Large Filing Separator Sheet

Case Number: 13-1892-EL-FAC

File Date: 5/9/2014

Section: 2 of 2

Number of Pages: 186

Description of Document: Report of the Management/Performance and Financial Audits

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

Organization

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

- Certificate of Accountability of Independent Auditors
- Quarterly FAC Filing – First Quarter 2012
- Second Quarter 2012 – Blended
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- BTU Adjustments

- Freight and Barge Vouchers
- Fuel Analysis Reports
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- Reliability Must Run Generation
- Review Related to Service Interruptions and Unscheduled Outages
- FAC Filings, Supporting Workpapers and Documentation
- Lawrenceburg Generating Station
- OVEC Demand Charges
- Audit Trail for Reconciling Adjustments
- Renewable Energy Resources
- Carrying Costs on Deferred Fuel Balances
- Active Management
- Audit Fees Included in FAC
- Conesville Coal Preparation Plant
- [redacted] and Related Revenue

[redacted]

- Emission Allowances
- Changes to Fuel, Purchased Power Procurement and Emission Allowance Procurement
- Internal Audits
- AEP River Transportation Division

Certificate Of Accountability Of Independent Auditors

To: American Electric Power-Ohio

We have examined the quarterly FAC of Ohio Power Company ("OPCO" or "AEP Ohio") for the years ended December 31, 2012 and December 31, 2013 which support the calculation of the Fuel Adjustment Clause ("FAC") rates for the 12 month periods January through December 2012 and 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 period October 2012 through December 2013. In conducting our review, we were aware of and considered the guidance set forth in former Chapter 4901:1 – 11 and related appendices of the Ohio Administrative Code relating to "Uniform Financial Audit Program Standards and Specifications for the Electric Fuel Component". Our examination for this purpose was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants and, accordingly, included examining on a test basis, the accounting records and such other procedures as we considered necessary in the circumstances. We did not make a detailed examination as would be required to determine that each transaction was recorded in accordance with the financial procedural aspects of former Chapter 4901:1 – 11 and related appendices of the Ohio Administrative Code. Our examination does not provide a legal determination of AEP Ohio's compliance with specific requirements.

The quarterly FAC and AER filings are the responsibility of the Company's management. Our responsibility is to express an opinion as to AEP Ohio's fair determination of the FAC rates for January 2012 through December 31, 2013 calculated with those quarterly filings, which include the Reconciliation Adjustments for the period July 2011 through December 2013 that were reflected by AEP Ohio through the Company's quarterly FAC filings, and to express an opinion as to AEP Ohio's fair determination of the Rider AER rates for October 2012 through December 2013, that were reflected by AEP Ohio through the Company's quarterly AER Filings.

In our opinion, except for the error corrections and other concerns noted in this report, AEP Ohio has determined, in all material respects, the FAC rates for the 12-month periods January through December 2012 and January through December 2013 in accordance with its proposed procedures and its interpretation of what should be includable in the FAC rates.

In our opinion, except for the concerns noted in this report, AEP Ohio has determined, in all material respects, the AER rates for October 2012 through December 2013 in accordance with its proposed procedure, and its interpretation of what should be includable in the AER rates.

Larkin & Associates PLLC

Larkin & Associates PLLC

Livonia, Michigan

Quarterly FAC Filing – First Quarter 2012 - Blended

On December 1, 2011, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from July through September 2011 and projected data for the period January through March 2012. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 3 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's first quarter 2012 FAC filings by reproducing Schedules 1 through 3 as Exhibits 7-1 through 7-5, and then briefly summarizing each schedule.

Exhibit 7-1
OPCO and CSP Combined Schedule 1, January – March 2012

Schedule 1

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2012 through March 2012
Summary - Proposed FAC Rate

		A	B	C
		Schedule 2	Schedule 3	
Line	Delivery Voltage	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	3.65934	0.00000	3.65934
2	Primary	3.53239	0.00000	3.53239
3	Sub/Transmission	3.46202	0.00000	3.46202

Schedule 1: This schedule reflects the then current FAC rate components by delivery voltage. Column A reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period January through March 2012. Column B presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through September 2011. Column C reflects the sum of the FC and RA components.

Exhibit 7-2
OPCO and CSP Combined Schedule 2, January – March 2012

Schedule 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2012 through March 2012
FC Component

Line	Description		Forecast Period - 1st Quarter 2012 January	February	March	Total
1	Fuel & Purchased Power		184,711,107	169,001,458	149,137,318 $	502,849,883
2	Environmental (Consumables and Allowances)		15,848,072	14,476,070	13,877,449 $	44,201,591
3	(Gains) and Losses On Sales of Allowances		(325,000)	(325,000)	(325,000) $	(975,000)
4	Other		-	-	- $	-
5	Total Includible FAC Costs		$ 200,234,179 $	183,152,528 $	162,689,767 $	546,076,474
6	Less: Assigned to Off-System (Including AEP Affiliates)		68,497,295	59,332,006	41,534,886 $	169,364,187
7	FAC for Internal Load		$ 131,736,884 $	123,820,522 $	121,154,881 $	376,712,287
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.93337	0.93030	0.93146	0.93337
9	FAC for Retail Load Before Renewables		$ 122,959,255 $	115,190,232 $	112,850,925 $	351,611,947
10	Renewables/RECs		5,720,346	5,034,843	4,773,172 $	15,528,361
11	FAC for Retail Load		$ 128,679,601 $	120,225,075 $	117,624,097 $	367,140,308
12	Retail Non-Shopping Sales - Generation Level Kwh		3,834,400,207	3,346,595,168	3,461,993,539	10,642,988,914
13	FC Component of FAC Rate At Generation Level - Cents/kWh					3.44960
			Secondary	Primary	Sub Trans	
14	FC Component of FAC Rate At Generation Level		3.44960	3.44960	3.44960	
15	Loss Factor		1.0608	1.0240	1.0036	
16	FC at the Meter Level - Cents/kWh	Line 14 x Line 15	3.65934	3.53239	3.46202	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period January through March 2012. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the first quarter of 2012, AEP Ohio has projected includable FAC costs totaling $546.076 million for CSP and OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the first quarter of 2012, these projected off-system costs totaled $169.364 million for CSP and OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component for renewable energy credits ("RECs"), which totaled $15.528 million for CSP and OPCO. The addition of the RECs result in total FAC costs for retail load of $367.140 million for CSP and OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.44960 cents per kWh for CSP and OPCO and was calculated by dividing the projected FAC for retail load by the projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. CSP and OPCO applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of 3.65934, 3.53239 and 3.46202 cents per kWh.

Exhibit 7-3
OPCO and CSP Combined Schedule 3, Page 1, January – March 2012

Schedule 3
Page 1 of 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2012 through March 2012
RA

Actual Period - July 2011 through September 2011

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ 597,146,420
2	Jul-11	4,327,319,410	$ 141,697,966	$ 143,360,802	$ 1,662,836	$ 4,592,992	$ (140,961)	$ 6,114,868
3	Aug-11	3,930,514,690	$ 128,333,661	$ 134,081,144	$ 5,747,483	$ 4,608,176	$ (140,961)	$ 10,214,699
4	Sep-11	3,285,080,912	$ 106,222,558	$ 112,680,990	$ 6,458,432	$ 4,661,217	$ (44,739,334)	$ (33,619,685)
5	***Ending Balance***	*11,542,915,012*	*$ 376,254,165*	*$ 390,122,936*	*$ 13,868,751*	*$ 13,862,385*	*$ (45,021,255)*	*$ 579,856,301*
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 913,051
7	*Total (Over)/Under Recovery Balance							$ 580,769,353 *
8	Loss Adjusted Retail Sales Billing Period - kWh							10,642,988,914
9	RA Component at Generation - Cents/kWh							5 45683

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		5.45683	5.45683	5 45683
11	Loss Factor		1.0608	1 0240	1.0036
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**5.78860**	**5.58779**	**5.47647**

* Balance Moved to Phase-In Rider to be effective with the first billing cycle of January 2012.

Schedule 3: This three-page schedule represents the Companies RA components of its third quarter 2011 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under-recovery of fuel expenses for each month during the period July through September 2011, which were calculated as the difference between the monthly FAC revenues for the third quarter of 2011 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the carrying costs associated with those under-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The addition of the carrying charges and other credits and charges resulted in total under-recoveries of $579.856 million for CSP and OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with Ormet. For the third quarter of 2011, these deferrals totaled $913,051 for CSP and OPCO. The derivation of these deferral amounts are summarized on Schedule 3, page 3.

After adding the amounts associated with Ormet, CSP's and OPCO's under recovery for the third quarter of 2011 was $580.769 million, the balance of which was transferred to the Phase-In Rider, which became effective with the first billing cycle of January 2012. From these amounts, each Company calculated the RA component of its FAC rate at Generation level by dividing the under recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for CSP and OPCO for this filing was 5.45683 cents per kWh. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the

FAC rate at meter level. For CSP and OPCO, the application of the loss factors results in RA components of the FAC rate of 5.78860, 5.58779 and 5.47647 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

AEP Ohio stated that the under-recovery balance is not included in the RA component of Schedule 1, due to its inclusion in the Phase-In Rider.

Exhibit 7-4
OPCO and CSP Combined Schedule 3, Page 2, January – March 2012

Schedule 3
Page 2 of 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2012 through March 2012
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Jul-11	S 280,980,015	S 133,222,113	S 147,757,902	0.96080	S 141,965.092	S 1,395,710	S 143,360,802
2	Aug-11	S 244,041,284	S 105,571,788	S 138.469.496	0.95789	S 132,638,957	S 1,442,187	S 134,081,144
3	Sep-11	S 210,295,749	S 94,189,095	S 116.106,654	0.95373	S 110.734,805	S 1,946,185	S 112,680.990
4	Total	S 735,317,048	S 332,982,996	S 402,334,052		S 385,338,854	S 4,784,082	S 390,122,936

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh: Whlse (WPC)	Retail	Total	Jurisdictional Ratios: Whlse (WPC)	Retail
Actual						
5	Jul-11	202,986,657	4,505,564,882	4,708,551,539	0.04311	0.95689
6	Aug-11	200,577,437	4,090,368,141	4,290,945,578	0.04674	0.95326
7	Sep-11	185,986,999	3,406,322,257	3,592,309,256	0.05177	0.94823
Forecast						
8	Jan-12	273,725,095	3,834,400,207	4,108,125,302	0.06663	0.93337
9	Feb-12	250,736.657	3,346,595,168	3,597,331,825	0.06970	0.93030
10	Mar-12	254,759,447	3,461,993,539	3,716,752,986	0.06854	0.93146

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the third quarter of 2011. Specifically, page 2 of Schedule 3 (lines 1-4) shows, for each Company, total monthly FAC costs incurred from July through September 2011. For each month (July through September), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the third quarter of 2011, CSP and OPCO added an amount totaling $4,784,082 for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the third quarter of 2011 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for July through September 2011. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for January through March 2012, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of .93337, .93030 and .93146 (January, February and March 2012, respectively) for CSP and OPCO.

Exhibit 7-5
OPCO and CSP Combined Schedule 3, Page 3, January – March 2012

Schedule 3
Page 3 of 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2012 through March 2012
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jul-11	$ -	$ 304,350	$ 304,350
2	Aug-11	$ -	$ 304,350	$ 304,350
3	Sep-11	$ -	$ 304,350	$ 304,350
4	Total	$ -	$ 913,051	$ 913,051

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

Ormet Interim Agreement

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

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

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

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

After September 17, 2009, the Companies have continued to accrue carrying charges on the deferral related to the Ormet Interim Agreement, which the Companies have included in their RA adjustment calculations during 2011 as shown on Schedule 3, page 3 of the Companies' quarterly FAC filings. The \$913,051 for the Ormet Interim Agreement deferral included in the RA relate back to this.

On September 1, 2010, AEP Ohio filed an application for a Significant Excessive Earnings Test ("SEET"), which utilities are required to file annually at the PUCO in order to demonstrate whether significantly excessive earnings were made. In its Opinion and Order dated January 11, 2011, the PUCO determined that CSP generated \$42.6 million in significantly excessive earnings in 2009, which the Commission ordered be refunded to customers through bill credits and the elimination of any deferrals. As a result of the Commission's Opinion and Order, CSP's Ormet interim agreement deferral amount (including carrying charges) effectively became zero as of December 31, 2010. The Companies' March 1, 2011 quarterly FAC filing (Schedule 3, page 1, line 8) reflected a line item called "SEET Refund", which removed the deferral and Ormet carrying charges which totaled \$18,717,599. AEP Ohio's response to LA-2012/2013-1-121 stated that no special agreements with Ormet have impacted AEP Ohio's 2012 or 2013 quarterly FAC filings.

Second Quarter 2012 - Blended

On March 1, 2012, AEP Ohio submitted its quarterly FAC filings, reflecting the merger of CSP and OPCo (now referred to as OPCo), which provided actual data from October through December 2011 and projected data for the period April through June 2012. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 3 supporting the Companies proposed calculations for OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's second quarter 2012 FAC filings by reproducing Schedules 1 through 3 as Exhibits 7-6 through 7-10, and then briefly summarizing each schedule.

Exhibit 7-6
OPCO and CSP Combined Schedule 1, April – June 2012

Schedule 1

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
Summary - Proposed FAC Rate

		A	B	C
		Schedule 2	Schedule 3	
Line	Delivery Voltage	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	3.67755	0.00000	3.67755
2	Primary	3.54997	0.00000	3.54997
3	Sub/Transmission	3.47925	0.00000	3.47925

Schedule 1: This schedule reflects the then current FAC rate components by delivery voltage. Column A reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period April through June 2012. Column B presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through December 2011. Column C reflects the sum of the FC and RA components.

Exhibit 7-7
OPCO and CSP Combined Schedule 2, April – June 2012

Schedule 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
FC Component

Line	Description		April	May	June	Total
			Forecast Period - 2nd Quarter 2012			
1	Fuel & Purchased Power		130,768,264	144,690,719	166,077,060	$ 441,536,042
2	Environmental (Consumables and Allowances)		12,149,437	12,506,628	14,161,520	$ 38,817,585
3	(Gains) and Losses On Sales of Allowances		(325,000)	(725,000)	(725,000)	$ (1,775,000)
4	Other		-	-	-	$ -
5	Total Includible FAC Costs		$ 142,592,701	$ 156,472,346	$ 179,513,580	$ 478,578,627
6	Less: Assigned to Off-System (Including AEP Affiliates)		35,586,844	46,055,236	59,615,890	$ 141,257,971
7	FAC for Internal Load		$ 107,005,857	$ 110,417,110	$ 119,897,689	$ 337,320,656
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92668	0.92831	0.92736	0.92746
9	FAC for Retail Load Before Renewables		$ 99,160,187	$ 102,501,308	$ 111,188,321	$ 312,852,444
10	Renewables/RECs		4,922,565	4,282,014	3,056,983	$ 12,261,562
11	FAC for Retail Load		$ 104,082,753	$ 106,783,322	$ 114,245,304	$ 325,114,006
12	Retail Non-Shopping Sales - Generation Level Kwh		2,922,078,018	3,105,476,601	3,350,445,531	9,378,000,150
13	FC Component of FAC Rate At Generation Level - Cents/kWh					3.46677
			Secondary	**Primary**	**Sub/Trans**	
14	FC Component of FAC Rate At Generation Level		3.46677	3.46677	3.46677	
15	Loss Factor		1.0608	1.0240	1.0036	
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**3.67755**	**3.54997**	**3.47925**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period April through June 2012. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the second quarter of 2012, AEP Ohio has projected includable FAC costs totaling $478.579 million for OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the second quarter of 2012, these projected off-system costs totaled $141.258 million for OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component for renewable energy credits ("RECs"), which totaled $12.262 million for OPCO. The addition of the RECs result in total FAC costs for retail load of $325.114 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.46677 cents per kWh for OPCO and was calculated by dividing the projected FAC for retail load by the projected retail non-shopping sales at the Generation level.

OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. OPCO applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of 3.67755, 3.54997 and 3.47925 cents per kWh.

Exhibit 7-8
OPCO and CSP Combined Schedule 3, Page 1, April – June 2012

Schedule 3
Page 1 of 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
RA

Actual Period - October 2011 through December 2011

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ 580,769,353
2	Oct-11	3,231,944,687	$ 106,510,060	$ 117,839,533	$ 11,329,473	$ 4,506,912	$ (4,093,559)	$ 11,742,826
3	Nov-11	3,158,604,359	$ 106,255,761	$ 109,226,099	$ 2,970,338	$ 4,606,108	$ 1,839,372	$ 9,415,818
4	Dec-11	3,391,808,212	$ 116,626,473	$ 129,544,666	$ 12,918,193	$ 4,632,825	$ (67,495,787)	$ (49,944,769)
5	**Ending Balance**	9,782,357,258	$ 329,392,294	$ 356,610,298	$ 27,218,004	$ 13,745,844	$ (69,749,973)	$ 551,983,229
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 913,051
7	Total (Over)/Under Recovery Balance							$ 552,896,280 *
8	Loss Adjusted Retail Sales Billing Period - kWh							9,378,000,150
9	RA Component at Generation - Cents/kWh							5.89567

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		5.89567	5.89567	5.89567
11	Loss Factor		1.0608	1.0240	1.0036
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**6.25413**	**6.03717**	**5.91690**

*** Balance Moved to Phase-In Rider**

Schedule 3: This three-page schedule represents the Companies RA components of its fourth quarter 2011 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under-recovery of fuel expenses for each month during the period October through December 2011, which were calculated as the difference between the monthly FAC revenues for the fourth quarter of 2011 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the carrying costs associated with those under-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The addition of the carrying charges and other credits and charges resulted in total under-recoveries of $551.983 million for CSP and OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with Ormet. For the fourth quarter of 2011, these deferrals totaled $913,051 for OPCO. The derivation of these deferral amounts are summarized on Schedule 3, page 3.

After adding the amounts associated with Ormet, OPCO's under recovery for the fourth quarter of 2011 was $552.896 million, the balance of which was moved to the Phase-In Rider. The under-recovery balance is no longer included in the RA component of Schedule 1 of this quarterly filing. From these amounts, OPCO calculated the RA component of its FAC rate at Generation level by dividing the under recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for OPCO for this filing was 5.89567 cents per kWh for OPCO. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. For OPCO, the application of the loss factors results in RA components of the FAC rate of 6.25413, 6.03717 and 5.91690 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Exhibit 7-9
OPCO and CSP Combined Schedule 3, Page 2, April – June 2012

Schedule 3
Page 2 of 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Oct-11	$ 180,948,590	$ 59,120,779	$ 121,827,811	0.95891	$ 116,821,728	$ 1,017,805	$ 117,839,533
2	Nov-11	$ 157,085,853	$ 45,432,200	$ 111,653,653	0.94833	$ 105,884,497	$ 3,341,602	$ 109,226,099
3	Dec-11	$ 205,332,226	$ 71,537,891	$ 133,794,335	0.94845	$ 126,897,884	$ 2,646,782	$ 129,544,666
4	Total	$ 543,366,669	$ 176,090,870	$ 367,275,799		$ 349,604,109	$ 7,006,189	$ 356,610,298

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh Whlse (WPC)	Jurisdictional Sales at Gen Level Kwh Retail	Jurisdictional Sales at Gen Level Kwh Total	Jurisdictional Ratios Whlse (WPC)	Jurisdictional Ratios Retail
Actual						
5	Oct-11	174,172,730	3,346,842,754	3,521,015,484	0.04947	0.95053
6	Nov-11	188,492,610	3,275,034,317	3,463,526,927	0.05442	0.94558
7	Dec-11	201,443,085	2,479,006,411	2,680,449,496	0.07515	0.92485
Forecast						
8	Apr-12	231,184,020	2,922,078,018	3,153,262,038	0.07332	0.92668
9	May-12	239,827,834	3,105,476,601	3,345,304,436	0.07169	0.92831
10	Jun-12	262,442,229	3,350,445,531	3,612,887,760	0.07264	0.92736

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the fourth quarter of 2011. Specifically, page 2 of Schedule 3 (lines 1-4) shows, for each Company, total monthly FAC costs incurred from October through December 2011. For each month (October through December), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the fourth quarter of 2011, OPCO added an amount totaling $7,006,189 for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the fourth quarter of 2011 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for October through December 2011. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for April through June 2012, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of .92668, .92831 and .92736 (April, May and June 2012, respectively) for CSP and OPCO.

Exhibit 7-10
OPCO and CSP Combined Schedule 3, Page 3, April – June 2012

Schedule 3
Page 3 of 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Oct-11	$ -	$ 304,350	$ 304,350
2	Nov-11	$ -	$ 304,350	$ 304,350
3	Dec-11	$ -	$ 304,350	$ 304,350
4	Total	$ -	$ 913,051	$ 913,051

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

Second Quarter 2012 - Unblended

Pursuant to a March 7, 2012 Commission Entry in Docket No. 11-346-EL-SSO et al., which ordered that Ohio Power file unblended FAC rates to be effective March 9, 2012, AEP Ohio filed unblended FAC rates on March 16, 2012 for the second quarter of 2012. Ohio Power, however, requested that its March 1 blended FAC filing be approved instead of its March 16 unblended FAC filing.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's second quarter 2012 unblended FAC filings by reproducing Schedules 1 through 3 as Exhibits 7-11 through 7-14, and then briefly summarizing each schedule.

Exhibit 7-11
OPCO and CSP Unblended Schedule 1, April – June 2012

Schedule 1

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
Summary - Proposed FAC Rate

Columbus Southern Power Rate Zone

		A	B	C
		Schedule 2	Schedule 3	
Line	Delivery Voltage	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	4.05043	0.00000	4.05043
2	Primary	3.91833	0.00000	3.91833
3	Sub/Transmission	3.84404	0.00000	3.84404

Ohio Power Rate Zone

		A	B	C
		Schedule 2	Schedule 3	
Line	Delivery Voltage	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	3.44632	0.00000	3.44632
2	Primary	3.32024	0.00000	3.32024
3	Sub/Transmission	3.24047	0.00000	3.24047

Schedule 1: This schedule reflects the then current FAC rate components by delivery voltage. Column A reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period April through June 2012. Column B presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through December 2011. Column C reflects the sum of the FC and RA components.

Exhibit 7-12
OPCO and CSP Unblended Schedule 2a, April – June 2012

Schedule 2a

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
FC Component

			Forecast Period - 2nd Quarter 2012			
Line	Description		April	May	June	Total
1	Fuel & Purchased Power		130,768,264	144,690,719	166,077,060	$ 441,536,042
2	Environmental (Consumables and Allowances)		12,149,437	12,506,628	14,161,520	$ 38,817,585
3	(Gains) and Losses On Sales of Allowances		(325,000)	(725,000)	(725,000)	$ (1,775,000)
4	Other		-	-	-	$ -
5	Total Includible FAC Costs		$ 142,592,701	$ 156,472,346	$ 179,513,580	$ 478,578,627
6	Less: Assigned to Off-System (Including AEP Affiliates)		35,586,844	46,055,236	59,615,890	$ 141,257,971
7	FAC for Internal Load		$ 107,005,857	$ 110,417,110	$ 119,897,689	$ 337,320,656
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92668	0.92831	0.92736	0.92746
9	FAC for Retail Load Before Renewables		99,160,187	102,501,308	$ 111,188,321	$ 312,852,444
10	Renewables/RECs		4,922,565	4,282,014	3,056,983	$ 12,261,562
11	FAC for Retail Load (Total Company)		$ 104,082,752	$ 106,783,322	$ 114,245,304	$ 325,114,006
12	OPCo % FAC for Retail Load	56.33%				$ 183,127,074
13	Retail Non-Shopping Sales - Generation Level Kwh (Total Company)		2,922,078,018	3,105,476,601	3,350,445,531	9,378,000,150
14	OPCo % Non-Shopping Sales	60.46%				3.22981
15	FC Component of FAC Rate At Generation Level - Cents/kWh					
			Secondary	**Primary**	**Sub/Trans**	
16	FC Component of FAC Rate At Generation Level		3.22981	3.22981	3.22981	
17	Loss Factor		1.0662	1 0280	1.0033	
18	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**3.44362**	**3.32024**	**3.24047**	

Schedule 2a: This schedule reflects AEP Ohio's estimates OPCO's percentage of monthly fuel costs it expected to incur during the period April through June 2012. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the second quarter of 2012, AEP Ohio has projected includable FAC costs totaling $478.579 million, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2a, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the second quarter of 2012, these projected off-system costs totaled $141.258 million. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2a reflects the Companies' projected component for renewable energy credits ("RECs"), which totaled $12.262 million. The addition of the RECs result in total FAC costs for retail load of $183.127 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.22981 cents per kWh for OPCO and was calculated by dividing OPCO's projected FAC for retail load by OPCO's portion of projected retail non-shopping sales at the Generation level.

OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. OPCO applied the loss factors of 1.0662, 1.0280 and 1.0033 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of 3.44362, 3.32024 and 3.24047 cents per kWh.

Exhibit 7-13
OPCO and CSP Unblended Schedule 2b, April – June 2012

Schedule 2b

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
FC Component

Line	Description		Forecast Period - 2nd Quarter 2012 April	May	June	Total
1	Fuel & Purchased Power		130,768,264	144,690,719	166,077,060	$ 441,536,042
2	Environmental (Consumables and Allowances)		12,149,437	12,506,628	14,161,520	$ 38,817,585
3	(Gains) and Losses On Sales of Allowances		(325,000)	(725,000)	(725,000)	$ (1,775,000)
4	Other		-	-	-	$ -
5	Total Includible FAC Costs		$ 142,592,701	$ 156,472,346	$ 179,513,580	$ 478,578,627
6	Less Assigned to Off-System (Including AEP Affiliates)		35,586,844	46,055,236	59,615,890	$ 141,257,971
7	FAC for Internal Load		$ 107,005,857	$ 110,417,110	$ 119,897,689	$ 337,320,656
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92668	0.92831	0.92736	0.92746
9	FAC for Retail Load Before Renewables		99,160,187	102,501,308	$ 111,188,321	$ 312,852,444
10	Renewables/RECs		4,922 565	4,282,014	3,056,983	$ 12,261,562
11	FAC for Retail Load (Total Company)		$ 104,082,752	$ 106,783,322	$ 114,245,304	$ 325,114,006
12	CSP % FAC for Retail Load	43.67%				$ 141,986,932
13	Retail Non-Shopping Sales - Generation Level Kwh		2,922,078,018	3,105,476,601	3,350,445,531	9,378,000,150
14	CSP % Non-Shopping Sales	39.54%				3.82911
15	FC Component of FAC Rate At Generation Level - Cents/kWh					
			Secondary	**Primary**	**Sub/Trans**	
16	FC Component of FAC Rate At Generation Level		3.82911	3.82911	3 82911	
17	Loss Factor		1.0578	1.0233	1.0039	

Schedule 2b: This schedule reflects AEP Ohio's estimates CSP's percentage of monthly fuel costs it expected to incur during the period April through June 2012. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the second quarter of 2012, AEP Ohio has projected includable FAC costs totaling $478.579 million for CSP and OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2b, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the second quarter of 2012, these projected off-system costs totaled $141.258 million. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2b reflects the Companies' projected component for renewable energy credits ("RECs"), which totaled $12.262 million. The addition of the RECs result in total FAC costs for retail load of $141.987 million for CSP. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.82911 cents per kWh for CSP and was calculated by dividing CSP's portion of projected FAC for retail load by CSP's portion of projected retail non-shopping sales at the Generation level.

CSP then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. CSP applied the loss factors of 1.0578, 1.0233 and 1.0039 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of 4.05043, 3.91833 and 3.84404 cents per kWh.

Exhibit 7-14
OPCO and CSP Unblended Schedule 3, April – June 2012

Schedule 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012

Actual Period - October 2011 through December 2011

Columbus Southern Power Rate Zone

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	FAC Cost
1	**Beginning Balance**			
2	Oct-11	1,281,255,822	$ 49,785,918	$ 59,376,154
3	Nov-11	1,217,139,701	$ 45,699,336	$ 45,964,350
4	Dec-11	1,369,580,104	$ 50,542,207	$ 56,143,281
5	**Ending Balance**	3,867,975,627	$ 146,027,461	$ 161,483,785
	Remove Pool Capacity Payments 4th Quarter			$ (10,193,130)
	Revised CSP Ending Balance			$ 151,290,655

Ohio Power Rate Zone

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost
1	**Beginning Balance**			
2	Oct-11	1,950,688,865	$ 56,724,142	$ 58,463,379
3	Nov-11	1,941,464,658	$ 60,556,425	$ 63,261,749
4	Dec-11	2,022,228,108	$ 66,084,266	$ 73,401,385
5	**Ending Balance**	5,914,381,631	$ 183,364,833	$ 195,126,513
	AEP Ohio	9,782,357,258		$ 346,417,168
	CSP Rate Zone	39.54%		43.67%
	OPCO Rate Zone	60.46%		56.33%

Schedule 3: This schedule represents the Companies' RA components of its fourth quarter 2011 FAC filings. Specifically, Schedule 3 reflects CSP's and OPCO's respective beginning balances for each month during the period October through December 2011, which were calculated for retail sales, renewable and FAC revenue, and FAC costs. In addition, this schedule reflects the removal of fourth quarter pool capacity payments to calculate the revised CSP ending balance. This removal of the pool capacity payments resulted in a revised ending FAC balance of $151.291 million for CSP. This schedule also shows an ending FAC balance of $195.127 million for OPCO.

Explanation From AEP as to Why It Can No Longer Unbundle Fuel Costs Between Ohio Power and CSP

During the interviews conducted at AEP Ohio's offices on February 20, 2014, the Company stated that it is no longer able to unbundle FAC-includable costs separately between CSP and OPCO following the December 2011 merger. Larkin issued follow-up data request LA-2012/2013-4-2 which requested that AEP Ohio explain fully why it is no longer able to unbundle the FAC-includable costs separately between CSP and OPCO. In response, AEP Ohio stated:

> *The Company merged the systems that produce individual fuel costs due to the approval of the merger. The Company no longer has the fuel costs separated by the unmerged operating companies, and doing so would disallow the ability for fuel costs and true-ups to be done on an unmerged basis. The Company allocated the forecasted fuel costs based on the data available pre-merger, December 2011. This allocation was done in support of the Commission's desire to maintain the delta between CSP and OPCO rate zone fuel rates at the time of merger. While the forecasted component was allocated to maintain the delta, there is no basis in using this split for actual fuel costs. Due to shopping levels and the inability to provide actual data fuel by unmerged companies, to allocate actual fuel on this basis could result in unfair and unreasonable rates to customers in each rate zone.*

Third Quarter 2012

On June 1, 2012, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from January through March 2012 and projected data for the period July through September 2012. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 3 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's third quarter 2012 FAC filings by reproducing Schedules 1 through 3, broken out separately between CSP and OPCO as Exhibits 7-15 through 7-18, and then briefly summarizing each schedule.

Exhibit 7-15
CSP and OPCO Schedule 1, July – September 2012

Schedule 1

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2012 through September 2012
Summary - Proposed FAC Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		A	B	C	D
			Schedule 2	Schedule 3	
Line	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	4.05043	4.23165	-0.14171	4.089940
2	Primary	3.91833	4.08485	-0.13679	3.948060
3	Sub/Transmission	3.84404	4.00347	-0.13407	3.869400

OHIO POWER RATE ZONE

		A	B	C	D
			Schedule 2	Schedule 3	
Line	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	3.44362	3.56973	-0.14171	3.428020
2	Primary	3.32024	3.44589	-0.13679	3.309100
3	Sub/Transmission	3.24047	3.37724	-0.13407	3.243170

Schedule 1: Column A of this schedule reflects the then current FAC rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period July through September 2012. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through March 2012. Column D reflects the sum of the FC and RA components.

Exhibit 7-16
CSP and OPCO Schedule 2, July – September 2012

Schedule 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2012 through September 2012
FC Component

Line	Description			July	August	September	Total
				Forecast Period - 3rd Quarter 2012			
	TOTAL COMPANY						
1	Fuel & Purchased Power			191,880,462	193,679,061	154,695,848	$ 540,255,371
2	Environmental (Consumables and Allowances)			15,745,185	16,179,652	13,727,295	$ 45,652,132
3	(Gains) and Losses On Sales of Allowances			(725,000)	(725,000)	(725,000)	$ (2,175,000)
4	Other			-	-	-	$ -
5	Total Includible FAC Costs			$ 206,900,647	$ 209,133,713	$ 167,698,143	$ 583,732,503
6	Less: Assigned to Off-System (Including AEP Affiliates)			71,939,126	74,502,726	54,217,369	$ 200,659,221
7	FAC for Internal Load			$ 134,961,521	$ 134,630,987	$ 113,480,774	$ 383,073,282
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2		0.93088	0.93031	0.93135	0.93081
9	FAC for Retail Load Before Renewables			$ 125,632,981	$ 125,248,554	$ 105,690,319	$ 356,570,198
10	Renewables/RECs			2,818,249	2,624,224	2,975,986	$ 8,418,459
11	FAC for Retail Load (Total Company)			$ 128,451,230	$ 127,872,778	$ 108,666,305	$ 364,988,657
13	Retail Non-Shopping Sales - Generation Level Kwh			3,551,086,513	3,583,020,083	2,971,205,545	10,105,312,141
	COLUMBUS SOUTHERN POWER RATE ZONE						
14	CSP % for Retail Load		43.67%				$ 159,390,547
15	CSP % Non-Shopping Sales		39 54%				3,995,640,421
16	FC Component of FAC Rate At Generation Level - Cents/kWh						3.98911
				Secondary	**Primary**	**Sub/Trans**	
17	FC Component of FAC Rate At Generation Level			3.98911	3.98911	3.98911	
18	Loss Factor			1.0608	1.0240	1 0036	
19	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**		**4.23165**	**4.08485**	**4.00347**	
	OHIO POWER RATE ZONE						
19	OPCo % for Retail Load		56.33%				$ 205,598,111
21	OPCo % Non-Shopping Sales		60 46%				6,109,671,720
22	FC Component of FAC Rate At Generation Level - Cents/kWh						3.36513
				Secondary	**Primary**	**Sub/Trans**	
23	FC Component of FAC Rate At Generation Level			3.36513	3.36513	3.36513	
24	Loss Factor			1 0608	1.0240	1.0036	
25	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**		**3.56973**	**3.44589**	**3.37724**	
	Combined						
	% for Retail Load						$ 364,988,657
	%Non-Shopping Sales						10,105,312.141
	FC Component of FAC Rate At Generation Level - Cents/kWh						3 61185
				Secondary	**Primary**	**Sub/Trans**	
	FC Component of FAC Rate At Generation Level			3.61185	3.61185	3 61185	

[redacted]

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period July through September 2012. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the third quarter of 2012, AEP Ohio has projected includable FAC costs totaling $583.733 million, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the third quarter of 2012, these projected off-system costs totaled $200.659 million. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived their FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component for renewable energy credits ("RECs"), which totaled $8.418 million. The addition of the RECs result in total FAC costs for retail load of $159.391 million for CSP and $205.598 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.98911 cents per kWh for CSP and 3.36513 cents per kWh for OPCO and was calculated by dividing each Company's projected FAC for retail load by their respective projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. CSP applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of 4.23165, 4.08485 and 4.00347 cents per kWh. OPCO applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of 3.56973, 3.44589 and 3.37724 cents per kWh.

Exhibit 7-17
CSP and OPCO Schedule 3, Page 1, July – September 2012

Schedule 3
Page 1 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2012 through September 2012
RA

Actual Period - January 2012 through March 2012

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ -
2	Jan-12	3,461,728,429	$ 123,203,708	$ 111,149,548	$ (12,054,160)	$ -	$ -	$ (12,054,160)
3	Feb-12	2,927,680,736	$ 105,628,286	$ 102,158,124	$ (3,470,162)	$ -	$ -	$ (3,470,162)
4	Mar-12	2,734,438,016	$ 94,596,203	$ 96,621,357	$ 2,025,154	$ -	$ -	$ 2,025,154
5	**Ending Balance**	9,123,847,181	$ 323,428,197	$ 309,929,029	$ (13,499,168)	$ -	$ -	$ (13,499,168)
6	Total (Over)/Under Recovery Balance							$ (13,499,168)
7	Loss Adjusted Retail Sales Billing Period - kWh							10,105,312,141
8	RA Component at Generation - Cents/kWh							(0 13358)

Line			Secondary	Primary	Sub/Trans
9					
10	RA Component of FAC Rate At Generation Level		(0.13358)	(0 13358)	(0.13358)
11	Loss Factor		1.0608	1.024	1.0036
	RA at the Meter Level - Cents/kWh	Line 10 x Line 11	-0.14171	-0.13679	-0.13407

*** Balance Moved to Phase-In Rider**

Schedule 3: This two-page schedule represents the Companies' RA components of their third quarter 2012 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under-recovery of fuel expenses for each month during the period January through March 2012, which were calculated as the difference between the monthly FAC revenues for the first quarter of 2012 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the carrying costs associated with those under-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The first quarter of 2012 did not have any carrying costs or other charges and credits, resulting in total over-recoveries of $13.499 million.

From this amount, the Companies calculated the RA component of its FAC rate at Generation level by dividing the over-recovery by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for this filing was (.13358) cents per kWh. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. The application of the loss factors results in RA components of the FAC rate of (.14171), (.13679) and (.13407) cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Exhibit 7-18
CSP and OPCO Schedule 3, Page 2, July – September 2012

Schedule 3
Page 2 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2012 through December 2012
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Jan-12	$ 185,333,462	$ 70,778,336	$ 114,555,126	0.93882	$ 107,546,643	$ 3,602,905	$ 111,149,548
2	Feb-12	$ 167,429,321	$ 61,770,197	$ 105,659,124	0.93745	$ 99,050,146	$ 3,107,978	$ 102,158,124
3	Mar-12	$ 154,791,428	$ 56,205,751	$ 98,585,677	0.92976	$ 91,661,019	$ 4,960,338	$ 96,621,357
4	Total	$ 507,554,211	$ 188,754,284	$ 318,799,927		$ 298,257,808	$ 11,671,221	$ 309,929,029

Monthly Jurisdictional Allocation Ratios

		Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
Line	Month	Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
5	Jan-12	234,572,935	3,611,868,991	3,846,441,926	0.06098	0.93902
6	Feb-12	202,844,551	3,040,145,602	3,242,990,153	0.06255	0.93745
7	Mar-12	214,395,515	2,837,988,614	3,052,384,129	0.07024	0.92976
Forecast						
8	Jul-12	263,696,164	3,551,086,513	3,814,782,677	0.06912	0.93088
9	Aug-12	268,391,410	3,583,020,083	3,851,411,493	0.06969	0.93031
10	Sep-12	219,018,204	2,971,205,545	3,190,223,749	0.06865	0.93135

Page 2 of Schedule 3 reflects monthly data on the Companies' actual fuel costs during the first quarter of 2012. Specifically, page 2 of Schedule 3 (lines 1-4) shows total monthly FAC costs incurred from January through March 2012. For each month (January through March), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level, to derive its "Retail FAC Before Renewables". During the first quarter of 2012, the Companies added amounts totaling $11,671,221 for renewables, which reflects the revenue requirement associated with solar panels that were installed by AEP Ohio pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that future FAC revenues will first be applied towards recovering renewable energy costs so that they are not embedded in the long-term deferrals of either CSP or OPCO. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the first quarter of 2012 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for January through March 2012. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for July through September 2012, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of .93088, .93031 and .93135 (July, August and September 2012, respectively) for the Companies.

Fourth Quarter 2012

On August 31, 2012, AEP Ohio submitted quarterly FAC filings, as well as its first Alternative Energy Rider ("AER") quarterly filing,[56] for CSP and OPCO, which reflected actual data from April through June 2012 and projected data for the period October through December 2012. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 6 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's fourth quarter 2012 FAC filings by reproducing Schedules 1 through 3, broken out separately between CSP and OPCO as Exhibits 7-19 through 7-22, and then briefly summarizing each schedule.

[56] The AER will be discussed in the next chapter of this report.

Exhibit 7-19
CSP and OPCO Schedule 1, October – December 2012

Schedule 1

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2012 through December 2012
Summary - Proposed FAC Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		A	B	C	D
			Schedule 2	Schedule 3	
Line	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	4.08994	4.13724	-0.07958	4.057660
2	Primary	3.94806	3.99371	-0.07682	3.916890
3	Sub/Transmission	3.86940	3.91415	-0.07529	3.838860

OHIO POWER RATE ZONE

		A	B	C	D
			Schedule 2	Schedule 3	
Line	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	3.42802	3.50572	-0.07958	3.426140
2	Primary	3.30910	3.38410	-0.07682	3.307280
3	Sub/Transmission	3.24317	3.31669	-0.07529	3.241400

Schedule 1: Column A of this schedule reflects the then current FAC rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period October through December 2012. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through June 2012. Column D reflects the sum of the FC and RA components.

Exhibit 7-20
CSP and OPCO Schedule 2, October – December 2012

Schedule 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2012 through December 2012
FC Component

Line	Description		Forecast Period - 4th Quarter 2012 October	November	December	Total
	TOTAL COMPANY					
1	Fuel & Purchased Power		145,047,798	137,005,571	170,136,028	$ 452,189,397
2	Environmental (Consumables and Allowances)		13,458,061	12,045,206	15,238,075	$ 40,741,341
3	(Gains) and Losses On Sales of Allowances		(325,000)	(325,000)	3,494,000	$ 2,844,000
4	Other		-	-	-	$ -
5	Total Includible FAC Costs		$ 158,180,860	$ 148,725,777	$ 188,868,102	$ 495,774,739
6	Less. Assigned to Off-System (Including AEP Affiliates)		47,299,411	36,196,203	59,272,365	$ 142,767,979
7	FAC for Internal Load		$ 110,881,448	$ 112,529,574	$ 129,595,738	$ 353,006,760
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92737	0.93169	0.93308	0.93084
9	FAC for Retail Load Before Renewables		$ 102,828,129	$ 104,842,678	$ 120,923,191	$ 328,591,628
10	Energy & Capacity Value of Renewables (RECs moved to Rider AER)		2,369,585	2,676,224	2,851,362	$ 7,897,171
11	FAC for Retail Load (Total Company)		$ 105,197,714	$ 107,518,903	$ 123,774,553	$ 336,488,799
13	Retail Non-Shopping Sales - Generation Level Kwh		2,982,573,959	3,052,977,995	3,469,293,021	9,504,844,975
	COLUMBUS SOUTHERN POWER RATE ZONE					
14	CSP % for Retail Load	43.56%				$ 146,574,521
15	CSP % Non-Shopping Sales	39.54%				3,758,215,703
16	FC Component of FAC Rate At Generation Level - Cents/kWh					3.90011
			Secondary	Primary	Sub/Trans	
17	FC Component of FAC Rate At Generation Level		3.90011	3.90011	3.90011	
18	Loss Factor		1.0608	1.0240	1.0036	
19	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**	4.13724	3.99371	3.91415	
	OHIO POWER RATE ZONE					
19	OPCo % for Retail Load	56.44%				$ 189,914,278
21	OPCo % Non-Shopping Sales	60.46%				5,746,629,272
22	FC Component of FAC Rate At Generation Level - Cents/kWh					3.30479
			Secondary	Primary	Sub/Trans	
23	FC Component of FAC Rate At Generation Level		3.30479	3.30479	3.30479	
24	Loss Factor		1.0608	1.0240	1.0036	
25	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**	3.50572	3.3841	3.31669	

Schedule 2: *This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to* incur during the period October through December 2012. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the fourth quarter of 2012, AEP Ohio has projected includable FAC costs totaling $495.775 million, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the fourth quarter of 2012, these projected off-system costs totaled $142.768 million. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component energy and capacity value of renewables, which totaled $7.897 million. The component for renewable energy credits ("RECs") was moved to the AER. The addition of the renewable's energy and capacity value result in total FAC costs for retail load of $146.575 million for CSP and $189.914 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.90011 cents per kWh for CSP and 3.30479 cents per kWh for OPCO and was calculated by dividing each Company's projected FAC for retail load by their respective projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. The Companies applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of 4.13724, 3.99371 and 3.91415 cents per kWh for CSP and FCs of 3.50572, 3.3841 and 3.31669 cents per kWh for OPCO.

Exhibit 7-21
CSP and OPCO Schedule 3, Page 1, October – December 2012

Schedule 3
Page 1 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2012 through December 2012
RA

Actual Period - April 2012 through June 2012

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ (13,499,168)
2	Apr-12	2,400,870,309	$ 86,168,758	$ 91,781,742	$ 5,612,984	$ -	$ -	$ 5,612,984
3	May-12	2,565,621,174	$ 93,284,889	$ 92,614,731	$ (670,158)	$ -	$ -	$ (670,158)
4	Jun-12	2,653,055,283	$ 96,773,828	$ 98,200,075	$ 1,426,247	$ -	$ -	$ 1,426,247
5	**Ending Balance**	7,619,546,766	$ 276,227,475	$ 282,596,548	$ 6,369,073	$ -	$ -	$ (7,130,095)
6	Total (Over)/Under Recovery Balance							$ (7,130,095)
7	Loss Adjusted Retail Sales Billing Period - kWh							9,504,844,975
8	RA Component at Generation - Cents/kWh							(0.07502)
9					**Secondary**	**Primary**	**Sub/Trans**	
10	RA Component of FAC Rate At Generation Level				(0.07502)	(0.07502)	(0 07502)	
11	Loss Factor				1.0608	1.024	1.0036	
	RA at the Meter Level - Cents/kWh	Line 10 x Line 11			-0.07958	-0.07682	-0.07529	

Schedule 3: This two-page schedule represents the Companies' RA components of their fourth quarter 2012 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under/over-recovery of fuel expenses for each month during the period April through June 2012, which were calculated as the difference between the monthly FAC revenues for the second quarter of 2012 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the carrying costs associated with those under/over-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The second quarter of 2012 did not have any carrying costs or other charges and credits, thus resulting in total over-recoveries of $7.130 million.

The Companies calculated the RA component of its FAC rate at Generation level by dividing the over-recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for this filing was 0.07502 cents per kWh. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. The application of the loss factors results in RA components of the FAC rate of (.07958), (.07682) and (.07529) cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Exhibit 7-22
CSP and OPCO Schedule 3, Page 2, October – December 2012

Schedule 3
Page 2 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2012 through December 2012
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Apr-12	$ 158,957,267	$ 63,252,958	$ 95,704,309	0.92200	$ 88,239,373	$ 3,542,369	$ 91,781,742
2	May-12	$ 162,305,745	$ 64,067,842	$ 98,237,903	0.92032	$ 90,410,307	$ 2,204,424	$ 92,614,731
3	Jun-12	$ 162,186,036	$ 59,813,212	$ 102,372,824	0.92977	$ 95,183,181	$ 3,016,894	$ 98,200,075
4	Total	$ 483,449,048	$ 187,134,012	$ 296,315,036		$ 273,832,861	$ 8,763,687	$ 282,596,548

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh: Whlse (WPC)	Retail	Total	Jurisdictional Ratios: Whlse (WPC)	Retail
Actual						
5	Apr-12	210,422,891	2,487,162,857	2,697,585,748	0.07800	0.92200
6	May-12	230,162,037	2,658,427,457	2,888,589,494	0.07968	0.92032
7	Jun-12	208,267,491	2,757,031,835	2,965,299,326	0.07023	0.92977
Forecast						
8	Oct-12	233,587,106	2,982,573,959	3,216,161,065	0.07263	0.92737
9	Nov-12	223,846,769	3,052,977,995	3,276,824,764	0.06831	0.93169
10	Dec-12	248,798,490	3,469,293,021	3,718,091,511	0.06692	0.93308

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the second quarter of 2012. Specifically, page 2 of Schedule 3 (lines 1-4) shows, for each Company, total monthly FAC costs incurred from April through June 2012. For each month (April through June), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the second quarter of 2012, AEP Ohio added amounts totaling $8,763,687 for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that the forecasted REC costs have been removed from the FAC for recovery through the AER. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the second quarter of 2012 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for April through June 2012. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for October through December 2012, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of .92737, .93169 and .93308 for each month of October, November and December 2012.

First Quarter 2013

On December 3, 2012, AEP Ohio submitted quarterly FAC filings, as well as its AER quarterly filings, for CSP and OPCO, which reflected actual data from July through September 2012 and projected data for the period January through March 2013. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 6 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's first quarter 2013 FAC filings by reproducing Schedules 1 through 3 as Exhibits 7-23 through 7-26, and then briefly summarizing each schedule.

Exhibit 7-23
OPCO and CSP Schedule 1, January – March 2013

Schedule 1

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2013 through March 2013
Summary - Proposed FAC Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		A	B	C	D
			Schedule 2	Schedule 3	
Line	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	4.05766	4.22822	-0.31902	3.909200
2	Primary	3.91689	4.08154	-0.30796	3.773580
3	Sub/Transmission	3.83886	4.00023	-0.30182	3.698410

OHIO POWER RATE ZONE

		A	B	C	D
			Schedule 2	Schedule 3	
Line	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	3.42614	3.58282	-0.31902	3.263800
2	Primary	3.30728	3.45853	-0.30796	3.150570
3	Sub/Transmission	3.24140	3.38963	-0.30182	3.087810

Schedule 1: Column A of this schedule reflects the then current FAC rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period January through March 2013. Column C presents the Companies

reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through September 2012. Column D reflects the sum of the FC and RA components.

Exhibit 7-24
OPCO and CSP Schedule 2, January – March 2013

Schedule 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2013 through March 2013
FC Component

Line	Description		Forecast Period - 1st Quarter 2013 January	February	March	Total
	TOTAL COMPANY					
1	Fuel & Purchased Power		163,884,954	146,481,015	131,804,271	$ 442,170,239
2	Environmental (Consumables and Allowances)		19,039,629	17,830,373	15,358,652	$ 52,228,654
3	(Gains) and Losses On Sales of Allowances		60,000	60,000	60,000	$ 180,000
4	Other		-	-	-	$ -
5	Total Includible FAC Costs		$ 182,984,583	$ 164,371,388	$ 147,222,923	$ 494,578,894
6	Less: Assigned to Off-System (Including AEP Affiliates)		92,242,068	88,022,576	69,916,385	$ 250,181,030
7	FAC for Internal Load		$ 90,742,515	$ 76,348,811	$ 77,306,537	$ 244 397,864
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.87727	0.86920	0.87038	0.87257
9	FAC for Retail Load Before Renewables		$ 79,605,686	$ 66,362,387	$ 67,286,064	$ 213,254,759
10	Energy & Capacity Value of Renewables (RECs moved to Rider AER)		2,517,909	2,103,747	2,057,413	$ 6,679,068
11	FAC for Retail Load (Total Company)		$ 82,123,596	$ 68,466,133	$ 69,343,477	$ 219,933,828
13	Retail Non-Shopping Sales - Generation Level Kwh		2,268,648,381	1,869,507,757	1,940,659,715	6,078,815,853
	COLUMBUS SOUTHERN POWER RATE ZONE					
14	CSP % for Retail Load	43.56%				$ 95,803,175
15	CSP % Non-Shopping Sales	39.54%				2,403,563,788
16	*FC Component of FAC Rate At Generation Level - Cents/kWh*					3 98588
			Secondary	**Primary**	**Sub/Trans**	
17	FC Component of FAC Rate At Generation Level		3.98588	3.98588	3.98588	
18	Loss Factor		1.0608	1.0240	1.0036	
19	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**	**4.22822**	**4.08154**	**4.00023**	
	OHIO POWER RATE ZONE					
19	OPCo % for Retail Load	56 44%				$ 124,130,652
21	OPCo % Non-Shopping Sales	60.46%				3,675,252,065
22	FC Component of FAC Rate At Generation Level - Cents/kWh					3.37747
			Secondary	**Primary**	**Sub/Trans**	
23	*FC Component of FAC Rate At Generation Level*		*3.37747*	*3.37747*	*3 37747*	
24	Loss Factor		1.0608	1.0240	1.0036	
25	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**	**3.58282**	**3.45853**	**3.38963**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period January through March 2013. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the first quarter of 2013, AEP Ohio has projected includable FAC costs totaling $494.579 million for CSP and OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the first quarter of 2013, these projected off-system costs totaled $250.181 million for CSP and OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component energy and capacity value of renewables, which totaled $6.679 million. The component for renewable energy credits ("RECs") was moved to the AER. The addition of the renewable's energy and capacity value result in total FAC costs for retail load of $95.803 million for CSP and $124.131 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.98588 cents per kWh for CSP and 3.37747 cents per kWh for OPCO and was calculated by dividing each Company's projected FAC for retail load by their respective projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. Each Company applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of 4.22822, 4.08154 and 4.00023 cents per kWh for CSP and FCs of 3.58282, 3.45853 and 3.38963 cents per kWh for OPCO.

Exhibit 7-25
OPCO and CSP Schedule 3, Page 1, January – March 2013

Schedule 3
Page 1 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2013 through March 2013
RA

Actual Period - July 2012 through September 2012

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	**Beginning Balance**							$ -
2	Jul-12	3,212,845.267	$ 117,882,772	$ 115,481,965	$ (2,400,807)	$ -	$ -	$ (2,400,807)
3	Aug-12	2,885,647,619	$ 105,775,062	$ 94,277,796	$ (11,497,266)	$ -	$ -	$ (11,497,266)
4	Sep-12	2,124,289,385	$ 77,284,538	$ 72,901,230	$ (4,383,308)	$ -	$ -	$ (4,383,308)
5	**Ending Balance**	8,222,782,271	$ 300,942,372	$ 282,660,991	$ (18,281,381)	$ -	$ -	$ (18,281,381)
6	Total (Over)/Under Recovery Balance							$ (18,281,381)
7	Loss Adjusted Retail Sales Billing Period - kWh							6,078,815,853
8	RA Component at Generation - Cents/kWh							(0 30074)
9					Secondary	Primary	Sub/Trans	
10	RA Component of FAC Rate At Generation Level				(0.30074)	(0.30074)	(0.30074)	
11	Loss Factor				1.0608	1.024	1.0036	
	RA at the Meter Level - Cents/kWh		Line 10 x Line 11		**-0.31902**	**-0.30796**	**-0.30182**	

Schedule 3: This two-page schedule represents the Companies' RA components of their first quarter 2013 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under/over-recovery of fuel expenses for each month during the period July through September 2012, which were calculated as the difference between the monthly FAC revenues for the third quarter of 2012 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the carrying costs associated with those over-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The first quarter of 2013 did not have any carrying costs or other charges and credits, thus resulting in total over-recoveries of $18.281 million.

The Companies calculated the RA component of its FAC rate at Generation level by dividing the over-recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for this filing was 0.30074 cents per kWh. The Companies applied the loss factors of 1.0608, 1.024, and 1.0036 related to the secondary, primary and sub/trans voltage levels, respectively to these RA components in order to derive the RA portion of the FAC rate at meter level. The application of the loss factors results in RA components of the FAC rate of (0.31902), (0.30796) and (0.30182) cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Exhibit 7-26
OPCO and CSP Schedule 3, Page 2, January – March 2013

Schedule 3
Page 2 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2013 through March 2013
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Jul-12	$ 215,891,699	$ 94,110,757	$ 121,780,942	0.93612	$ 114,001,576	$ 1,480,389	$ 115,481,965
2	Aug-12	$ 200,442,843	$ 100,336,757	$ 100,106,086	0.92895	$ 92,993,549	$ 1,284,247	$ 94,277,796
3	Sep-12	$ 153,946,346	$ 76,058,104	$ 77,888,242	0.91452	$ 71,230,355	$ 1,670,875	$ 72,901,230
4	Total	$ 570,280,888	$ 270,505,618	$ 299,775,270		$ 278,225,480	$ 4,435,511	$ 282,660,991

Monthly Jurisdictional Allocation Ratios

		Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
Line	Month	Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
5	Jul-12	228,422,018	3,347,379,473	3,575,801,491	0.06388	0.93612
6	Aug-12	229,928,824	3,006,385,407	3,236,314,231	0.07105	0.92895
7	Sep-12	206,432,213	2,208,682,751	2,415,114,964	0.08548	0.91452
Forecast						
8	Jan-13	317,378,113	2,268,648,381	2,586,026,494	0.12273	0.87727
9	Feb-13	281,333,847	1,869,507,757	2,150,841,605	0.13080	0.86920
10	Mar-13	289,020,631	1,940,659,715	2,229,680,345	0.12962	0.87038

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the third quarter of 2012. Specifically, page 2 of Schedule 3 shows total monthly FAC costs incurred from July through September 2012. For each month (July through September), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the third quarter of 2012, AEP Ohio added amounts totaling $4,435,511 for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that the forecasted REC costs have been removed from the FAC for recovery through the AER. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the third quarter of 2012 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for July through September 2012. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for January through March 2013, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of .87727, .86920 and .87038 for each month of January, February and March 2013.

Second Quarter 2013

On March 1, 2013, AEP Ohio submitted quarterly FAC filings, as well as quarterly AER filings, for CSP and OPCO, which reflected actual data from October through December 2012 and projected data for the period April through June 2013. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 6 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's second quarter 2013 FAC filings by reproducing Schedules 1 through 3 as Exhibits 7-27 through 7-30, and then briefly summarizing each schedule.

Exhibit 7-27
OPCO and CSP Schedule 1, April – June 2013

Schedule 1

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2013 through June 2013
Summary - Proposed FAC Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		A	B	C	D
			Schedule 2	Schedule 3	
Line	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	3.90920	4.36890	0.12352	4.492420
2	Primary	3.77358	4.21734	0.11924	4.336580
3	Sub/Transmission	3.69841	4.13333	0.11686	4.250190

OHIO POWER RATE ZONE

		A	B	C	D
			Schedule 2	Schedule 3	
Line	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	3.26380	3.70203	0.12352	3.825550
2	Primary	3.15057	3.57361	0.11924	3.692850
3	Sub/Transmission	3.08781	3.50241	0.11686	3.619270

Schedule 1: Column A of this schedule reflects the then current FAC rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period April through June 2013. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through December 2012. Column D reflects the sum of the FC and RA components.

Exhibit 7-28
OPCO and CSP Schedule 2, April – June 2013

Schedule 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2013 through June 2013
FC Component

Line	Description		Forecast Period - 2nd Quarter 2013 April	May	June	Total
	TOTAL COMPANY					
1	Fuel & Purchased Power		132,348,765	142,825,679	137,377,855	$ 412,552,298
2	Environmental (Consumables and Allowances)		15,350,280	16,473,620	16,182,610	$ 48,006,510
3	(Gains) and Losses On Sales of Allowances		60,000	94,000	94,000	$ 248,000
4	Other		-	-	-	$ -
5	Total Includible FAC Costs		$ 147,759,045	$ 159,393,298	$ 153,654,465	$ 460,806,808
6	Less: Assigned to Off-System (Including AEP Affiliates)		85,203,622	90,921,191	81,296,268	$ 257,421,081
7	FAC for Internal Load		$ 62,555,422	$ 68,472,107	$ 72,358,197	$ 203,385,727
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0 84331	0.85101	0 85046	0.84842
9	FAC for Retail Load Before Renewables		$ 52,753,613	$ 58,270,448	$ 61,537,753	$ 172,557,409
10	Energy & Capacity Value of Renewables (RECs moved to Rider AER)		2,499,889	2.144,706	1,536,720	$ 6,181,315
11	FAC for Retail Load (Total Company)		$ 55,253,502	$ 60,415,154	$ 63,074,473	$ 178,738,724
13	Retail Non-Shopping Sales - Generation Level Kwh		1,477 493,015	1,623,947,956	1,679,689,410	4,781,130.382
	COLUMBUS SOUTHERN POWER RATE ZONE					
14	CSP % for Retail Load	43.56%				$ 77,858,588
15	CSP % Non-Shopping Sales	39.54%				1,890,458,953
16	FC Component of FAC Rate At Generation Level - Cents/kWh					4.11850
			Secondary	Primary	Sub/Trans	
17	FC Component of FAC Rate At Generation Level		4.11850	4.11850	4.11850	
18	Loss Factor		1 0608	1.0240	1.0036	
19	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**	**4.3689**	**4.21734**	**4.13333**	
	OHIO POWER RATE ZONE					
19	OPCo % for Retail Load	56.44%				$ 100,880,136
21	OPCo % Non-Shopping Sales	60.46%				2,890,671,429
22	FC Component of FAC Rate At Generation Level - Cents/kWh					3.48985
			Secondary	Primary	Sub/Trans	
23	FC Component of FAC Rate At Generation Level		3.48985	3 48985	3.48985	
24	Loss Factor		1.0608	1.0240	1.0036	
25	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**	**3.70203**	**3.57361**	**3.50241**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period April through June 2013. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the second quarter of 2013, AEP Ohio has projected includable FAC costs totaling $460.807 million for CSP and OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

*As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-*system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the second quarter of 2013, these projected off-system costs totaled $257.421 million for CSP and OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component for the energy and capacity value of renewables, which totaled $6.181 million. The component for renewable energy credits ("RECs") was moved to the AER. The addition of the renewable's energy and capacity value result in total FAC costs for retail load of $77.859 million for CSP and $100.880 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 4.11850 cents per kWh for CSP and 3.48985 cents per kWh for OPCO and was calculated by dividing each Company's projected FAC for retail load by their respective projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. The Companies applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of 4.3689, 4.21734 and 4.13333 cents per kWh for CSP and FCs of 3.70203, 3.57361 and 3.50241 cents per kWh for OPCO.

Exhibit 7-29
OPCO and CSP Schedule 3, Page 1, April – June 2013

Schedule 3
Page 1 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2013 through June 2013
RA

Actual Period - October 2012 through December 2012

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
·	**Beginning Balance**							$ (7,130,095)
2	Oct-12	1,989,223,280	$ 72,512,674	$ 75,491,454	$ 2,978,780	$ -	$ 47,431	$ 3,026,211
3	Nov-12	1,896,976,201	$ 69,381,088	$ 73,786,390	$ 4,405,302	$ -	$ -	$ 4,405,302
4	Dec-12	2,045,287,888	$ 73,602,655	$ 78,868,485	$ 5,265,830	$ -	$ -	$ 5,265,830
5	**Ending Balance**	5,931,487,369	$ 215,496,417	$ 228,146,329	$ 12,649,912	$ -	$ 47,431	$ 5,567,248
6	Total (Over)/Under Recovery Balance							$ 5,567,248
7	Loss Adjusted Retail Sales Billing Period - kWh							4,781,130,382
8	RA Component al Generation - Cents/kWh							0.11644
9					**Secondary**	**Primary**	**Sub/Trans**	
10	RA Component of FAC Rate At Generation Level				0.11644	0.11644	0.11644	
11	Loss Factor				1.0608	1.024	1.0036	
	RA at the Meter Level - Cents/kWh	Line 10 x Line 11			**0.12352**	**0.11924**	**0.11686**	

Schedule 3: This two-page schedule represents the Companies' RA components of their second quarter 2013 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under-recovery of fuel expenses for each month during the period October through December 2012, which were calculated as the difference between the monthly FAC revenues for the fourth quarter of 2012 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the carrying costs associated with those under-recoveries as well as other credits and charges, which,

according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The addition of the other credits and charges resulted in total under-recoveries of $5.567 million for CSP and OPCO.

The Companies calculated the RA component of its FAC rate at Generation level by dividing the under-recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for this filing was .11644 cents per kWh. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. The application of the loss factors results in RA components of the FAC rate of .12352, 11924 and .11686 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Exhibit 7-30
OPCO and CSP Combined Schedule 3, Page 2, April – June 2013

Schedule 3
Page 2 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2013 through June 2013
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Oct-12	$ 180,522,142	$ 98,122,872	$ 82,399,270	0.90287	$ 74,395,829	$ 1,095,625	$ 75,491,454
2	Nov-12	$ 171,539,777	$ 90,611,833	$ 80,927,944	0.90269	$ 73,052,845	$ 733,545	$ 73,786,390
3	Dec-12	$ 187,799,296	$ 101,914,951	$ 85,884,345	0.90779	$ 77,964,949	$ 903,536	$ 78,868,485
4	Total	$ 539,861,215	$ 290,649,656	$ 249,211,559		$ 225,413,623	$ 2,732,706	$ 228,146,329

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
5	Oct-12	222,566,850	2,068,793,575	2,291,360,425	0.09713	0.90287
6	Nov-12	213,457,400	1,980,218,689	2,193,676,089	0.09731	0.90269
7	Dec-12	217,242,442	2,138,714,527	2,355,956,969	0.09221	0.90779
Forecast						
8	Apr-13	274,527,610	1,477,493,015	1,752,020,626	0.15669	0.84331
9	May-13	284,311,228	1,623,947,956	1,908,259,184	0.14899	0.85101
10	Jun-13	295,336,063	1,679,689,410	1,975,025,472	0.14954	0.85046

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the fourth quarter of 2012. Specifically, page 2 of Schedule 3 shows total monthly FAC costs incurred from October through December 2012. For each month (October through December), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the fourth quarter of 2012, AEP Ohio added amounts totaling $2,732,706 for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that the forecasted REC costs have been removed from the FAC for recovery through the AER. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC under recoveries for the third quarter of 2012 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for October through December 2012. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for April through June 2013, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of .84331, .85101 and .85046 for each month of April, May and June 2013.

Third Quarter 2013

On May 30, 2013, AEP Ohio submitted quarterly FAC filings, as well as quarterly AER filings, for CSP and OPCO, which reflected actual data from January through March 2013 and projected data for the period July through September 2013. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 6 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's third quarter 2013 FAC filings by reproducing Schedules 1 through 3, broken out separately between CSP and OPCO as Exhibits 7-31 through 7-34, and then briefly summarizing each schedule.

Exhibit 7-31
CSP and OPCO Schedule 1, July – September 2013

Schedule 1

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2013 through September 2013
Summary - Proposed FAC Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		A	B	C	D
			Schedule 2	Schedule 3	
Line	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	4.49242	4.23694	-0.17042	4.066520
2	Primary	4.33658	4.08996	-0.16450	3.925460
3	Sub/Transmission	4.25019	4.00848	-0.16123	3.847250

OHIO POWER RATE ZONE

		A	B	C	D
			Schedule 2	Schedule 3	
Line	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	3.82555	3.59021	-0.17042	3.419790
2	Primary	3.69285	3.46567	-0.16450	3.301170
3	Sub/Transmission	3.61927	3.39662	-0.16123	3.235390

Schedule 1: Column A of this schedule reflects the then current FAC rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period July through September 2013. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through March 2013. Column D reflects the sum of the FC and RA components.

Exhibit 7-32
CSP and OPCO Schedule 2, July – September 2013

Schedule 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2013 through September 2013
FC Component

			Forecast Period - 3rd Quarter 2013			
Line	Description		July	August	September	Total
	TOTAL COMPANY					
1	Fuel & Purchased Power		170,159,618	165,076,603	136,251,818	$ 471,488,039
2	Environmental (Consumables and Allowances)		18,027,100	18,564,134	16,183,686	$ 52,774,920
3	(Gains) and Losses On Sales of Allowances		94,000	94,000	94,000	$ 282,000
4	Other		-	-	-	$ -
5	Total Includible FAC Costs		$ 188,280,718	$ 183,734,736	$ 152,529,504	$ 524,544,958
6	Less: Assigned to Off-System (including AEP Affiliates)		111,471,863	110,754,162	94,856,636	$ 317,082,661
7	FAC for Internal Load		$ 76,808,855	$ 72,980,574	$ 57,672,868	$ 207,462,297
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0 86082	0.84743	0.81302	0.84419
9	FAC for Retail Load Before Renewables		$ 66,118,599	$ 61,845,928	$ 46,889,195	$ 175,136,623
10	Energy & Capacity Value of Renewables (RECs moved to Rider AER)		1,439,118	1,325,784	1,552,996	$ 4,317,897
11	FAC for Retail Load (Total Company)		$ 67,557,716	$ 63,171,712	$ 48,442.191	$ 179,454,520
13	Retail Non-Shopping Sales - Generation Level Kwh		1,971,110.376	1,804,806,751	1,173,871,847	4,949,788,975
	COLUMBUS SOUTHERN POWER RATE ZONE					
14	CSP % for Retail Load	43.56%				$ 78,170,389
15	CSP % Non-Shopping Sales	39.54%				1,957 146,561
16	FC Component of FAC Rate At Generation Level - Cents/kWh					3 99410
			Secondary	Primary	Sub/Trans	
17	FC Component of FAC Rate At Generation Level		3 99410	3.99410	3.99410	
18	Loss Factor		1.0608	1.0240	1.0036	
19	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**	**4.23694**	**4.08996**	**4.00848**	
	OHIO POWER RATE ZONE					
19	OPCo % for Retail Load	56.44%				$ 101,284,131
21	OPCo % Non-Shopping Sales	60.46%				2,992,642,414
22	FC Component of FAC Rate At Generation Level - Cents/kWh					3 38444
			Secondary	Primary	Sub/Trans	
23	FC Component of FAC Rate At Generation Level		3 38444	3.38444	3.38444	
24	Loss Factor		1.0608	1.0240	1.0036	
25	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**	**3.59021**	**3.46567**	**3.39662**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period July through September 2013. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the third quarter of 2013, AEP Ohio has projected includable FAC costs totaling $524.545 million, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the third quarter of 2013, these projected off-system costs totaled $317.083 million. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived their FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component energy and capacity value of renewables, which totaled $4.318 million. The component for renewable energy credits ("RECs") was moved to the AER. The addition of the renewable's energy and capacity value result in total FAC costs for retail load of $78.170 million for CSP and $101.284 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.99410 cents per kWh for CSP and 3.38444 cents per kWh for OPCO and was calculated by dividing each Company's projected FAC for retail load by their respective projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. The Companies applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of 4.23694, 4.08996 and 4.00848 cents per kWh for CSP and FCs of 3.59021, 3.46567 and 3.39662 cents per kWh for OPCO.

Exhibit 7-33
CSP and OPCO Schedule 3, Page 1, July – September 2013

Schedule 3
Page 1 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2013 through September 2013
RA

Actual Period - January 2013 through March 2013

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3, p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery	
1	**Beginning Balance**							$ (18,281,381)	2 quarter lag (1stQ 2013)
2	Jan-13	2,109,104,449	$ 74,427,797	$ 81,592,699	$ 7,164,902	$ -	$ -	$ 7,164,902	
3	Feb-13	1,738,515,922	$ 61,482,000	$ 68,346,212	$ 6,864,212	$ -	$ -	$ 6,864,212	
4	Mar-13	2,067,119,583	$ 76,591,431	$ 72,891,931	$ (3,699,500)	$ -	$ -	$ (3,699,500)	
5	**Ending Balance**	5,914,739,954	$ 212,501,228	$ 222,830,842	$ 10,329,614	$ -	$ -	$ (7,951,767)	
6	Total (Over)/Under Recovery Balance				5,251,336.00			$ (7,951,767)	
7	Loss Adjusted Retail Sales Billing Period - kWh				$ 1,612,876			4,949,788,975	
8	RA Component at Generation - Cents/kWh							(0.16065)	
9					Secondary	Primary	Sub/Trans		
10	RA Component of FAC Rate At Generation Level				(0.16065)	(0.16065)	(0.16065)		
11	Loss Factor				1.0608	1.024	1.0036		
	RA at the Meter Level - Cents/kWh		*Line 10 x Line 11*		*-0.17042*	*-0.16450*	*-0.16123*		

Schedule 3: This two-page schedule represents the Companies' RA components of their third quarter 2013 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under/over-recovery of fuel expenses for January, February, and March 2013, which were calculated as the difference between the monthly FAC revenues for the first quarter of 2013 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the carrying costs associated with those under- and over-recoveries, as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The third quarter of 2013 did not have any carrying costs or other charges and credits, resulting in total over-recoveries of $7.952 million.

From this amount, the Companies calculated the RA component of its FAC rate at Generation level by dividing the over-recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for this filing was (.16065) cents per kWh. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. The application of the loss factors results in RA components of the FAC rate of (.17042), (.16450) and (.16123) cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Exhibit 7-34
CSP and OPCO Schedule 3, Page 2, July – September 2013

Schedule 3
Page 2 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2013 through September 2013
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Jan-13	$ 192,545,891	$ 103,155,570	$ 89,390,321	0.89637	$ 80,126,802	$ 1,465,897	$ 81,592,699
2	Feb-13	$ 176,563,096	$ 101,605,213	$ 74,957,883	0.89240	$ 66,892,415	$ 1,453,797	$ 68,346,212
3	Mar-13	$ 188,407,429	$ 109,688,036	$ 78,719,393	0.90111	$ 70,934,832	$ 1,957,099	$ 72,891,931
4	Total	$ 557,516,416	$ 314,448,819	$ 243,067,597		$ 217,954,049	$ 4,876,793	$ 222,830,842

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh: Whlse (WPC)	Jurisdictional Sales at Gen Level Kwh: Retail	Jurisdictional Sales at Gen Level Kwh: Total	Jurisdictional Ratios: Whlse (WPC)	Jurisdictional Ratios: Retail
Actual						
5	Jan-13	255,288,966	2,208,292.042	2,463,581,008	0.10363	0.89637
6	Feb-13	219,138,215	1,817,399,375	2,036,537,590	0.10760	0.89240
7	Mar-13	237,355,344	2,162,826,797	2,400,182,141	0.09889	0.90111
Forecast						
8	Jul-13	318,689,312	1,971,110,376	2,289,799,689	0.13918	0.86082
9	Aug-13	324,946,312	1,804,806,751	2,129,753,063	0.15257	0.84743
10	Sep-13	269,966,933	1,173,871,847	1,443,838,780	0.18698	0.81302

Page 2 of Schedule 3 reflects monthly data on the Companies' actual fuel costs during the first quarter of 2013. Specifically, page 2 of Schedule 3 shows total monthly FAC costs incurred from January through March 2013. For each month (January through March), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level, to derive its "Retail FAC Before Renewables". During the first quarter of 2013, the Companies added amounts totaling $4,876,793 for renewables, which reflects the revenue requirement associated with solar panels that were installed by AEP Ohio pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that the forecasted REC costs have been removed from the FAC for recovery through the AER. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the first quarter of 2013 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for January through March 2013. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for July through September 2013, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of .86082, .84743 and .81302 (July, August and September 2013, respectively) for the Companies.

Fourth Quarter 2013

On August 30, 2013, AEP Ohio submitted quarterly FAC filings, as well as its AER quarterly filings, for CSP and OPCO, which reflected actual data from April through June 2013 and projected data for the period October through December 2014. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 6 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's fourth quarter 2013 FAC filings by reproducing Schedules 1 through 3 as Exhibits 7-35 through 7-38, and then briefly summarizing each schedule.

Exhibit 7-35
CSP and OPCO Schedule 1, October – December 2013

Schedule 1

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2013 through December 2013
Summary - Proposed FAC Rate

COLUMBUS SOUTHERN POWER RATE ZONE

Line	Delivery Voltage	A Current FAC Rate	B Schedule 2 Forecast (FC) Component	C Schedule 3 Reconciliation (RA) Adjustment Comp.	D Total of FC and RA Components
1	Secondary	4.06652	4.09664	0.25800	4.354640
2	Primary	3.92546	3.95452	0.24905	4.203570
3	Sub/Transmission	3.84725	3.87574	0.24409	4.119830

OHIO POWER RATE ZONE

Line	Delivery Voltage	A Current FAC Rate	B Schedule 2 Forecast (FC) Component	C Schedule 3 Reconciliation (RA) Adjustment Comp.	D Total of FC and RA Components
1	Secondary	3.41979	3.47133	0.25800	3.729330
2	Primary	3.30117	3.35091	0.24905	3.599960
3	Sub/Transmission	3.23539	3.28415	0.24409	3.528240

Schedule 1: Column A of this schedule reflects the then current FAC rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period October through December 2013. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through June 2013. Column D reflects the sum of the FC and RA components.

Exhibit 7-36
CSP and OPCO Schedule 2, October – December 2013

Schedule 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2013 through December 2013
FC Component

			Forecast Period - 4th Quarter 2013			
Line	Description		October	November	December	Total
	TOTAL COMPANY					
1	Fuel & Purchased Power		137,210,678	131,851,130	147,544,466	$ 416,606,274
2	Environmental (Consumables and Allowances)		14,288,613	13,349,473	17,436,251	$ 45,074,337
3	(Gains) and Losses On Sales of Allowances		94,000	80,000	(13,803,000)	$ (13,649,000)
4	Other		-	-	-	$ -
5	Total Includible FAC Costs		$ 151,593,290	$ 145,260,603	$ 151,177,717	$ 448,031,610
6	Less: Assigned to Off-System (Including AEP Affiliates)		96,127,992	86,224,793	94,114,334	$ 276,467,119
7	FAC for Internal Load		$ 55,465,298	$ 59,035,810	$ 57,063,383	$ 171,564,491
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.83704	0 84405	0.85660	0 84640
9	FAC for Retail Load Before Renewables		$ 46,426,673	$ 49,829,176	$ 48,880,494	$ 145,211,828
10	Energy & Capacity Value of Renewables (RECs moved to Rider AER)		2,154,400	2,330,949	2,503,671	$ 6,989,020
11	FAC for Retail Load (Total Company)		$ 48,581,074	$ 52,160,124	$ 51,384,165	$ 152,200,847
13	Retail Non-Shopping Sales - Generation Level Kwh		1,361,404,187	1,379,474,628	1,600,964,607	4,341,843,423
	COLUMBUS SOUTHERN POWER RATE ZONE					
14	CSP % for Retail Load	43 56%				$ 66,298,689
15	CSP % Non-Shopping Sales	39.54%				1,716,764,889
16	FC Component of FAC Rate At Generation Level - Cents/kWh					3.86184
			Secondary	**Primary**	**Sub/Trans**	
17	FC Component of FAC Rate At Generation Level		3.86184	3.86184	3.86184	
18	Loss Factor		1.0608	1.0240	1.0036	
19	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**	**4.09664**	**3.95452**	**3.87574**	
	OHIO POWER RATE ZONE					
19	OPCo % for Retail Load	56 44%				$ 85,902,158
21	OPCo % Non-Shopping Sales	60.46%				2,625,078,533
22	FC Component of FAC Rate At Generation Level - Cents/kWh					3.27237
			Secondary	**Primary**	**Sub/Trans**	
23	FC Component of FAC Rate At Generation Level		3.27237	3 27237	3.27237	
24	Loss Factor		1.0608	1.0240	1.0036	
25	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**	**3.47133**	**3.35091**	**3.28415**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period October through December 2013. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the fourth quarter of 2013, AEP Ohio has projected includable FAC costs totaling \$448.032 million for CSP and OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the fourth quarter of 2013, these projected off-system costs totaled $276.467 million for CSP and OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component energy and capacity value of renewables, which totaled $6.989 million. The component for renewable energy credits ("RECs") was moved to the AER. The addition of the renewable's energy and capacity value result in total FAC costs for retail load of $66.299 million for CSP and $85.902 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.86184 cents per kWh for CSP and 3.27237 cents per kWh for OPCO and was calculated by dividing each Company's projected FAC for retail load by their respective projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. Each Company applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of 4.09664, 3.95452 and 3.87574 cents per kWh for CSP and FCs of 3.47133, 3.35091 and 3.28415 cents per kWh for OPCO.

Exhibit 7-37
CSP and OPCO Schedule 3, Page 1, October – December 2013

Schedule 3
Page 1 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2013 through December 2013
RA

Actual Period - April 2013 through June 2013

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery	
1	Beginning Balance							$ 5,567,248	2 quarter lag (2nd Q 2013) Oct,Nov,Dec 2012
2	Apr-13	1,455,403.298	$ 59,412,301	$ 63,515,810	$ 4,103,509	$ -	$ -	$ 4,103.509	
3	May-13	1,524,949,181	$ 62,217,560	$ 64,026,321	$ 1,808,761	$ -	$ -	$ 1,808.761	
4	Jun-13	1,600,225,281	$ 63,031,466	$ 62,111,807	$ (919,659)	$ -	$ -	$ (919,659)	
5	Ending Balance	4,580,577,740	$ 184,661,327	$ 189,653,938	$ 4,992,611	$ -	$ -	$ 10,559.859	
6	Total (Over)/Under Recovery Balance				5,251,336.00			$ 10,559,859	
7	Loss Adjusted Retail Sales Billing Period - kWh				$ (3,442,575)			4,341,843,423	
8	RA Component at Generation - Cents/kWh							0.24321	
9					Secondary	Primary	Sub/Trans		
10	RA Component of FAC Rate At Generation Level				0 24321	0.24321	0.24321		
11	Loss Factor				1.0608	1.024	1.0036		
	RA at the Meter Level - Cents/kWh		Line 10 x Line 11		0.25800	0.24905	0.24409		

Schedule 3: This two-page schedule represents the Companies' RA components of their fourth quarter 2013 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under/over-recovery of fuel expenses for each month during the period April through June 2013, which were calculated as the difference between the monthly FAC revenues for the second quarter of 2013 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the carrying costs associated with those under/over-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The fourth quarter of 2013 did not have any carrying costs or other charges and credits, thus resulting in total under-recoveries of $10.560 million.

The Companies calculated the RA component of its FAC rate at Generation level by dividing the under-recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for this filing was 0.24321 cents per kWh. The Companies applied the loss factors of 1.0608, 1.024, and 1.0036 related to the secondary, primary and sub/trans voltage levels, respectively to these RA components in order to derive the RA portion of the FAC rate at meter level. The application of the loss factors results in RA components of the FAC rate of .25800, .24905 and .24409 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Exhibit 7-38
CSP and OPCO Schedule 3, Page 2, October – December 2013

Schedule 3
Page 2 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2013 through December 2013
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Apr-13	$ 176,218,671	$ 105,867,848	$ 70,350,823	0.87049	$ 61,239,688	$ 2,276,122	$ 63,515,810
2	May-13	$ 158,915,302	$ 88,016,607	$ 70,898,695	0.87750	$ 62,213,605	$ 1,812,716	$ 64,026,321
3	Jun-13	$ 162,066,834	$ 92,920,127	$ 69,146,707	0.88050	$ 60,883,676	$ 1,228,131	$ 62,111,807
4	Total	$ 497,200,807	$ 286,804,582	$ 210,396,225		$ 184,336,969	$ 5,316,969	$ 189,653,938

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh: Whlse (WPC)	Retail	Total	Jurisdictional Ratios: Whlse (WPC)	Retail
Actual						
5	Apr-13	225,785,765	1,517,660,008	1,743,445,773	0.12951	0.87049
6	May-13	221,912,463	1,589,613,155	1,811,525,618	0.12250	0.87750
7	Jun-13	237,355,344	1,672,146,349	1,909,501,693	0.12430	0.87570
Forecast						
8	Oct-13	265,055,810	1,361,404,187	1,626,459,997	0.16296	0.83704
9	Nov-13	254,878,103	1,379,474,628	1,634,352,731	0.15595	0.84405
10	Dec-13	268,012,513	1,600,964,607	1,868,977,120	0.14340	0.85660

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the fourth quarter of 2012. Specifically, page 2 of Schedule 3 shows total monthly FAC costs incurred from April through June 2013. For each month (April through June), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the second quarter of 2013, AEP Ohio added amounts totaling $5,316,969 for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that the forecasted REC costs have been removed from the FAC for recovery through the AER. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the second quarter of 2013 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for April through June 2013. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for October through December 2013, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of .83704, .84405 and .85660 for each month of October, November and December 2013.

First Quarter 2014

On November 27, 2013, AEP Ohio submitted quarterly FAC filings, as well as its AER quarterly filings, for CSP and OPCO, which reflected actual data from July through September 2013 and projected data for the period January through March 2014. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 6 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's first quarter 2014 FAC filings by reproducing Schedules 1 through 3 as Exhibits 7-39 through 7-42, and then briefly summarizing each schedule.

Exhibit 7-39
OPCO and CSP Schedule 1, January – March 2014

Schedule 1

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2014 through March 2014
Summary - Proposed FAC Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		A	B	C	D
			Schedule 2	Schedule 3	
Line	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	4.35464	4.09664	-0.08125	4.015390
2	Primary	4.20357	3.95452	-0.07844	3.876080
3	Sub/Transmission	4.11983	3.87574	-0.07687	3.798870

OHIO POWER RATE ZONE

		A	B	C	D
			Schedule 2	Schedule 3	
Line	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	3.72933	3.47133	-0.08125	3.390080
2	Primary	3.59996	3.35091	-0.07844	3.272470
3	Sub/Transmission	3.52824	3.28415	-0.07687	3.207280

Schedule 1: Column A of this schedule reflects the then current FAC rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period January through March 2014. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through September 2013. Column D reflects the sum of the FC and RA components.

Exhibit 7-40
OPCO and CSP Schedule 2, January – March 2014

Schedule 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2014 through March 2014
FC Component

Line	Description		Forecast Period - 1st Quarter 2014 January	February	March	Total
	TOTAL COMPANY					
1	Fuel & Purchased Power		137,210,678	131,851,130	147,544,466	$ 416,606,274
2	Environmental (Consumables and Allowances)		14,288,613	13,349,473	17,436,251	$ 45,074,337
3	(Gains) and Losses On Sales of Allowances		94,000	60,000	(13,803,000)	$ (13,649,000)
4	Other		-	-	-	$ -
5	Total Includible FAC Costs		$ 151,593,290	$ 145,260,603	$ 151,177,717	$ 448,031,610
6	Less: Assigned to Off-System (Including AEP Affiliates)		96,127,992	86,224,793	94,114,334	$ 276,467,119
7	FAC for Internal Load		$ 55,465,298	$ 59,035,810	$ 57,063,383	$ 171,564,491
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.83704	0 84405	0.85660	0 84640
9	FAC for Retail Load Before Renewables		$ 46,426,673	$ 49,829.176	$ 48,880,494	$ 145,211,828
10	Energy & Capacity Value of Renewables (RECs moved to Rider AER)		2,154,400	2,330,949	2,503,671	$ 6,989,020
11	FAC for Retail Load (Total Company)		$ 48,581,074	$ 52.160,124	$ 51 384,165	$ 152,200,847
13	Retail Non-Shopping Sales - Generation Level Kwh		1,361,404,187	1.379,474,628	1,600,964,607	4,341,843,423
	COLUMBUS SOUTHERN POWER RATE ZONE					
14	CSP % for Retail Load	43.56%				$ 66,298,689
15	CSP % Non-Shopping Sales	39 54%				1,716,764,889
16	FC Component of FAC Rate At Generation Level - Cents/kWh					3.86184

Line	Description		Secondary	Primary	Sub/Trans
17	FC Component of FAC Rate At Generation Level		3.86184	3.86184	3.86184
18	Loss Factor		1.0608	1.0240	1.0036
19	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**	4.09664	3.95452	3.87574

Line	Description		Total
	OHIO POWER RATE ZONE		
19	OPCo % for Retail Load	56.44%	$ 85,902,158
21	OPCo % Non-Shopping Sales	60.46%	2,625,078,533
22	FC Component of FAC Rate At Generation Level - Cents/kWh		3.27237

Line	Description		Secondary	Primary	Sub/Trans
23	FC Component of FAC Rate At Generation Level		3 27237	3.27237	3.27237
24	Loss Factor		1.0608	1.0240	1.0036
25	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**	3.47133	3.35091	3.28415

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period January through March 2014. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the first quarter of 2014, AEP Ohio has projected includable FAC costs totaling $448.032 million for CSP and OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the first quarter of 2014, these projected off-system costs totaled $276.467 million for CSP and OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component energy and capacity value of renewables, which totaled $6.989 million. The component for renewable energy credits ("RECs") was moved to the AER. The addition of the renewable's energy and capacity value result in total FAC costs for retail load of $66.299 million for CSP and $85.902 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.86184 cents per kWh for CSP and 3.27237 cents per kWh for OPCO and was calculated by dividing each Company's projected FAC for retail load by their respective projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. Each Company applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of 4.09664, 3.95452 and 3.87574 cents per kWh for CSP and FCs of 3.47133, 3.35091 and 3.28415 cents per kWh for OPCO.

Exhibit 7-41
OPCO and CSP Schedule 3, Page 1, January – March 2014

Schedule 3
Page 1 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2014 through March 2014
RA

Actual Period - July 2013 through September 2013

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	Beginning Balance							$ (7,951,767)
2	Jul-13	1,816,710,057	$ 67,235,837	$ 64,786,492	$ (2,449,345)	$ -	$ -	$ (2,449,345)
3	Aug-13	1,569,920,404	$ 58,093,271	$ 61,564,301	$ 3,471,030	$ -	$ -	$ 3,471,030
4	Sep-13	1,352,755,407	51,536,029	$ 55,140,366	$ 3,604,337	$ -	$ -	$ 3,604,337
5	Ending Balance	4,739,385,868	$ 176,865,137	$ 181,491,159	$ 4,626,022	$ -	$ -	$ (3,325,745)
6	Total (Over)/Under Recovery Balance							$ (3,325,745)
7	Loss Adjusted Retail Sales Billing Period - kWh							4,341,843,423
8	RA Component at Generation - Cents/kWh							(0.07660)
9					Secondary	Primary	Sub/Trans	
10	RA Component of FAC Rate At Generation Level				(0.07660)	(0.07660)	(0.07660)	
11	Loss Factor				1.0608	1.024	1.0036	
	RA at the Meter Level - Cents/kWh		Line 10 x Line 11		-0.08125	-0.07844	-0.07687	

Schedule 3: This two-page schedule represents the Companies' RA components of their first quarter 2014 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under/over-recovery of fuel expenses for each month during the period July through September 2013, which were calculated as the difference between the monthly FAC revenues for the third quarter of 2013 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the carrying costs associated with those under/over-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The first quarter of 2014 did not have any carrying costs or other charges and credits, thus resulting in total over-recoveries of $3.326 million.

The Companies calculated the RA component of its FAC rate at Generation level by dividing the over-recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for this filing was (.07660) cents per kWh. The Companies applied the loss factors of 1.0608, 1.024, and 1.0036 related to the secondary, primary and sub/trans voltage levels, respectively to these RA components in order to derive the RA portion of the FAC rate at meter level. The application of the loss factors results in RA components of the FAC rate of (.08125), (.07844) and (.07687) cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Exhibit 7-42
OPCO and CSP Schedule 3, Page 2, January – March 2014

Schedule 3
Page 2 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2014 through March 2014
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Jul-13	$ 194,152,972	$ 121,763,398	$ 72,389,574	0.88156	$ 63,815,753	$ 970,739	$ 64,786,492
2	Aug-13	$ 202,395,235	$ 131,813,831	$ 70,581,404	0.86388	$ 60,973,863	$ 590,438	$ 61,564,301
3	Sep-13	$ 169,222,930	$ 106,398,626	$ 62,824,304	0.86319	$ 54,229,311	$ 911,055	$ 55,140,366
4	Total	$ 565,771,137	$ 359,975,855	$ 205,795,282		$ 179,018,927	$ 2,472,232	$ 181,491,159

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh: Whlse (WPC)	Retail	Total	Jurisdictional Ratios: Whlse (WPC)	Retail
Actual						
5	Jul-13	225,497,021	1,901,738,954	2,127,235,975	0.10600	0.89400
6	Aug-13	259,243,459	1,645,243,887	1,904,487,346	0.13612	0.86388
7	Sep-13	224,422,066	1,416,002,943	1,640,425,009	0.13681	0.86319
Forecast						
8	Jan-14	265,055,810	1,361,404,187	1,626,459,997	0.16296	0.83704
9	Feb-14	254,878,103	1,379,474,628	1,634,352,731	0.15595	0.84405
10	Mar-14	268,012,513	1,600,964,607	1,868,977,120	0.14340	0.85660

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the third quarter of 2013. Specifically, page 2 of Schedule 3 shows total monthly FAC costs incurred from July through September 2013. For each month (July through September), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the third quarter of 2013, AEP Ohio added amounts totaling $2,472,232 for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that the forecasted REC costs have been removed from the FAC for recovery through the AER. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the third quarter of 2013 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for July through September 2013. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for January through March 2014, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of .83704, .84405 and .85660 for each month of January, February and March 2014.

Second Quarter 2014

On November 13, 2013, AEP Ohio was authorized to unbundle the FAC and establish the Auction Phase-In Rider ("APIR"), which includes the 10% slice-of-system, energy-only auction clearing price of $42.78/MWh that was accepted by the Commission Finding and Order dated February 26, 2014 of Case No. 14-300-EL-FAC, and the Fixed Cost Rider ("FCR"), to replace the FAC. On March 3, 2014, AEP Ohio submitted the initial quarterly APIR and FCR filings, as well as quarterly AER filings, for CSP and OPCO, which reflected actual data from September through December 2013 and projected data for the period April through June 2014. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 11 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule. The filing also includes additional copies of Schedules 1 and 11, reflecting the recovery of the reconciliation component over nine months instead of three months.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's second quarter 2014 FAC filings by reproducing Schedule 3, which covers actual costs for October through December 2013.

Exhibit 7-43
OPCO and CSP Schedule 3, Page 1, April – June 2014

Schedule 3
Page 1 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2014 through June 2014
RA

Actual Period - October 2013 through December 2013

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	Beginning Balance							$ 10,559,859
2	*Oct-13*	*1,136,792,592*	$ *45,324,451*	$ *46,411,688*	$ *3,087,237*	$ -	$ -	$ *3,087,237*
3	Nov-13	1,239,197,737	$ 49,339,877	$ 52.394,497	$ 3,054,620	$ -	$ -	$ 3,054,620
4	Dec-13	1,539,913,698	59,202,797	$ 57,734,889	$ (1,467,908)	$ -	$ -	$ (1,468,672)
5	Ending Balance	3,915,904,027	$ 153,867,125	$ 158,541,074	$ 4,673,949	$ -	$ -	$ 15,233,044
6	Total (Over)/Under Recovery Balance							$ 15,233,044
7	Loss Adjusted Retail Sales Billing Period - kWh							3,484,851,600
8	RA Component at Generation - Cents/kWh							0.43712

Schedule 3: This two-page schedule represents the Companies' RA components of their second quarter 2014 filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under-recovery of fuel expenses for each month during the period October through December 2013, which were calculated as the difference between the monthly FAC revenues for the fourth quarter of 2013 and the monthly jurisdictional retail FAC costs for the same period. The second quarter of 2014 did not have any carrying costs or other charges and credits, thus resulting in total under-recoveries of $15.233 million.

The Companies calculated the RA component of its FAC rate at Generation level by dividing the under-recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for this filing was 0.43712 cents per kWh.

Exhibit 7-44
OPCO and CSP Combined Schedule 3, Page 2, April – June 2014

Schedule 3
Page 2 of 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2014 through June 2014
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
1	Oct-13	$ 158,043,903	$ 102,654,713	$ 55,389,190	0.84609	$ 46,864,240	$ 1,547,448	$ 48,411,688
2	Nov-13	$ 145,501,215	$ 86,943,080	$ 58,558,135	0.85820	$ 50,254,420	$ 2,140,077	$ 52,394,497
3	Dec-13	$ 177,128,838	$ 113,489,072	$ 63,639,766	0.87465	$ 55,662,521	$ 2,072,368	$ 57,734,889
4	Total	$ 480,673,956	$ 303,086,865	$ 177,587,091		$ 152,781,181	$ 5,759,893	$ 158,541,074

Monthly Jurisdictional Allocation Ratios

Retail Sales at Gen Level Kwh		
Line	Month	Retail
Forecast		
5	Apr-14	1,025,761,491
6	May-14	1,150,409,085
7	Jun-14	1,308,681,024

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the fourth quarter of 2013. Specifically, page 2 of Schedule 3 (lines 1-4) shows total monthly FAC costs incurred from October through December 2013. For each month (October through December), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the fourth quarter of 2013, AEP Ohio added amounts totaling $5,759,893 for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that the forecasted REC costs have been removed from the FAC for recovery through the AER. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the fourth quarter of 2013 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' forecasted monthly jurisdictional sales at the generation level for April through June 2014, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above.

Minimum Review Requirements

As noted above, Larkin referred to the objectives and procedures outlined in Appendix E of former Chapter 4901:1-11 of the Ohio Administrative Code as guidance for the review requirements of this project. The purpose of the Uniform Financial Audit Program Standards and Specifications for the Electric Fuel Component is to provide uniform standards and specifications as guidelines for an independent auditing firm which conducted an EFC "financial audit"[57] pursuant to former section 4905.66(B)(2) of the Revised Code and former rule 4901:1-*11-09* of the Administrative Code. *The EFC "financial audit" program is only a guide for the* auditor and should not be used to the exclusion of the auditor's initiative, imagination and thoroughness.

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

> *The auditor's review shall include, but not be limited to, a review of:*
>
> *(1) Purchasing procedures for fuel procurement not under long-term contracts;*
>
> *(2) Procedures for accounting for fuel receipts, testing, and payments;*
>
> *(3) Procedures for weighing, testing and reporting coal burned;*
>
> *(4) Procedures for amortizing nuclear fuel costs corresponding to nuclear generated energy;*
>
> *(5) Procedures for recording purchases and interchanges;*
>
> *(6) Procedures for accounting treatment of emission allowances; and*
>
> *(7) Procedures for calculating the 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 AEP Ohio's procedures for accounting for fuel receipts, testing of samples to ensure quality, and payments to vendors. OPCO uses the same accounting procedures for fuel receipts, testing and payments. These procedures are as follows:

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

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

Larkin also reviewed the Companies' procedures for weighing, testing and reporting coal burned per data request LA-2012/13-1-002. Specifically, consumed tonnage is measured either by belt scales or weigh feeders as coal is fed into units and/or bunkers. Unit burn samples are collected using mechanical sampling systems that are in conformance with American Society for Testing Standards ("ASTM"). In addition, unit samples are collected and sent to the AEP Central Coal Lab to be analyzed. The analyzed results are then fed into the [redacted] system. Burn reports, which include tonnage and quality characteristics, can be generated by the [redacted] system for the relevant reporting period.

OPCO's procedures for recording purchases and interchanges of energy, as described in response to LA-2012/2013-1-003, involves the Company's Accounting Department being provided information regarding power purchases from third parties and/or affiliates. The Accounting Department then records such data into Account 555 – Purchased Power.

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

OPCO Jointly Owned Generation

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

- Cardinal Plant Units 2 and 3 are operated by Cardinal Operating Company and are owned by Buckeye Power, a non-affiliated partner. OPCO owns Unit 1.
- Amos Plant Unit 3 is operated and co-owned by Appalachian Power Company ("APCo").
- APCo also operates Sporn Plant Units 2, 4 and 5, but these units are owned 100 percent by OPCO.

OPCo participates in four jointly owned power plants with Duke Ohio ("Duke") and AES (Dayton Power & Light or "DP&L") and are referred to as the Cincinnati, Columbus and Dayton ("CCD") owners. These four jointly owned plants include the following:

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

Cardinal Plant Units 2 and 3

- The total costs of the entire plant are recorded in a fuel ledger and then such costs are allocated to the joint owners.
- The current month's fuel receipts are added to Beginning Inventory. From this, a weighted average rate is determined for the Available Tons in Inventory. Consumed expense is then calculated at the available rate for the consumed tons.
- Ending Inventory is calculated as Available Inventory less Consumption.

- The joint owners' share of ending inventory is based on twelve-month generation taken. This amount is updated quarterly.
- The calculation for the joint owners' consumption is based on the energy taken each month. Joint owners' receipts are calculated as the difference between Beginning Inventory and Available Inventory.
- Available Inventory is calculated as Ending Inventory plus Consumption.

Amos Plant Unit 3

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

Sporn Plant Units 2, 4 and 5

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

- Sporn Unit 5 was retired in February 2012.

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

- The total costs of each plant are recorded in a fuel ledger and then such costs are allocated to the joint owners.
- The current month's fuel receipts are added to Beginning Inventory. From this a weighted average rate is determined for Available Tons in Inventory. Consumed expense is then calculated at the available rate for the consumed tons.
- Ending inventory is calculated as Available Inventory less Consumption.
- OPCo, Duke and AES-DP&L all have an ownership share of their respective plant's ending inventory. Each joint owner's consumption is calculated based on a composite ratio. This ratio represents the energy used for the month plus an ownership portion, which represents the energy necessary to maintain each unit in a state of readiness. Each joint owner's receipts are calculated as the difference between Beginning Inventory and Available Inventory with Available Inventory calculated as Ending Inventory plus Consumption.
- An additional allocation is calculated for both the Conesville Unit 4 (for 2012 only) and Beckjord Unit 6 power plants. Plant inventory is allocated, based on historic consumption, to segregate a portion of the total coal pile between the jointly owned unit and the non-jointly owned unit(s). With respect to the units operated by Duke and DP&L, these companies bill the other CCD owners for their respective portion of coal optimization credits/charges which are recorded as part of fuel consumed.

Larkin requested in LA-2012/2013-1-119 that, for each month of 2012 and 2013, the Company provide copies of invoices issued to AEP Ohio for fuel, transportation and consumables for each jointly owned plant. In response, AEP Ohio provided five confidential attachments (A-D)[58], which were copies of invoices from Dayton Power & Light Company ("DP&L"), Duke Energy ("Duke") an Duke Energy Ohio ("Duke Ohio").

The first set of invoices (Confidential Attachment A) were issued to CSP and/or AEP Ohio by DP&L in 2012 and 2013 and were broken out by the Company's share of the fuel related categories: (1) coal related items, (2) oil related items, (3) net change in M&S, and (4) CSP's share of gains and losses. Of these four categories, the coal related items made up the vast majority of the charges on each of the invoices. In addition, for each invoice, a separate workpaper titled "Coal Inventory Transactions" was attached which show how the coal related portion of each invoice was derived. The exhibit below provides a summary of the categories that comprised the DP&L invoices issued to CSP in 2012.

[58] Attachment B is in two parts, thus a total of five confidential attachments.

Exhibit 7-45

[redacted]

[redacted]

As shown in the exhibit in Column D, the 2012 activity reflects net losses totaling [redacted] The exhibit below provides a similar summary of the categories that comprised the DP&L invoices issued to CSP in 2013.

Exhibit 7-46

[redacted]

[redacted]

As shown in the exhibit in Column D, the 2013 activity reflects net gains totaling $[redacted]

The transactions included on the fuel related invoices that Duke issued to CSP and OPCO in 2012 and 2013 include a line item called "Coal Margin Settlement" and another titled "Broker

Fees". AEP Ohio stated that the combination of these two items represent coal sales/transfer losses, which are included in the FAC. [redacted]

Exhibit 7-47

[redacted]

[redacted]

As shown in the exhibit above, the 2012 activity reflects net coal sale losses of [redacted]. Column F in the exhibit below summarizes [redacted].

Exhibit 7-48

[redacted]

[redacted]

As shown in the exhibit above, the 2013 activity reflects net coal sale [redacted].

Of the invoices the Company received from the joint owners in 2012 and 2013, AEP Ohio provided the following summary of the portions from each invoice that are included in the FAC:

DP&L Fuel Related Bills

- Coal consumed and coal sales/transfers gains/losses (Account 5010001) are included in the FAC.
- Oil consumed (Account 5010019) is included in the FAC.

DP&L O&M Related Bills

These DP&L billed O&M costs are included in the FAC:

- Fuel (Ash Handling (Account 5010000)
- Fuel Procurement - Unloading and Handling (Account 5010003)
- Ash Sale Proceeds (Account 5010012)
- Gypsum Handling/Disposal Costs (Account 5010027)
- Urea Expense (Account 5020002)
- Limestone Expense (Account 5020004)

Duke Related Fuel Bills

- Coal consumed and coal sales/transfers gains/losses (Account 5010001) are included in the FAC.
- Oil consumed (Account 5010019) is included in the FAC.

Duke O&M Related Bills

These Duke-billed O&M costs are included in the FAC:

- Fuel Procurement - Unloading and Handling (Account 5010003)
- Ash Sale Proceeds (Account 5010012)
- Gypsum Sale Proceeds (Account 5010028)
- Lime Expense (Account 5020001)
- Trona Expense (Account 5020003)
- Lime Hyrdrate Expense (Account 5020004)

FAC Deferrals

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

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

As a result of implementing this Order, CSP had 17 different FAC rates and OPCO had 23 different FAC rates. The PUCO stated that the collection of any deferrals, including carrying costs that are remaining at the end of the ESP "shall occur from 2012 through 2018 as necessary to recover the actual fuel expenses incurred plus carrying costs."[59]

As noted above, the original ESP period ("ESP 1") ended December 31, 2011. On December 14, 2011, a second ESP ("ESP 2") was approved by the Commission in Case No. 11-346-EL-SSO, which had an effective date of January 1, 2012. On December 31, 2011, CSP and OPCO merged and OPCO was the resulting company out of the merger. The initial Commission Order in that proceeding authorized separate rate zones for former CSP and OPCO customers, but a uniform FAC rate was established. However, on February 23, 2012, in its Entry on Rehearing, the Commission reversed its authorization of ESP 2 which resulted in OPCO filing a modified ESP application, and which the Commission ultimately approved on August 8, 2012 with certain modifications.

Specifically, the Commission's Order required that the FAC rates for CSP and OPCO revert back to being on an unmerged basis and that a new Alternative Energy Rider ("AER") be established in order for AEP Ohio to recover certain alternative energy costs that had been previously recovered through the FAC. In addition, the Commission directed that AEP Ohio transition to a competitive retail marketplace for generation through an auction process. The initial auction reflects an energy auction of 10% delayed until April 1, 2014. Subsequently, on June 1, 2014, now delayed until November 1, 2014, 60% of the Company's SSO energy load will provided by auction and 100% of OPCO SSO requirements will be supplied through auction beginning January 1, 2015. As a result, the FAC will terminate on December 31, 2014

In LA-2012/2013-1-56, Larkin requested that AEP Ohio provide, for CSP and OPCO separately, the most current estimates and projections of the deferred FAC costs through the end of the ESP period. In addition, for CSP and OPCO, LA-2012/2013-1-56 requested an estimate of the collection period necessary to fully recover the deferred FAC costs after the ESP period ends,

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

including an estimate of the prospective surcharge and rate impact. In response, AEP Ohio stated that it had not projected the deferred FAC costs through the ESP term, but the Company had designed the Phase-in Recovery Rider ("PIRR") to collect the deferral balances for OPCO and CSP over a 7 year period, per the Commission's Order in Case No. 11-346-EL-SSO and 11-348-EL-SSO. AEP Ohio did not provide a deferral balance for CSP or OPCo as of December 31, 2012, but stated that OPCO's deferral balance was $492,390,964 as of December 31, 2013. In addition, AEP Ohio stated that it issued a SEET[60] refund to CSP customers which reduced CSP's deferral balance to zero as of December 31, 2013.

LA-2012/2013-1-5 asked the Companies to identify, by amount and account, any fuel amounts being deferred that affected the review period and to explain why such amounts were being deferred. In its response, AEP Ohio stated that no fuel amounts were deferred during the audit period that affected the recorded fuel cost.

The Companies' response to data request LA-2012/2013-1-47, which requested a complete set of supporting workpapers for all the calculations in the quarterly FAC filings for the review period (and discussed in more detail later in this report), included the Accounting Department's summary schedules and monthly FAC workbooks of actual cycle calculations of under/over recovery, as well as carrying charge calculations. The Company also provided monthly AER workbooks of estimated cycle calculations of under/over recovery. The monthly FAC workbooks are discussed in more detail in a later section of this chapter. The AER workbooks and information supporting the AER rates is discussed in Chapter 8.

Review Related To Coal Order Processing

The following is a description of AEP Ohio's procedures for processing fuel purchase orders (per LA-2012/2013-1-6):

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

[60] Significant Excessive Earnings Test.

Purchase Orders And Approved Purchase Requisitions

Data requests LA-2012/2013-1-7 and LA-2012/2013-1-8 requested copies of fuel purchase orders ("POs") and approved purchase requisitions recorded in July 2012 and July 2013. In response, AEP Ohio referred to the confidential response to EVA-2012/2013-1-3. The response to EVA-2012/2013-1-3 included two confidential attachments, which were summaries of all new coal POs that were in place or executed in both 2012 and 2013. These summaries also included a listing of any POs to which change orders were made along with a notation which indicated the justification for each change order. AEP Ohio also provided the POs, amendments, and justification for fuel oil PO's executed in 2013 as well as natural gas PO's executed in 2012 and 2013. As the number of POs in the confidential attachment was voluminous, Larkin selected a sample of POs for review. Each PO that Larkin selected was properly executed and was accompanied by an intercompany memo which summarized the details of the corresponding PO. No exceptions were noted.

Invoice and Voucher Procedures

In order to enable us to track the Company's processing of fuel invoices, Larkin obtained copies of cash vouchers and payment documentation for fuel purchases recorded in July 2012 and July 2013. These documents were provided in the confidential response to data request LA-2012/2013-1-9.

For CSP, the confidential information provided in LA-2012/2013-1-9 included payment documentation for the Conesville plant. For OPCO, the information provided in LA-2012/2013-1-9 included payment documentation for the Gavin, Mitchell, Kammer, and Muskingum River plants. For each purchase, this documentation included a summary of invoices paid by CSP and OPCo, invoices, payment vouchers (with supporting detail), and a report titled "Penalty/Premium Pricing Report", which is a detailed calculation report of the amounts due to the Companies vendors for deliveries under a given contract or purchase order. Also included was a report titled "Daily Fuel Report", which recorded the daily unit activity for July 2012 and July 2013, the year to date unit activity, and the commodity total and shipments for the months of July 2012 and July 2013 and July 2012 and July 2013 year to date.

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

Fuel Ledger

Larkin reviewed the data the Company's provided in response to LA-2012/2013-1-10, which requested OPCO's fuel ledgers for the period January 2012 through December 2013. Upon reviewing the fuel ledgers, including accompanying reconciliation pages, Larkin was able to tie the amounts shown to the FAC workbooks provided in LA-2012/2013-1-47 and the general ledger (See additional discussion below).

BTU Adjustments

As part of its review, Larkin requested that the Companies provide documentation for Btu adjustments for fuel purchases recorded in July 2012 and July 2013 per data request LA-2012/2013-1-11. In its response, AEP Ohio referred to the response to data request LA-2012/2013-1-15, in which AEP Ohio provided confidential documents titled "Analysis Results Summary Report". AEP Ohio provided these confidential reports for the following power plants: Cardinal, Cook Coal Terminal, Conesville, Gavin, Kammer, Mitchell, and Muskingum River. Upon its initial review of the Analysis Results Summary Reports, Larkin noted that each such report had a calculation under the heading "Btu". From these reports, Larkin compared the Btu adjustment calculation to the specific contract as well as recalculated the amounts used in the Btu adjustment calculation. No exceptions were noted.

Larkin reviewed the 2012 and 2013 Btu adjustment examples provided by the Company in response to LA-2012/13-10-02, as shown below:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Freight And Barge Vouchers

LA-2012/2013-1-12 requested that AEP Ohio provide freight cash vouchers for two days of coal receipts in July 2012 and July 2013 as well as copies of the portions of the corresponding coal received reports. For CSP, the confidential response to LA-2012/2013-1-12 included documentation related to nine payments that CSP made for freight associated with coal received at the Conesville Plant during July 2012, including 4 payments to [redacted], 4 payments to [redacted] and 1 payment [redacted], and one payment to [redacted] during July 2013. Specifically, this documentation included:

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

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

For OPCO, the confidential response to LA-2012/2013-1-12 included documentation related to seven payments during July 2012 that OPCO made for freight associated with coal received at the Muskingum River station, including five payments to [redacted], and two payments to [redacted]. and ten payments during July 2013, including five payments to [redacted], two payments to [redacted], and three payments to [redacted] Specifically, this documentation included:

- Copies of invoices and/or freight bills for the payments referenced above;
- Copies of payment vouchers (each also including a Request for Payment Detail) that are associated with those payments;
- Copies of Transportation Cost Reports, which provides a breakout of the coal deliveries to which the freight costs shown on the payment vouchers and invoices/freight bills relate;

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

LA-2012/2013-1-13 requested that AEP Ohio provide two cash vouchers from each barge company for coal unloaded at Company plants during July 2012 and July 2013 as well as copies of the portions of the corresponding coal unloading reports and purchase orders. In response, AEP Ohio stated that Conesville and Picway (former CSP plants) do not incur any barging costs and that the Company's remaining barging services are provided by AEP River Transportation Division ("RTD"), and AEP affiliate. OPCO's barging services are discussed in further detail in the AEP River Transportation Division section of this report. As the RTD is an affiliated company of OPCO, RTD issues a monthly invoice, which is settled by an inter-unit journal entry. As part of its response to LA-2012/2013-1-13, AEP Ohio provided a confidential copy of the journal entry, RTD invoices for July 2012 and July 2013, which included data related to coal shipments received at the Gavin, Kammer, Mitchell, and Muskingum River plants. In addition, the Companies' provided copies of Transportation Cost Reports, which provided the detail for barging shipments of coal received in July 2012 and July 2013 for the noted plants.

Upon reviewing and comparing the data listed on the July 2012 and July 2013 RTD invoices (documents titled Billed Freight – Coal – Captive) and the July 2012 and July 2013 [redacted] Transportation Cost reports, Larkin was able to verify the quantities and prices from the [redacted] reports to the RTD invoice.

Fuel Analysis Reports

LA-2012/20103-1-14 requested that AEP Ohio provide the Company's procedures for preparing monthly fuel analysis reports. In response, AEP Ohio stated that fuel analysis data is captured in the [redacted] and fed to the [redacted] system. In addition, AEP Ohio stated that monthly fuel analysis reports can be generated for each plant from the [redacted] system.

LA-2012/2013-1-15 requested that AEP Ohio provide copies of fuel analysis reports related to fuel purchases recorded during July 2012 and July 2013. In its confidential response the Company provided copies of the aforementioned Analysis Results Summary Reports for the Cardinal, Conesville, Cook Coal Terminal, Gavin, Kammer, Mitchell, and Muskingum River plants. These reports listed the Companies' fuel purchases by mine, station and vendor, and broke out the fuel purchases by quantity, moisture, ash, sulfur, SO2 lbs/mmBTU's, and BTUs on an "as received" as well as a "dry" basis.

Retroactive Escalations

Larkin requested that AEP Ohio identify all pending or approved retroactive escalations that affect fuel cost for the period January 2012 through December 2013. In response to LA-2012/2013-1-16, the Company stated that there are no pending retroactive escalations and summaries of approved escalations were provided with EVA-2012/2013-1-1 in a confidential attachment.

Review Related To Station Visitation And Coal Processing Procedure

Larkin conducted a site visit to OPCO's Cardinal Plant ("Cardinal") on February 21, 2014. Data requests LA-2012/2013-1-17 through LA-2012/2013-1-39 relate to fulfilling the objectives of the station visit and the review of the Company's coal processing procedure from the receipt of coal to the disposition of fly ash.

A description of the Companies' coal receiving procedures and controls for shortages, overages, and other discrepancies for the Cardinal plant was provided in AEP Ohio's response to LA-2012/2013-1-17. The coal is delivered to the Cardinal Unit 1 plant by one of two ways: truck or barge.

For barge coal [redacted], a contracted company, handles the harbor and movement of the barges. This process is overseen by Cardinal yard personnel. The coal is taken directly to the coal silos or coal pile. Shipped and unloaded weights are maintained in [redacted], where they can be verified in the system. Corrections to volumes are recognized through coal pile surveys conducted semi-annually.

For truck coal, the coal is dumped directly to the truck hopper. Similar to barge coal, trucked coal is taken to either the coal silos or to the coal pile.

LA-2012/2013-1-18 asked AEP Ohio to describe the process of how coal is weighed when it is received. In response, the Company's stated that Cardinal Unit 1 utilizes a belt scale to weigh the coal tons that are unloaded from barges. In addition, inbound and outbound truck scales are used to weigh the truck.

LA-2012/2013-1-19 and LA-2012/2013-1-19 asked AEP Ohio to describe how freight bill and car number discrepancies are handled and to describe how damaged railroad cars are checked and who investigates shortage claims. In response to both data requests, AEP stated that no rail coal is received by Cardinal Unit 1.

LA-2012/2013-1-38 requested a description of how freight bills, barge number and coal quantity and quality discrepancies are handled. In response, the Company stated that such discrepancies are handled in the following manner:

- AEPSC Fuel Accounting pays the barge freight bills for Cardinal Unit 1 and Cardinal plant personnel verify barge numbers at the time of unloading and noted discrepancies are verified with AEP River Operations.
- Both loaded and unloaded weights are maintained in the [redacted] system and large discrepancies are verified with the vendor.
- Quality discrepancies based on unloaded quality are raised by the supplier and addressed by fuel procurement. As it relates to coal that is based on the supplier quality check samples are taken at the plant to verify the quality and noted discrepancies are addressed by fuel procurement.

LA-2012/2013-1-39 requested a description of how damaged barges are checked and who instigates claims for shortages. In response, AEP Ohio stated that barges are inspected upon receipt at the harbor and that any notices of damaged barges are provided to AEP River Operations where all repairs are performed.

A description of the Company's coal sampling procedures was provided in response to LA-2012/2013-1-22 as follows:

- As barge coal is received at Cardinal, it is sampled by a mechanical coal sample system. As for trucked coal, each truck is sampled by a mechanical auger that is run by PSI, an independent contractor. The coal is sampled by a mechanical coal sampler as it is taken to the unit for consumption.

- All samples are further processed at the plant and are then sent to the AEP Coal Laboratory for analysis. Samples are labeled with a bar code and this bar code is entered into [redacted] and is used to identify the sample, while maintaining anonymity at the lab. Samples are then shipped to the lab using the AEP internal mail system. A third party carrier is utilized to ship the sample to the lab in situations where the analysis of a sample needs to be expedited. The lab scans the bar code and all laboratory analysis are assigned to the sample by that bar code.

LA-2012/2013-1-23 requested that for each Company operated coal-fired plant, that AEP Ohio identify the portion of total coal deliveries that were not analyzed at the point of receipt. In its confidential response, AEP Ohio provided a table that reflects the requested percentages, which Larkin has reproduced in the exhibit below.

Exhibit 7-49
Percentage of Coal Deliveries Not Analyzed

[redacted]

In response to Larkin's inquiry as to why such a relative high percentage of coal deliveries were not analyzed, especially at Gavin and Kammer, AEP Ohio stated that coal is unable to be analyzed by point of receipt when the sampling equipment is down for maintenance.[61]

LA-2012/2013-1-24 asked the Company to provide its procedures for sampling and testing Powder River Basin ("PRB") coal and to provide the associated documentation from the Company's vendors. In response, AEP Ohio stated it does not have procedures in place for sampling and testing PRB coal since shipments originating in the PRB are paid on vendor analysis. In addition, AEP Ohio provided 3 confidential attachments which were comprised of "Penalty/Premium Pricing Reports", which reflected the quality analyses that was entered into the Company's fuel accounting system for payment on PRB deliveries received during 2012 and 2013. In addition, AEP Ohio provided "Shipment Quality Reports", which reflected the analysis performed by OPCO's suppliers as it relates to PRB coal shipped to Gavin and Kammer.

LA-2012/2013-1-25 requested copies of the reports related to the annual field visit and inspection of PRB mines that are conducted by AEP and in which included the sampling procedures used at the PRB mines and/or load-out locations from each mine from which plants that are owned or operated by or for CSP and OPCO receive coal. In its response, AEP Ohio stated:

[61] Response to LA-2012/2013-11-01.

During the period of September10 th – 12nd, 2013 Freelin Wright, Manager of the AEP Central Coal Lab, accompanied by Mary Dishon, Transportation Coordinator FEL, Patrick Mears, Production Engineer Dolet Hills and Russell Stanfield, FEL Western Field Representative visited the following PRB load outs and their onsite labs: [redacted] *East and West;* [redacted]

During the visits the sample systems at each location that generated the payment samples were visually inspected and an explanation of their sampling processes was given by the Coal Company representatives. All the systems were found to be in good mechanical condition and sized correctly for the lots to be sampled. All the locations had documentation of Bias Tests and ongoing sample system quality control reports.

The on site labs for each site were toured and quality control procedures and documentation were shared by the Lab supervisors. The labs were all third party facilities either managed by [redacted]*. All the facilities were found to contain up to date equipment and knowledgeable employees.*

Overall there was nothing that was observed that would lead us to believe that ASTM D05 procedures and best industry practices were not being adhered to in the collection and analysis of the payment samples at the locations visited.

Russ Stanfield also makes multiple trips to the PRB, that total to approximately four weeks each year, to observe the semi-annual calibrations at most of the mines in the PRB.

Scale calibration logs for the periods January through July 2012 and January through July 2013 were requested in LA-2012/2013-1-26. In its response, AEP Ohio provided two confidential Excel files (for 2012 and 2013), which contained belt scale calibration data for the requested periods for the Cardinal, Conesville, Gavin, Kammer, Mitchell, Muskingum River and Picway plants. With the exception of a few instances where minor items were documented (e.g. belt alignment, dirty weigh bridge, etc.) there were generally no problems noted on the scale calibration logs.

A description of the procedures followed when coal scales are inoperable was provided in the response to LA-2012/2013-1-27 including:

- If the barge scale is inoperable at Cardinal, a coal shipment's weight is determined at the loading point.
- If either truck scale happens to inoperable, the receipt of trucks is halted until the scale is repaired.

Copies of laboratory sampling reports for coal purchases recorded in July 2012 and July 2013 were requested in LA-2012/2013-1-28 in order to compare such reports with accounting and purchasing records. The Companies' confidential response included the previously noted "Analysis Results Reports" and included data related to coal sampling at the Cardinal plant that occurred in July 2012 and July 2013.

AEP Ohio's procedure for handling coal from the stockpile to the firebox or boiler at the Cardinal plant was provided in response to LA-2012/2013-1-29. Specifically, coal is either fed from one of three coal silos or it is reclaimed directly from the coal pile onto belts which feed the units. Each of these belts has a belt scale which tabulates the tons before they are fed into the unit supply bunkers. The coal is then fed from the bunkers to the pulverizers and across feeder belts. These feeder belts also have the ability to weigh the coal. Upon being pulverized, the coal is transferred to the unit for consumption by air.

AEP Ohio's procedure for taking physical inventories of coal and fuel oil is described in the response to LA-2012/2013-1-30. Specifically, fuel oil is measured monthly by using a tank level indicator and physical inventories of coal pile inventory are conducted twice a year. If the difference between book and physical inventory is two percent or greater of the coal consumed, then a second physical inventory is conducted within six months. A Circular Letter dated October 17, 1996 (and revised November 12, 2007), which outlined specific coal pile inventory procedures and guidelines, was provided as a confidential attachment to AEP Ohio's response to LA-2012/2013-1-30.

The Company provided working papers on physical inventories taken at the Cardinal plant in June and December 2012 and June 2013 in the response to LA-2012/2013-1-33, which consisted of the following documentation:

- Journal Entry Detail Reports
- Fuel Ledger for Cardinal
- Cardinal Station Survey Analysis Reports
- Intercompany emails and memos
- Inventory Ledger for the Cardinal plant
- Coal Receipts Ledger for the Cardinal plant
- Daily Fuel Reports
- Coal Storage Inventory Reports
- Fuel Data Reporting System reports

The documentation listed above included four intercompany memos, which described the results of the Coal Storage Inventory Reports. The Spring 2012 memo (dated June 21, 2012), which discusses a coal pile survey conducted at Cardinal in May 2012 (encompassing the period December 6, 2011 through May 30, 2012 at Units 1, 2 and 3), stated in part:

> *In accordance with AEP System Accounting Bulletin #4, the following corrections are required to book inventories. The book inventory correction for the Units 1&2 Pile (High Sulfur) is 59,924 tons, to be apportioned to consumption as follows: Unit 1: 18,032 tons, Unit 2: 38,731 tons, and Unit 3: 3,161 tons. The book inventory correction for the Unit 3 Pile (Low Sulfur) is 2,051 tons, to be apportioned to consumption as follows: Unit 1: 617 tons, Unit 2: 1,326 tons, and Unit 3: 108 tons. All corrections are weight averaged, based on the total coal consumption for each unit.*

The exhibit below summarizes the Spring 2012 coal pile inventory adjustments described above.

Exhibit 7-50
Coal Pile Inventory – Cardinal Plant (Spring 2012)

[redacted]

In order to determine the dollar impacts associated with these inventory adjustments, Larkin reviewed a document titled "Cardinal Station Survey Analysis June 2012 Spring Survey" (provided in the response to LA-2012/2013-1-33), in which the 61,975 ton variance noted above was broken out on a line item referred to as the "Actual Unit Tons Per File" in the manner shown in the exhibit below.

Exhibit 7-51
Actual Unit Tons per File – Cardinal Plant (Spring 2012)

[redacted]

In addition, this document reflected an additional breakout of this variance on a line item referred to as "Survey Adjustment Tons", in which the 61,975 tons were apportioned between OPCO and Buckeye. It was from these apportioned amounts that AEP Ohio reflected the dollar impacts associated with the inventory adjustments related to the Spring 2012 physical coal inventory as shown in the exhibit below.

Exhibit 7-52
Dollar Impacts Associated with Coal Pile Inventory Adjustments – Cardinal Plant (Spring 2012)

[redacted]

As shown in the exhibit above, AEP Ohio's coal inventory adjustments reflected debits to Account Nos. 1510001 and 1520000 in amounts totaling [redacted] and [redacted], respectively.

The OPCO related portion of these amounts were [redacted]. The related credits were made to Account Nos. 5010013 and 5010003, respectively.

The Fall 2012 memo (dated January 3, 2013), which discusses a coal pile survey conducted at Cardinal in December 2012 (encompassing the period May 30, 2012 through December 18, 2012 at Units 1, 2, and 3), stated in part:

> *In accordance with AEP System Accounting Bulletin #4, the following corrections are required to book inventories. The book inventory correction for the Units 1&2 Pile (High Sulfur) is 72,345 tons; the book inventory correction for the Unit 3 Pile (Low Sulfur) is -1,109 tons to be apportioned to consumption as follows: Unit 1: 32,074.63 tons, Unit 2: 40,270.37 tons, and Unit 3: -1,109 tons. All corrections are weight averaged, based on the total coal consumption for each unit.*

The exhibit below summarizes the Fall 2012 coal pile inventory adjustments described above.

Exhibit 7-53
Coal Pile Inventory – Cardinal Plant (Fall 2012)

[redacted]

Similar to the Spring 2012 physical inventory adjustment, in order to determine the dollar impacts associated with the inventory adjustments, Larkin reviewed a document titled "Cardinal Station Survey Analysis December 2012 Winter Survey" (provided in the response to LA-2012/2013-1-33), in which the 71,236 ton variance noted above was broken out on "Actual Unit Tons Per File" line item as shown in the exhibit below.

Exhibit 7-54
Actual Unit Tons per File – Cardinal Plant (Fall 2012)

[redacted]

In addition, this document reflected an additional breakout of this variance on a line item referred to as "Survey Adjustment Tons", in which the 71,236 tons were apportioned between OPCO and Buckeye. It was from these apportioned amounts that AEP Ohio reflected the dollar impacts associated with the inventory adjustments related to the Fall 2012 physical coal inventory as shown in the exhibit below.

Exhibit 7-55
Dollar Impacts Associated with Coal Pile Inventory Adjustments – Cardinal Plant (Fall 2012)

[redacted]

As shown in the exhibit above, AEP Ohio's coal inventory adjustments reflected debits to Account Nos. 1510001 and 1520000 in amounts totaling [redacted]. The OPCO related portion of these amounts were [redacted]. Similar to the previously discussed inventory adjustment, the related credits were made to Account Nos. 5010013 and 5010003, respectively.

The Spring 2013 memo (dated June 26, 2013), which discusses a coal pile survey conducted at Cardinal in June 2013 (encompassing the period December 18, 2012 through June 5, 2013 at Units 1, 2, and 3), stated in part:

> *In accordance with AEP System Accounting Bulletin #4, the following corrections are required to book inventories. The book inventory correction for the Units 1&2 Pile is 70,069 tons: the book inventory correction for Unit 3 is 19,941 tons, to be apportioned to consumption as follows: Unit 1: 29,221.45 tons, Unit 2: 40,847.55 tons, and Unit 3: 19,941 tons. All corrections are weight averaged, based on the total cost consumption for each unit.*

The exhibit below summarizes the Spring 2013 coal pile inventory adjustments described above.

Exhibit 7-56
Coal Pile Inventory – Cardinal Plant (Spring 2013)

Coal Pile Inventory - Cardinal Plant (Spring 2013)			
Description	**Units 1&2**	**Unit 3**	**Total**
Book Inventory (Tons)	505,191	163,243	668,434
Survey Inventory (Tons)	575,260	183,183	758,443
Difference, Book-Survey (Tons)	(70,069)	(19,941)	(90,010)
Percent of Book Value	-13.9%	-12.2%	
Percent of Coal Consumed	-5.4%	-2.6%	

Similar to the 2012 physical inventory adjustments, in order to determine the dollar impacts associated with the Spring 2013 inventory adjustments, Larkin reviewed a document titled "Cardinal Station Survey Analysis June 2013 Spring Survey" (provided in the response to LA-2012/2013-1-33), in which the 90,010 ton variance noted above was broken out on "Actual Unit Tons Per File" line item as shown in the exhibit below.

Exhibit 7-57
Actual Unit Tons per File – Cardinal Plant (Spring 2013)

	Unit 1	Unit 2	Unit 3	Total
Actual Unit Tons per File	23,613.00	32,940.00	33,457.00	90,010.00

In addition, this document reflected an additional breakout of this variance on a line item referred to as "Survey Adjustment Tons", in which the 90,010 tons were apportioned between OPCO and Buckeye. It was from these apportioned amounts that AEP Ohio reflected the dollar impacts associated with the inventory adjustments related to the Spring 2013 physical coal inventory as shown in the exhibit below.

Exhibit 7-58
Dollar Impacts Associated with Coal Pile Inventory Adjustments – Cardinal Plant (Spring 2013)

[redacted]

As shown in the exhibit above, AEP Ohio's coal inventory adjustments reflected debits to Account Nos. 1510001 and 1520000 in amounts totaling [redacted] The OPCO related portion of these amounts were [redacted]. Similar to the previously discussed inventory adjustments, the related credits were made to Account Nos. 5010013 and 5010003, respectively.

The Fall 2013 memo (dated December 30, 2013), which discusses a coal pile survey conducted at Cardinal in December 2013 (encompassing the period June 4, 2013 through December 17, 2013 at Units 1, 2, and 3), stated in part:

> *In accordance with AEP System Accounting Bulletin #4, the following corrections are required to book inventories. The book inventory correction for the Units 1&2 Pile is 66,566 tons: the book inventory correction for Unit 3 is 14,248 tons, to be apportioned to*

consumption as follows: Unit 1: 36,542.64 tons, Unit 2: 30,023.36 tons, and Unit 3: 14,248 tons. All corrections are weight averaged, based on the total cost consumption for each unit.

The exhibit below summarizes the Fall 2013 coal pile inventory adjustments described above.

Exhibit 7-59
Coal Pile Inventory – Cardinal Plant (Fall 2013)

[redacted]

Similar to the previously discussed physical inventory adjustments, in order to determine the dollar impacts associated with the Fall 2013 inventory adjustments, Larkin reviewed a document titled "Cardinal Station Survey Analysis December 2013 Winter Survey" (provided in the response to LA-2012/2013-1-33), in which the 80,814 ton variance noted above was broken out on "Actual Unit Tons Per File" line item as shown in the exhibit below.

Exhibit 7-60
Actual Unit Tons per File – Cardinal Plant (Fall 2013)

[redacted]

In addition, this document reflected an additional breakout of this variance on a line item referred to as "Survey Adjustment Tons", in which the 80,814 tons were apportioned between OPCO and Buckeye. It was from these apportioned amounts that AEP Ohio reflected the dollar impacts associated with the inventory adjustments related to the Fall 2013 physical coal inventory as shown in the exhibit below.

Exhibit 7-61
Dollar Impacts Associated with Coal Pile Inventory Adjustments – Cardinal Plant (Fall 2013)

[redacted]

As shown in the exhibit above, AEP Ohio's coal inventory adjustments reflected debits to Account Nos. 1510001 and 1520000 in amounts totaling [redacted]. The OPCO related portion of these amounts were [redacted]. Similar to the previously discussed inventory adjustments, the related credits were made to Account Nos. 5010013 and 5010003, respectively.

Data request LA-2012/2013-1-32 asked the Company how it accounts for base coal inventory at each plant that is owned or operated by CSP and/or OPCO. In response, AEP Ohio stated that Coal Inventory for OPCO is accounted for in Account 151 and the physical base (not coal inventory) below the coal pile is part each plant's property. In addition, no accounting adjustments were made between the coal inventory and the coal pile base in plant property during 2012 or 2013 nor did AEP Ohio amortize any amount of base coal into fuel costs in either 2012 or 2013.

AEP Ohio's response to LA-2012/2013-1-34 provided the following description which relates to the levels of review applicable to plant operating statistics:

- The [redacted] has three general types of data which is derived directly from the plants: fuel consumption; generation; and outages and curtailments.
- Scale readings measure fuel consumption. These readings are corrected periodically through coal pile surveys if necessary.
- The [redacted] application transmits generation data. The Companies verify the accuracy of the data entered into [redacted] by performing a generation-checkout process.
- Outage and curtailment events are entered into [redacted] which is a front-end system where records are reviewed with plant staff throughout the operating month. After month-

end, the plants have 10 days to review, correct, and approve the event records before being submitted to GADS.

Larkin requested copies of generating station reports for the review period in LA-2012/2013-1-35. In its confidential response, AEP Ohio stated that it does not have a document titled "generating station reports". However, the Companies provided a confidential attachment titled "Monthly Generation Station Report" for Cardinal Unit 1 for the periods January through December 2012 and January through December 2013.

These confidential attachments reflected the gross generation, net generation, service hours, reserve hours, available hours, start-ups, and heat rate (on a gross and net kWh basis), for the Unit 1 at the Cardinal plant.

LA-2012/2013-1-36 asked the Companies to identify any internal investigations which resulted from what was reported on the Monthly Generating Station Reports provided in LA-2012/2013-1-35 for the review period. AEP Ohio responded that there had been no internal investigations conducted with regard to the information provided in LA-2012/2013-1-35 during the review period.

Larkin requested copies of the station reports for the review periods which were sent to the Company's general office for incorporation into company statistics and to provide workpapers sufficient to trace the reports to those statistics in LA-2012/2013-1-37. In response, AEP Ohio stated:

> *While some aspects of plant operation, such as outage events and coal scale data, are manually entered into a computer program at the generating plant, there are no "reports" that are sent to the Companies' general office for incorporation into Companies' statistics and workpapers. The electronic versions of these files are reviewed at the generating plant level as described in response to LA-2012/2013-34, but the electronic reports themselves are the "station reports", and not workpapers.*

Review Related To Fuel Supplies Owned Or Controlled By The Company

In response to LA-2012/2013-1-40, AEP Ohio confirmed that no AEPSC affiliates supply fuel to OPCO. In addition, none of the AEP Ohio companies own or control any coal mines or entities that supply fuel to the Companies.

Review Related To Purchased Power

Documentation relating to the review of purchased power is included in the responses to LA-2012/2013-1-41 and LA-2012/2013-1-42. LA-2011-41 asked the Company to provide the following information: "For CSP and OPCO, for purchases of power recorded in July 2012 and July 2013 that are included in the FAC, please provide the related invoices, and paid cash voucher or cash receipts." In the confidential response to LA-2012/2013-1-41, the Company provided (1) a summary of July 2012 invoices; (2) copies of July 2012 invoices (3) a summary of July 2013 invoices; (4) copies of July 2013 invoices; (5) July 2012 FAC schedule for OPCO used to reconcile the purchased power to the July 2012 invoice summary; and (6) July 2013 FAC schedule for OPCO used to reconcile the purchased power to the invoice summary.

The summary of invoices broke out the Companies purchases of power by (1) total invoice amount, (2) total [redacted], and (3) physical purchases allocated to OPCO which are the amounts included in the FAC. There were substantial differences noted between the total invoice amounts versus what was allocated to OPCO (i.e., the FAC).

For both July 2012 and July 2013, Larkin attempted to tie out the amounts allocated to OPCO's physical purchases that were reflected on the invoice summary to workpaper "EXH OPCO 1" from the monthly FAC Excel workbooks that were provided in LA-2012/2013-1-47 (see additional discussion below). Larkin was able to tie out most of these amounts, but not all. However, Larkin was able to tie out the remaining amounts to the FAC schedules that were provided as confidential attachments 5 and 6 to the supplemental response to LA-2012/2013-1-41, which in turn, tied to the FAC workpaper "EXH OPCO 1" noted above. In addition, in LA-2012/2013-1-50, AEP Ohio provided monthly reconciliations between recorded purchased power in the general ledger and the amounts included in the monthly FAC workbooks. Upon reviewing the FAC schedules provided in LA-2012/2013-1-41 as well as the monthly reconciliations provided in LA-2012/2013-1-50, Larkin was able to tie out the July 2012 and July 2013 purchased power amounts from LA-2012/2013-1-41. There were minor unreconciled differences on the monthly reconciliations, but such amounts were immaterial.

Reliability Must Run Generation

As confirmed in the response to LA-2012/2013-1-42, dispatch of the Company's generating units was under the control of PJM during the review period of January 2012 through December 2013.

LA-2012/2013-1-43 asked: "During the review period were any of the Companies' generating units designated as 'must run' for reliability or voltage control purposes? If so, please identify the units, hours, and cost/Mwh for each 'must run' situation at the Companies' generating units during this period."

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

As part of its response to LA-2012/2013-1-43, AEP Ohio provided three confidential attachments. The first two attachments (Attachment 1 and 2) was an extensive listing of the hours that each of the generating units listed above were required to operate as a "Must Run" resource by PJM in 2012 and 2013. The third confidential attachment (Attachment 3) provided the average production cost of each "must run" generating unit referenced above for 2012 and 2013. These were expressed in terms of $/MW for each month of 2012 and 2013 and are reproduced in the exhibits below.

Exhibit 7-62
Average Production Cost of "Must Run" Generating Units - 2012

[redacted]

Exhibit 7-32
Average Production Cost of "Must Run" Generating Units - 2013

[redacted]

Review Related to Service Interruptions and Unscheduled Outages

Documentation relating to the review of Service Interruptions and Unscheduled Outages includes AEP-Ohio's responses to LA-2012/2013-1-44 and LA-2012/2013-1-45.

LA-2012/2013-1-44 asked about instances in which customers' power supplies were interrupted (or requested to be interrupted) during the review period January 2012 through December 2013. In response, AEP Ohio stated that during the review period of January 2012 through December 2013, there was not an instance of a generation-caused customer interruption.

LA-2012/2013-1-45 requested AEP Ohio 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 Companies 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, AEP Ohio provided an attachment, which provided a brief description of what caused the unscheduled outages during the review period at the OPCO owned generating units listed below.

2012	2013
Amos Unit 3	Amos Unit 3
Cardinal Unit 1	Beckjord Unit 6
Conesville Units 3, 4, 5 & 6	Cardinal Unit 1
Darby Units 2, 3 & 4	Conesville Units 4, 5 & 6
Gavin Units 1 & 2	Darby Units 1 & 2
Kammer Units 1, 2 & 3	Kammer Units 1, 2 & 3
Mitchell Units 1 & 2	Mitchell Units 1 & 2
Muskingum River Units 1, 2, 3, 4 & 5	Muskingum River Units 1, 2, 3, 4 & 5
Picway Unit 5	Picway Unit 5
Racine Units 1 & 2	Racine Units 1 & 2
Sporn Units 2, 4 & 5	Sporn Units 2 & 4
Stuart Units 1, 2, 3 & 4	Stuart Units 1, 2, 3 & 4
Waterford Units CT1, CT2, CT3 & ST1	Waterford Units CT1, CT2, CT3, ST1
Zimmer Unit 1	Zimmer Unit 1

With respect to items 2 through 5 from LA-2012/2013-1-45, AEP Ohio stated:

> *During 2012 and 2013 Ohio Power Company was a member of the AEP East Pool. Forced outages and curtailments to the Company's generating resources, as well as other impacts due to weather or load variations are managed on an AEP East fleet basis along with those of the other AEP East pool members. Multiple steps were taken to minimize the effects of forced outages concerning the generating plants. These steps include planning work as soon as possible when necessary, or attempting to safely operate the unit as long as possible until such time that any required maintenance could be performed when it would have less of an impact on the fleet.*
>
> *Power may be secured, if needed, to minimize the effects of any generation or load variations on an AEP East fleet basis. That power is not categorized as replacing any specific generating capacity. Therefore, it is not possible to determine whether power purchases were made to replace power lost due to an unscheduled outage versus, say,*

power purchased to offset a curtailment at another unit, owned by another pool member, that may have occurred at the same time as an unscheduled outage. Consequently, it is not possible to price the "replacement" power or determine, from a lost generation perspective, cost impacts resulting from periods during which the unscheduled outage occurred.

FAC Filings, Supporting Workpapers and Documentation

Documentation relating to the review of supporting workpapers for calculations in the FAC filings was requested in data requests LA-2012/2013-1-46 through LA-2012/2013-1-52. LA-2012/2013-1-46 requested copies of AEP Ohio's quarterly FAC filings. The Company provided CSP's and OPCO's FAC filings for the first, second, third and fourth quarters of 2012 and 2013.

Data requests LA-2012/2013-1-47, LA-2012/2012-1-49, LA-2012/2013-1-50 and LA-2012/2013-1-51 requested the Excel files associated with the FAC filings as well as all documentation which provides a complete audit trail to the Company's FAC calculations.

LA-2012/2013-1-49 asked that:

> *For each Reconciliation Adjustment (RA) in a Rider FAC filing covering the review period, please provide a complete audit trail for all amounts in the RA portions of such filings including: (1) the accounting records and other documentation needed to trace each dollar amount in the RAs through from the Rider FAC filings to the fuel ledger, from the fuel ledger to the general ledger, and from the fuel ledger to the purchase orders and invoices; (2) the complete documentation to trace the energy and system loss quantities in the Rider FAC filings to the source documents; (3) all journal entries, journal entry supporting documentation and workpapers related to recording RA adjustments in the Company's accounting records; and (4) provide all calculations and supporting documentation related to computing RA adjustments in the Companies' Rider FAC filings.*

AEP Ohio's provided the materials requested above in its response to LA-2012/2013-1-47. Specifically, the Company provided an index of attachments and the Accounting Department's summary schedules and monthly Excel FAC workbooks which contained the actual cycle calculations of under/over recovery as well as carrying charge calculations, which are the main support for the Company's FAC filings including the RA portion of such filings. The FAC workbooks are comprised of several pages of data, which is culminated from several sources including:

1. General Ledger
2. NER/NEC – Net Energy Requirements and Net Energy Cost reports
3. PSUM Report – Monthly Purchase Summary Report from ECR
4. MCSR0162 Final Reports - Tariff Summary Revenue – by voltage level – one month billed & accrued
5. East Pool Interchange Power Statements

In addition to the foregoing sources of data, the monthly FAC workbooks also contained the following workpapers:

1. Computation of Firm Retail Revenues, FAC Costs and the total Over/Under recovery for each month. The amounts calculated on this workpaper are reflected on Schedule 3 from the Company's quarterly FAC filings.
2. A workpaper which calculates the FAC retail allocators.
3. A workpaper showing the FAC rates.
4. A workpaper which calculates the allocation factor for the FAC allowance accounts.
5. A workpaper which calculates the kWh delivered to customers served under OAD tariffs (Shopping kWh).

Upon reviewing the monthly FAC workbooks, Larkin was able to tie out the amounts reflected in the workbooks to the FAC filings using the source data listed above and performing recalculations. In addition, the FAC schedules provided in the response LA-2012/2013-1-41 and the monthly purchased power reconciliations provided in the response to LA-2012/2013-1-50 also facilitated Larkin's ability to tie out the amounts reflected in the FAC workbooks.

Lawrenceburg Generating Station

On March 15, 2007, CSP entered into an agreement to purchase the Lawrenceburg Generating Station ("Lawrenceburg") from AEP Generating Company. Lawrenceburg is a combined-cycle natural gas power plant with a generating capacity of 1,096 MW and is located in Lawrenceburg, Indiana.

The non-fuel purchased power costs associated with Lawrenceburg are included in the FAC for CSP as shown on the EXH OPCO 1 workpaper, which was included in the monthly FAC workbooks provided in LA-2012/2013-1-47. In data request LA-2012/2013-1-57, Larkin asked AEP Ohio for a summary of the non-energy components related to Lawrenceburg that were included in the FAC during 2012 and 2013. In response, AEP Ohio referred to the response to LA-2012/2013-1-58, which had requested that for each month of the review period, the Company identify, and provide an audit trail for the capacity costs associated with Lawrenceburg and the Ohio Valley Electric Corporation ("OVEC") that are charged through the FAC. The response to LA-2012/2013-1-58 included two confidential attachments, which reflected the requested information for Lawrenceburg and OVEC. Larkin has reproduced the Company's confidential attachments and the exhibit below reflect the components of the Lawrenceburg capacity costs flowing through the FAC during each month of 2012.

Exhibit 7-63
Lawrenceburg Actual Purchased Power Capacity Costs Billed to OPCO - 2012

[redacted]

As shown in the exhibit above, the Ohio retail portion of Lawrenceburg related capacity costs flowing through the FAC during 2012 totaled [redacted]. Upon comparing the 2012 Lawrenceburg capacity data reflected in the exhibit above to the FAC workbooks, Larkin noted discrepancies with the Ohio retail allocation percentages for the months of January, May and July. However, the net effect is an immaterial rounding difference in the amount of Lawrenceburg related capacity costs flowing through the FAC.[62]

The exhibit below reflects the components of the Lawrenceburg capacity costs flowing through the FAC during each month of 2013.

[62] The net effect of three differences with the Ohio retail allocation percentages on the Lawrenceburg capacity costs flowing through the FAC in 2012 totals only $114.

Exhibit 7-64
Lawrenceburg Actual Purchased Power Capacity Costs Billed to OPCO - 2013

[redacted]

As shown in the exhibit above, the Ohio retail portion of Lawrenceburg related capacity costs flowing through the FAC during 2013 totaled [redacted]. Upon comparing the 2013 Lawrenceburg capacity data reflected in the exhibit above to the FAC workbooks, no exceptions were noted.

OVEC Demand Charges

The exhibit below reflects the components of the OVEC demand charges flowing through the FAC during each month of 2012.

Exhibit 7-65
OVEC Actual Purchased Power Demand/Capacity Costs Billed to OPCO - 2012

[redacted]

As shown in the exhibit above, the Ohio retail portion of OVEC demand charges flowing through the FAC during 2012 totaled [redacted]. However, upon comparing the 2012 OVEC demand charges reflected in the exhibit above to the FAC workbooks, Larkin noted minor differences with the Ohio retail allocation percentages for the months of January, May and July. That resulted in an immaterial difference in the amount of OVEC related demand charges flowing through the FAC.[63]

The exhibit below reflects the components of the OVEC demand charges flowing through the FAC during each month of 2013.

[63] The net effect of three discrepancies with the Ohio retail allocation percentages on the OVEC demand charges flowing through the FAC in 2012 totals $183.

Exhibit 7-66
OVEC Actual Purchased Power Demand/Capacity Costs Billed to OPCO - 2013

[redacted]

As shown in the exhibit above, the Ohio retail portion of OVEC demand charges flowing through the FAC during 2013 totaled [redacted]. However, upon comparing the 2013 OVEC demand charges reflected in the exhibit above to the FAC workbooks, for the month of December, Larkin noted a [redacted] discrepancy in the Ohio retail portion of OVEC demand charge which is the amount that flows through the FAC. This discrepancy is the result of the December figure [redacted] in the exhibit above (from LA-2012-1-2013/1-58) being an estimated amount whereas the OVEC demand charge of $6,358,472 reflected in the December 2013 FAC workbook is an actual amount. After application of the Ohio retail allocation percentage, the correct December 2013 OVEC demand charge flowing through the FAC is [redacted] as summarized in the exhibit below. The correct overall amount of OVEC demand charges flowing through the FAC during 2013 was [redacted]

Exhibit 7-67
Ohio Retail Share of OVEC Demand Charges for December 2013

[redacted]

Audit Trail for Reconciling Adjustments

As discussed previously, LA-2012/2013-1-50 requested a complete audit trail for all amounts in the RA portions of the FAC filings for each sub-account of purchased power during the review period. In response, the Company provided monthly reconciliations between purchased power recorded in the general ledger and purchased power included as part of monthly FAC costs. These monthly reconciliations were provided as part of AEP's implementation of Larkin's recommendation from the 2009 FAC audit that AEP Ohio provide a better audit trail as it relates to being able trace the Company's monthly purchased power costs from the vendor invoices and paid cash vouchers (provided in the response to LA-2012/2013-1-41) to the FAC workbooks provided in LA-2012/2013-1-47.

Renewable Energy Resources

Please see Chapter 8 of this report, which discusses the Alternative Energy Rider ("AER").

Carrying Costs on Deferred Fuel Balances

AEP Ohio confirmed that its quarterly FAC filings for the 2012 and 2013 audit period did not include carrying costs.

Active Management

LA-2012/2013-1-48 asked whether AEP Ohio engaged in "active management" of its fuel, purchased power or emission allowance positions during the review period, and if so, to identify, quantify and provide the accounting documentation for each such transaction during that period. In addition, LA-2012/2013-1-48 asked AEP Ohio to fully explain the reasoning and estimated economic benefit that was anticipated for each transaction. In response, AEP Ohio stated:

> *No, the Company does not engage in "active management" as previously defined by the auditor to be "the practice of flattening one's position on a frequent (daily) basis to align coal commitments with power sales outlook."*

Audit Fees Included in FAC

Larkin requested that AEP Ohio explain how it recorded FAC audit fees by account during 2012 and 2013. In response to LA-2012/2013-5-2, the Company explained that it recorded FAC audit fees in Account No. 5010000, which was allocated between retail and off-system sales. The Ohio retail jurisdictional factor was then applied prior to the audit fees being included in the FAC. The accounting for the FAC audit fees is reflected in the exhibit below.

Exhibit 7-68
Ohio Share of FAC Audit Fees

Description	April 2012	July 2012	Total
FAC Audit Fees in Account No. 5010000	$ 37,740	$ 52,260	$ 90,000
Firm Allocation Factor	67.70%	65.02%	
Ohio Retail Portion of Firm	92.20%	93.61%	
Ohio Retail Percentage	62.42%	60.87%	
Ohio Share of FAC Audit Fees	$ 23,557	$ 31,808	$ 55,365
Source: LA-2012/2013-5-2			

As shown in the exhibit, audit fees totaling $55,365 on an Ohio retail basis was included in the FAC between April and July 2012. The response to LA-2012/2013-5-1 stated that there were no audit fees paid during 2013.

Conesville Coal Preparation Plant

Prior to April 5, 2013, CSP owned the Conesville Coal Preparation Plant ("CCPP") which was operated by Conesville Coal Preparation Company, a wholly-owned subsidiary. The CCPP was built in the mid 1980s in order to provide more flexibility to AEPSC in its coal procurement for the Conesville station. EVA had recommended in the 2009 management/performance audit that AEPSC should undertake a study to determine whether there is an economic justification for continuing to operate the Conesville Coal Preparation Plant given the renegotiation of the [redacted] combined with a reduction in overall Conesville coal demand. AEPSC agreed to perform the study, which was ultimately provided to the auditors on April 21, 2011.

In its study, AEPSC concluded that it was not economic to continue operating the CCPP beyond the first quarter of 2012. This conclusion came with a caveat with respect to new hazardous air pollution regulations. AEPSC had revised its Asset Retirement Obligation ("ARO") and increased its monthly charge to the CCPP in anticipation of the first quarter 2012 closing.

In the 2010 management/performance audit report, EVA had recommended that AEPSC work to minimize the costs associated with the closure of the CCPP. Pursuant to that recommendation, data request EVA-2012/2013-1-21 requested a description of AEPSC's efforts to minimize the costs associated with closing the CCPP during 2012 and 2013. In response, AEP Ohio stated that during 2012 and 2013 there were no such efforts made on AEPSC's part to minimize the CCPP closure related costs as all such efforts were undertaken during 2011.

As to how the CCPP's fuel costs were affected in 2012 and 2013, a review of the respective incomes statement, which were provided in LA-2012/2013-3-2, indicated that for Account No. 501 - Fuel-Steam Power, CCPP incurred costs totaling $14,540 during 2012 versus $2,712 which was incurred in 2011, or a difference of $11,828. In addition, CCPP incurred costs in this account totaling $7,736 during 2013 versus the aforementioned $14,540 in 2012, or a difference of ($6,804).

LA-2012/2013-3-4 asked AEP Ohio to provide details on any CCPP related credits and accrual reversals that went into Account 151 in 2012 and 2013. In response, the Company provided an attachment, which reflected a summary of the CCPP's 2012 journal entry reclassifications, which Larkin has reproduced in the exhibit below. AEP Ohio stated that there were no such adjustments or fuel billings from the CCPP during 2013.

Exhibit 7-69
CCPP 2012 Journal Entry Reclassification

CONESVILLE COAL PREPARATION COMPANY							
2012 Journal Entry Reclassification							
BUSINESS UNIT 290							
Month	Year	Dept	Account	Journal ID	Journal Date	Description	Amount
March	2012	11778	4081002	SEVACCCCPC	3/30/2012	CCPC FICA ACCRUAL	(6,313.55)
March	2012	11778	4081002	SEVACCCCPC	3/31/2012	CCPC FICA ACCRUAL	(650.40)
March	2012	11778	9200000	SEVACCCCPC	3/30/2012	CCPC SEVERANCE ACCRUAL	(82,530.00)
March	2012	11778	9200000	SEVACCCCPC	3/31/2012	CCPC SEVERANCE ACCRUAL	(8,502.00)
March	2012	11778	9200000	OVH1518388	3/23/2012	2011 INCENTIVE ACCRUAL	(55,742.31)
March	2012	11778	9200000	AJE1860007	3/31/2012	2011 Incentive Accrual/Reclassed from 1860007	(44,593.19)
March	2012	11778	4010001	SACCPCINV	3/31/2012	M&S Transfer to Other AEP Locations	(18,749.74)
Total	March						(217,081.19)
April	2012	11778	4081002	AJEINCACC	3/31/2012	Manual True-up (clear residual acct balance and	(6,601.49)
April	2012	11778	9260027	AJEINCACC	3/31/2012	offset payout on 3-14)	(1,812.15)
April	2012	11778	4081002	HRPAY12420	3/14/2012	Payout on 3-14	4,896.89
April	2012	11778	9260027	HRPAY12420	3/14/2012	Payout on 3-14	537.29
April	2012	11778	4081002	OVH1518388	3/23/2012	System True-up (#'s processed through	(7,675.67)
April	2012	11778	9260027	OVH1518388	3/23/2012	Labor Distribution)	(2,107.05)
Total	April						(12,762.18)
June	2012	11778	4081002	AJECIPADJ	7/2/2012	To correct 2011 ICP in 2012 paid by other	4,966.22
June	2012	11778	9200000	AJECIPADJ	7/2/2012	AEP Entities such as AEPSC, CCT, Cardinal &	64,917.83
June	2012	11778	9260027	AJECIPADJ	7/2/2012	OPCo (Conesville Plant)	2,378.18
Total	June						72,262.23
July	2012	11778	4010001	SACCPCINV	7/31/2012	Operation Exp - Nonassociated	20,721.83
Total	July						20,721.83
						Total To Date	(136,859.31)

In a follow-up question, Larkin asked that AEP Ohio provide details on the allocation to co-owners of the CCPP credits and accrual reversals during 2012 and 2013. In response to LA-2012/2013-3-5, AEP Ohio stated that the credits and accrual reversals listed in the exhibit above (provided in LA-2012/2013-3-4) were recorded to the Conesville Unit 4 coal pile in 2012 and that each CCD owner would receive their corresponding amount, which is predicated on that month's coal receipt split.

As it relates to the sale of the CCPP, during the interviews that were conducted at AEP Ohio's headquarters on February 19, 2014, the Company stated that it distributed a packet to prospective buyers of the prep plant in January 2012. AEP Ohio provided the materials from this packet in the response to EVA-2012/2013-1-22. In addition, this response included a bid received from [redacted] *who ultimately purchased the CCPP as well as the* Final Agreement between AEP Ohio and [redacted] for the sale of the CCPP.

On April 20, 2012, [redacted] submitted its "Binding Offer for the Acquisition of 100% of Substantially All of the Conesville Preparation Company's Assets". Specifically, [redacted] Binding Offer included the following provisions:

The cash purchase price and other consideration would be as follows:

- [redacted] would pay the sum of [redacted] in cash at closing.
- As additional consideration, [redacted] would also be assuming the reclamation and water treatment liabilities in perpetuity.
- In addition, given its position as a substantial provider of coal for the Company's Conesville generating facility, [redacted] believes it is able to offer as still further consideration for the Company substantial savings in the delivery of coal to such generating facility by the existing belt delivery facilities running from the preparation plant to such generating facility.

The final Asset Purchase Agreement between AEP Ohio and [redacted] for the sale of the CCPP was executed on April 5, 2013. As noted above, the [redacted] purchase price for the CCPP was [redacted]. According to the response to LA-2012/2013-3-3, at the closing of the sale on April 5, 2013, Conesville Coal Preparation Company ("CCPC") received net cash proceeds totaling [redacted] which was comprised of [redacted] less property taxes of [redacted] which were paid by [redacted] In addition, this response stated that the gross proceeds of [redacted] (less the recorded book value of $[redacted] of the land sold) resulted in a net gain of [redacted] which CCPC recorded in Account 4211000. The subsequent payments under the sale agreement (i.e., [redacted]) will occur outside the review period.[64]

The response to EVA-2012/2013-1-22 stated that there were no CCPP costs included in the FAC in either the 2012 or 2013.

[redacted] and Related Revenue

During the audit period Ohio Power granted a license to [redacted] to relocate, construct and operate a [redacted] for the purpose of [redacted] to [redacted][65] The decisions to treat the transactions with [redacted] as defined above were made over a period of several months in the spring of 2012. As a result of this arrangement to [redacted], Ohio Power is receiving a stream of revenue, which the Company records in Account 456. Ohio Power indicated in its confidential response to EVA-2012/13-3-8 that [redacted]

[64] During Larkin's onsite visit on February 19, 2014, AEP Ohio stated that it would receive an additional $[redacted] in April 2014 and the final [redacted] at December 31, 2014.

[65] Interview #7, Coal Procurement, 2/19/2014 and confidential responses to EVA-2012/13-3-8 and LA-2012/13-3-12.

[redacted] The Company's response to EVA-2012/2013-3-8 states further that [redacted]

As described in Chapter 3, EVA is recommending that the revenue Ohio Power is receiving related to the [redacted] which the Company is recording in Account 456 be reflected as a net reduction to the cost of coal charged to the ratepayer. Data request LA-2012/13-3-12 requested the Company to provide the amount [redacted] Gavin plant revenues by account by month for 2012 and 2013. The Commission's December 3, 2013 Order stated at page 3, paragraph 7 that:

> *Upon request of EVA or Staff, AEP Ohio shall provide any and all documents or information requested. AEP Ohio may conspicuously mark such documents or information "confidential" if AEP Ohio believes the document should be deemed as such. In no event, however, shall AEP Ohio refuse or delay in providing such documents or information.*

The Company's refusal to provide and delay in providing the requested accounting information related to the revenue stream that it began to generate during the audit period related to the [redacted] appears to be a direct violation of that order.

Reflecting the revenue stream [redacted] as a reduction to the utility's cost of coal has been recognized as appropriate ratemaking by some utilities that have or are in the process of establishing similar arrangements. One instance of which we are aware involves an arrangement by [redacted] The April 1, 2014 response to RUCO UNS 2.07 in Arizona Corporation Commission Docket No. E-04230A-14-0011, et al. addressed this matter.

That data request had [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

The affiliated River Transportation Division (RTD) transports coal to [redacted] via barges. During the fourth quarter of 2013, the RTD revenue details began showing a separate line item for [redacted] Up to that point RTD revenues for barge transportation of coal to [redacted] were listed as [redacted] The Company's response to LA-2012/2013-13-1(f) clarified that the [redacted]

As noted above, the Company has established a [redacted] treatment arrangement for [redacted] with [redacted] under which the coal being delivered to [redacted] is sold to [redacted], which [redacted]. There is no reduction to the cost of the repurchased coal under this arrangement. As described in the response to LA-2012/2013-13-1 [redacted].

2013-FAF-2.

During 2013, Ohio Power recorded [redacted].[66] There were no like revenues in 2012. The 2013 revenues were recorded during the months of September, November and December 2013. Although these revenues relate to the [redacted] AEP Ohio did not reflect them as an offset to [redacted] coal costs.

As noted above and described in Chapter 3 of this report, EVA has recommended that the revenue stream Ohio Power received during the audit period related to the [redacted] which the Company is recording in Account 456 be reflected as a net reduction to the cost of coal charged to the ratepayer. The reduction to the cost of [redacted] coal that should be reflected as a reduction to FAC costs is in accordance with EVA's recommendation. The Company's confidential supplemental Attachment to its supplemental response to LA-2012/2013-3-12 provided the following [redacted] that OPCO recorded in 2013 by month:

[66] Response to LA-2012/2013-3-12 Confidential Attachment 1.

Exhibit 7-70
[redacted] Recorded by OPCO in 2013 by Month

[redacted]

Net Losses from Sales of [redacted] to Third Parties

In response to EVA-2012/2013-1-19, the Company provided the following information on net losses that it had recorded in 2012 and 2013 in account 5010033 resulting from the sales of Conesville's [redacted] coal to third parties along with associated CCD (gain)/loss activity.

Account 5010033 is one of the fuel sub-accounts that is included in the FAC.

For 2012, the Company had net losses of [redacted], as summarized below:

Exhibit 7-71
Net Losses on Transactions Relating to Selling Conesville's [redacted] to Third Parties with [redacted] - 2012

[redacted]

For 2013, the Company had net losses of [redacted], as summarized below:

Exhibit 7-72
Net Losses on Transactions Relating to Selling Conesville's [redacted] to Third Parties with [redacted] - 2013

[redacted]

Emission Allowances

AEP Ohio provided documentation related to accounting detail associated with costs and revenues, purchases and sales of emission allowances, and monthly emission allowance inventory in the responses to LA-2012/2013-1-54 and LA-2012/2013-1-55.

Specifically, LA-2012/2013-1-54 requested the detailed general ledger pages for all purchases and sales of emission allowances ("EA") and for gains or losses realized on such purchases and sales of EAs. In response, AEP Ohio stated that the requested detail regarding EAs is not reflected in the general ledger. The Company referred to the response to EVA-2012/2013-1-29 for a schedule of emission allowance purchases, sales as well as related gains and losses for both CSP and OPCO. The following exhibit summarizes the emission allowance purchases, sales, and related gains and losses that occurred during the period January through December 2012.

Exhibit 7-73
2012 Emission Allowance Activity

	January-12		February-12		March-12		April-12		May-12		June-12	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2												
Sales						$3,303						
Gains												
Losses												
Purchases												
Seasonal NOx												
Sales							2,000	$15,000	50	$500		
Gains												
Losses								$13,804		$170		
Purchases												
Annual NOx												
Sales	3,025	$165,500	1,435	$73,225			1,500	$45,000	1,208	$45,604		
Gains		$131,437		$70,428				$41,831		$39,928		$65
Losses												
Purchases												

	July-12		August-12		September-12		October-12		November-12		December-12	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2												
Sales											58,825	$9,310,036
Gains												$7,537,909
Losses												$1,788,774
Purchases					22,482	$19,241					17,900	$3,111,724
Seasonal NOx												
Sales	812	$4,060	7,705	$71,141			1,500	$19,500				
Gains				$6,358								
Losses		$7,203		$37,480				$270,443				
Purchases							1,640	$780,610	13	$11,219		
Annual NOx												
Sales	856	$25,680	4,030	$131,050	4,000	$120,000	1,000	$33,500			1,000	$37,000
Gains		$23,446		$122,533		$111,562		$31,390				$34,402
Losses												
Purchases												

The table below summarizes the emission allowance purchases, sales and related gains and losses that occurred during the period January through December 2013.

Exhibit 7-74
2013 Emission Allowance Activity

	January-13		February-13		March-13		April-13		May-13		June-13	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2												
Sales						$1,340						
Gains												
Losses												
Purchases												
Seasonal NOx												
Sales											500	$8,750
Gains												
Losses												$3,629
Purchases							(110)	-$18,648				
Annual NOx												
Sales	1,854	$79,935	5,701	$220,770	3,500	$125,750	1,162	$48,304	1,000	$40,000	1,000	$41,000
Gains		$76,186		$208,101								
Losses						$88,623		$22,868		$20,326		$19,197
Purchases					3,522	$2,747,730						

	July-13		August-13		September-13		October-13		November-13		December-13	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2												
Sales											46,341	$7,461,516
Gains												$6,470,214
Losses												$1,173,437
Purchases											9,738	$822,480
Seasonal NOx												
Sales	500	$10,000	1,000	$21,000			1,180	$27,140	733	$16,859		
Gains								$731				
Losses		$2,379		$3,759						$91,505		
Purchases									1,388	$814,968		
Annual NOx												
Sales	1,000	$41,500	1,000	$42,000			1,500	$57,750	2,100	$80,850	500	$19,250
Gains												
Losses		$17,697		$18,197				$32,545		$45,563		$91,109
Purchases											2,856	$2,700,548

LA-2012/2013-1-55 requested monthly emission allowance inventory (quantity of allowances and cost) and for AEP Ohio to show how it was allocated between native and non-native customers. In response, AEP Ohio stated that the Companies do not allocate EA inventory between native and non-native load customers.

AEP Ohio's response to LA-2012/2013-1-55 also included confidential attachments which reflected monthly EA inventory balances from December 2011 to December 2013. The exhibit below summarizes the monthly EA ending inventory balances for each month of the period December 2011 through December 2012.

Exhibit 7-75
2012 Emission Allowance Inventory

[redacted]

The exhibit below summarizes the monthly EA inventory balances for each month of the period January through December 2013.

Exhibit 7-76
2013 Emission Allowance Inventory

[redacted]

Changes to Fuel, Purchased Power Procurement and Emission Allowance Procurement

Documentation related to the review of changes to fuel, purchased power procurement and emission allowance procurement during the period January 2012 through December 2013 includes AEP Ohio's responses to LA-2012/2013-1-60 and LA-2012/2013-1-61.

LA-2012/2013-1-60 asked the Companies' 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, AEP Ohio stated that on June 28, 2012, an announcement was made with respect to a change in leadership and responsibility in the Fuel, Emissions, and Logistics ("FEL") organization. In addition, on January 4, 2013, it was announced that the director level for FEL fuel procurement functions would be eliminated. There were no significant organizational changes to the Purchased Power Procurement or Emission Allowance Procurement business units during the January 2012 through December 2013 review period.

LA-2012/2013-1-61 requested information similar to LA-2012/2-13-1-60, although from a procedural versus organizational standpoint. In response to LA-2012/2013-1-61, AEP Ohio stated that there were no procedural, policy or accounting changes related to the Fuel, Purchased Power and Emission Allowance Procurement.

Internal Audits

LA-2012/2013-1-64 requested that the Companies' provide a listing and copies of any and all internal audit reports related to fuel procurement, synfuel, coal trading, fuel inventory management, purchased power, emission allowances, accounting for FAC-includable costs, portfolio optimization, energy sales, PJM charges and revenues, fuel and purchased power invoices, PJM invoices, allocation of PJM revenues and costs to Ohio retail load customers, allocation of other FAC includable costs and revenues to Ohio retail load customers, and/or other FAC related subject matter for the review period.

In response, AEP Ohio provided six internal audit reports, which were issued at various points during 2012 and 2013. The following indicates the areas that were the subject of the internal audits, along with a summary of recommendations for each area:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

AEP River Transportation Division

The AEP-owned barge company, called AEP River Transportation Division (RTD) is owned by Indiana and Michigan Power Company (IMPC), a subsidiary company of AEP. Barge freight services are provided by RTD to OPCo (its affiliate) and other AEP operating companies which receive coal deliveries via river transportation under the Barge Transportation Agreement.

Per the May 1986 Barge Transportation Agreement, RTD provides barge transportation services to the AEP operating subsidiaries that have coal plants located on the Kanawha, Green and Ohio Rivers, including Ohio Power Company (OPCo), Appalachian Power Company (APCo), and AEP Generating Company (AEPGC). RTD has operated barges, tugboats and other facilities for the transportation of coal on the Kanawha, Green and Ohio Rivers and other navigable waterways to transport coal to APCO, OPCO, AEPGC and IMPC since September 4, 1973. The generating stations owned by these AEP operating companies require large quantities of coal, which can be delivered to such stations in river barges.

Article V of the May 1986 Agreement provides that the RTD transportation services are to be priced as follows:

ARTICLE V

PRICE

> *The Division shall charge to each Shipper, and each Shipper shall pay to the Division, the costs of any transportation services performed by the Division for such Shipper. Such costs shall consist of all charges and expenses directly attributable to the performance of such service, a fair and equitable allocation of other charges and expenses of the Division (taking into account the transportation services performed by the Division for*

I&MECo), a provision for taxes at the combined normal tax and surtax rate applicable to corporations under Section 11 or any successor section of the Internal Revenue Code of 1954, as in effect from time to time, and an amount equal to 9.21% per annum of I&MECo's net investment in the Division. The determination of the 9.21% composite rate is shown in Appendix B. The Division will use the 9.21% composite after tax rate of return on its net investment until such time as it receives approval from the Public Service Commission of West Virginia and/or The Virginia State Corporation Commission, if necessary, to adjust the return on common equity on January 1 of each calendar year to the rate of return on common equity determined and allowed by the FERC in the most recent wholesale rate proceeding involving I&MECo. In the absence of a FERC order during the calendar year preceding each January 1, the rate of return on common equity would be that authorized by the Public Service Commission of Indiana in an I&MECo retail electric rate proceeding, during the calendar year preceding such January 1, otherwise the existing rate of return continues until the next January 1. For purposes of this Agreement, I&MECo's net investment in the Division during any period shall be understood to consist of its investment in real and personal property and an amount equal to 1/8 of the aggregate operation, maintenance, rental and general expenses of the Division for each annual period, plus prepayments and deferred expenses at the end of such period. If for any period the aggregate charges of the Division for transportation services performed do not equal the aggregate costs of performing such services, a prospective adjustment in rates will be made. A review of the need for such prospective adjustments shall be undertaken at least annually.

Demurrage and standby charges shall be assessed as provided in Appendix A hereto.

The Barge Demurrage Charges and Towboat Standby Charges, provided as Appendix A to the Barge Transportation Agreement is dated as effective March 1, 1978.

The SEC Release No. 35-24039 dated March 4, 1986, Order Authorizing the Rendition of Associated and Nonassociated Transportation Services, indicates that the primary purpose of the RTD is to move coal for the operating companies of the AEP System at the most reasonable price.

Pages 2-5 of that SEC Release address the subject of cost recovery as follows:

The basic principle used to determine barge rates is that revenues should equal costs. Since 1973, this principle has been adhered to on total cumulative revenues for the period 1973 to 1984 of approximately $260.5 million. The River Transportation Division's rates have been based on a detailed cost of service analysis, following normal transportation industry practice, based on a zone rate system where each river movement bears an equitable share of total costs. The zone rate structure, as a whole, is reasonable and free of undue discrimination.

The zone rate system was designed and established so that projected revenues would be expected to cover costs. Zone rates are set prospectively in such an amount that the expected revenues will be sufficient to recover projected costs for the next period. These expenses include (1) direct expenses from each river movement, (2) an allocation of all other expenses, net of credited revenues from providing services to nonassociates and (3) provisions for taxes. The variance for each zone (deficit or surplus of revenues over expenses by zone) at the end of each calendar year is carried over to the next year and *added to or subtracted from the projected costs to be recovered by the rates set to recover projected costs. The review to adjust rates is undertaken at least once a year, although an adjustment for significant cost shocks (i.e. fuel oil price changes, tax changes, wage escalations) are made as they occur and would not wait for the annual adjustment process.*

Specific barge rates are determined by zone. Currently there are four zones, each zone being treated as a cost center. Direct charges such as labor, fuel and rents are assigned to each cost center on a projected basis. Overhead costs such as supervisory salaries and expenses, general office operations and other costs are proportionately allocated to the four cost centers in the same proportion as direct expenses. Revenues from all services provided to nonassociates are first credited to reduce overhead costs, and then applied to direct charges in I&M's Federal Energy Regulatory Commission ("FERC") Account 151. I&M proposes by this application-declaration to include a provision for taxes based on or measured by income and an amount for the cost of capital of its net investment in the River Transportation Division (including working capital requirements), and to allocate such costs to zones on the same basis as overhead. A cost per ton-mile in each zone is determined by dividing projected total zone costs by projected total ton-miles moved within each zone. A barge rate for any specific move within a zone is the product of: (1) cost per ton-mile, (2) the number of adjusted miles for the movement (actual miles adjusted for down time), and (3) the number of net tones moved. In general, movements within each zone share similar characteristics, and are considered to be different from movements in other zones. These rates were reviewed before November 1, 1985 to determine what adjustment to rates, if any, were needed to adjust revenues to equal costs. I&M proposes to enter into a Barge Transportation Agreement with any Applicant requiring barge transportation services incorporating the barging rates as described, and entitling the Applicant to a service priority over any nonassociated company. Rates for nonassociated service will be at the highest practicable level, based on market conditions.

I&M proposes that the cost of capital on its net investment in the River Transportation Division be established at 9.21% per annum, which rate was approved in orders of the Corporation Commission of Virginia and the West Virginia Public Service Commission in 1981 and 1984, respectively, and which I&M proposes to begin applying after approval by this Commission. It represents a weighted average cost of capital based on I&M's capitalization ratio as of September 1, 1973, when the original transportation assets were acquired. The cost of long-term debt and preferred stock are the effective rates of the most recent long-term debt and preferred stock issues by I&M prior to September 1, 1973. The return on common equity is the return ordered by FERC on March 18, 1980, in I&M's general rate proceeding. I&M proposes to use the 9.21% composite rate until such time as state Commissions authorize, if necessary, an adjustment of the return on common equity on January 1 of each calendar year to the rate of return on common equity determined and allowed by FERC in the most recent wholesale rate proceeding involving I&M. In the absence of a FERC order during the calendar year preceding each January 1, it is proposed that the rate of return on common equity would be that authorized by the Public Service Commission of Indiana in an I&M retail electric rate proceeding during the calendar year preceding such January 1, otherwise the existing rate of return continues until the next January 1.

The costing procedures for barge rates were provided in response to LA-2012/2013-1-93, in Confidential Attachment 1 to that response. [redacted]:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

The RTD's 2012 through 2013 Rate Matrix, which provides the affiliated coal barging rates for OPCo based on the 2012 and 2013 budgets, were provided in Confidential Attachments 1 and 2 to LA-2012/2013-1-94. This lists the barging rates for each OPCo plant from each potential load-out area to the plant. OPCo plants that are supplied with coal by the RTD include Amos, Cardinal, Kammer, Mitchell, Muskingum River, Sporn, and Gavin.

A listing of all operating leases for captive barges was provided with the response to LA-2012/2013-1-108. Copies of the five largest operating leases based upon annual cost in 2012 and 2013 to OPCo were provided in the Confidential Attachments to LA-2012/2013-1-110. Those lease and charter agreements list OPCo as Charterer for (1) [redacted] (2) [redacted] (3) [redacted] (4) [redacted] and (5) [redacted]. The agreements provide that the [redacted] is the owner of the vessels. Section 8 (provided at LA-2012/2013-1-110 Confidential Attachment 1, page 13 of 65) provides as follows concerning maintenance and repairs:

[redacted]

The response to LA-2012/2013-1-109 indicates there are no operating leases between OPCo and River Operations for OPCO-owned barges for the review period.

The affiliated freight rate true ups for the nine quarters starting with the fourth quarter of 2011 through the fourth quarter 2013 for OPCo were provided in Confidential Attachment 1 to LA-2012/2013-1-95. That information is summarized in the following table:

Exhibit 7-77
River Operations, Summary of OPCO Quarterly Actualizations

[redacted]

For 2012, I&M had approximately [redacted] in revenue from OPCo related to the RTD. Costs and expenses were $[redacted], offset by $[redacted] for third party gains, less I&M's return on investment of approximately [redacted]. RTD also delivers urea to OPCo. For 2012 RTD shipped both coal and urea to OPCO plants. The 2012 quantities included urea tonnage of approximately [redacted] and coal tonnage of [redacted]. The net cost (based on RTD's Costs and Expenses, less the Third Party Gain, plus RTD's Return on Investment) for OPCo for 2012 was approximately [redacted]. For the [redacted] tons of urea and coal delivered, this is an average cost of approximately [redacted] per ton. In comparison, the average cost per ton for the fourth quarter of 2011 was [redacted], as shown in the above table.

For 2013, I&M had approximately [redacted] in revenue from OPCo related to the RTD. Costs and expenses were $[redacted], offset by $[redacted] for third party gains, less I&M's return on investment of approximately [redacted]. RTD also delivers urea to OPCo. For 2013 RTD shipped both coal and urea to OPCO plants. The 2013 quantities included urea tonnage of approximately [redacted] and coal tonnage of [redacted]. The net cost (based on RTD's Costs and Expenses, less the Third Party Gain, plus RTD's Return on Investment) for OPCo for 2013 was approximately [redacted]. For the [redacted] tons of urea and coal delivered, this is an average cost of approximately [redacted] per ton. In comparison, the average cost per ton for the fourth quarter of 2012 was [redacted], as shown in the above table.

Intercompany barge optimization reports (cross charter reports) are utilized by RTD, and are provided in response to LA-2012/2013-1-106 for December 2011 and each month of 2012 through 2013. These reports show, by month, the barge days associated with Captive chartered to Commercial and Commercial chartered to Captive, as well as the monthly amounts of Commercial Expense/Captive Revenue and Captive Expense/Commercial Revenue. For 2012, the total amounts of Commercial Expense/Captive Revenue and Captive Expense/Commercial Revenue were [redacted] million and [redacted] million, respectively. For 2013, the total amounts of Commercial Expense/Captive Revenue and Captive Expense/Commercial Revenue were [redacted] million and [redacted] million, respectively. The balance between these two amounts reflects the RTD operating plan to optimize combined fleet performance and not have cross-subsidies to either the captive or the commercial side of the barge transportation business.

The RTD's Barge Operations Income Statements and Balance Sheets for Captive Operations for December 2011 and each month of 2012 through 2013 were provided in Confidential Attachments 1 and 2 to LA-2012/2-13-1-103. LA-2012/2013-1-103 also provided the consolidated financial statements, the pre-consolidation financial statement information for captive operations business segments and the consolidating entries and adjustments for 2012 and 2013 captive operations.

The RTD's "Actual Net Investment Base & Cost of Capital Billing Adder" for 2011, 2012 and 2013 was provided in the revised Confidential Attachments 1, 2 and 3 to LA-2012/2013-1-104.

The Investment Base consists of a "Working Capital Requirement" that is based on RTD's Expenses, less Sub-lease Revenues, plus a prior period Over- or Under-Collection. The result of these items is an amount of "Net Expenses" which is multiplied by 0.125 (i.e., by 1/8th).

To the Working Capital Requirement are added Real Property and Personal Property (based on a 13-month average of Net Book Value). The items included under "Personal Property" include additions for the average net book value of I&M RTD's personal property, prepayments and materials and supplies, and subtractions for current liabilities and accruals and accumulated deferred income taxes. The addition of these items results in an Investment Base, which is multiplied by a "Before Tax" rate of return of [redacted]% for 2011, [redacted] for 2012, and [redacted] for 2013, to derive an Actual Return on Investment. The derivation of the "Rate of Return on Assets" of [redacted] for 2011, [redacted] for 2012, and [redacted] for 2013 are shown on page 5 of LA-2012/2013-1-104 Confidential Attachments 1, 2, and 3. It is based upon a capitalization consisting of Long Term Debt, Preferred Stock and Common Stock

The derivation of the net investment base components reflect AEP's implementation of certain recommendations made in conjunction with the 2009 audit. In the RTD "Investment Base" calculations, RTD is now applying the 1/8 to what appears to be operating expenses. As described in the 2009 audit, RTD had previously been applying the 1/8th to Balance Sheet accounts.

It appears that the way the RTD charges to the AEP captive operations are set up with the billing and a subsequent true-up (actualization), the operating companies, including OPCo, will essentially be paying the RTD for all of its costs, including the return component. Given this set-up, there does not appear to be much risk, if any, that RTD will not collect its cost of service (including the return component) from the AEP captive operating utilities that use RTD for transportation services. While some return on investment would appear to be warranted since RTD has a net investment in assets that are used to provide service, we would question whether the Return on Common Equity (especially the [redacted] ROE that was applied in 2012 and [redacted] that was applied in 2013) is appropriate and commensurate with the risk of this operation.

The Ohio PUC has not allowed either CSP or Ohio Power to use a 1/8th O&M calculation for cash working capital in any distribution rate cases from 2000 to the present. In Case Nos. 11-352-EL-AIR et al, Ohio Power's more recent distribution rate case, the Staff report, at page 7, stated that the Applicant did not prepare a lead lag study; therefore, the Staff cannot recommend a working capital allowance. A similar statement is contained in the Staff report in CSP's last distribution rate case, Case Nos. 11-351-EL-AIR et al, at page 7.

The following table shows the estimated annual revenue requirement to OPCO from the RTD's Working Capital Requirement, derived from information provided in LA-2012/2013-1-97 and 104:

Exhibit 7-78
Estimated Annual Revenue Requirement to OPCO from RTD Working Capital Requirement

[redacted]

The above table shows the total amount of annual revenue requirement on the RTD Working Capital component of the RTD investment base, and the estimated portion of that becomes a cost of OPCO for 2010 and 2011. Additionally, the following table shows how much of the total annual RTD revenue requirement for the RTD investment base relates to the RTD Working Capital component:

Exhibit 7-79
Portion of Total Annual Cost for RTD Investment Base Comprised by RTD Working Capital Requirement

[redacted]

The use of a 1/8th O&M calculation for determining a working capital component of investment base has been controversial. It assumes there is a net lag between the collection of revenue and the payment of cash expenses of approximately 45 days (365 / 8 = 45.625 days). The validity of this assumption should be tested via a lead-lag study. AEP should be required to analyze the receipt of revenue and the payment of cash expenses for RTD captive operations, similar to a lead-lag study.

The use of a 1/8 formula for computing cash working capital has been discredited for a number of reasons, including because it would always produce a positive cash working capital allowance, even in situations where funds were being supplied to the service provider through operations. Other AEP operating utilities have conducted lead-lag studies.[67] It appears questionable that the RTD would be incapable of having an appropriate lead-lag study analysis of its cash receipts and expenditures as the basis for a cash working capital component of the RTD "Investment Base." An appropriately conducted lead-lag study analysis would also tend to be more reliable than the 1/8 formula assumption currently being used by RTD.

RTD rates for transporting coal to OPCo are based on mileage. Per the confidential attachment provided with LA-2012/2013-1-111, for 2013 [redacted]

LA-2012/2013-1-98 asked whether the RTD or AEP or OPCO had information with respect to barge transportation rates charged by competitive carriers such as [redacted]. The Company's confidential response indicated that Crouse was the only carrier used 2012 and no outside carriers were use in 2013.

As explained in the response to LA-2012/2013-1-101, Ohio Power or AEP does not issue RFPs for barge transportation as this service is provided by the RTD at cost.

[67] For example, Appalachian Power Company filed lead-lag studies for its generation and distribution operations in Virginia State Corporation Commission Docket No. PUE-2011-00037.

As explained in the response to LA-2012/2013-1-102, OPCO did not contract for barge transportation service with carriers other than the RTD. The RTD fulfills all of AEP's barging needs, other than the occasional transaction, such as the one noted above, as described in response to LA-2012/201301-98.

As identified in the response to LA-2012/2013-1-100, total demurrage revenue recognized in 2012 for RTD was [redacted] OPCO's portion of that was [redacted]. Total demurrage revenue recognized in 2013 for RTD was [redacted]. OPCo's portion of that was [redacted]. Per LA-2012/2013-1-99, demurrage is billed according to contract terms and is reported as affiliated or outside revenue by RTD based on the identity of the customer.

Larkin requested that AEP Ohio provide copies of invoices related to demurrage charges for all river-supplied coal plants for the periods 2012 and 2013. In response to LA-2012/2013-1-112, AEP Ohio provided copies of the demurrage invoices for coal shipments that were submitted to AEP Ohio in 2012 and 2013. The exhibit below summarizes the 2012 demurrage charges which relate to coal shipments delivered to the Cardinal plant.

Exhibit 7-80
Cardinal Plant Demurrage in 2012

Cardinal Plant Demurrage in 2012			
Period	Invoice Date	Invoice Number	Amount
April 2012	5/7/2012	MEM0319251	$ 6,216
May 2012	6/18/2012	MEM0322834	$ 9,600
May 2012	6/18/2012	MEM0322835	$ 6,144
June 2012	7/19/2012	MEM0325599	$ 2,361
July 2012	8/15/2012	MEM0327669	$ 469
October 2012	11/13/2012	MEM0338088	$ 200
October 2012	11/13/2012	MEM0338091	$ 2,724
November 2012	12/10/2012	MEM0340770	$ 4,500
		Total	$ 32,214

Larkin requested that AEP Ohio explain (1) whether there were any problems at the Cardinal Plant in May 2012 which contributed to the relatively high demurrage of $15,744 ($9,600 + $6,144) during that month, and (2) how the demurrage costs were charged or allocated among the Cardinal units. In its confidential response to LA-2012/2013-4-20 the Company stated:

[redacted]

[redacted]

The exhibit below summarizes the 2012 demurrage charges which relate to coal shipments delivered to the Gavin Plant.

Exhibit 7-81
Gavin Plant Demurrage in 2012

Gavin Plant Demurrage in 2012			
Period	Invoice Date	Invoice Number	Amount
February 2012	4/5/2012	MEM0316633	$ 16,269
April 2012	5/7/2012	MEM0319255	$ 30,778
May 2012	6/18/2012	MEM0322841	$ 45,670
June 2012	7/24/2012	MEM0325904	$ 41,326
July 2012	8/15/2012	MEM0327652	$ 17,796
November 2012	12/10/2012	MEM0340771	$ 26,513
December 2012	1/8/2013	MEM0342974	$ 9,877
		Total	$188,229

Larkin requested that AEP Ohio explain whether there were any problems at the Gavin Plant in May and June 2012 which contributed to the high demurrage charges of $45,670 and $41,326, respectively. In its confidential response to LA-2012/2013-4-25 the Company stated:

> *Gavin plant experienced several planned and forced outages in May and June of 2012, which contributed to the lack of unloading, and ultimately, demurrage charges.*

The exhibit below summarizes the 2013 demurrage charges which relate to coal shipments delivered to the Cardinal Plant.

Exhibit 7-82
Cardinal Plant Demurrage in 2013

Cardinal Plant Demurrage in 2013			
Period	Invoice Date	Invoice Number	Amount
February 2013	3/11/2013	MEM0349127	$ 6,500
February 2013	3/11/2013	MEM0349128	$ 13,491
April 2013	5/6/2013	MEM0353473	$ 10,250
April 2013	5/6/2013	MEM0353474	$ 19
May 2013	6/4/2013	MEM0355321	$ 96,750
June 2013	7/5/2013	MEM0357333	$ 18,300
June 2013	7/5/2013	MEM0357334	$ 3,512
July 2013	8/5/2013	MEM0359522	$ 11,600
August 2013	9/5/2013	MEM0361739	$ 27,200
October 2013	11/14/2013	MEM0367542	$ 3,100
October 2013	11/14/2013	MEM0367543	$ 12,389
November 2013	12/12/2013	MEM0370192	$ 23,700
		Total	$226,811

Larkin requested that AEP Ohio explain whether there were any problems at the Cardinal Plant in February 2013 which contributed to the relatively high demurrage charges of $19,991 ($6,500

+ $13,491) during that month. In its confidential response to LA-2012/2013-4-21, AEP Ohio stated:

> *In February 2013, there were 10 days that the plant was operating with only one barge unloader due to the other loader being out of service.*

Larkin requested similar information as it related to demurrage charges at the Cardinal Plant for the periods May through August 2013 as well as November 2013. The Company's confidential responses were provided as follows:

As it relates to the period May through August 2013, in response to LA-2012/2013-4-22 AEP Ohio stated:

> [redacted]

As it relates to November 2013, in its confidential response to LA-2012/2013-4-23, the Company stated:

> *There were 7 days that the plant had one of its two barge unloaders out of service. Also during that time, coal from the storage pile had to be blended with coal from barges. Blending coal can only be done with one of the plant's two barge unloaders, which limits unloading capabilities.*

As it relates to December 2013, Larkin asked whether there were any demurrage charges and if so, to specify how much demurrage was charged for each unit. In its confidential response to LA-2012/2013-4-24, the Company stated that the only charges in December 2013 related to [redacted] Cardinal for which the Company provided an invoice issued to Buckeye in the amount of $[redacted].

The exhibit below summarizes the 2013 demurrage charges which relate to coal shipments delivered to the Gavin Plant.

Exhibit 7-83
Gavin Plant Demurrage in 2013

Gavin Plant Demurrage in 2013			
Period	Invoice Date	Invoice Number	Amount
January 2013	2/11/2013	MEM0346406	$ 31,587
February 2013	3/11/2013	MEM03349129	$ 9,714
March 2013	4/5/2013	MEM0351155	$ 16,056
June 2013	7/5/2013	MEM0357335	$ 47,713
July 2013	8/5/2013	MEM0359523	$ 588
		Total	$ 105,658

Larkin requested that AEP Ohio explain whether there were any problems at the Gavin Plant in January 2013 which contributed to the high demurrage charges of $31,587. In its response to LA-2012/2013-4-26 the Company stated:

> *The Powder River Basin ("PRB") inventory pile at the Gavin Plant was discontinued at the end of calendar year 2012, but there were some PRB shipments that carried over into 2013. Consequently, the carry-over PRB coal was being drawn directly from the barge in January, 2013. Demurrage charges were incurred during the month as the draw could not exceed a 20% PRB blend for the plant burn.*

As it relates to June 2013, Larkin requested that AEP Ohio explain whether there were any problems at the Gavin Plant in June 2013 which contributed to the high demurrage charges of $47,713. In addition, Larkin asked how the Gavin Plant managed to improve its barge unloading performance from [redacted] of demurrage for July 2013, including what changed in July that resulted in the noted improvement to barge unloading performance. In its response to LA-2012/2013-4-27 the Company stated:

> *There were two forced unit outages and one planned unit outage in June 2013, which resulted in lower than normal consumption that contributed to higher demurrage charges.*
>
> *The Gavin Plant burned more coal in July than June. As the coal was delivered in a ratable manner, the plant personnel was unloading coal to meet July's higher burn more steadily, thus resulting in a steep decline in demurrage days.*

Based on our review of RTD information to date, we believe there may be a need to revise, prospectively, the way the RTD Net Investment Base and Cost of Capital Billing Adder that is used to determine RTD charges to OPCo is derived.

There was a notable decline in RTD deliveries of coal to Plant Gavin in the fourth quarter of 2013, as shown in information provided in response to LA-2012/2013-1-95 and summarized below:

Exhibit 7-84
Tons of Coal Delivered to Plant Gavin

Tons of Coal Delivered to Plant Gavin
By AEP River Transportation Division

Period	Tons Delivered	
Q1 2013	1,916,141	
Q2 2013	1,585,572	
Q3 2013	1,447,338	
Oct & Nov 2013	534,539	4th Quarter
Dec-13	313,139	847,678
Total 2013	5,796,729	

Source: LA-2012/2013-1-95

This period also roughly corresponded to changes in the RTD revenue listing, where in periods prior to September 2013, RTD revenue from coal deliveries to [redacted]" but subsequently is listed as [redacted] As noted in a prior section of this report, AEP Ohio commenced a [redacted] with [redacted] to have [redacted]. This process involves [redacted]. This arrangement has also complicated the audit trail and related documentation. So we have asked AEP Ohio to provide some clarification, as noted below.

AEP was asked to explain the drop-off in fourth quarter 2013 tonnage and clarify how RTD is billing OPCo and [redacted] for barge transport of coal to [redacted], in LA-2012/2013-13-1

During the fourth quarter of 2013, the RTD revenue details began showing a separate line item for [redacted]. Up to that point RTD revenues for barge transportation of coal to [redacted] were listed as [redacted]. The Company's response to LA-2012/2013-13-1(f) clarified that the [redacted] In response to LA-2012/2013-13-1(a) the Company confirmed that the information shown in LA-2012/2013-1-95 was correct. The reason for the lower RTD deliveries was that less tons of coal were needed at Gavin during the fourth quarter of 2013.

Based on our review of RTD information to date, we have the following recommendations:

AEP should be required to analyze the receipt of revenue and the payment of cash expenses for RTD captive operations, similar to a lead-lag study, and to present such information to support its assumption that RTD has a significant Cash Working Capital requirement. If adequate supporting information is not provided to substantiate that RTD has a significant Cash Working Capital requirement and the amount of that requirement using lead-lag study analysis of cash receipts and cash payments, the RTD Working Capital component of the RTD investment base should be removed from the cost charged by RTD to OPCo from January 1, 2012 forward.

8 RENEWABLES AND THE ALTERNATIVE ENERGY RIDER (AER) COMPONENT

Management/Performance Audit

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 8-1. 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 derive methane gas, wood waste, fuel cells, and storage facilities.

Exhibit 8-1
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 that documents how their compliance obligations are calculated and provides a listing of the REC certificate numbers that were surrendered as part of their compliance obligation. If the utility has failed to meet its requirements in any year and such under-compliance is deemed to have been avoidable, the utility will be assessed a monetary penalty referred to as the "alternative compliance payment ("ACP"). The non-solar ACP is initially set at $45 per MWh and will be adjusted annually by the PUCO according to changes in the Consumer Price Index. The solar ACP is initially set at $450 per MWh. In 2012 and 2013, the solar ACP was set at $350 per MWh and then gets reduced by $50 every two years thereafter until it hits $50 per MWh in 2024. ACPs are deposited into the Ohio Advanced Energy Fund which provides funding for renewable and energy efficient projects within the state. ACPs are not recoverable through the FAC.

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

Ohio Power Compliance

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. Exhibit 8-2 provides the baseline for retail sales and the REC requirements for solar and non-solar, Ohio and other for 2012 and 2013.

Exhibit 8-2
Baseline Requirements

[redacted]

To comply with this requirement, companies must surrender renewable energy credits (REC) from qualified resources (Note: 1 REC= 1 MWh) equal to the renewable obligation. Given a

REC have a five-year lifetime following their acquisition, surplus unused credits can be carried over and consumed in a following year.

These compliance reports show AEP-Ohio complied with its renewable energy requirement primarily through three major long-term renewable power purchase agreements and supplemented with purchases of qualifying renewable energy credits, co-firing biomass at selected coal plants and Ohio's renewable energy technology program. A breakdown of the major REC providers used for compliance is provided in Exhibit 8-3.

Exhibit 8-3
Major REC Providers

[redacted]

As shown, the bulk of the Ohio non-solar requirement is met by the 99 MW AEP [redacted] project. Prior to the [redacted] Power Purchase Agreement (PPA) being approved by the Commission, Ohio Power [redacted]. Once this PPA was approved in 2013, Ohio Power received not only the project power output and capacity credit values but also all associated RECs [redacted]. Of the 2013 RECs created by the project in 2013, a total of [redacted]

Ohio Power operations also qualified for RECs from its co-firing biomass and biodiesel at its Conesville #4-6, Picway and Muskingum #1-4 coal fired stations. Overall, this biomass co-firing qualified for [redacted] in 2012 and [redacted] in 2013.

The remaining Ohio non solar requirement was met through [redacted]

The entire requirement for outside of Ohio non-solar requirements for qualifying resources connected to PJM grid were supplied under its 100 MW PPA with the [redacted] wind project in Indiana. [redacted]

[redacted]

[redacted]

Given the high capital costs for the wind and solar resources and the high biomass fuel costs, these resources are more expensive than Ohio Power's conventional fossil fired power resources. For the first nine months of 2012, the high costs for the renewable power and credit purchases were recovered in the fuel adjustment clause.

However, beginning in October 2012, the renewable cost recovery has been divided between the fuel adjustment clause for the value of the provided renewable power and capacity for the 3 renewable projects under Power Purchase Agreements [redacted]) and the Alternative Energy Rider (AER) for the remaining above market value for the three contracts and for all the remaining REC credit purchases. Since the fuel adjustment clause expires December 31, 2014 and the AER continues, AEP developed an allocation methodology to allow for recover of the REC values in the AER.

The FAC cost allocation methodology covering the period October 2012-December 2013 calculates the value of the energy and capacity provided. It assigns the value of the energy produced under the three agreements to be equal to the monthly average spot clearing price for nearest PJM pricing points multiplied by the power each produced during the month. This approach would very roughly approximate to what the company would have received if it sold the output on the open market.

The AEP capacity used for the wind projects in this calculation is based upon the capacity credit given by PJM. Given wind speeds need to reach near 14m/s for a wind turbine to produce power at its nameplate capacity, their rated capacity is generally not available during system peak demand periods and PJM assigns only a fraction of wind project capacity towards the power pool reserve margin requirement. [redacted]

For the [redacted] [redacted] project, PJM assigns no capacity credit since the project was not registered as a PJM resource. Given the [redacted] project reduces the system peak demand, AEP currently assigns only a 3.84 MW capacity credit to the facility in its capacity credit calculation. AEP's assigned 38 percent credit value is less than what many other US grid connected solar resources typically receive since they operate near their full rated capacity during the summer peak periods but is equal to the PJM solar default value for solar grid connected resources. EVA recommends that AEP apply the same capacity credit methodology as PJM uses for its grid connected resources based upon its output for prior annual peak periods. EVA anticipates that during the prior 2012 and 2013 periods, the power output was above 38 percent during the system peak periods.

AEP's proposed methodology for calculating capacity value for the three renewable project's capacity was to use the PJM capacity auction clearing price. Under this method, AEP applied the PJM auction value of $16.46/MW-day for the period October 2012-May 2013 and then updated to the most recent capacity auction of $27.73/MW-day for June-December 2013. These clearing prices are widely considered as being far below true market capacity cost and values that have been debated in prior PUCO dockets. In its July 2012 decision 10-2929-EL-UNC, the Commission set the system capacity value of $188.88 MW-day that should be used in the AEP renewable capacity credit calculations.

As shown in Exhibit 5-10, by using the Commission approved generation capacity value, the total renewable contract capacity credit for the 15 month period (October 2012-December 2013) under the Fuel Adjustment Credit would have increased by $2.115 million and the Alternative Energy Rider decreased by this same amount.

[68] Given that [redacted] wind project receives only a 9.73% of nameplate capacity credit based upon its performance during region peak demand periods, a significant risk exists that [redacted] capacity credit may be reduced once sufficient performance data during system peaks is collected. This future adjustment could lower its future capacity system value and assign a greater cost to the AER.

Exhibit 8-4
Revised Capacity Credit Calculations

[redacted]

Overall if AEP had used the Ohio Commission credit value in combination with a higher solar capacity value (10.1 MW vs 3.84 MW) for the [redacted] contract, the total renewable capacity credit value under the Fuel Adjustment Clause would have been increased by $ 2.655 million and the AER would be reduced by a corresponding amount. This change has significant future implications since the FAC is set to expire at the end of 2013 and the AER continues.

FINANCIAL AUDIT

Organization

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

- Background
- Audit Period for Review of Renewables Cost and Rider AER
- Quarterly AER Filing – Fourth Quarter 2012
- Rider AER - First Quarter 2013
- Rider AER - Second Quarter 2013
- Rider AER – Third Quarter 2013
- Rider AER – Fourth Quarter 2013
- Rider AER – First Quarter 2014
- Rider AER – Second Quarter 2014
- Minimum Review Requirements
- REC Inventories

- REC Costs Included in Rider FAC
- Determination of REC Values
- [redacted] RECs
- [redacted] RECs
- [redacted] RECs
- Value for Non-Solar, Non-Ohio REC Inventory Before Rider AER Effective Date
- Fulfillment of Renewables Obligation
- Non-Solar REC Inventory and REC Consumption
- REC Accounting
- Biodiesel and Biomass Testing and Biodiesel RECs

Background

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

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 8-5
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.*

In its July 31, 2008 Application for an Electric Security Plan (and FAC), AEP Ohio requested full cost recovery of its renewable energy purchases and renewable energy credits ("RECs") with the caveat that the Companies proposed including all of its renewable energy costs within the FAC mechanism, and not as part of the deferred FAC costs pursuant to Section 4928.144 of the revised Ohio code. In its Opinion and Order dated March 18, 2009, the PUCO approved the Companies' proposed inclusion of renewable energy purchases and RECs as includable FAC costs citing Section 4928.64(E) which states:

> *All costs incurred by an electric distribution utility in complying with the requirements of this section shall be bypassable by any consumer that has exercised choice of supplier under Section 4928.03 of the Revised Code.*

On January 27, 2011, AEP-Ohio witness Philip J. Nelson submitted direct testimony in Case Nos. 11-346-EL SSO and 11-348-EL-SSO in which the Company had proposed the implementation of an Alternative Energy Rider ("Rider AER"), which would segregate the REC value from Renewable Energy Purchase Agreements ("REPA"). Specifically, the REC component of renewable energy costs would be recovered through the AER and the non-REC portion of and the non-REC portion of such costs would continue to be recovered through FAC.

On August 8, 2012, the Commission issued its Opinion and Order in Case Nos. 11-346-EL-SSO, et al, in which the Alternative Energy Rider ("AER") was established. The AER is a mechanism through which AEP-Ohio can recover its prudently incurred alternative energy compliance costs and according to the response to LA-2012/2013-1-65, became effective (along with other provisions of the modified ESP) in "Cycle 1 September 2012".

Audit Period for Review of Renewables Cost and Rider AER

The audit period for renewables is 2012 and 2013. We reviewed the Company's renewables costs for 2012 and 2013. The Alternative Energy Rider was only in effect for part of this period. Rider AER became effective in October 2012 as a result of AEP Ohio's first quarterly filing on August 31, 2012, which reflected projected information for October through December 2012. As noted above, Rider AER recovers the REC value of the Company's renewable purchased power agreements. The capacity costs and energy value of the REPAs continues to be recovered through the FAC.

As a result of implementing Rider AER in October 2012, the Company began computing a capacity and an energy value for its REPAs, with the REC value being the reminder after subtracting the capacity value and energy value from the total cost.

Quarterly Rider AER Filing - Fourth Quarter 2012

On August 31, 2012, AEP Ohio submitted its first Alternative Energy Rider ("AER") quarterly filing, for CSP and OPCO, which reflected projected data for the period October through December 2012. AEP Ohio's filing for this quarter included a submittal letter, Schedules 4 through 6 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule. The Companies' Rider AER was filed with its quarterly Rider FAC filing.

The sections below discuss AEP Ohio's fourth quarter 2012 Rider AER filings by reproducing Schedules 4 through 6, broken out separately between CSP and OPCO as Exhibits 8-1 through 8-3, and briefly summarizing each schedule.

Exhibit 8-6
CSP and OPCO Schedule 4, October – December 2012

Schedule 4

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
October 2012 through December 2012
Summary - Proposed AER Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		B	C	D
		Schedule 5	Schedule 6	
Line	Delivery Voltage	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.08273	0.00000	0.082730
2	Primary	0.07986	0.00000	0.079860
3	Sub/Transmission	0.07827	0.00000	0.078270

OHIO POWER RATE ZONE

		B	C	D
		Schedule 5	Schedule 6	
Line	Delivery Voltage	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.05586	0.00000	0.055860
2	Primary	0.05392	0.00000	0.053920
3	Sub/Transmission	0.05285	0.00000	0.052850

Schedule 4: Column B reflects the forecast component ("FC") rate necessary to recover the estimated REC cost for the period October through December 2012. Column C will be used for a reconciliation adjustment ("RA") for the October through December 2012 period. Column D reflects the sum of the FC and RA components.

Exhibit 8-7
CSP and OPCO Schedule 5, October – December 2012

Schedule 5

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
October 2012 through December 2012
FC Component

				Forecast Period - 4th Quarter 2012			
Line	Description			October	November	December	Total
	TOTAL COMPANY						
1	Renewable Energy Credits			1,787,582	2,018,906	2,151,027	$ 5,957,515
2	Retail Non-Shopping Sales - Generation Level Kwh			2,982,573,959	3,052,977,995	3,469,293,021	9,504,844,975
3	COLUMBUS SOUTHERN POWER RATE ZONE						
4	CSP % for Retail Load		49.20%				$ 2,931,097
5	CSP % Non-Shopping Sales		39.54%				3,758,215,703
6	FC Component of AER Rate At Generation Level - Cents/kWh						0.07799
				Secondary	Primary	Sub/Trans	
7	FC Component of AER Rate At Generation Level			0.07799	0.07799	0.07799	
8	Loss Factor			1.0608	1.0240	1.0036	
9	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**		**0.08273**	**0.07986**	**0.07827**	
10	OHIO POWER RATE ZONE						
11	OPCo % for Retail Load		50.80%				$ 3,026,418
12	OPCo % Non-Shopping Sales		60.46%				5,746,629,272
13	FC Component of AER Rate At Generation Level - Cents/kWh						0.05266
				Secondary	Primary	Sub/Trans	
14	FC Component of AER Rate At Generation Level			0.05266	0.05266	0.05266	
15	Loss Factor			1.0608	1.0240	1.0036	
16	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**		**0.05586**	**0.05392**	**0.05285**	

Schedule 5: This schedule reflects AEP Ohio's estimates of monthly REC costs it expected to incur during the period October through December 2012. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the fourth quarter of 2012, AEP Ohio projected REC costs totaling $5.958 million.

As stated in Chapter 7, the component for renewable energy credits ("RECs") was moved from the FAC to the AER, commencing with AEP Ohio's first Rider AER filing, which reflected the projected cost of RECs for October through December 2012. The Companies calculated the FC portion of the AER rate at the Generation level. This amounted to .07799 cents per kWh for CSP and .05266 cents per kWh for OPCO. This was calculated by dividing each Company's projected AER for retail load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO applied loss factors to each respective FC portion of the AER rate based on delivery voltage levels in order to derive the FC portion of the AER rate at meter level. The Companies applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of .08273, .07986 and .07827 cents per kWh for CSP and FCs of .05586, .05392 and .05285 cents per kWh for OPCO.

Exhibit 8-8
CSP and OPCO Schedule 6, October – December 2012

Schedule 6

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
October 2012 through December 2012
RA

Actual Period - April 2012 through June 2012

Line	Month	Kwh Retail Non-Shopping Sales	Renewable Revenue	Renewable Cost	AER (Over)/Under Recovery
1	Beginning Balance				
2	Apr-12	2,400,870,309	$ -	$ -	$ -
3	May-12	2,565,621,174	$ -	$ -	$ -
4	Jun-12	2,653,055,283	$ -	$ -	$ -
5	Ending Balance	7,619,546,766	$ -	$ -	$ -
6	Total (Over)/Under Recovery Balance				$ -
7	Loss Adjusted Retail Sales Billing Period - kWh				9,504,844,975
8	RA Component at Generation - Cents/kWh				0.00000

Line			Secondary	Primary	Sub/Trans
9					
10	RA Component of FAC Rate At Generation Level		-	-	-
11	Loss Factor		1.0608	1.024	1.0036
12	RA at the Meter Level - Cents/kWh	Line 10 x Line 11	0.00000	0.00000	0.00000

Schedule 6: This schedule represents the Companies' RA components for the fourth quarter 2012 AER filing. The Rider AER filing for the fourth quarter of 2012 did not yet have any actual REC revenue or costs. The RA component for this filing was zero.

Rider AER – First Quarter 2013

On December 3, 2012, AEP Ohio submitted quarterly FAC filings, which included quarterly AER filings for CSP and OPCO based on projected data for the period January through March 2013. AEP Ohio's filing for this quarter included a submittal letter, and Rider AER Schedules 4 through 6 supporting the Companies proposed calculations for CSP and OPCO.

The Companies used the same methodology described above as it relates to the format of the schedules in their initial Rider AER filing. The sections below discuss AEP Ohio's first quarter 2013 AER filings by reproducing Schedules 4 through 6, broken out separately between CSP and OPCO as Exhibits 8-5 through 8-7, and briefly summarize each schedule.

Exhibit 8-9
CSP and OPCO Schedule 4, January – March 2013

Schedule 4

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
January 2013 through March 2013
Summary - Proposed AER Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		A	B	C	D
			Schedule 5	Schedule 6	
Line	Delivery Voltage	Current AER Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.08273	0.16354	0.00000	0.163540
2	Primary	0.07986	0.15787	0.00000	0.157870
3	Sub/Transmission	0.07827	0.15473	0.00000	0.154730

OHIO POWER RATE ZONE

		A	B	C	D
			Schedule 5	Schedule 6	
Line	Delivery Voltage	Current AER Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.05586	0.11043	0.00000	0.110430
2	Primary	0.05392	0.10660	0.00000	0.106600
3	Sub/Transmission	0.05285	0.10447	0.00000	0.104470

Schedule 4: Column A of this schedule reflects the then current AER rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period January through March 2013. Column C will present the Companies' reconciliation adjustment ("RA") for Rider AER when it begins to apply. Column D reflects the sum of the FC and RA components.

Exhibit 8-10
CSP and OPCO Schedule 5, January – March 2013

Schedule 5

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
Janury 2013 through March 2013
FC Component

Line	Description			January	February	March	Total
				Forecast Period - 1st Quarter 2013			
	TOTAL COMPANY						
1	Renewable Energy Credits			2,839,344	2,372,310	2,320,061	$ 7,531,716
2	Retail Non-Shopping Sales - Generation Level Kwh			2,268,648,381	1,869,507,757	1,940,659,715	6,078,815,853
3	COLUMBUS SOUTHERN POWER RATE ZONE						
4	CSP % for Retail Load		49.20%				$ 3,705,604
5	CSP % Non-Shopping Sales		39.54%				2,403,563,788
6	FC Component of AER Rate At Generation Level - Cents/kWh						0.15417
				Secondary	Primary	Sub/Trans	
7	FC Component of AER Rate At Generation Level			0.15417	0.15417	0.15417	
8	Loss Factor			1.0608	1.0240	1.0036	
9	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**		**0.16354**	**0.15787**	**0.15473**	
10	OHIO POWER RATE ZONE						
11	OPCo % for Retail Load		50.80%				$ 3,826,111
12	OPCo % Non-Shopping Sales		60.46%				3,675,252,065
13	FC Component of AER Rate At Generation Level - Cents/kWh						0.10410
				Secondary	Primary	Sub/Trans	
14	FC Component of AER Rate At Generation Level			0.10410	0.10410	0.10410	
15	Loss Factor			1.0608	1.0240	1.0036	
16	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**		**0.11043**	**0.1066**	**0.10447**	

Schedule 5: This schedule reflects AEP Ohio's estimates of monthly REC costs it expected to incur during the period January through March 2013. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the first quarter of 2013, AEP Ohio projected REC costs totaling $7.532 million.

As stated in Chapter 7, commencing with the Companies' first quarterly Rider AER filing, which covered projected REC costs for the period of October through December 2012, the estimated cost for renewable energy credits ("RECs") was moved from Rider FAC to Rider AER. The Companies calculated the FC portion of the AER rate at the Generation level. This amounted to .15417 cents per kWh for CSP and .10410 cents per kWh for OPCO and was calculated by dividing the projected AER for retail load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO applied loss factors to each respective FC portion of the AER rate based on delivery voltage levels in order to derive the FC portion of the AER rate at meter level. The Companies applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of .16354, .15787 and .15473 cents per kWh for CSP and FCs of .11043, .1066 and .10447 cents per kWh for OPCO.

Exhibit 8-11
CSP and OPCO Schedule 6, January – March 2013

Schedule 6

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
January 2013 through March 2013
RA

Actual Period - July 2012 through September 2012

Line	Month	Kwh Retail Non-Shopping Sales	Renewable Revenue	Renewable Cost	AER (Over)/Under Recovery
1	Beginning Balance				
2	Jul-12	3,212,845,267	$ -	$ -	$ -
3	Aug-12	2,885,647,619	$ -	$ -	$ -
4	Sep-12	2,124,289,385	$ -	$ -	$ -
5	Ending Balance	8,222,782,271	$ -	$ -	$ -
6	Total (Over)/Under Recovery Balance				$ -
7	Loss Adjusted Retail Sales Billing Period - kWh				6,078,815,853
8	RA Component at Generation - Cents/kWh				0.00000

Line			Secondary	Primary	Sub/Trans
9			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		-	-	-
11	Loss Factor		1.0608	1.024	1.0036
12	RA at the Meter Level - Cents/kWh	Line 10 x Line 11	0.00000	0.00000	0.00000

Schedule 6: This schedule will provide for the RA component of their Rider AER. The Companies' first quarter of 2013 Rider AER filing did not yet have any REC revenue or costs, thus resulting in no RA adjustment in this filing. The Companies will calculate the RA component of its AER rate at Generation level by dividing the recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 5 section above. The RA component for this filing was zero.

Rider AER – Second Quarter 2013

On March 1, 2013, AEP Ohio submitted quarterly FAC filings, which included quarterly AER filings for CSP and OPCO based on projected data for the period April through June 2013. AEP Ohio's filing for this quarter included a submittal letter and Rider AER Schedules 4 through 6 supporting the Companies proposed calculations for CSP and OPCO.

The Companies used the same methodology described above as it relates to the format of the schedules in their initial Rider AER filing. The sections below discuss AEP Ohio's second quarter 2013 AER filings by reproducing Schedules 4 through 6, broken out separately between CSP and OPCO as Exhibits 8-8 through 8-10, and briefly summarize each schedule.

Exhibit 8-12
CSP and OPCO Schedule 4, April – June 2013

Schedule 4

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
April 2013 through June 2013
Summary - Proposed AER Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		A	B	C	D
			Schedule 5	Schedule 6	
Line	Delivery Voltage	Current AER Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.16354	0.14908	-0.05199	0.097090
2	Primary	0.15787	0.14391	-0.05018	0.093730
3	Sub/Transmission	0.15473	0.14105	-0.04918	0.091870

OHIO POWER RATE ZONE

		A	B	C	D
			Schedule 5	Schedule 6	
Line	Delivery Voltage	Current AER Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.11043	0.10067	-0.05199	0.048680
2	Primary	0.10660	0.09718	-0.05018	0.047000
3	Sub/Transmission	0.10447	0.09524	-0.04918	0.046060

Schedule 4: Column A of this schedule reflects the then current AER rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period April through June 2013. Column C will present the Companies' reconciliation adjustment ("RA") for Rider AER when it begins to apply. Column D reflects the sum of the FC and RA components.

Exhibit 8-13
CSP and OPCO Schedule 5, April – June 2013

Schedule 5

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
April 2013 through June 2013
FC Component

				Forecast Period - 2nd Quarter 2013			
Line	Description			April	May	June	Total
	TOTAL COMPANY						
1	Renewable Energy Credits			2,183,904	1,873,616	1,342,480	$ 5,400,000
2	Retail Non-Shopping Sales - Generation Level Kwh			1,477,493,015	1,623,947,956	1,679,689,410	4,781,130,382
3	COLUMBUS SOUTHERN POWER RATE ZONE						
4	CSP % for Retail Load		49.20%				$ 2,656,800
5	CSP % Non-Shopping Sales		39.54%				1,890,458,953
6	FC Component of AER Rate At Generation Level - Cents/kWh						0.14054
				Secondary	Primary	Sub/Trans	
7	FC Component of AER Rate At Generation Level			0.14054	0.14054	0.14054	
8	Loss Factor			1.0608	1.0240	1.0036	
9	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**		**0.14908**	**0.14391**	**0.14105**	
10	OHIO POWER RATE ZONE						
11	OPCo % for Retail Load		50.80%				$ 2,743,200
12	OPCo % Non-Shopping Sales		60.46%				2,890,671,429
13	FC Component of AER Rate At Generation Level - Cents/kWh						0.09490
				Secondary	Primary	Sub/Trans	
14	FC Component of AER Rate At Generation Level			0.09490	0.09490	0.09490	
15	Loss Factor			1.0608	1.0240	1.0036	
16	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**		**0.10067**	**0.09718**	**0.09524**	

Schedule 5: This schedule reflects AEP Ohio's estimates of monthly REC costs it expected to incur during the period April through June 2013. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the second quarter of 2013, AEP Ohio projected REC costs totaling $5.4 million.

The Companies calculated the FC portion of the AER rate at the Generation level. This amounted to .14054 cents per kWh for CSP and .09490 cents per kWh for OPCO and was calculated by dividing the projected AER for retail load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO applied loss factors to each respective FC portion of the AER rate based on delivery voltage levels in order to derive the FC portion of the AER rate at meter level. The Companies applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of .14908, .14391 and .14105 cents per kWh for CSP and FCs of .10067, .09718 and .09524 cents per kWh for OPCO.

Exhibit 8-14
CSP and OPCO Schedule 6, April – June 2013

Schedule 6

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
April 2013 through June 2013
RA

Line	Month	Kwh Retail Non-Shopping Sales	Renewable Revenue	Renewable Cost	AER (Over)/Under Recovery	
		Actual Period - October 2012 through December 2012				
1	**Beginning Balance**					
2	Oct-12	1,989,223,280	$ 1,680,069	$ (109,604)	$ (1,789,694)	
3	Nov-12	1,896,976,201	$ 1,437,232	$ 1,160,728	$ (276,503)	
4	Dec-12	2,045,287,888	$ 1,488,260	$ 1,211,301	$ (276,959)	
5	**Ending Balance**	5,931,487,369	$ 4,605,561	$ 2,262,425	$ (2,343,156)	
6	Total (Over)/Under Recovery Balance				$ (2,343,156)	
7	Loss Adjusted Retail Sales Billing Period - kWh				4,781,130,382	
8	RA Component at Generation - Cents/kWh				-0.04901	
9				**Secondary**	**Primary**	**Sub/Trans**
10	RA Component of FAC Rate At Generation Level			(0.04901)	(0.04901)	(0.04901)
11	Loss Factor			1.0608	1.024	1.0036
12	**RA at the Meter Level - Cents/kWh**		Line 10 x Line 11	**-0.05199**	**-0.05018**	**-0.04918**

Schedule 6: This schedule will provide for the RA component of Rider AER. This resulted in total over-recovery adjustment of $2.343 million. The Companies calculated the RA component of its AER rate at Generation level by dividing the over-recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 5 section above. The RA component for this filing was (.04901) cents per kWh. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. The application of the loss factors results in RA components of the FAC rate of (.05199), (.05018) and (.04918) cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Rider AER – Third Quarter 2013

On May 30, 2013, AEP Ohio submitted quarterly AER filings for CSP and OPCO, projected data for the period July through September 2013 and a RA component based on information from January through March 2013. AEP Ohio's filing for this quarter included a submittal letter, Schedules 4 through 6 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial AER filing. The sections below discuss AEP Ohio's third quarter 2013 AER filings by reproducing Schedules 4 through 6, broken out separately between CSP and OPCO as Exhibits 8-11 through 8-13, and then briefly summarizing each schedule.

Exhibit 8-15
CSP and OPCO Schedule 4, July – September 2013

Schedule 4

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
July 2013 through September 2013
Summary - Proposed AER Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		A	B	C	D
			Schedule 5	Schedule 6	
Line	Delivery Voltage	Current AER Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.09709	0.10060	-0.04811	0.052490
2	Primary	0.09373	0.09711	-0.04644	0.050670
3	Sub/Transmission	0.09187	0.09517	-0.04551	0.049660

OHIO POWER RATE ZONE

		A	B	C	D
			Schedule 5	Schedule 6	
Line	Delivery Voltage	Current AER Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.04868	0.06792	-0.04811	0.019810
2	Primary	0.04700	0.06557	-0.04644	0.019130
3	Sub/Transmission	0.04606	0.06426	-0.04551	0.018750

Schedule 4: Column A of this schedule reflects the then current AER rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated REC cost for the period July through September 2013. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated on Schedule 6 for the REC over or under recovery it experienced January through March 2013. Column D reflects the sum of the FC and RA components.

Exhibit 8-16
CSP and OPCO Schedule 5, July – September 2013

Schedule 5

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
July 2013 through September 2013
FC Component

Line	Description		Forecast Period - 3rd Quarter 2013 July	August	September	Total
	TOTAL COMPANY					
1	Renewable Energy Credits		1,257,213.969	1,158,205.161	1,356,698.372	$ 3,772,118
2	Retail Non-Shopping Sales - Generation Level Kwh		1,971,110,376	1,804,806,751	1,173,871,847	4,949,788,975
3	COLUMBUS SOUTHERN POWER RATE ZONE					
4	CSP % for Retail Load	49.20%				$ 1,855,882
5	CSP % Non-Shopping Sales	39.54%				1,957,146,561
6	FC Component of AER Rate At Generation Level - Cents/kWh					0.09483
			Secondary	Primary	Sub/Trans	
7	FC Component of AER Rate At Generation Level		0 09483	0 09483	0 09483	
8	Loss Factor		1.0608	1.0240	1.0036	
9	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**	**0.1006**	**0.09711**	**0.09517**	
10	OHIO POWER RATE ZONE					
11	OPCo % for Retail Load	50.80%				$ 1,916,236
12	OPCo % Non-Shopping Sales	60.46%				2,992,642,414
13	FC Component of AER Rate At Generation Level - Cents/kWh					0.06403
			Secondary	Primary	Sub/Trans	
14	FC Component of AER Rate At Generation Level		0.06403	0.06403	0 06403	
15	Loss Factor		1.0608	1.0240	1.0036	
16	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**	**0.06792**	**0.06557**	**0.06426**	

Schedule 5: This schedule reflects AEP Ohio's estimates of monthly REC costs it expected to incur during the period July through September 2013. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the third quarter of 2013, AEP Ohio projected REC costs totaling $3.772 million.

The Companies calculated the FC portion of the AER rate at the Generation level. This amounted to .09483 cents per kWh for CSP and .06403 cents per kWh for OPCO and was calculated by dividing the projected AER for retail load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the AER rate based on delivery voltage levels in order to derive the FC portion of the AER rate at meter level. The Companies applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of .1006, .09711 and .09517 cents per kWh for CSP and FCs of .06792, .06557 and .06426 cents per kWh for OPCO.

Exhibit 8-17
CSP and OPCO Schedule 6, July – September 2013

Schedule 6

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
July 2013 through September 2013
RA

			Actual Period - January 2013 through March 2013			
Line	Month	Kwh Retail Non-Shopping Sales	Renewable Revenue	Renewable Cost	AER (Over)/Under Recovery	
1	Beginning Balance				$ -	
2	Jan-13	2,109,104,449	$ 3,458,029	$ 1,805,006	$ (1,653,023)	
3	Feb-13	1,738,515,922	$ 2,550,565	$ 2,136,246	$ (414,319)	
4	Mar-13	2,067,119,583	$ 2,494,839	$ 2,317,473	$ (177,366)	
5	Ending Balance	5,914,739,954	$ 8,503,433	$ 6,258,725	$ (2,244,708)	
6	Total (Over)/Under Recovery Balance				$ (2,244,708)	
7	Loss Adjusted Retail Sales Billing Period - kWh				4,949,786,975	
8	RA Component at Generation - Cents/kWh				-0.04535	
9				Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level			(0.04535)	(0.04535)	(0.04535)
11	Loss Factor			1.0608	1.024	1.0036
12	RA at the Meter Level - Cents/kWh		Line 10 x Line 11	-0.04811	-0.04644	-0.04551

Schedule 6: This schedule represents the Companies' RA components of their third quarter 2013 AER filings. Specifically, Schedule 6 reflects the Companies' beginning cumulative balance (zero in this filing) as well as the over- or under-recovery of REC costs for each month during the period January through March 2013, which were calculated as the difference between the monthly renewable revenues for the first quarter of 2013 and the monthly renewable costs for the same period. This resulted in total over-recoveries of $2.245 million.

The Companies calculated the RA component of its AER rate at Generation level by dividing the over-recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 5 section above. The RA component for this filing was (.04535) cents per kWh. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. The application of the loss factors results in RA components of the FAC rate of (.04811), (.04644) and (.04551) cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Rider AER – Fourth Quarter 2013

On August 30, 2013, AEP Ohio submitted its quarterly AER filings, for CSP and OPCO, projected data for the period October through December 2013, and an RA component based on information from April through June 2013. AEP Ohio's filing for this quarter included a submittal letter and Schedules 4 through 6 showing the Companies' proposed Rider AER calculations for CSP and OPCO.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial AER filing. The sections below discuss AEP Ohio's fourth quarter 2013

AER filings by reproducing Schedules 4 through 6, broken out separately between CSP and OPCO as Exhibits 8-14 through 8-16.

Exhibit 8-18
CSP and OPCO Schedule 4, October – December 2013

Schedule 4

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
October 2013 through December 2013
Summary - Proposed AER Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		A	B	C	D
			Schedule 5	Schedule 6	
Line	Delivery Voltage	Current AER Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.05249	0.18562	-0.02469	0.160930
2	Primary	0.05067	0.17918	-0.02383	0.155350
3	Sub/Transmission	0.04966	0.17561	-0.02335	0.152260

OHIO POWER RATE ZONE

		A	B	C	D
			Schedule 5	Schedule 6	
Line	Delivery Voltage	Current AER Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.01981	0.12533	-0.02469	0.100640
2	Primary	0.01913	0.12099	-0.02383	0.097160
3	Sub/Transmission	0.01875	0.11858	-0.02335	0.095230

Schedule 4: Column A of this schedule reflects the then current AER rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated REC cost for the period October through December 2013. Column C presents the Companies' reconciliation adjustment ("RA"), which is calculated based on information for April through June 2013. Column D reflects the sum of the FC and RA components.

Exhibit 8-19
CSP and OPCO Schedule 5, October – December 2013

Schedule 5

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
October 2013 through December 2013
FC Component

Line	Description		Forecast Period - 4th Quarter 2013 October	November	December		Total
	TOTAL COMPANY						
1	Renewable Energy Credits		1,882,085 290	2,036,317.983	2,187,207.998	$	6,105,611
2	Retail Non-Shopping Sales - Generation Level Kwh		1,361,404,187	1,379,474,628	1,600,964,607		4,341,843,423
3	**COLUMBUS SOUTHERN POWER RATE ZONE**						
4	CSP % for Retail Load	49.20%				$	3.003,961
5	CSP % Non-Shopping Sales	39.54%					1,716.764,889
6	FC Component of AER Rate At Generation Level - Cents/kWh						0.17498
			Secondary	Primary	Sub/Trans		
7	FC Component of AER Rate At Generation Level		0.17498	0.17498	0.17498		
8	Loss Factor		1.0608	1.0240	1.0036		
9	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**	**0.18562**	**0.17918**	**0.17561**		
10	**OHIO POWER RATE ZONE**						
11	OPCo % for Retail Load	50.80%				$	3,101,651
12	OPCo % Non-Shopping Sales	60.46%					2,625,078,533
13	FC Component of AER Rate At Generation Level - Cents/kWh						0.11815
			Secondary	Primary	Sub/Trans		
14	FC Component of AER Rate At Generation Level		0.11815	0.11815	0.11815		
15	Loss Factor		1.0608	1.0240	1.0036		
16	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**	**0.12533**	**0.12099**	**0.11858**		

Schedule 5: This schedule reflects AEP Ohio's estimates of monthly REC costs it expected to incur during the period October through December 2013. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the fourth quarter of 2013, AEP Ohio has projected REC costs totaling $6.106 million.

The Companies calculated the FC portion of the AER rate at the Generation level. This amounted to .17498 cents per kWh for CSP and .11815 cents per kWh for OPCO and was calculated by dividing the projected AER for retail load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO applied loss factors to each respective FC portion of the AER rate based on delivery voltage levels in order to derive the FC portion of the AER rate at meter level. The Companies applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of .18562, .17918 and .17561 cents per kWh for CSP and FCs of .12533, .12099 and .11858 cents per kWh for OPCO.

Exhibit 8-20
CSP and OPCO Schedule 6, October – December 2013

Schedule 6

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
October 2013 through December 2013
RA

		Actual Period - April 2013 through June 2013			
Line	Month	Kwh Retail Non-Shopping Sales	Renewable Revenue	Renewable Cost	AER (Over)/Under Recovery
1	**Beginning Balance**				$ (2,343,156)
2	Apr-13	1,455,403,298	$ 715,037	$ 679,490	$ (35,547)
3	May-13	1,524,949,161	$ 979,406	$ 1,648,129	$ 668,723
4	Jun-13	1,600,225,281	$ 1,176,496	$ 1,876,093	$ 699,597
5	**Ending Balance**	4,580,577,740	$ 2,870,939	$ 4,203,712	$ (1,010,383)
6	Total (Over)/Under Recovery Balance				$ (1,010,383)
7	Loss Adjusted Retail Sales Billing Period - kWh				4,341,843,423
8	RA Component at Generation - Cents/kWh				-0.02327

Line			Secondary	Primary	Sub/Trans
9			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		(0.02327)	(0.02327)	(0.02327)
11	Loss Factor		1.0608	1.024	1.0036
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**-0.02469**	**-0.02383**	**-0.02335**

Schedule 6: This schedule represents the Companies' RA components of their fourth quarter 2013 AER filings. Specifically, Schedule 6 reflects the Companies' beginning cumulative over-recovered balance as well as the under/over-recovery of REC costs for each month during the period April through June 2013, which were calculated as the difference between the monthly renewable revenues for the second quarter of 2013 and the monthly renewable costs for the same period. This resulted in total over-recoveries of $1.010 million.

The Companies calculated the RA component of its AER rate at Generation level by dividing the over-recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 5 section above. The RA component for this filing was (.02327) cents per kWh. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. The application of the loss factors results in RA components of the FAC rate of (.02469), (.02383) and (.02335) cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Rider AER – First Quarter 2014

On November 27, 2013, AEP Ohio submitted its first Alternative Energy Rider ("AER") quarterly filing, for CSP and OPCO, which reflected projected data for the period January through March 2014 and an RA component based on information from July through September 2013. AEP Ohio's filing for this quarter included a submittal letter and Schedules 4 through 6 supporting the Companies proposed calculations for CSP and OPCO.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial AER filing. The sections below discuss AEP Ohio's first quarter 2014

AER filings by reproducing Schedules 4 through 6, broken out separately between CSP and OPCO as Exhibits 8-17 through 8-19.

Exhibit 8-21
CSP and OPCO Schedule 4, January – March 2014

Schedule 4

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
January 2014 through March 2014
Summary - Proposed AER Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		A	B	C	D
			Schedule 5	Schedule 6	
Line	Delivery Voltage	Current AER Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.16093	0.18562	0.07605	0.261670
2	Primary	0.15535	0.17918	0.07341	0.252590
3	Sub/Transmission	0.15226	0.17561	0.07195	0.247560

OHIO POWER RATE ZONE

		A	B	C	D
			Schedule 5	Schedule 6	
Line	Delivery Voltage	Current AER Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.10064	0.12533	0.07605	0.201380
2	Primary	0.09716	0.12099	0.07341	0.194400
3	Sub/Transmission	0.09523	0.11858	0.07195	0.190530

Schedule 4: Column A of this schedule reflects the then current AER rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated REC cost for the period January through March 2014. Column C presents the Companies' reconciliation adjustment ("RA"), which is calculated based on information for July through September 2013. Column D reflects the sum of the FC and RA components.

Exhibit 8-22
CSP and OPCO Schedule 5, January – March 2014

Schedule 5

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
January 2014 through March 2014
FC Component

Line	Description			Forecast Period - 1st Quarter 2014			Total
				January	February	March	
	TOTAL COMPANY						
1	Renewable Energy Credits			1,882,085.290	2,036,317.983	2,187,207.998	$ 6,105,611
2	Retail Non-Shopping Sales - Generation Level Kwh			1,361,404,187	1,379,474,628	1,600,964,607	4,341,843,423
3	COLUMBUS SOUTHERN POWER RATE ZONE						
4	CSP % for Retail Load		49.20%				$ 3,003,961
5	CSP % Non-Shopping Sales		39.54%				1,716,764,889
6	FC Component of AER Rate At Generation Level - Cents/kWh						0.17498
				Secondary	Primary	Sub/Trans	
7	FC Component of AER Rate At Generation Level			0.17498	0.17498	0.17498	
8	Loss Factor			1.0608	1.0240	1.0036	
9	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**		**0.18562**	**0.17918**	**0.17561**	
10	OHIO POWER RATE ZONE						
11	OPCo % for Retail Load		50.80%				$ 3,101,651
12	OPCo % Non-Shopping Sales		60.46%				2,625,078,533
13	FC Component of AER Rate At Generation Level - Cents/kWh						0.11815
				Secondary	Primary	Sub/Trans	
14	FC Component of AER Rate At Generation Level			0.11815	0.11815	0.11815	
15	Loss Factor			1.0608	1.0240	1.0036	
16	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**		**0.12533**	**0.12099**	**0.11858**	

Schedule 5: This schedule reflects AEP Ohio's estimates of monthly REC costs it expected to incur during the period January through March 2014. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the first quarter of 2014, AEP Ohio has projected REC costs totaling $6.106 million.

The Companies calculated the FC portion of the AER rate at the Generation level. This amounted to .17498 cents per kWh for CSP and .11815 cents per kWh for OPCO and was calculated by dividing the projected AER for retail load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO applied loss factors to each respective FC portion of the AER rate based on delivery voltage levels in order to derive the FC portion of the AER rate at meter level. The Companies applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of .18562, .17918 and .17561 cents per kWh for CSP and FCs of .12533, .12099 and .11858 cents per kWh for OPCO.

Exhibit 8-23
CSP and OPCO Schedule 6, January – March 2014

Schedule 6

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
January 2014 through March 2014
RA

			Actual Period - July 2013 through September 2013			
Line	Month	Kwh Retail Non-Shopping Sales	Renewable Revenue	Renewable Cost	AER (Over)/Under Recovery	
1	**Beginning Balance**				$ (2,244,708)	
2	Jul-13	1,816,710,057	$ 427,316	$ 1,751,155	$ 1,323,839	
3	Aug-13	1,569,920,404	$ 512,291	$ 2,268,994	$ 1,756,703	
4	Sep-13	1,352,755,407	$ 441,513	$ 2,718,362	$ 2,276,849	
5	**Ending Balance**	4,739,385,868	$ 1,381,120	$ 6,738,511	$ 3,112,683	
6	Total (Over)/Under Recovery Balance				$ 3,112,683	
7	Loss Adjusted Retail Sales Billing Period - kWh				4,341,843,423	
8	RA Component at Generation - Cents/kWh				0.07169	
9				Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level			0.07169	0.07169	0.07169
11	Loss Factor			1.0608	1.024	1.0036
12	**RA at the Meter Level - Cents/kWh**		Line 10 x Line 11	**0.07605**	**0.07341**	**0.07195**

Schedule 6: This schedule represents the Companies' RA components of their first quarter 2014 AER filings. Specifically, Schedule 6 reflects the Companies' beginning over-recovered balance as well as the under/over-recovery of REC expenses for each month during the period July through September 2013, which were calculated as the difference between the monthly renewable revenues for the third quarter of 2013 and the monthly renewable costs for the same period. This resulted in total over-recoveries of $3.113 million.

The Companies calculated the RA component of its AER rate at Generation level by dividing the recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 5 section above. The RA component for this filing was .07169 cents per kWh. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. The application of the loss factors results in RA components of the FAC rate of (.07605), (.07341) and (.07195) cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Rider AER – Second Quarter 2014

On March 3, 2014, AEP Ohio submitted its AER quarterly filing, for CSP and OPCO, which reflected projected data for the period April through May 2014 and an RA component based on information from October through December 2013. AEP Ohio's filing for this quarter included a submittal letter and Schedules 4 through 6 supporting the Companies proposed calculations for CSP and OPCO.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial AER filing. The sections below discuss AEP Ohio's second quarter 2014 AER filings by reproducing Schedules 4 through 6, broken out separately between CSP and OPCO as Exhibits 8-20 through 8-22.

Exhibit 8-24
CSP and OPCO Schedule 4, April – June 2014

Schedule 4

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
April 2014 through June 2014
Summary - Proposed AER Rate

COLUMBUS SOUTHERN POWER RATE ZONE

		A	B	C	D
			Schedule 5	Schedule 6	
Line	Delivery Voltage	Current AER Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	0.26167	0.23863	-0.01109	0.227540
2	Primary	0.25259	0.23035	-0.01071	0.219640
3	Sub/Transmission	0.24756	0.22576	-0.01049	0.215270

OHIO POWER RATE ZONE

		A	B	C	D
			Schedule 5	Schedule 6	
Line	Delivery *Voltage*	Current AER Rate	Forecast (FC) *Component*	Reconciliation (RA) *Adjustment Comp.*	Total of FC and RA *Components*
1	Secondary	0.20138	0.16114	-0.01109	0.150050
2	Primary	0.19440	0.15555	-0.01071	0.144840
3	Sub/Transmission	0.19053	0.15245	-0.01049	0.141960

Schedule 4: Column A of this schedule reflects the then current AER rate by delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated REC cost for the period April through June 2014. Column C presents the Companies' reconciliation adjustment ("RA"), which is calculated based on information for October through December 2013. Column D reflects the sum of the FC and RA components.

Exhibit 8-25
CSP and OPCO Schedule 5, April – June 2014

Schedule 5

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
April 2014 through June 2014
FC Component

Line	Description			Forecast Period - 2nd Quarter 2014			Total
				April	May	June	
	TOTAL COMPANY						
1	Renewable Energy Credits			2,100,000	2,100,000	2,100,000	$ 6,300,000
2	Retail Non-Shopping Sales - Generation Level Kwh			1,025,761,491	1,150,409,085	1,308,681,024	3,484,851,600
3	COLUMBUS SOUTHERN POWER RATE ZONE						
4	CSP % for Retail Load		49.20%				$ 3,099,600
5	CSP % Non-Shopping Sales		39 54%				1,377,910,323
6	FC Component of AER Rate At Generation Level - Cents/kWh						0.22495
				Secondary	Primary	Sub/Trans	
7	FC Component of AER Rate At Generation Level			0.22495	0.22495	0.22495	
8	Loss Factor			1.0608	1.0240	1.0036	
9	**FC at the Meter Level - Cents/kWh**	**Line 17 x Line 18**		**0.23863**	**0.23035**	**0.22576**	
10	OHIO POWER RATE ZONE						
11	OPCo % for Retail Load		50.80%				$ 3,200,400
12	OPCo % Non-Shopping Sales		60.46%				2,106,941,277
13							0 15190
				Secondary	Primary	Sub/Trans	
14	FC Component of AER Rate At Generation Level			0.15190	0.15190	0.15190	
15	Loss Factor			1.0608	1.0240	1.0036	
16	**FC at the Meter Level - Cents/kWh**	**Line 23 x Line 24**		**0.16114**	**0.15555**	**0.15245**	

Schedule 5: This schedule reflects AEP Ohio's estimates of monthly REC costs it expected to incur during the period April through June 2014. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the second quarter of 2014, AEP Ohio has projected REC costs totaling $6.3 million.

The Companies calculated the FC portion of the AER rate at the Generation level. This amounted to .22495 cents per kWh for CSP and .15190 cents per kWh for OPCO and was calculated by dividing the projected AER for retail load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO applied loss factors to each respective FC portion of the AER rate based on delivery voltage levels in order to derive the FC portion of the AER rate at meter level. The Companies applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FCs of .23863, .23035 and .22576 cents per kWh for CSP and FCs of .16114, .15555 and .15245 cents per kWh for OPCO.

Exhibit 8-26
CSP and OPCO Schedule 6, April – June 2014

Schedule 6

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly AER For Billing During
April 2014 through June 2014
RA

			Actual Period - October 2013 through December 2013			
Line	Month	Kwh Retail Non-Shopping Sales	Renewable Revenue	Renewable Cost	AER (Over)/Under Recovery	
1	**Beginning Balance**				$ (1,010,383)	
2	Oct-13	1,136,792,592	$ 2,035,424	$ 2,087,094	$ 51,670	
3	Nov-13	1,239,197,737	$ 1,605,527	$ 2,248,291	$ 642,764	
4	Dec-13	1,539,913,698	$ 2,021,133	$ 1,972,692	$ (48,441)	
5	**Ending Balance**	3,915,904,027	$ 5,662,084	$ 6,308,077	$ (364,390)	
6	Total (Over)/Under Recovery Balance				$ (364,390)	
7	Loss Adjusted Retail Sales Billing Period - kWh				3,484,851,600	
8	RA Component at Generation - Cents/kWh				-0.01046	
9				Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level			(0.01046)	(0.01046)	(0.01046)
11	Loss Factor			1.0608	1.024	1.0036
12	**RA at the Meter Level - Cents/kWh**		Line 10 x Line 11	**-0.01109**	**-0.01071**	**-0.01049**

Schedule 6: This schedule represents the Companies' RA components of their second quarter 2014 AER filings. Specifically, Schedule 6 reflects the Companies' beginning over-recovered balance as well as the under/over-recovery of REC expenses for each month during the period October through December 2013, which were calculated as the difference between the monthly renewable revenues for the fourth quarter of 2013 and the monthly renewable costs for the same period. This resulted in total over-recoveries of $364,390.

The Companies calculated the RA component of its AER rate at Generation level by dividing the recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 5 section above. The RA component for this filing was (.01046) cents per kWh. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. The application of the loss factors results in RA components of the FAC rate of (.01109), (.01071) and (.01049) cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Minimum Review Requirements

As noted above, 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.

Those Standards provides for the following Minimum Review Requirements:

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;*

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 AEP Ohio a series of questions pertaining to its renewable energy purchases and RECs from data requests LA-2012/2013-1-65 through LA-2012/2013-1-92.

Carrying Charges

RFP No. U13-FPP/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 AEP Ohio 2012 and 2013 quarterly AER filings, there were no carrying charges.

Status Relative to the 3% Provision in Section, 4928.64(C)(3), Revised Code

RFP No. U13-FPP/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:

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.

AEP Ohio provided its confidential Annual Compliance Plan Status Reports for 2012 and 2013 in the response to EVA-2012/2013-4-2. The Company's 2012 compliance report stated that OPCO achieved compliance by meeting the 2012 benchmark for the Ohio Alternative Energy Portfolio Standard for both solar and non-solar renewables. Specifically, as it relates to AEP Ohio's non-solar renewables, the 2012 compliance report stated in part:

Non-Solar achievement was met through REC purchases, a renewable energy purchase agreement with wind as the renewable energy resource, the OPCo customer Renewable Energy Technology program, and OPCo biomass and biodiesel co-firing for the In-State Benchmark, while the additional non-Solar Benchmark was achieved through a renewable energy purchase agreement with wind as the renewable energy resource.

As it relates to AEP Ohio's solar renewables, the compliance stated in part:

Solar achievement was met through OPCo facilities, the OPCo customer REC Purchase and Renewable Energy Technology programs, and an In-State renewable energy purchase agreement for the In-State Benchmark, while the additional Solar Benchmark was met through adjacent-State REC purchases.

A summary of AEP Ohio's compliance with the 2012 renewable energy benchmark is provided in the exhibit below.

Exhibit 8-27
Summary of AEP Ohio's Compliance with the 2012 Renewable Energy Benchmark

	Compliance Year 2012 Summary			
Line No.	Year	MWH Sales Unadjusted	Proposed Adjustments	MWH Sales Adjusted
1	2009	45,466,718	4,104,903	41,361,815
2	2010	46,808,205	4,029,891	42,778,314
3	2011	43,707,876	6,166,126	37,541,750
4	Basis for 2012 Compliance Obligation			40,560,626
	2012 Statutory Compliance Obligation			
5	2012 Non-Solar renewable benchmark			1.44%
6	2012 Solar renewable benchmark			0.06%
7	Total 2012 renewable benchmark			1.50%
	2012 Compliance Obligation			
8	Non-Solar MWHs needed for complia			584,073
9	Minimum required from Ohio facilities			292,037
10	Solar MWHs needed for compliance			24,336
11	Minimum required from Ohio facilities			12,168
	Under Compliance in 2012			
12	Non-Solar MWHs			0
13	Solar MWHs			0
	2012 Alternative Compliance Payments			
14	Non-Solar, per MWH			$ 47.56
15	Solar, per MWH			$ 350.00
	2012 Payments			
16	Non-Solar Total			$ -
17	Solar Total			$ -

As shown in the exhibit, the Company met the 1.50% renewable energy benchmark for 2012, in which 1.44% related to the non-solar renewable benchmark and .06% related to the solar renewable benchmark.

The Company's 2013 compliance report stated that OPCO achieved compliance by meeting the 2013 benchmark for the Ohio Alternative Energy Portfolio Standard for both solar and non-solar renewables. With the exception of 2013 compliance not including the biomass co-firing for the In-State Benchmark, AEP Ohio's solar and non-solar compliance was met in the same manner as that described in the 2012 compliance report.

A summary of AEP Ohio's compliance with the 2013 renewable energy benchmark is provided in the exhibit below.

Exhibit 8-28
Summary of AEP Ohio's Compliance with the 2013 Renewable Energy Benchmark

	Compliance Year 2013 Summary			
Line No.	Year	MWH Sales Unadjusted	Proposed Adjustments	MWH Sales Adjusted
1	2010	46,808,205	4,029,891	42,778,314
2	2011	43,707,876	6,166,126	37,541,750
3	2012	31,585,376	5,866,596	25,718,780
4	Basis for 2013 Compliance Obligation			35,346,281
	2013 Statutory Compliance Obligation			
5	2013 Non-Solar renewable benchmark			1.91%
6	2013 Solar renewable benchmark			0.09%
7	Total 2013 renewable benchmark			2.00%
	2013 Compliance Obligation			
8	Non-Solar MWHs needed for complia			675,114
9	Minimum required from Ohio facilities			337,557
10	Solar MWHs needed for compliance			31,812
11	Minimum required from Ohio facilities			15,906
	Under Compliance in 2013			
12	Non-Solar MWHs			0
13	Solar MWHs			0
	2013 Alternative Compliance Payments			
14	Non-Solar, per MWH			$ 48.56
15	Solar, per MWH			$ 350.00
	2013 Payments			
16	Non-Solar Total			$ -
17	Solar Total			$ -

As shown in the exhibit, the Company met the 2.00% renewable energy benchmark for 2013, in which 1.91% related to the non-solar renewable benchmark and .09% related to the solar renewable benchmark.

Both the 2012 and 2013 compliance reports concluded by stating that OPCO was compliant with the solar and non-solar benchmarks and that achievement of this compliance was based on actual RECs achieved in solar and non-solar. In addition, OPCO's 2012 and 2013 compliance year RECs were transferred to OPCO's GATS reserve subaccount.

REC Inventories

Larkin inquired as to whether AEP-Ohio maintains more than one REC inventory and if so, to describe the purpose of each. In response to LA-2012/2013-1-68, the Company stated that it maintains the following three REC inventories:

- Solar RECs that were used during all of 2012 and 2013.
- Non-solar, non-Ohio RECs which have been used since accounting for the AER commenced on October 1, 2012.
- Non-solar, Ohio generated RECs which have been used since accounting for the AER commenced on October 1, 2012.

In its response to LA-2012/2013-1-67, AEP-Ohio stated that its Accounting Department maintains an inventory system for its RECs. In addition, AEP-Ohio provided its monthly REC inventory balances which is reflected in the exhibit below.

Exhibit 8-29
Monthly REC Inventory for 2012 and 2013

[redacted]

As shown in the above table, prior to October 2012, the Company had maintained an inventory of the quantities of non-solar, non-Ohio RECs but had reflected [redacted]

LA-2012/2013-1-69 asked whether the Company participates in any speculative REC purchases utilizing below-the-line shareholder funds and if so, to describe the procurement and inventory methodologies used to account for such RECs. In response, AEP Ohio stated that OPCO has not made any speculative REC purchases.

As it relates to maintaining REC inventory, LA-2012/2013-1-70 requested that AEP Ohio provide the following:

(a) Whether the Company relies on any particular accounting guidance for how items are entered into or extracted from REC inventory, and if so, to describe such guidance.

    Response: AEP-Ohio stated that since 2009, OPCO has used the framework for the accounting for emission allowances as the basis for accounting for the RECs necessary to meet OPCO's obligations under Ohio's Renewable Portfolio Standards. In addition, separate inventories are maintained for specific REC obligations.

(b) Describe the kinds of costs, other than REC purchase costs, that are included in REC inventory.

    Response: Only related costs to purchase RECs are included in REC inventories.

(c) Indicate the value at which RECs are entered into inventory if they are generated by AEP Ohio, and if other than zero, to describe the methodology used for determining the value.

    Response: Beginning with the implementation of the AER in September 2012, only an incremental renewable value of RECs generated from biodiesel is included in Ohio non-solar REC inventory. In addition, only a small number of biodiesel RECs have been created.

(d) Indicate the value at which RECs are entered into inventory if they are purchased as part of a bundled energy transaction.

    Response: Prior to the implementation of the AER in September 2012, the prorated renewable value of solar RECs, as part of a bundled energy purchase, were included in solar REC inventory expense. With respect to wind purchases during that period, no value was associated with RECs received due to the market for RECs being immature at the time AEP-Ohio entered into that Purchase Power Agreement ("PPA").

    As for REC values associated with bundled energy purchases, as of September 2012, the Company began using a residual method to value the RECs for REC inventory expense purposes. AEP-Ohio stated that this method is consistent with OPCO's AER testimony with respect to how REC values would be determined. The residual value method is calculated as follows:

    REC Value = Total bundled price less energy and capacity values.

(e) Explain when RECs are considered consumed or surrendered and when the costs appear in the Company's rates.

    Response: AEP Ohio stated that RECs are considered consumed or expensed when the obligation has been incurred using accrual accounting. Upon the RECs being expensed, that cost is included for cost recovery under either the FAC or the AER.

REC Costs Included in Rider FAC

LA-2012/2013-1-71 asked AEP Ohio to identify all specific costs, by amount and account, in REC inventory that were charged to FAC-includable accounts during 2012 and 2013. As summarized in the exhibit below, [redacted]

Exhibit 8-30
REC Inventory Costs for 2012 and 2013

[redacted]

Upon reviewing the monthly FAC filing workbooks provided in the response to LA-2012/2013-1-47, Larkin verified that the [redacted] in the response to LA-2012/2013-1-71, [redacted]

69 [redacted]

Exhibit 8-31
Monthly REC Inventory Costs Included in Account No. 5570009 for 2012 and 2013

[redacted]

Determination of REC Values

Larkin requested that AEP-Ohio show in detail how non-solar RECs were valued during 2012 and 2013 and to identify and provide all accounting policies and procedures in effect during 2012 and 2013 as it relates to valuing RECs. In response to LA-2012/2013-1-72, AEP-Ohio provided Confidential Attachment 2, which is an intercompany memo that discusses the accounting treatment of RECs upon the AER being implemented effective October 2012. Specifically, this intercompany memo stated in part:

[redacted]

[redacted]

[redacted]

[70] FASB Accounting Standards Codification Topic 980 - Regulated Operations.

[redacted]

[redacted] RECs

The response to LA-2012/2013-1-72 also included Confidential Attachment 1, which reflected the Companies' determination of REC values for the [redacted] and [redacted]. AEP-Ohio stated that it made bundled purchases[71] from [redacted] during 2012 and 2013, but commenced assigning a value to the REC component upon the implementation of AER accounting beginning in October 2012. [redacted] commenced operations in January 2013 and purchases from that facility were also unbundled into separate components (see additional discussion below), to determine the REC values. The exhibit below summarizes the valuation of the [redacted] RECs.

[71] Bundled purchases are comprised of energy, capacity and REC components.

Exhibit 8-32
[redacted] REC Values

[redacted]

As shown in the exhibit above, AEP-Ohio used capacity rates of $16.46/ MW-day from October 2012 through May 2013 and $27.73/MW-day from June through December 2013[72].

We found that AEP Ohio's use of energy values and of the MW's attributable to capacity were reasonableThe Commission's findings in Case No. 10-2929-EL-UNC and testimony submitted by AEP Ohio in that docket and elsewhere presented reasons why the PJM RPM capacity auction pricing results for the periods encompassing the 2012 and 2013 periods were unrealistically low and were not compensatory or representative of AEP Ohio's capacity costs.

In Case No. 10-2929-EL-UNC, *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company,* capacity costs were addressed. Witnesses for AEP Ohio presented testimony concerning why the PJM capacity

[72] A footnote on Confidential Attachment 1from LA-2-12/2-13-1-72 indicates the following with respect to the $16.46 and $27.73 capacity rates used by AEP-Ohio: RPM BRA Clearing Price (PJM's Base Residual Auction for Reliability Pricing Model).

prices set in PJM's Reliability Pricing Model (RPM) auctions were extremely low for the periods June 2012 through May 2013 and June 2013 through May 2014, and how the PJM RPM prices for capacity were not compensatory or representative of AEP Ohio's capacity costs, and why such rates were unrealistically low, and, if used, would create problems such as introducing uneconomic bypass opportunities for CRES providers. Additionally, it was pointed out that AEP Ohio's circumstances as a holder of Fixed Resource Requirements ("FRR") obligations as a member of PJM reflected the embedded (fully allocated accounting) costs of the assets that AEP Ohio must hold under its FRR requirement obligations, rather than the capacity prices set in PJM's RPM auctions.[73] In Case No. 10-2929-EL-UNC, for example, AEP Ohio claimed that using capacity prices set in PJM's RPM auctions

> *. . .would simply involve the sale of AEP Ohio's capacity at a discounting, subsidizing CRES providers at the expense of AEP Ohio which would be taking a loss on the resale of their existing capacity (potentially reallocating those shortfalls to non-shopping AEP Ohio customers). In essence, it would be an uneconomic bypass, not efficiency gains from true competition.*[74]

Other witnesses for AEP Ohio explained how the development of the FRR as an alternative to the RPM was driven largely by AEP, and ultimately how FERC had agreed that it was not necessary or appropriate to force utilities such as AEP to participate in the RPM auction. As described in the Direct Testimony of AEP Ohio witness Dana Horton (at page 8) FERC's April 20, 2006 Initial Order, paragraph 110 stated that: "We agree with AEP that LSEs and states should have the option of choosing an alternative to the forward procurement auction if they identify sufficient capacity to meet their loads...." Rules were accordingly developed that enabled utilities such as AEP Ohio to meet its capacity obligations through the use of its own generation (including bilateral arrangements) and to maintain reserve margins established by the PJM planning process rather than through the PJM auction process. As pointed out by AEP Ohio witness William Klum, the three-year time horizon used in the PJM RPM process "is inconsistent with the fundamental conventions of generation finance" (p.4) and "the term of the RPM is simply too short to be used by investors (both debt and equity) as a mechanism for financing new construction." (p.5). Testimony filed by AEP Ohio witness Kelly Pearce supported a capacity rate as high as $355.72/MW-day (without an energy credit) and $338.14/MW-day reflecting an energy credit using AEP Ohio's proposed methodology.[75] The Commission's July 2, 2012 Opinion and Order in Case No. 10-2929-EL-UNC at page 36 ultimately found "... that a capacity charge of $188.88/MW-day is just, reasonable, and should be adopted." The Commission concluded that the $188.88 rate "should reasonably and fairly compensate the Company and should not significantly undermine the Company's ability to earn an adequate return on its investment."[76] Moreover,

> *... by adopting a cost-based state compensation mechanism for AEP Ohio, with a capacity charge of $188.88/MW-day, in conjunction with the authorized deferral of the Company's incurred capacity costs, to the extent that the total incurred capacity costs do*

[73] See, e.g., AEP Ohio Direct Testimony filed August 31, 2011 in Case No. 10-2929-EL-UNC.
[74] See, e.g., AEP Ohio Direct Testimony of Frank Graves, page 10, lines 9-14, in Case No. 10-2929-EL-UNC. Testimony by other AEP Ohio witnesses made similar points.
[75] See, e.g., AEP Ohio Direct Testimony of Kelly Pearce filed September 13, 2011 in Case Nos. 10-2376-EL-UNC/10-2929-EL-UNC et al., at pages 9-10.
[76] Commission's July 2, 2012 Opinion and Order in Case No. 10-2929-EL-UNC at page 36.

> *not exceed $188.88/MW-day not recovered from CRES provider billings reflecting the adjusted RPM-based price, we have accomplished those objectives, while also protecting the interests of all stakeholders.*[77]

Based on all of the foregoing and a review of the evidence presented concerning AEP Ohio's capacity costs in 10-2929-EL-UNC among other proceedings, we believe that the $188.88/MW-day capacity cost should also be applied to AEP Ohio's wind REPAs for purposes of ascertaining the REC values of such renewables purchases using the residual method.

Larkin prepared a similar REC valuation schedule for [redacted], but used a capacity rate of $188.88/MW-day. This capacity rate was found to be just and reasonable by the Commission in its Opinion and Order dated July 2, 2012 in Case No. 10-2929-EL-UNC. Specifically, on page 36 of its Opinion and Order, the Commission stated in part:

> *Accordingly, we adopt Staff's proposed energy credit, as modified above to account for AEP-Ohio's full requirements contract with Wheeling Power Company, and find that a capacity charge of $188.88/MW-day is just, reasonable, and should be adopted...The Commission believes that, by adopting a cost-based state compensation mechanism for AEP-Ohio, with a capacity charge of $188.88/MW-day, in conjunction with the authorized deferral of the Company's incurred capacity costs, to the extent that the total incurred capacity costs do not exceed $188.88/MW-day not recovered from CRES provider billings reflecting the adjusted RPM-based price, we have accomplished those objectives, while also protecting the interests of all stakeholders.*

The exhibit below reflects Larkin's valuation of the [redacted] RECs using the $188.88/MW-day capacity rate.

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[77] Id.

Exhibit 8-33
[redacted] REC Values Recomputed Using $188.88/MW-Day Capacity Cost

[redacted]

The effect of using the Commission ordered capacity rate of $188.88/MW-day results in a shifting of costs associated with [redacted] from the AER to the FAC in the amounts of [redacted], before considering the changes in beginning and ending REC inventory, as shown in the exhibit below.

Exhibit 8-34
Effect of Using Commission Ordered Capacity Rate

[redacted]

The response to LA-2012/2013-1-74 stated [redacted] is the Company's sole source of non-Ohio non-solar renewable energy and that prior to AER accounting being implemented in October 2012, the [redacted] REC values were not unbundled, i.e., the entire bundled cost was recorded to a purchase power account that was recovered through the FAC. With the implementation of the AER, the [redacted] purchases were unbundled at which time the REC component was assigned to a new non-Ohio, non-solar REC inventory account. The effect of Larkin using the Commission ordered capacity rate of $188.88/MW-day reduced AEP-Ohio's ending REC inventory balances [redacted].

Exhibit 8-35
[redacted] *Inventory Summary*

[redacted]

[redacted] RECs

As stated above, [redacted] did not begin operations until January 2013 and the costs associated with that REPA were unbundled into separate components in a manner similar to [redacted] as shown in the exhibit below.

Exhibit 8-36
[redacted] REC Value per AEP-Ohio

[redacted]

As shown in the exhibit above, for [redacted], AEP-Ohio used the capacity rates of \$16.46/MW-day from January through May 2013 and \$27.73/MW-day from June through December 2013, based on PJM RPM auction prices applicable during those periods. Similar to [redacted], and as shown in the exhibit below, Larkin prepared a similar REC valuation schedule for [redacted] using the capacity rate of \$188.88/MW-day that was found to be just and reasonable by the Commission in its Opinion and Order in Case No. 10-2929-EL-UNC.

Exhibit 8-37
[redacted] REC Values Recomputed Using \$188.88/MW-Day Capacity Cost

[redacted]

Similar to [redacted] the effect of using the Commission ordered capacity rate of \$188.88/MW-day results in a shifting of costs associated with [redacted] from the AER to the FAC in the amount of [redacted]

Exhibit 8-38
Effect of Using \$188.88/MW-Day Capacity Cost

[redacted]

Larkin asked that AEP-Ohio explain in detail the monthly position of CSP and OPCO as it relates to Ohio non-solar REC for each month of 2012 and 2013, and whether the Companies were in a short position throughout 2012 and 2013 with respect to non-solar RECs. In addition, Larkin asked whether the Companies anticipate fulfilling their 2012 and 2013 obligations for Ohio non-solar RECs from purchases made during the first quarters of 2013 and 2014. In response to LA-2012/2013-1-79, AEP-Ohio stated in part:

> *Prior to AER accounting implemented in October 2012, the Company's monthly position in Non-Solar Ohio-generated RECs was short. The Confidential Attachment LA-2012-13-079.pdf provides the Non-Solar Ohio-Generated REC activity during the AER accounting period. As shown, the Company had a long position in four months only, May 2013 through August 2013. An ending inventory of zero indicates a short position. As required by accrual accounting, in any month where the Company would be short, an accrued purchase was recorded to allow consumption but not permit the inventory to go negative. Accrued purchases are reduced in months where acquisitions exceed consumption. The Company's 2013 year-end short position will be fulfilled from purchases made during the first quarter of 2014.*

The exhibit below reflects the Company's long position from May through August 2013 as stated in the passage above. As also shown in the exhibit, the effect of using the Commission ordered capacity rate of $188.88/MW-day reduced AEP-Ohio's ending REC inventory balances for [redacted] in the amount of [redacted]:

Exhibit 8-39
Effect of Using $188.88/MW-Day Capacity Cost

[redacted]

[redacted] Solar RECs

Similar to the non-solar RECs, Larkin also requested that AEP-Ohio show in detail how its solar RECs were valued during 2012 and 2013. In response to LA-2012/2013-4-12, the Company provided a confidential attachment which reflected the valuation of the [redacted] solar RECs during 2012 and 2013, which are reproduced in the exhibit below.

Exhibit 8-40
[redacted] REC Values per AEP-Ohio

[redacted]

As shown in the exhibit above, for [redacted], AEP-Ohio used the capacity rates of \$16.46/MW-day from October 2012 through May 2013 and \$27.73/MW-day from June through December 2013, based on the PJM RPM capacity auction results applicable during those periods. Similar to [redacted], as shown in the exhibit below, Larkin prepared a similar REC valuation schedule for [redacted] using the capacity rate of \$188.88/MW-day that was found to be just and reasonable by the Commission in its Opinion and Order in Case No. 10-2929-EL-UNC.

Exhibit 8-41
[redacted] [redacted] REC Values Using $188.88/MW-Day Capacity Cost

[redacted]

The effect of using the Commission ordered capacity rate of $188.88/MW-day results in a shifting of costs associated with [redacted] [redacted] from the AER to the FAC in the amounts of [redacted], respectively, before accounting for beginning and ending REC inventory cost impacts, as shown in the exhibit below.

Exhibit 8-42
[redacted] REC Value Summary

[redacted]

The effect of using the Commission ordered capacity rate of $188.88/MW-day also reduces AEP-Ohio's ending REC inventory balances for [redacted] by the amounts of [redacted] as shown in the exhibit below.

Exhibit 8-43
[redacted] [redacted] Inventory Summary

[redacted]

Value for Non-Solar, Non-Ohio REC Inventory Before Rider AER Effective Date

In response to Larkin's request that AEP-Ohio provide all written guidance, accounting policy directives and other written documentation from the Accounting Policy Group related to the use of a zero dollar value for the non-solar, non-Ohio REC inventory quantities for each month of 2012 before Rider AER became effective, the Company, referring to the confidential attachment from LA-2012/2013-1-72, stated that its use of a zero dollar value for non-solar, non-Ohio RECs ended when AER accounting commenced in October 2012[78]. LA-2012/2013-1-76, requested that the Company provide comparable market information which supports the use of [redacted]

[78] See the response to LA-2012/2013-1-75.

Exhibit 8-44
Summary of the Ohio contiguous REC quotes for 2011, 2012 and 2013

[redacted]

[redacted]. The market price of RECs can represent another data set with which the results of the Company's residual method for determining REC cost can be compared. For October 2012 through December 2013, the market prices for non-solar RECs were below the cost for such RECs derived by the Company's residual method.

Fulfillment of Renewables Obligation

LA-2012/2013-1-77 asked whether any of the 2012 or 2013 non-Ohio non-solar REC obligation was fulfilled with REC purchases. In response, AEP-Ohio stated that all of its 2012 and 2013 non-Ohio non-solar REC obligation was fulfilled solely by [redacted] wind farm, the Company's sole contract source of such RECs. In addition, when asked whether any of the 2012 or 2013 non-Ohio non-solar REC obligation was fulfilled with spot market or contract purchases of renewable power, including, but not limited to Purchase Power Agreements ("PPA"), AEP-Ohio referred to the response to LA-2012/2013-1-77 (discussed above).

Larkin requested that the Company provide a summary and details of CSP's and OPCO's status as it relates to renewable energy objectives and minimum requirements for 2012 and 2013, including whether there was any shortfall in achieving the minimum requirements. Larkin also requested copies of any waivers obtained by AEP-Ohio as it related to meeting renewable energy objectives for 2012 and 2013. In response to LA-2012/2013-1-84, AEP-Ohio stated that OPCO met the 2012 Ohio renewable energy requirements for both solar and non-solar, thus no waivers were necessary. The Company stated that it expects to meet those same requirements for 2013.

Non-Solar REC Inventory and REC Consumption

As it relates to physical REC inventory, LA-2012/2013-1-80 requested that AEP-Ohio provide a listing of the out of state non solar inventory positions for each month of 2012 and 2013, and within that listing to provide quantities of these RECs for each of the following:

- RECs related to previous year compliance
- RECs used for 2012 and 2013 compliance in each month
- Unused out of state non-solar RECs that are in the inventory quantity that could be used for 2012, 2013 or subsequent period compliance.

In response, the Company stated that it has been maintaining a Non-Solar Non-Ohio REC accounting inventory since AER accounting began on October 1, 2012. In addition, AEP-Ohio stated that RECs are removed from inventory upon consumption for compliance purposes and that ending inventory balances are eligible to be used for subsequent period compliance. The exhibit below, which was provided as a confidential attachment in LA-2012/2013-1-74, is a schedule of the Company's REC activity, including consumption by month.

Exhibit 8-45
REC Activity Including Consumption By Month

[redacted]

REC Accounting

LA-2012/2013-1-81 asked AEP-Ohio to indicate the accounts in which the following renewable items were booked in 2012 and 2013 and to provide the 2012 and 2013 detail general ledger pages for each such account:

- REC Purchase Costs
- Gains on Sale of RECs
- Loss on Sales of RECs
- Costs associated with Attribute Tracking System(s)
- Consumed or surrendered RECs

In response, the Company provided a schedule which Larkin has reproduced in the exhibit below.

Exhibit 8-46
REC General Ledger Detail

Description	Account No.	2012	2013
REC Purchase Costs			
Solar	1740036	$2,806,483	$ 3,205,888
Non-Solar, Ohio Generated			
Pre-AER	5570009	$4,026,875	$ -
AER	1740041	$ 477,000	$ 8,286,001
Non-Solar, Non-Ohio			
Pre-AER	5570009	$ -	$ -
AER	1740041	$3,903,895	$14,088,378
Gain on Sale of RECs	5570009	$ 571,618	$ -
Loss on Sale of RECs	5570009	$ -	$ 84,523
Costs Associated with Attribute Tracking System	5570009	$ 39,129	$ 78,112
Consumed or Surrendered RECs			
Solar	5570009	$2,137,375	$ 3,031,810
Non-Solar, Ohio Generated	5570009	$8,254,184	$ 6,143,938
Non-Solar, Non-Ohio	5570009	$ 793,403	$11,155,457
Source: LA-2012/2013-1-81			

Biodiesel and Biomass Testing

As it relates to biodiesel fuel, LA-2012/2013-1-83 requested that AEP-Ohio:

a. Identify the plants, units and dates where biodiesel testing was conducted during 2012 and 2013.

b. Identify the cost per MMBtu of the biodiesel fuel burned for each plant during 2012 and 2013.

c. Show in detail how AEP-Ohio identified and separated (1) the energy value, and (2) the REC value for the biodiesel fuel burned in 2012 and 2013.

In response, the Company provided a chart, which Larkin has replicated in the exhibit below, that identifies the plants and months where biodiesel fuel was burned and the quantity of RECs created.[79]

Exhibit 8-47
Biodiesel RECs

Date	Muskingum River Units 1-4	Conesville Units 5&6	Conesville Unit 4 (AEP's Split)	Picway
January 2012	197	52	0	0
February 2012	114	69	0	0
March 2012	18	14	0	0
April 2012	18	15	8	0
May 2012	17	82	0	0
June 2012	21	41	42	0
July 2012	39	13	18	0
August 2012	91	76	1	0
September 2012	0	31	28	0
October 2012	22	32	0	0
November 2012	28	33	0	0
December 2012	15	54	0	0
Total RECs	580	512	97	0
January 2013	17	24	0	0
February 2013	54	3	0	0
March 2013	25	9	0	0
April 2013	29	22	0	0
May 2013	0	18	34	0
June 2013	0	10	37	1
July 2013	0	31	37	0
August 2013	0	9	1	0
September 2012	0	27	22	0
October 2013	0	0	0	0
November 2013	0	24	0	0
December 2013	0	72	0	0
Total RECs	125	249	131	1

In terms of separating the energy and REC values from the biodiesel fuel as well as calculating the cost per MMBtu of the biodiesel fuel burned, the response to LA-2012/2013-1-83 stated in part:

[79] Per LA-2012/2013-1-83, the quantity of RECs is calculated as a plant's net MWh generation multiplied by biodiesel MMBtus burned divided by all MMBtus burned.

Prior to the implementation of AER accounting in October 2012, the Company did not separate the energy value from the REC value. For AER accounting, a REC value is assigned and put into the Non-Solar Ohio-Generated REC inventory. The REC portion represents the incremental cost above the replaced fuel (biodiesel over fuel oil) on an equivalent heat value basis. LA-2012-13-083, Attachment 1 illustrates how the Company separates the energy value from the REC value, and also includes the biodiesel cost per MMBtu burned.

According to Attachment 1 from LA-2012/2013-1-83, AEP-Ohio determined the valuation of the biodiesel RECs through the calculation of the following variables (identified below): A - (B x C/D x E)

A = cost of biodiesel burned

B = gallons of biodiesel blend consumed

C = Btu/gal of biodiesel blend

D = Btu/gal of fuel oil

E = average unit cost of fuel oil

By using the inputs from Attachment 1 to LA-2012/2013-1-83 for the variables noted above, the resulting biodiesel REC valuation for the four generating plants are reflected in the exhibit below.

Exhibit 8-48
Valuation of RECs Generated

Valuation of RECs Generated					
Production Month	GATS & Accounting Month	Muskingum River Units 1-4	Conesville Unit 5&6	Conesville Unit 4 (AEP's split)	Picway
Sep-12	Oct-12	$ 30.59	$ 2,570.19	$1,142.13	$ -
Oct-12	Nov-12	$ 5,976.02	$ 2,465.98	$ 30.72	$ -
Nov-12	Dec-12	$ 6,825.26	$ 3,154.35	$ 13.15	$ -
	Total	$ 12,831.87	$ 8,190.52	$1,186.00	$ -
Dec-12	Jan-13	$ 3,250.87	$ 6,691.20	$ 175.56	$ -
Jan-13	Feb-13	$ 3,281.45	$ 3,127.73	$ 67.91	$ -
Feb-13	Mar-13	$ 7,318.16	$ 416.71	$ (43.88)	$ -
Mar-13	Apr-13	$ 4,060.49	$ 1,677.47	$ 131.64	$ -
Apr-13	May-13	$ 4,788.42	$ 2,174.69	$ 1.11	$ -
May-13	Jun-13	$ -	$ 1,217.90	$1,530.70	$ -
Jun-13	Jul-13	$ -	$ 966.20	$1,496.83	$103.35
Jul-13	Aug-13	$ -	$ 2,916.29	$1,275.54	$ -
Aug-13	Sep-13	$ -	$ 937.29	$ 39.18	$ -
Sep-13	Oct-13	$ -	$ 2,624.67	$ 880.93	$ -
Oct-13	Nov-13	$ -	$ 83.32	$ -	$ -
Nov-13	Dec-13	$ -	$ 2,270.54	$ -	$ -
	Total	$ 22,699.39	$25,104.01	$5,555.52	$103.35

In addition, AEP-Ohio determined the cost per MMBtu of biodiesel burned through the calculation of the following variables (same as those identified above): A / (B x C) x 1,000,000. By using the inputs from Attachment 1 to LA-2012/2013-1-83 for the noted variables, the resulting cost per MMBtu of biodiesel burned for the four generating plants are reflected in the exhibit below.

Exhibit 8-49
Cost per MMBtu of Biodiesel Burned

Production Month	GATS & Accounting Month	Muskingum River Units 1-4	Conesville Unit 5&6	Conesville Unit 4 (AEP's split)	Picway
Sep-12	Oct-12	$ 24.07	$ 23.86	$ 23.16	$ -
Oct-12	Nov-12	$ 24.13	$ 23.91	$ 23.25	$ -
Nov-12	Dec-12	$ 24.09	$ 24.15	$ 23.23	$ -
	Total	$ 72.29	$ 71.92	$ 69.64	$ -
Dec-12	Jan-13	$ 24.11	$ 24.06	$ 23.23	
Jan-13	Feb-13	$ 24.16	$ 24.24	$ 23.30	
Feb-13	Mar-13	$ 24.02	$ 25.87	$ 23.30	
Mar-13	Apr-13	$ 24.40	$ 24.21	$ 23.30	
Apr-13	May-13	$ 24.40	$ 24.17	$ 23.28	
May-13	Jun-13		$ 24.19	$ 23.28	
Jun-13	Jul-13		$ 24.19	$ 23.28	$ 22.29
Jul-13	Aug-13		$ 24.10	$ 23.21	
Aug-13	Sep-13		$ 24.13	$ 23.04	
Sep-13	Oct-13		$ 24.15	$ 23.08	
Oct-13	Nov-13		$ 24.12		
Nov-13	Dec-13		$ 24.19		
	Total	$ 121.09	$ 291.62	$ 232.30	$ 22.29

As it relates to biomass testing, according to the response to LA-2012/2013-1-82, the Company did not conduct such biomass burning in either 2012 or 2013.

Larkin requested that the Company provide a summary and details of CSP's and OPCO's status as it relates to renewable energy objectives and minimum requirements for 2012 and 2013, including whether there was any shortfall in achieving the minimum requirements. Larkin also requested copies of any waivers obtained by AEP-Ohio as it related to meeting renewable energy objectives for 2012 and 2013. In response to LA-2012/2013-1-84, AEP-Ohio stated that OPCO met the 2012 Ohio renewable energy requirements for both solar and non-solar, thus no waivers were necessary. The Company stated that it expects to meet those same requirements for 2013.

Supporting Workpapers and Documentation for AER Filings

Documentation relating to the review of supporting workpapers for the calculations in the AER filings was requested in data requests LA-2012/2013-1-86 through LA-2012/2013-1-92. LA-2012/2013-1-86 requested copies of AEP Ohio's quarterly AER filings (which are filed in conjunction with the FAC filings). The first combined quarterly filing which included the AER was filed on August 31, 2012, and included forecasted AER data for October, November and December 2012. As the fourth quarter of 2012 represented the initial implementation of the

AER, the first quarterly filing to contain actual data in the RA portion was not filed until March 1, 2013. This quarterly filing included actual data for October, November and December 2012.

Data requests LA-2012/2013-1-87, LA-2012/2013-1-88, LA-2012/2013-1-89, LA-2012/2013-1-90 and LA-2010/2013-1-91 requested the Excel files associated with the AER filings as well as all documentation which provides a complete audit trail to the Company's AER calculations. The responses to these data requests referred to LA-2012/2013-1-46 and LA-2012/2013-1-47, which requested similar supporting documentation, but in the context of the FAC. The one exception was the response to LA-2012/2013-1-89, which included two confidential attachments that provided the monthly REC expenses included in the AER as well as the under-over recovery for the fourth quarter of 2012 and all of 2013.

Upon comparing the amounts reflected for renewables on workpaper "EXH OPCO 1" in the monthly FAC workbooks (provided in LA-2012/2013-1-47) to the RA portion of the quarterly FAC filings (Schedule 3, page 2), Larkin noted that for each month during the period January through September 2012, Schedule 3 of the quarterly FAC filing reflected an additional $11,928 ($5,952 for CSP and $5,976 for OPCO) for the cost of renewables included in the FAC. Larkin requested that AEP Ohio explain the rationale for adding the $11,928 related to solar panels to the monthly renewable costs. In response to LA-2012/2013-9-2, the Company stated that it had installed solar panels on two of its service centers to provide RECs in order for OPCO to meet its renewable obligations and that a monthly revenue requirement had been calculated to recover the costs of these solar panels. In addition, AEP Ohio stated that OPCO has recovered these costs from ratepayers through the FAC since 2009 pursuant to Senate Bill 221, but that when the AER was implemented in October 2012, the Company moved the solar panel revenue requirement from the FAC to the AER to better reflect the cost of renewable energy. The exhibit below reflects the solar panel related revenue requirement calculations for CSP and OPCO which results in the additional $11,928 being added to the renewable costs each month.

Exhibit 8-50
CSP and OPCO Solar Panel Related Monthly Revenue Requirement

	CSP				OPC		
	Solar	Inverter	Total		Solar	Inverter	Total
Description	20 Yr Prop.	10 Yr Prop.				10 Yr Prop.	
Investment	$ 453,346	$ 48,052	$ 501,398		$ 485,065	$ 42,003	$ 527,068
Carrying Charge Rate w/ITC c	11.97%	14.81%			11.17%	16.61%	
Carrying Charge	$ 54,284	$ 7,115	$ 61,399		$ 54,194	$ 6,976	$ 61,170
O&M Expense	$ 9,067	$ 961	$ 10,028		$ 9,701	$ 840	$ 10,541
Revenue Requirement	$ 63,351	$ 8,076	$ 71,427		$ 63,895	$ 7,816	$ 71,711
Months			12				12
Monthly Revenue Requirement			$ 5,952				$ 5,976

When comparing the over/(under) recovery amounts that were reflected in the quarterly AER filings to the confidential attachments provided with LA-2012/2013-1-89, a variance in the amount of $35,784 was noted in December 2012 as well as August, September and December 2013 as summarized in the exhibit below.

Exhibit 8-51
Comparison of Over/(Under) Recovery Amount per Month

[redacted]

Upon Larkin's inquiry regarding these discrepancies, in response to LA-2012/2013-10-1 AEP-Ohio stated that the $35,784 reflected the quarterly distribution center solar panel costs, which total $11,928 on a monthly basis.

Upon attempting to tie out the monthly non-solar renewable amounts (i.e., [redacted] from the monthly FAC workbooks to the energy and capacity portions of the renewable costs allocated to the FAC (per LA-2012/2013-1-72), Larkin noted the variances reflected in the exhibit below.

Exhibit 8-52
Variances of the Energy and Capacity Portions of the Renewable Costs Allocated to the FAC

[redacted]

Larkin requested that AEP Ohio explain and reconcile the noted discrepancies and in its confidential response to LA-2012/2013-9-1, the Company provided the explanations listed below.

[redacted]

[redacted]

Larkin noted other discrepancies when comparing the Monthly Billed and Accrued kWh reflected on the AER worksheets provided in LA-2012/2013-1-47 to the Retail Non-Shopping Sales kWh reflected in the quarterly AER filings. These discrepancies are summarized in the exhibit below.

[redacted]

Exhibit 8-53
Discrepancies Between the Monthly Billed & Accrued and the Retail Non-Shopping Sales Kwh

[redacted]

As shown in the exhibit above, the kWh discrepancies [redacted] As a result of these apparent errors, Larkin was concerned that the AER revenues and calculated AER rates reflected in the quarterly AER filings were incorrect. Larkin asked a series of questions about these discrepancies in data request LA-2012/2013-8-1. In response, AEP Ohio provided the following explanations:

- The kWh applicable to the AER were entered onto the spreadsheets in the early months of the AER, but was found to be not required or used to derive AER revenues, costs or the AER over/under amount. The Company also stated that the kWh on the AER worksheets should be disregarded.
- As it relates to the calculation of the AER rate, AEP Ohio stated that only the actual AER revenue dollars and costs from the AER worksheet is used to calculate the AER rate.[81] The Company divides the forecasted RECs allocated to retail load by the forecasted non-shopping sales to derive a forecasted AER rate per Schedule 5 from the quarterly AER filings (FC component). Schedule 6 from the quarterly AER filings (RA component) reflects the actual revenues and expenses, which are compared to derive the over/under

[81] The AER worksheets calculated the AER rate by dividing the AER revenues by the kWh.

amount which is rolled over to the following quarter. In other words, in the quarterly filings, forecasted costs and kWh sales are used to derive a rate that is based on forecasted data. These rates and costs are then compared to the actual revenue and costs and trued-up through the RA component of the quarterly filings.

- In terms of the source for the AER revenues reflected on the AER worksheets, AEP Ohio provided AER revenue schedules as a supplement to LA-2012/2013-1-47 (see additional discussion below).

Larkin compared the AER revenue amounts from the supplemental AER revenue schedules to the AER worksheets (which are the source for the AER revenue dollars in the quarterly filings) and noted discrepancies with the December 2012 and February 2013 which are reflected in the exhibit below.

Exhibit 8-54
Discrepancies of AER Revenue Amounts

[redacted]

As shown in the exhibit, the difference of [redacted] in December 2012 and February 2013 results in a wash between the two months.