45 Plant

On February 18, 2013, DP&L entered into four separate contract agreements[38] with [redacted], all of which relate to the installation of a refined coal facility at Stuart Station pursuant to a tax credit under Section 45 of the Internal Revenue Code. Specifically, DP&L The four contracts include (1) a Refined Coal Sales Agreement; (2) a Feedstock Supply Agreement; (3) a Lease Agreement; and (4) a Site Services Agreement. A brief summary of each contract agreement is as follows[39]:

Refined Coal Sales Agreement [redacted].

Feedstock Supply Agreement - [redacted]

Lease Agreement - [redacted].

Site Services Agreement - [redacted]

The response to EVA-2013-1-48 included a "Letter Agreement" to DP&L [redacted].

[redacted]

[38] The four contracts were provided in response to EVA-2013-1-48.
[39] The four contracts are discussed in further detail in the EVA section of this report.
[40] Exhibit A-2 of the Lease Agreement describes the Lease Area as [redacted]".

[redacted] The Letter Agreement set forth the understanding between DP&L and [redacted] with regard to certain matters relating to the contract agreements. Specific to those matters was the following assignment:

> [redacted].

DP&L's response to LA-2013-2-2 provided documentation relating to the sales of coal to [redacted]. Specifically, LA-2013-2-2 asked

> "Please provide the accounting entries in 2013, by plant, for coal sales, coal repurchases and lease revenues for each Internal Revenue Code Section 45 coal treatment/synfuel plant. Show the amounts recorded in each account for each month of 2013 for synfuel/treated-coal related (1) coal sales, (2) coal repurchases and (3) lease revenue.
>
> a. Please show the total amounts for each month, and also show the details of allocations between (1) joint owners, (2) DP&L Wholesale and Retail and (3) DP&L Fuel Rider and DPLER."

In its confidential response to LA-2013-2-2, the Company provided documentation related to the sale of coal to [redacted], as well as the 2013 accruals and accounting analysis reflecting all postings to FERC Account 456099. DP&L stated that the coal sales to [redacted] were not included in the Fuel Rider during 2013.

The aforementioned documentation consisted of DP&L invoices issued to [redacted], documents referred to as "[redacted]" as well as the relevant pages from the Company's general ledger ("G/L"). Each of the G/L pages provided included the following four footnotes: [redacted]

Upon reviewing this information, Larkin noted that it only covered the periods October through December 2013. As a result, Larkin developed follow-up questions related to the timing and treatment of the revenues generated by the coal sales to [redacted] as well as those revenues related to the lease agreement between [redacted]. Pursuant to Larkin's request for additional information, a conference call between Larkin, EVA and DP&L was conducted on July 23, 2014. During this conference call, DP&L revealed that the information provided in LA-2013-2-2 was incomplete insofar as the Company did not include the revenue associated with the lease payments. As a supplement to LA-2013-2-2, DP&L provided a schedule which provided, by month, a breakout of the [redacted]. A summary of this information, which includes the portion of such revenues that were allocated to Stuart Station's joint owners Duke and AEP, provided in the exhibit below.

Exhibit 5-39. Summary of [redacted] Related Revenue

[redacted]

Conclusion:

As stated in the response to LA-2013-2-2, DP&L did not include the [redacted] related revenues in the Fuel Rider during 2013. For the reasons discussed in the EVA section of this report, Larkin concurs with EVA that the [redacted] related revenues should flow through the Fuel Rider since the refined coal was effectively purchased on behalf of DP&L's jurisdictional customers. Therefore, Larkin has modified the schedule that DP&L provided in the supplemental response to LA-2013-2-2 to include the wholesale and DPLER allocations in order to derive the net DP&L retail share of the [redacted] coal spray and lease revenues. This is shown in the exhibit below.

Exhibit 5-40. DP&L Share of [redacted] Coal Spray and Lease Revenue

[redacted]

As shown in the exhibit, after applying the wholesale and DPLER allocation factors, the DP&L retail portion of the [redacted] coal spray and lease revenue that should flow through the Fuel Rider totaled $[redacted] for 2013.

Memorandum Of Findings And Recommendations

Our findings and recommendations are summarized in Chapter 1.

6 RENEWABLES AND THE ALTERNATIVE ENERGY RIDER (AER) COMPONENT

Alternative Energy Portfolio Requirements

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

At least half of the alternative energy requirement must be satisfied from "renewable energy sources" which must include solar. The percentage required by year is provided on Exhibit 6-1. The other requirement is that at least 50 percent of the renewable energy must come from in-state facilities and the balance must come from facilities that can deliver into the state. Technologies that qualify under the renewable category include: solar, wind, hydroelectric, geothermal, waste derived fuel, biomass, biologically derived methane gas, wood waste, fuel cells, and storage facilities.

Exhibit 6-1. Renewable Energy Benchmark Requirements

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

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

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

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

In May 2014, Senate Bill 310 was passed and in June signed into law which freeze the state's renewable portfolio standards at current levels through 2015. Additionally, and in some ways more significantly, the legislation removes the requirement that at least 50 percent of the state's renewable energy be met with in-state facilities. Instead, the entire requirement could be met by facilities in Ohio as well as neighboring states. Also, under the legislation, the solar alternative compliance payment, or SACP, in Ohio will be frozen at 2014 levels through 2016. Currently, Ohio's SACP is set at $300, and after 2016 it will decline $50 every two years to reach a minimum of $50 by 2026. The freeze has limited effect on 2014 because the standards are frozen at that level. The biggest impact may be on Ohio in-state solar REC's which have historically been the highest cost component of the REC portfolio. The general consensus is that the differentials between in-state and out-of-state REC's will narrow. What is not clear is whether this is just a two-year freeze or a precursor for major changes going forward.

REC Procurement Strategy

DP&L's strategy is [redacted] This strategy has worked well for DP&L in 2013 give adequate availability and competitive prices. Further, this strategy [redacted].

REC Purchases

RECs purchases are usable within a five-year period. Any RECs held by DP&L at December 31, 2013 that are in excess of its 2013 Benchmarks will be applied to future year benchmarks. The REC's purchased by the Company are summarized by category in Exhibit 6-2. The solar REC's are significantly higher in costs than the non-solar REC's; the in-state REC's are higher in cost than the out-of-state REC's.

Exhibit 6-2. Summary of REC Purchases by Category

[redacted]

Audit Period Purchases

REC purchases during the audit period are summarized in Exhibit 6-3. The prices paid for REC's compare favorably to market prices.

Exhibit 6-3. REC Purchases During 2013 Period

[redacted]

Audit Period Compliance

DP&L did not have quarterly AER filings for the 2013 review period. According to the Company's Annual Compliance Plan Status Reports for 2013, DP&L achieved compliance by meeting the 2013 benchmarks for the Ohio Alternative Energy Portfolio Standard for both solar and non-solar renewables.

Financial Audit

Scope and Objectives

To accomplish the review of DP&L's 2013 AER, the following aspects were included in the verification and testing:

- Review the Company's AER filings applicable to DP&L's actual 2013 renewables costs, revenues and carrying costs to verify the accuracy of the calculations
- Review the individual components of all transactions that have been included within the AER calculations
- Review the accuracy of calculations relate to any carrying charges included in the Company's quarterly AER calculations,
- Review the Company's performance related to the 3% provision contained within Section 4928.64(C)(3), Revised Code as detailed in Rule 4901:1-40-47, OAC.
- Compare the costs recovered in the AER to the costs incurred.

Minimum Review Requirements

Larkin referred to the objectives and procedures outlined in Attachment 4 of the RFP as guidance for the review requirements of this project. The Financial Audit Program Standards are intended to be used as a guide for the auditor in conformance with the specific requirements of the Alternative Energy Rider and should not be used to the exclusion of the auditor's initiative, imagination and thoroughness.

The information included here was used as guidance, in addition to appropriate discretion on the part of the auditor in order to conduct the regulatory verification of D&PL's renewables costs and

REC inventory accounting in conformance with the specific requirements of the Company's AER that applied for the 2013 review period. Larkin reviewed and applied relevant criteria in review of the Company's decisions and actions related to its AEPS compliance activities.

The guidelines provide that the financial audit shall include at least the following items:

(1) A review of the Company's AER quarterly filings during the audit period to verify the accuracy of the calculations;[41]

(2) A review of the individual components (including, but not limited to, transactions of RECs or S-RECs and costs of implementing associated RFPs) that have been included within the Company's AER calculations in order to verify that the costs were appropriately included;

(3) A review to verify the accuracy of calculations related to any carrying charges included in the Company's quarterly AER calculations;

(4) A review of the Company's status relative to the 3% provision contained within Section, 4928.64(C)(3), Revised Code, and as further detailed in the Rule 4901:1-40-07, Ohio Administrative Code;

(5) A review comparing the costs recovered through the Company's AER during the audit period to the costs incurred; and

(6) A review of any other specific items as identified by the Commission or its Staff.

As part of its review of renewable energy resources, Larkin asked DP&L a series of questions pertaining to its renewable energy purchases and RECs from data requests LA-2013-85 through LA-2013-112. Larkin also asked DP&L about certain renewable cost/AER matters in informal follow-up questions.

Period for Review of Renewables Cost and AER

The audit period for DP&L's renewables is calendar 2013. We reviewed the Company's renewables costs for 2013. DP&L's Alternative Energy Rider was in effect for 2013.

DP&L's AER Rates for the 2013 Review Period

The Alternative Energy Rider is intended to compensate DP&L for advanced generation plant investments and compliance costs realized in meeting the renewable portfolio standards prescribed by Section 4928.64 of the Ohio Revised Code. DP&L did not have quarterly AER filings for the 2013 review period. Rather, during 2013, DP&L's AER rates were $0.0006405

[41] For the 2013 review period, DP&L's AER rates were not based upon quarterly filings. Larkin reviewed DP&L's 2013 renewable costs and AER results from the applicable DP&L AER filings, focusing on DP&L's actual AER results for the 2013 review period.

per kWh (per Second Revised Sheet No. G26) that was approved in Case No. 10-89-EL-RDR which was applicable through July 31, 2013, and $0.0017847 per kWh (per Third Revised Sheet No. G26) that was approved in Case No. 13-1200-EL-RDR that became applicable with the first billing unit in August 2013 and continued for the remainder of 2013.

Background

On June 24, 2009, the Commission adopted a Stipulation and Recommendation ("Stipulation") in DP&L's electric security plan proceeding authorizing, among other things, DP&L to institute an avoidable Alternative Energy Rider ("AER") to recover costs incurred to comply with Section 4928.64, Revised Code. *In re Dayton Power and Light Company,* Case Nos. 08-1094-EL-SSO et al., Opinion and Order (June 24, 2009) (*ESP Proceeding*). DP&L's AER was approved subject to an annual true-up for actual costs incurred.

On April 15, 2010, DP&L filed an application to update its AER. Subsequently, DP&L revised its application on July 22, 2010, to reflect improvements in its costing methodology and presentation, including revisions to its affiliate cost and renewable energy credit ("REC") allocations.

On March 21, 2012, the Commission issued its Finding and Order in Case No. 10-89-EL-RDR approving an amended application filed DP&L on June 1, 2011. On March 5, 2012, Staff had filed a letter in that docket recommending that the Commission approve the amended application filed by DP&L on June 1, 2011. Staff had verified that DP&L properly allocated both REC costs and REC-related administrative costs to DPLER and that its AER costs were reasonable.

DP&L's AER rates were approved by the Commission by Finding and Order dated March 21, 2012 in Case No. 10-89-EL-RDR. DP&L filed its annual true-up Application in Case No. 12-1519-EL-RDR.

By Opinion and Order dated June 24, 2009, in Case Nos. 08-1094-EL-SSO, *et al.*, the Commission approved a Stipulation and Recommendation ("ESP Stipulation") which provides at paragraph 6 that the annual true-up of DP&L's AER is to be filed by no later than June 1st of each year.

Consequently, DP&L submitted an Application in Case No. 13-1200-EL-RDR in compliance with its ESP Stipulation. In support of its Application to true-up the AER, DP&L attached the following schedules:

Schedule A-1	–	Copy of redlined tariff schedules;
Schedule A-2	–	Copy of proposed tariff schedules;
Schedule B-1	–	AER Summary;
Schedule C-1	–	Projected Monthly Cost Calculation
Schedule D-1	–	Summary of Actual Costs for 2012;
Schedule E-1	–	Typical Bill Comparison; and
WPD-1	–	Calculation of Carrying Cost.

The adjustment proposed by DP&L's true-up application resulted in an AER rate of $0.0017847 per kWh, which reflects an increase of $0.86 per bill based on typical residential customer usage of 750 kWh per month. DP&L has applied carrying charges of 5.86%, based on the cost of debt approved in the 08-1094-EL-SSO ESP proceeding, to the under and/or over recovery of costs when computing the components of the proposed AER rate. DP&L requested that the Commission approve its Application with new tariff rates for its AER to be made effective on a bills-rendered basis with the Company's first billing unit beginning in August 2013.

Review of DP&L's Alternative Energy Rider Results for the 2013 Review Period

Larkin reviewed DP&L's AER workbooks for the 2013 review period. Because DP&L's AER costs are trued-up to actuals, Larkin's review focused on the workbook for December 2013, which reflects DP&L's weighted average cost of RECs for the year.

With DP&L's assistance, Larkin tied the December 2013 journal entry into the Company's Annual Alternative Energy Portfolio Status Report for calendar year 2013, which DP&L filed on April 15, 2014 in PUCO Case No. 14-0475-EL-ACP.

On May 1, 2014, in Case No. 14-806-EL-RDR, the Company filed Schedules, Workpapers, and Tariffs for Modifying its Alternative Energy Rider. Included with that filing was a Schedule 2 with actual costs for January 2013 through March 2014. As part of the current review cycle, Larkin reviewed DP&L's actual costs for January through December 2013 from that filing, which are summarized in the following table:

Exhibit 6-3. Summary of Actual Costs for January through December 2013

[redacted]

Source and Notes:
DP&L's May 1, 2014 Alternative Energy Rider Filing in Case No. 14-806-EL-RDR, Schedule 2
Year-to-Date amounts are based on the current month Total + previous month YTD total
[a] Carrying cost calculation testing revealed a minor rounding differences in the amounts for May and November 2013

Larkin reviewed DP&L's REC inventory and accounting entries. DP&L's December 31, 2013 journal entry support for 2013 REC expense showed the following REC expense by type of REC:

Exhibit 6-4. Summary of 2013 REC Expense

[redacted]

Larkin asked DP&L to reconcile and explain the difference of $67,725 between (1) the $2,518,684 REC expense for 2013 shown in the Company's May 1, 2014 filing in Case No. 14-806-EL-RDR[42] and (2) the $2,586,409 REC expense for 2013 from DP&L's December 31, 2013 journal entry support.[43] In an email dated July 25, 2014, DP&L explained that there were adjustments made late in 2013 (October and November) for earlier periods. DP&L stated that the $2,586,409 is the 2013 REC Expense and the $67,726 is a 2013 adjustment made to prior year expense. DP&L's response to this follow up query also referenced its response to LA-2013-107, and the file "6-1-2014 REC Expense (2013)" and noted that the difference is the sum of row 31 which incorporates years 2009-2012.

Larkin also asked DP&L to provide the accounting support for the $[redacted] compliance administrative expense for 2013 from DP&L's May 1, 2014 filing.[44] DP&L's compliance administrative expense is addressed in a subsequent subsection of this chapter.

Review of Carrying Charges

RFP No. U14-FAC/AER-1 provides at Attachment 4, Item 3 that the auditor conduct:

> A review to verify the accuracy of calculations related to any carrying charges included in the Company's quarterly AER calculations.

For the DP&L's 2013 AER costs, carrying charges were based on a cost of debt of [redacted]

The Company's May 1, 2014 filing in Case No. 14-806-EL-RDR included Workpaper 1, showing the calculation of carrying costs by month for the 2013 review period, as follows[45]:

[42] See, Exhibit 6-3 , above, Column A.
[43] See, Exhibit 6-4, above.
[44] See, Exhibit 6-3 above, Column B. In response to our informal follow-up, on July 25, 2014 DP&L provided a listing by month of compliance expense, showing compliance expense for DP&L, and an allocation of compliance cost to DPLER. Upon reviewing that information, Larkin had additional follow up, asking for work orders and some other information, from which to test the amount of this compliance cost borne by DP&L. On July 29, 2014, DP&L responded to those subsequent follow-up inquires.

Exhibit 6-5. Summary of Carrying Costs for January through December 2013

[redacted]

Larkin recalculated the AER carrying costs for each month of 2013 using the 5.86% rate that applied in 2013. Other than minor rounding differences in the May and November 2013 amounts, no exceptions were noted.

Status Relative to the 3% Provision in Section, 4928.64(C)(3), Revised Code/ Compliance with 2013 Renewable Energy Requirements

RFP No. U14-FAC/AER-1 provided standards for reviewing the Company's AER which included Attachment 4, Item 4, which states:

> A review of the Company's status relative to the 3% provision contained within Section, 4928.64(C)(3), Revised Code, and as further detailed in the Rule 4901:1-40-07, Ohio Administrative Code.

In accordance with Section 4928.64(C)(1) of the revised Ohio Code, the Commission annually reviews electric distribution utilities and/or electric services companies compliance with the benchmarks reflected in the Renewable and Solar Benchmarks exhibit above. As part of that review, the Commission identifies under-compliance or non-compliance that it determines is related to weather, equipment, resource shortages for advanced energy, or renewable energy sources, and which is outside a utility's or electric service company's control. Section 4928.64(C)(3) of the revised code states that:

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[45] DP&L's Workpaper 1, in its May 1, 2014 AER filing, included a carrying cost calculation through August 2014. For purposes of this review, Larkin tested the calculation of carrying costs on AER balances only for the months falling within the 2013 review period.

> An electric distribution utility or an electric services company need not comply with a benchmark division (B)(1) or (2) of this section to the extent that its reasonably expected cost of that compliance exceeds its reasonably expected cost of otherwise producing or acquiring the requisite electricity by three percent or more. The cost of compliance shall be calculated as though any exemption from taxes and assessments had not been granted under section 5727.75 of the Revised Code.

DP&L provided its confidential Annual Compliance Plan Status Reports for 2013 in the response to LA-2013-104 and in its related April 15, 2014 filing to the PUCO in Case No. 14-0475-EL-ACP. The Company's 2013 compliance report stated that DP&L achieved compliance by meeting the 2013 benchmark for the Ohio Alternative Energy Portfolio Standard for both solar and non-solar renewables.

The Renewable Energy requirement is calculated by applying the renewable energy standard multiplied by a three-year average of retail sales sold under its standard service offer minus industrial consumer load under the economic growth rider.

To comply with this requirement, companies must surrender renewable energy credits (RECs) from qualified resources (Note: 1 REC = 1 MWh) equal to the renewable obligation. Given that RECs have a five-year lifetime following their acquisition, surplus unused credits can be carried over and consumed in a following year.

As discussed in the management audit section of this report, DP&L is subject to the compliance standards as set forth in Section 4928.64 of the revised Ohio Code as it relates to an electric utility being required to provide electricity from alternative sources. Specifically, Section 4928.64, subsection (B) states in part that:

> *The baseline for a utility's or company's compliance with the alternative energy resource requirements of this section shall be the average of such total kilowatt hours it sold in the preceding three calendar years, except that the PUCO may reduce a utility's or company's baseline to adjust for new economic growth in the utility's certified territory or, in the case of an electric services company, in the company's service area in this state. Of the alternative energy resources implemented by the subject utility or company by 2025 and thereafter:*
>
> *i. Half may be generated by advanced energy resources;*
>
> *ii. At least half shall be generated from renewable energy resources, including one-half percent from solar energy resources, in accordance with the following benchmarks:*

Exhibit 6-6. Renewable and Solar Benchmarks

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

iii. *At least one-half of the renewable energy resources implemented by the utility or company shall be met through facilities located in this state; the remainder shall be met with resources that can be shown to be deliverable to this state.*

The Company's 2013 renewable requirement and compliance is summarized in the following table:[46]

[46] From page 3 of DP&L's 2013 Alternative Energy Portfolio Status Report filed on April 15, 2014 in Case No. 14-0475-EL-ACP.

Exhibit 6-7. 2013 Renewables Compliance Summary

[redacted]

DP&L's response to LA-2013-104 stated that DP&L met each of the 2013 alternative energy compliance obligations, and provided confidential details containing the facility, location, dates, and certificate numbers for the [redacted]

[redacted] used to meet its 2013 renewables requirements.

As shown in the above Exhibit, DP&L met each of the Benchmarks set forth above in 2013. DP&L's confidential response to LA-2013-104 shows the facility, location, and other details of the RECs obtained for 2013 compliance. Consistent with DP&L's initial renewable compliance plan approved by Commission order dated June 24, 2009 in the context of DP&L's Electric Security Plan ("ESP") (Case No. 08-1094-EL-SSO), DP&L satisfied its 2013 renewable energy requirements [redacted]. Specifically, DP&L [redacted].

REC Inventories

Pursuant to Ohio Revised Code §4928.65, RECs that were purchased by the Company are usable within a five-year period. Any RECs held by DP&L at December 31, 2013 that are in excess of its 2013 Benchmarks will be applied to future year benchmarks.

DP&L maintains separate REC inventories for DP&L and DPLER with a weighted average cost that is updated monthly. Inventories are maintained for these types of RECs:

(1) Non-Ohio, Non-Solar RECs,

(2) Non-Ohio Solar RECs,

(3) Ohio Non-Solar RECs, and

(4) Ohio Solar RECs.

Larkin reviewed DP&L's REC inventory support for 2013 and discussed this with DP&L representatives during an on-site interview on June 11, 2014. Larkin also selectively tested some of DP&L's weighted average REC and REC inventory calculations, noting no exceptions.

Each REC used by DP&L for 2013 compliance can be tied to a PJM-GATTS certificate number.

For purposes of tying REC inventory quantities to PJM-GATTS REC quantity reports, DP&L and DPLER REC quantities are combined; however, DP&L's REC inventory details are sufficient to separately identify the DP&L and DPLER RECs.

For accounting purposes, the costs of DP&L's and DPLER's RECs are recorded separately. DP&L records the REC activity for each month in its general ledger. Details are input into the REC inventory spreadsheets to update the weighted average cost.

Administrative Cost and Allocation Between DP&L and DPLER

For 2013, DP&L reported renewables compliance administrative cost of $[redacted]. In response to follow up inquiries, DP&L also provided the following breakout of compliance administrative cost:

Exhibit 6-8. 2013 Renewables Compliance Administrative Expense

[redacted]

Based on the information provided by DP&L to date, this appears to have resulted in the following renewables compliance cost amounts between DP&L:

Exhibit 6-9. 2013 Renewables Compliance Administrative Expense - DP&L and DPLER

[redacted]

1. DP&L explained in a July 29, 2014 email that the data shown above should not be interpreted as representing an allocation between DP&L and DPLER of 2013 Administrative Costs. The only month in which costs were allocated was January 2013, and there was only a total of [redacted] in Administrative costs that month of which 41% was allocated to DP&L based its baseline REC requirements relative to DPLER's. The other costs assigned to DP&L reflected actual hours of work done for DP&L from

February through December 2013 when RECs for DP&L were separately acquired. The other costs in addition to the January allocation to DPLER are corrections of prior charges in 2012. The above summary does not represent a heavily weighted allocation of administrative compliance cost to DP&L. Rather DP&L explained that DP&L is charged for time actually spent. The administrative costs incurred to meet DPLER's requirements are not charged to DP&L and are not reflected in the data above.

2. On August 15, 2014, DP&L provided a correction for 2014 renewables administrative cost, which allocates 42 percent of PJM GATS invoices and internal staff costs to DPLER, based on DPLER's three-year adjusted baseline. This correction, which DP&L stated that it is recording in August 2014, reduces DP&L's AER costs by $14,259 plus $334 of interest for a total reduction to DP&L's AER costs of $14,953.

Findings

DP&L did not have quarterly AER filings for the 2013 review period. Rather, during 2013, DP&L's AER rates for January through July were $0.0006405 per kWh (per Second Revised Sheet No. G26) that was approved in Case No. 10-89-EL-RDR and $0.0017847 per kWh (per Third Revised Sheet No. G26) that was approved in Case No. 13-1200-EL-RDR that became applicable with the first billing unit in August 2013 and continued for the remainder of 2013.

For 2013, DP&L reported REC expense of $[redacted] and compliance administrative expense of $[redacted] in DP&L's May 1, 2014 filing in Case No. 14-806-EL-RDR, Schedule 2, for a total expense of $[redacted]. Compared with 2013 AER revenue of $[redacted], DP&L had an over recovery of $[redacted].

For 2013, DP&L calculated $[redacted] AER carrying costs, using a cost of debt of [redacted]%, which had been approved by the Commission in Case No. 10-89-EL-RDR. Other than some minor rounding differences in May and November 2013, Larkin's recalculations of DP&L's AER carrying charges for 2013 were without exception.

As demonstrated in the above Exhibit 6-7 and in the details provided in DP&L's confidential response to LA-2013-104, DP&L met each of the 2013 Renewable Benchmarks established by Ohio SB 221.

DP&L maintains appropriate REC inventories, at weighted average cost, which is updated monthly, for each type of REC:

(1) Non-Ohio, Non-Solar RECs,

(2) Non-Ohio Solar RECs,

(3) Ohio Non-Solar RECs, and

(4) Ohio Solar RECs.

A concern had been identified with respect to DP&L's 2013 renewables administrative compliance cost, which, based on the information provided through July 28, 2014, appeared to be highly disproportional to the respective REC expense for DP&L and DPLER, each of which have similar renewables compliance requirements to meet, which are based on load. However, DP&L's subsequent explanations state that the only month in which costs were allocated was January 2013, and there was only a total of $[redacted] in Administrative costs that month of which [redacted] was allocated to DP&L based its baseline REC requirements relative to DPLER's. The other costs assigned to DP&L reflected actual hours of work done for DP&L from February through December 2013 when RECs for DP&L were separately acquired. The correction to DP&L's renewables administration cost described in Finding No. 43, to reduce DP&L's AER includable costs by $14,259 plus $334 of interest, for a total of $14,593, should be made.