BEFORE
THE PUBLIC UTILITIES COMMSSION OF OHIO

In the Matter of the Application of	**)**	
Ohio Power Company to Update Its	**)**	**Case No. 13-1406-EL-RDR**
Transmission Cost Recovery Rider	**)**	

APPLICATION

Ohio Power Company d/b/a AEP Ohio ("OPCo" or the "Company") submits this application to update its Transmission Cost Recovery Rider ("TCRR"). In support of its application, OPCo states the following:

1. OPCo is an electric utility as that term is defined in §4928.01(A)(11), Ohio Rev. Code.
2. OPCo is an electric utility operating company subsidiary of American Electric Power Company, Inc.
3. By Finding and Order issued May 26, 2006 in Case No. 06-273-EL-UNC, the Commission approved the Company's application in that docket to combine the transmission component of the Company's Standard Service Tariff with its TCRR.
4. As part of the Commission's approval of that application the Company is to file an annual update to its TCRR. The update would incorporate any over- or under- recovery deferral balance into the surcharge for the next calendar year. In addition to this true-up mechanism, the update also could adjust the ongoing level of the TCRR, if necessary, to minimize the anticipated level of over- or under- recoveries in the next calendar year.

5. Chapter 4901:1-36, Ohio Admin. Code, became effective April 2, 2009. As provided in that Chapter, electric utilities are authorized to recover all transmission and transmission-related costs, including ancillary and congestion costs, imposed on or charged to the utility, net of financial transmission rights and other transmission-related revenues credited to the utility, by the Federal Energy Regulatory Commission ("FERC") or a Regional Transmission Organization ("RTO"), Independent Transmission Operator, or similar organization approved by the FERC. The recovery of these costs is to be through a reconcilable rider, such as the Company's TCRR. (§4901:1-36-02 (A), Ohio Admin. Code).

6. The recovery of costs is to be pursuant to an application filed by the electric utility on an annual basis pursuant to a schedule set by Commission order. (§4901:1-36-03 (A) and (B), Ohio Admin. Code).

7. On April 15, 2009, the Commission issued an Entry in Case 08-777-EL-ORD directing the Company to submit by April 16th of each year the annual update to its TCRR rates. In its April 11, 2012 Entry in Case No. 12-1046-EL-RDR, the Commission approved the Company's request to file the annual update to its TCRR on June 15th of each year commencing with the Company's 2012 TCRR update, with rates to be effective with the first billing cycle in September.

8. The Company's most recent TCRR proceeding was in Case No. 12-1046-EL-RDR. In that case the Company's current TCRR rates became

effective at the beginning of the November 2012 billing month (October 26, 2012).

9. In accordance with the Commission's directive and Chapter 4901:1-36, Ohio Admin. Code, the following information is provided with this application:

Schedule A-1	Copy of proposed tariff schedules
Schedule A-2	Copy of redlined current tariff schedules
Schedule B-1	Summary of Total Projected Transmission Costs/Revenues
Schedule B-2	Summary of Current versus Proposed Transmission Revenues
Schedule B-3	Summary of Current and Proposed Rates
Schedule B-4	Graphs
Schedule B-5	Typical Bill Comparisons
Schedule C-1	Projected Transmission Cost Recovery Rider Cost/Revenues
Schedule C-2	Monthly Projected Cost for Each Rate Schedule
Schedule C-3	Projected Transmission Cost Recovery Rider Rate Calculations
Schedule D-1	Reconciliation Adjustment
Schedule D-2	Monthly Revenues Collected From Each Rate Schedule
Schedule D-3	Monthly Over and Under Recovery
Schedule D-3a	Carrying Cost Calculation
Schedule D-3b	Reconciliation of Throughput to Company Financial Records

Schedule D-3c Reconciliation of One Month's Bill from RTO to Financial Records of the Company

10. As reflected in Schedules B-1 and B-2, the Company's proposed TCRR revenues for the 12-month period beginning with the September 2013 billing month are $57,596,921 higher than what the TCRR revenues for that period would be under the current TCRR rates.[1] This represents an average increase in the TCRR of approximately 33.24%. The increase reflects $47,261,363 of under-recovery, including carrying charges.

11. The carrying charges identified in the prior paragraph were calculated in a manner consistent with the carrying charge calculation ordered by the Commission in Case No. 08-1202-EL-UNC, Finding and Order, December 17, 2008, and approved in Case No. 10-477-EL-RDR.

12. The under-recovery is chiefly attributable to three components. First, a PJM tariff change in December 2012 caused the Company to incur approximately $11 million in costs that were not forecasted for Black Start Service. Second, implementation of the new TCRR rates created regulatory lag of approximately $7 million. Finally, approximately $23 million of PJM Reactive Supply charges, plus carrying costs, had been inadvertently omitted from the TCRR charges, as explained below.

13. Reactive Supply charges are a true cost to the Company and included in the line items for recovery as shown on the Company's Schedule B-1. Reactive Supply charges (and credits) are billed by PJM to the Company

[1] The slight difference between the forecast of Total Transmission Cost net of true-up on Schedule B-1 and the forecast for total TCRR revenues under the proposed TCRR on Schedule B-2 is attributable to rounding.

as line items 1330 (charge) and 2330 (credit) on the PJM bill. The charge line item relates to FERC account 5550074 and the credit line item relates to FERC account 5550075. During the review phase for this filing, the Company discovered that from July 2011 through March 2013, the net of the two line items has been a credit but the separate charge line item was not recorded in account 5550074 and thus was inadvertently not included in the TCRR rate calculations. The Company reclassified the charges to the correct account (5550074) for inclusion in the current TCRR calculations.

14. Schedule B-1 contains a new line, Forecast Carrying Costs. The charge on this line is a forecast of the carrying costs that the Company will incur due to the under-recovery balance. The costs are forecasted using the same calculation procedure currently used to account for the over/under recovery, an example of which is shown on Schedule D-3a. The Company will true-up the forecast to the actual carrying costs in its next TCRR filing. This methodology will allow the Company to better reflect the over/under recovery that will likely occur throughout the year.

15. In its October 24, 2012 Finding and Order in Case No. 12-1046-EL-RDR, the Commission directed the Company to adopt a kWh-based methodology for allocating Net Marginal Loss costs beginning with this 2013 filing. This methodology is reflected on Schedule C-3. In addition, the Commission authorized the Company to establish a separate rate, the Transmission Under-Recovery Rider, in order to collect the under-

recovery of approximately $36 million, plus carrying charges, evenly over a three-year period. As of April 30, 2013, this rate has decreased the outstanding balance to $31,365,069. The Transmission Under-Recovery Rider will terminate when the full amount of the under-recovery has been collected.

16. The Company forecasts significant reductions in certain costs included in the TCRR due to the termination of the AEP East Power Pool and the advent of the slice-of-system energy auctions authorized in Case No. 11-346-EL-SSO. The costs are Net Congestion, Operating Reserves, Net Ancillary Services, PJM Administration Fees, and Net Marginal Losses. These reductions are reflected on Schedule C-1 in the form of monthly cost forecasts that are equal to the average of the forecast costs from July 2013, the traditional start of the TCRR forecast period, through May 2015, the expiration of the Company's current Electric Service Plan.

17. In FERC Docket No. ER08-1329-000, American Electric Power Service Corporation, on behalf of the Company (and other AEP East operating companies) filed an application to increase the Company's Open Access Transmission Tariff (OATT). The Company's TCRR filing reflects that current OATT rate. The settlement agreement in that case was approved on October 1, 2010. The new FERC-approved rate has been applied and is reflected in the over/under recovery in this year's TCRR filing.

18. The Company's proposed TCRR, as reflected in Schedule A-1 and supported by Schedules B-1, B-2 and C-3 and their related work papers, is

reasonable and should be approved. As always, the Company is receptive to exploring alternative recovery options in an effort to promote rate stability and to mitigate rate impacts.

19. The Company requests that its proposed updated TCRR rates be made effective on a bills rendered basis beginning on August 28, 2013 - the first day of the September 2013 billing cycle. This “bills rendered” effective date is consistent with the Finding and Order in Case Nos. 06-273-EL-UNC and 07-1156-EL-UNC, 08-1202-EL-UNC and 10-477-EL-RDR.

Based on the reasons stated above and the exhibits and work papers submitted with this filing, the Commission should approve the Company’s application.

Respectfully submitted,

/s/ Yazen Alami

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P.U.C.O. NO. 20

TRANSMISSION COST RECOVERY RIDER

Effective Cycle 1 September 2013, all customer bills subject to the provisions of this Rider, including any bills rendered under special contract, shall be adjusted by the Transmission Cost Recovery Rider per KW and/or KWH as follows:

Schedule	¢/KWH	$/KW
RS,RR, RR-1, RS-ES, RS-TOD, RLM, RS-TOD2, CPP, RTP and RDMS	1.56698	
GS-1, GS-1-TOD	1.33710	
GS-2 Secondary	0.40487	2.32
GS-2 Recreational Lighting, GS-TOD,GS-2-TOD and GS-2-ES	1.36033	
GS-2 Primary	0.39082	2.24
GS-2 Subtransmission and Transmission	0.38304	2.19
GS-3 Secondary	0.40913	3.75
GS-3-ES	1.22816	
GS-3 Primary	0.39494	3.62
GS-3 Subtransmission and Transmission	0.38707	3.55
GS-4 Primary	0.41119	3.52
GS-4 Subtransmission and Transmission	0.40300	3.45
EHG	0.76122	
EHS	1.20404	
SS	1.20404	
OL, AL	0.40303	
SL	0.40303	

Schedule SBS	¢/KWH	$/KW					
		5%	10%	15%	20%	25%	30%
Backup - Secondary	0.41841	0.05	0.09	0.14	0.18	0.23	0.28
- Primary	0.40390	0.04	0.09	0.13	0.18	0.22	0.27
-Subtrans/Trans	0.39585	0.04	0.09	0.13	0.17	0.22	0.26
Backup < 100 KW Secondary		0.19					
Maintenance - Secondary	0.44095						
- Primary	0.42483						
- Subtrans/Trans	0.41678						
GS-2 and GS-3 Breakdown Service		0.43					

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TRANSMISSION COST RECOVERY RIDER

Effective Cycle 1 September~~November~~ 2013~~2~~, all customer bills subject to the provisions of this Rider, including any bills rendered under special contract, shall be adjusted by the Transmission Cost Recovery Rider per KW and/or KWH as follows:

Schedule	¢/KWH	$/KW
RS,RR, RR-1, RS-ES, RS-TOD, RLM, RS-TOD2, CPP, RTP and RDMS	1.56698~~15708~~	
GS-1, GS-1-TOD	~~0.89975~~1.33710	
GS-2 Secondary	0.~~51223~~40487	~~1.54~~2.32
GS-2 Recreational Lighting, GS-TOD,GS-2-TOD and GS-2-ES	1.~~13915~~36033	
GS-2 Primary	0.~~49448~~39082	~~1.49~~2.24
GS-2 Subtransmission and Transmission	0.~~48310~~38304	~~1.45~~2.19
GS-3 Secondary	0.~~46084~~40913	~~2.69~~3.75
GS-3-ES	1.~~04135~~22816	
GS-3 Primary	0.~~44487~~39494	~~2.60~~3.62
GS-3 Subtransmission and Transmission	0.~~43463~~38707	~~2.54~~3.55
GS-4 Primary	0.~~34566~~41119	~~2.15~~3.52
GS-4 Subtransmission and Transmission	0.~~33770~~40300	~~2.10~~3.45
EHG	0.~~83211~~76122	
EHS	1.~~11466~~20404	
SS	1.~~11466~~20404	
OL, AL	0.~~36987~~40303	
SL	0.~~36987~~40303	

Schedule SBS	¢/KWH	$/KW					
		5%	10%	15%	20%	25%	30%
Backup - Secondary	0.~~40305~~41841	0.05~~12~~	0.09~~25~~	0.14~~37~~	0.18~~50~~	0.23~~62~~	0.28~~75~~
- Primary	0.~~38908~~40390	0.04~~12~~	0.09~~24~~	0.13~~36~~	0.18~~48~~	0.22~~60~~	0.27~~72~~
-Subtrans/Trans	0.~~38013~~39585	0.04~~12~~	0.09~~24~~	0.13~~35~~	0.17~~47~~	0.22~~59~~	0.26~~71~~
Backup < 100 KW Secondary		0.19					
Maintenance - Secondary	0.~~46263~~44095						
- Primary	0.~~44705~~42483						
- Subtrans/Trans	0.~~43649~~41678						
GS-2 and GS-3 Breakdown Service		0.~~19~~43					

Summary of Total Projected Transmission Costs / Revenues

	Ohio Power Company	
	($)	
NITS	$ 119,804,962	D
Transmission Enhancement Charges	$ 10,410,376	D
Scheduling	$ 1,327,953	E
Point to Point Revenues	$ (4,452,000)	D
Regulation Service	$ 6,131,460	E
Spinning Reserves	$ 67,104	E
Supplemental Reserves - Charges	$ 1,097,868	E
Net Congestion	$ (2,631,228)	E
Operating Reserves - Charges	$ 5,539,560	E
Load Response Program Subsidies	$ -	E
Net Ancillary Services - Synchronous Condensing	$ 4,452	E
- Reactive Supply - Charges	$ 7,634,460	E
- Blackstart - Charges	$ 13,942,104	E
PJM Administration Fees	$ 9,120,732	E
Net RTO Formation Costs & Expansion Cost Recovery Charge	$ 781,524	E
Phase - In Credit	$ (366,667)	O
Net Marginal Losses	$ 11,937,000	E
Total Transmission Costs	$ 180,349,661	
(Over)/Under Collection	$ 47,261,363	O
Forecast Carrying Costs	$ 3,331,644	O
	$ 230,942,668	

D = Demand, E = Energy, O = Other

Summary of Current versus Proposed Transmission Revenues

Ohio Power Company

	Forecast for September 2013 - August 2014				
	Metered kWh	**Current TCRR**	**Proposed TCRR**	**Difference**	**% Difference**
RS	8,881,307,554	$102,763,833	$139,168,313	36,404,480	35.43%
GS1	266,329,344	$2,396,298	$3,561,090	1,164,791	48.61%
GS2 Sec	987,898,635	$11,277,923	$13,366,494	2,088,571	18.52%
GS2 RL - GS - TOD	38,883,822	$442,945	$528,948	86,003	19.42%
GS2 Pri	76,852,043	$886,995	$1,062,520	175,525	19.79%
GS2 Sub/Trans	47,830,525	$529,547	$634,015	104,467	19.73%
GS3 Sec	1,252,314,373	$13,432,144	$15,803,396	2,371,252	17.65%
GS3 - TOD	0	$0	$0	-	0.00%
GS3 Pri	696,446,446	$6,791,132	$7,892,130	1,100,998	16.21%
GS3 Sub/Trans	125,687,890	$1,189,345	$1,385,275	195,931	16.47%
GS4 Pri	14,905,185	$109,333	$155,939	46,606	42.63%
GS4/IRP Sub/Trans	4,807,558,645	$32,840,280	$46,654,357	13,814,078	42.06%
EHG	7,683,731	$63,937	$58,490	(5,447)	-8.52%
SS	5,877,597	$65,515	$70,769	5,253	8.02%
AL	56,672,920	$209,616	$228,409	18,793	8.97%
SL	77,261,032	$285,765	$311,385	25,620	8.97%
Total	17,343,509,741	$173,284,609	$230,881,529	57,596,921	33.24%

Ohio Power Rate Zone

	(Stip rejection) May 2012 - Aug 2012 Rates		(ESP2.5 Order) Sep 2012 - Oct 2012 Rates		(current) Nov 2012 - Apr 2013 Rates		Actual 12 Months Billed 4/30/2013				Forecast September 2013 August 2014			Forecast September 2013 August 2014				
									Revenue				Revenue at Current	Proposed Rates		Revenue at Proposed	$ Change	% Change
	$ kWh	$ Demand	$ kWh	$ Demand	$ kWh	$ Demand	Metered kWh	Demand	kWh	Demand	Metered kWh	Demand	Rates	kWh	Demand	Rates		
Residential																		
Residential	0.0093015		0.0098403		0.0115708		5,657,342,977		59,736,629.76	-	4,144,253,335		47952326.49	0.0156698		64,939,620.91	16,987,294.42	35%
GS1	0.0082301		0.0094194		0.0089975		4,536		40.81	-	3,062		27.55	0.0133710		40.94	13.39	49%
GS2-Sec	0.0026532	1.65	0.0034361	1.72	0.0051223	1.54	3,399	36	17.41	55.44	2,577	-	13.20	0.0040487	2.32	10.43	(2.77)	0%
AL	0.0032986		0.0033291		0.0036987		12 982 965		45 775 46	-	9 634 066		35 633 52	0.0040303		38 828 17	3 194 65	9%
							5,670,333,877	36	59,782,463.44	55.44	4,153,893,040	-	47,988,000.76			64,978,500.46	16,990,499.70	35%
Commercial																		
Residential	0.0093015		0.0098403		0.0115708		-		-	-	-		-	0.0156698		-	-	#DIV/0!
GS1	0.0082301		0.0094194		0.0089975		250,867,153	-	2,204,294.93	-	122,959,920		1,106,331.88	0.0133710		1,644,097.09	537,765.21	49%
GS2-Sec	0.0026532	1.65	0.0034361	1.72	0.0051223	1.54	1,038,912,771	4,361,848	3,867,309.57	7,074,202.62	484,812,152	2,036,576	5,619,680.14	0.0040487	2.32	6,687,715.00	1,068,034.86	19%
GS2 RL - GS - TOD	0.0092133		0.0102608		0.0113915		67,909,852		699,419.68	-	32,266,565		367,564.58	0.0136033		438,931.77	71,367.19	19%
GS2-Pri	0.0025581	1.59	0.0033170	1.66	0.0049448	1.49	30,297,675	151,195	110,108.41	237,904.58	14,238,499	69,629	174,153.65	0.0039082	2.24	211,615.73	37,462.08	22%
GS2-Sub/Tran	0.0024965	1.55	0.0032407	1.62	0.0048310	1.45	2,588,400	28,832	9,947.51	43,799.97	1,304,759	13,845	26,378.18	0.0038304	2.19	35,317.75	8,939.57	34%
GS3-Sec	0.0022472	2.37	0.0029583	2.23	0.0046084	2.69	1,047,661,658	2,310,943	3,391,430.31	5,681,694.11	485,290,630	1,068,784	5,111,442.97	0.0040913	3.75	5,993,410.49	881,967.52	17%
GS3-Pri	0.0021666	2.29	0.0028558	2.15	0.0044487	2.60	274,066,559	562,795	839,574.33	1,331,501.10	124,908,313	257,362	1,224,821.54	0.0039494	3.62	1,424,964.35	200,142.81	16%
GS3-Sub/Tran	0.0021145	2.23	0.0027900	2.10	0.0043463	2.54	22,454,397	42,367	75,791.53	100,125.52	11,280,861	21,168	102,795.81	0.0038707	3.55	118,809.95	16,014.14	16%
EHG	0.0083313		0.0083313		0.0083211		14,731,160	-	122,651.08	-	7,369,099		61,319.01	0.0076122		56,095.05	(5,223.96)	-9%
SS	0.0053947		0.0053947		0.0111466		11,832,765	-	98,146.11	-	5,877,597		65,515.22	0.0120404		70,768.62	5,253.40	8%
AL	0.0032986		0.0033291		0.0036987		34,015,532		119,795.66	-	17,187,183		63,570.23	0.0040303		69,269.50	5,699.27	9%
SBS-Sub/Tran-Backup-5%	0.0021302	0.32	0.0025950	0.20	0.0038013	0.12	-	80 000	-	25 600 00	-	-	-	0.0039585	0.04	-	-	#DIV/0!
							2,795,337,922	7,537,980	11,538,469.12	14,494,827.90	1,307,495,579	3,467,364	13,923,573.21			16,750,995.31	2,827,422.10	20%
Industrial																		
GS1	0.0082301		0.0094194		0.0089975		12,392,966.00		109,056.30	-	6,366,191.21		57,279.81	0.0133710		85,122.34	27,842.53	49%
GS2-Sec	0.0026532	1.65	0.0034361	1.72	0.0051223	1.54	186,536,813.00	867,349.58	678,136.53	1,408,808.99	89,641,724.00	417,454	1,102,051.01	0.0040487	2.32	1,331,425.80	229,374.79	21%
GS2 RL - GS - TOD	0.0092133		0.0102608		0.0113915		5,254,401.00		53,927.14	-	2,589,719.82		29,500.79	0.0136033		35,228.74	5,727.95	19%
GS2-Pri	0.0025581	1.59	0.0033170	1.66	0.0049448	1.49	112,277,191.00	482,218.16	406,239.14	753,577.46	54,831,072.47	236,641	623,724.08	0.0039082	2.24	744,367.09	120,643.01	19%
GS2-Sub/Tran	0.0024965	1.55	0.0032407	1.62	0.0048310	1.45	97,984,146.00	394,171.83	331,479.99	600,469.68	46,525,765.22	192,002	503,169.09	0.0038304	2.19	598,697.00	95,527.91	19%
GS3-Sec	0.0022472	2.37	0.0029583	2.23	0.0046084	2.69	232,682,116.00	504,439.03	721,280.22	1,230,979.07	109,890,307.46	238,553	1,148,124.93	0.0040913	3.75	1,344,166.39	196,041.46	17%
GS3-Pri	0.0021666	2.29	0.0028558	2.15	0.0044487	2.60	555,662,859.00	1,109,575.91	1,604,319.65	2,594,133.66	256,876,715.86	516,036	2,484,461.62	0.0039494	3.62	2,882,560.02	398,098.40	16%
GS3-Sub/Tran	0.0021145	2.23	0.0027900	2.10	0.0043463	2.54	242,273,512.00	491,111.52	705,371.44	1,129,289.28	114,407,028.76	232,008	1,086,548.71	0.0038707	3.55	1,266,465.25	179,916.54	17%
GS4-Pri	0.0020345	2.14	0.0022055	2.25	0.0034566	2.15	37,342,800.00	67,792.68	77,724.70	146,996.17	14,905,184.66	26,889	109,333.49	0.0041119	3.52	155,939.35	46,605.86	43%
GS4/IRP-Sub/Tran	0.0019855	2.09	0.0021548	2.20	0.0033770	2.10	3,004,513,151	6,005,374	7,512,769.27	12,687,795.09	1,372,410,715	2,795,940	10,506,104.56	0.0040300	3.45	15,176,807.49	4,670,702.93	44%
EHG	0.0083313		0.0083313		0.0083211		634,333.00	-	5,282.06	-	314,631.79	-	2,618.08	0.0076122		2,395.04	(223.04)	-9%
AL	0.0032986		0.0033291		0.0036987		5 404 517 00		19 023 63	-	2,862,468.99		10,587.41	0.0040303		11,536.61	949.20	9%
							4,492,958,805	9,922,033	12,224,610	20,552,049	2,071,621,525	4,655,524	17,663,503.58			23,634,711.11	5,971,207.53	34%
Joint Service Territory	0.0019855	2.09	0.0021548	2.20	0.0033770	2.10	1,615,299,502	2,267,649	4,215,379.80	4,785,291.17	1,440,000,000	2,023,915	9,113,101.46	0.0040300	3.45	12,785,706.68	3,672,605.22	40%

Ohio Power Rate Zone

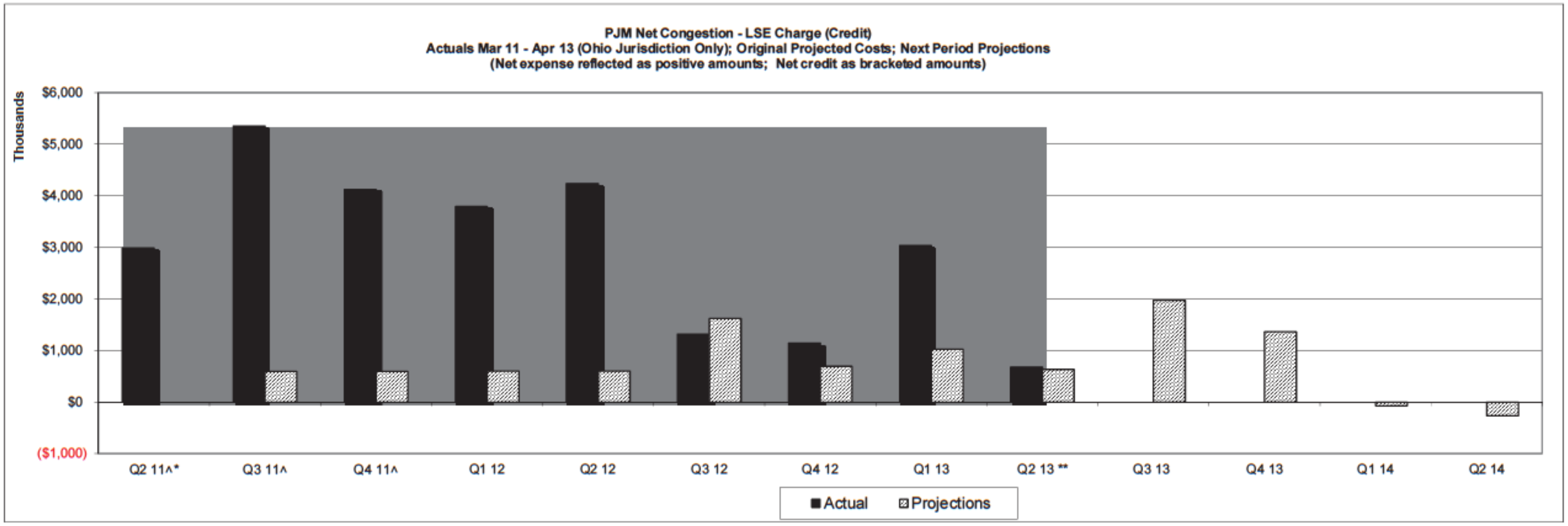
		(Stip rejection) May 2012 - Aug 2012 Rates		(ESP2.5 Order) Sep 2012 - Oct 2012 Rates		(current) Nov 2012 - Apr 2013 Rates		Actual 12 Months Billed 4/30/2013				Forecast September 2013 August 2014		Revenue at Current Rates	Forecast September 2013 August 2014				
										Revenue					Proposed Rates		Revenue at Proposed Rates	$ Change	% Change
		$ kWh	$ Demand	$ kWh	$ Demand	$ kWh	$ Demand	Metered kWh	Demand	kWh	Demand	Metered kWh	Demand	Rates	kWh	Demand	Rates		
Other																			
	GS1	0.0082301		0.0094194		0.0089975		2,036,931		17,823.22	-	2,192,756		19,729.32	0.0133710		29,319.34	9,590.02	49%
	GS2- Sec	0.0026532	1.65	0.0034361	1.72	0.0051223	1.54	747,184	2,528	2,707.67	4,112.45	794,075	2,660	8,164.54	0.0040487	2.32	9,387.14	1,222.60	15%
	GS2 RL - GS - TOD	0.0092133		0.0102608		0.0113915		410,540		4,503.15	-	477,587		5,440.43	0.0136033		6,496.76	1,056.33	19%
	GS3-Sec	0.0022472	2.37	0.0029583	2.23	0.0046084	2.69	588,004	1,247	1,594.18	2,950.68	591,967	1,256	6,106.58	0.0040913	3.75	7,131.80	1,025.22	17%
	AL	0.0032986		0.0033291		0.0036987		193,575		680.23	-	213,408		789.33	0.0040303		860.10	70.77	9%
	SL	0.0032986		0.0033291		0.0036987		45,696,023		160,434.14	-	50,146,936		185,478.47	0.0040303		202,107.20	16,628.73	9%
								49,672,257	3,774	187,742.59	7,063.13	54,416,729	3,916	225,708.67			255,302.34	29,593.67	13%
Munis																			
	GS2-Pri	0.0025581	1.59	0.0033170	1.66	0.0049448	1.49	522,900	1,420	2,015.43	2,216.62	518,144	1,413	4,667.40	0.0039082	2.24	5,190.00	522.60	11%
	GS3-Pri	0.0021666	2.29	0.0028558	2.15	0.0044487	2.60	7,760,100	17,122	26,928.05	41,311.48	7,711,856	17,011	78,535.24	0.0039494	3.62	92,035.50	13,500.26	17%
								8,283,000	18,542	28,943.48	43,528.10	8,230,000	18,424	83,202.64			97,225.50	14,022.86	17%
	Total							14,631,885,363	19,750,014	87,977,608.50	39,882,815.14	9,035,656,873	10,169,142	88,997,090.32			118,502,441.40	29,505,351.08	33%
AEP-Ohio																			
	Recap																		
	Residential							5,670,333,877	36	59,782,463.44	55.44	8,898,323,500	-	47,988,000.76			64,978,500.46	16,990,499.70	35%
	Commercial							2,795,337,922	7,537,980	11,538,469.12	14,494,827.90	2,784,272,825	7,034,638	13,923,573.21			16,750,995.31	2,827,422.10	20%
	Industrial							4,492,958,805	9,922,033	12,224,610.07	20,552,049.40	2,680,415,636	5,929,609	17,663,503.58			23,634,711.11	5,971,207.53	34%
	Joint Service Territory							1,615,299,502	2,267,649	4,215,379.80	4,785,291.17	2,880,000,000	4,052,478	9,113,101.46			12,785,706.68	3,672,605.22	40%
	Other							49,672,257	3,774	187,742.59	7,063.13	92,267,781	3,916	225,708.67			255,302.34	29,593.67	13%
	Munis							8,283,000	18,542	28,943.48	43,528.10	8,230,000	18,424	83,202.64			97,225.50	14,022.86	17%
	Total							14,631,885,363	19,750,014	87,977,608.50	39,882,815.14	17,343,509,741	17,039,065	88,997,090.32			118,502,441.40	29,505,351.08	33%
	RS							5,657,342,977	-	59,736,629.76	-	8,881,307,554	-	102,763,833			139,168,313.12	16,987,294.42	17%
	GS1							265,301,586	-	2,331,215.26	-	266,329,344	-	2,396,298			3,561,089.66	575,211.16	24%
	GS2 Sec							1,226,200,167	5,231,761	4,548,171.18	8,487,179.50	987,898,635	4,037,409	11,277,923			13,366,493.53	1,298,629.49	12%
	GS2 RL - GS - TOD							* 73,574,793	-	757,849.97	-	38,883,822	158,913 *	442,945			528,948.30	78,151.46	18%
	GS2 Pri							143,097,766	634,833	518,362.98	993,698.66	76,852,043	340,253	886,995			1,062,519.87	158,627.68	18%
	GS2 Sub/Trans							100,572,546	423,004	341,427.50	644,269.65	47,830,525	205,847	529,547			634,014.75	104,467.48	20%
	GS3 Sec							1,280,931,778	2,816,629	4,114,304.71	6,915,623.86	1,252,314,373	2,847,947	13,432,144			15,803,395.80	1,079,034.20	8%
	GS3 - TOD											-	-	-			-		
	GS3 Pri							837,489,518	1,689,494	2,470,822.03	3,966,946.24	696,446,446	1,420,327	6,791,132			7,892,129.99	611,741.47	9%
	GS3 Sub/Trans							264,727,909	533,478	781,162.97	1,229,414.80	125,687,890	253,176	1,189,345			1,385,275.20	195,930.68	16%
	GS4 Pri							37,342,800	67,793	77,724.70	146,996.17	14,905,185	26,889	109,333			155,939.35	46,605.86	43%
	GS4/IRP Sub/Trans							4,619,812,653.00	8,273,023.36	11,728,149.07	17,473,086.26	4,807,558,645	7,907,216	32,840,280			46,654,357.16	8,343,308.15	25%
	EHG							15,365,493	-	127,933.14	-	7,683,731	-	63,937			58,490.09	(5,447.00)	-9%
	SS							11,832,765	-	98,146.11	-	5,877,597	-	65,515			70,768.62	5,253.40	8%
	AL							52,596,589	-	185,274.98	-	56,672,920	-	209,616			228,408.87	9,913.90	5%
	SL							45,696,023	-	160,434.14	-	77,261,032	-	285,765			311,385.14	16,628.73	6%
	SBS							-	80,000.00	-	25,600.00	-							
	Total							14,631,885,363.00	19,750,014.41	87,977,608.50	39,882,815.14 #	17,343,509,741.36	17,197,977.66	173,284,608.50	-	-	230,881,529.44	29,505,351.08	17%

Columns Southern Power Rate Zone

	(Stip rejection) May 2012 - Aug 2012 Rate $ kWh	$ Demand	(ESP2.5 Order) Sep 2012 - Oct 2012 Rates $ kWh	$ Demand	(current) Nov 2012 - Apr 2013 Rates $ kWh	$ Demand	Actual 12 Months Billed 4/30/2013 Metered kWh	Demand	Revenue kWh	Revenue Demand	Forecast September 2013 August 2014 Metered kWh	Demand	Revenue at Current Rates	Forecast September 2013 August 2014 Proposed Rates kWh	Proposed Rates Demand	Revenue at Proposed Rates	$ Change	% Change
Residential																		
Residential	0.0103699		0.0098403		0.0115708		6,479,533,562		70,498,564	-	4,737,054,704		54,811,512.57	0.0156698		74,228,699.80	19,417,187.23	35%
GS1	0.0110600		0.0094194		0.0089975		3,612		31	-	2,836		25.52	0.0133710		37.93	12.41	49%
AL	0.0033747		0.0033291		0.0036987		10,081,383		35,547	-	7,372,920		27,270.22	0.0040303		29,715.08	2,444.86	9%
							6,489,618,557	-	70,534,141.69	-	4,744,430,460	-	54,838,808.30			74,258,452.80	19,419,644.50	35%
Commercial																		
Residential	0.0103699		0.0098403		0.0115708		(1,371)		(14)	-	(485)		(5.61)	0.0156698		(7.59)	(1.99)	35%
GS1	0.0110600		0.0094194		0.0089975		246,115,923		2,415,545	-	120,398,487		1,083,285.38	0.0133710		1,609,848.16	526,562.78	49%
GS2-Sec	0.0058552	1.941	0.0034361	1.720	0.0051223	1.540	812,970,098	3,041,827	4,160,996	5,276,074	388,002,747	1,452,507	4,224,327.28	0.0040487	2.320	4,940,723.01	716,395.73	17%
GS2-TOD/LM	0.0135027		0.0102608		0.0113915		7,209,206		86,370	-	3,495,968		39,824.32	0.0136033		47,556.70	7,732.38	19%
GS2-Pri	0.0056645	1.878	0.0033170	1.660	0.0049448	1.490	7,063,724	25,887	34,494	42,711	3,478,413	12,475	35,787.27	0.0039082	2.240	41,537.53	5,750.26	16%
GS3-Sec	0.0038545	2.073	0.0029583	2.230	0.0046084	2.690	1,217,630,865	2,846,428	4,878,890	6,696,629	578,413,231	1,349,673	6,296,179.55	0.0040913	3.750	7,427,735.32	1,131,555.76	18%
GS3-LM-TOD	0.0084657		0.0076945		0.0104135		-		-	-	-		-	0.0122816		-	-	0%
GS3-Pri	0.0037289	2.005	0.0028558	2.150	0.0044487	2.600	438,744,197	957,772	1,701,307	2,179,779	209,946,181	453,105	2,112,061.17	0.0039494	3.620	2,469,402.38	357,341.21	17%
GS4/IRP	0.0025694	2.507	0.0021548	2.2000000	0.0033770	2.1000000	405,744,145	784,149	1,018,564	1,904,332	154,142,153	299,514	1,149,518.39	0.0040300	3.450	1,654,517.73	504,999.33	44%
SL	0.0033747		0.0033291		0.0036987		1,031,856		3,641	-	513,306		1,898.56	0.0040303		2,068.78	170.21	9%
AL	0.0033747		0.0033291		0.0036987		37,202,696		131,139	-	18,387,245		68,008.90	0.0040303		74,106.12	6,097.21	9%
							3,173,711,339	7,656,063	14,430,932.80	16,099,523.54	1,476,777,246	3,567,274	15,010,885.24			18,267,488.13	3,256,602.88	22%
Industrial																		
GS1	0.0110600		0.0094194		0.0089975		6,100,444		59,547	-	3,155,829		28,394.57	0.0133710		42,196.59	13,802.02	49%
GS2-Sec	0.0058552	1.941	0.0034361	1.720	0.0051223	1.540	48,421,808	253,868	246,941	438,841	24,645,360	128,211	323,686.50	0.0040487	2.3200000	397,232.14	73,545.64	23%
GS2-TOD/LM	0.0135027		0.0102608		0.0113915		127,600		1,577	-	53,982		614.93	0.0136033		734.33	119.40	19%
GS2-Pri	0.0056645	1.878	0.0033170	1.660	0.0049448	1.490	7,328,650	39,502	36,105	65,757	3,785,914	20,095	48,662.56	0.0039082	2.240	59,809.54	11,146.98	23%
GS3-Sec	0.0038545	2.073	0.0029583	2.230	0.0046084	2.690	155,189,085	377,869	619,662	890,748	78,128,239	189,682	870,289.49	0.0040913	3.750	1,030,951.80	160,662.31	18%
GS3-Pri	0.0037289	2.005	0.0028558	2.150	0.0044487	2.600	206,865,281	374,999	791,133	833,467	97,003,380	176,813	891,252.40	0.0039494	3.620	1,023,167.74	131,915.34	15%
GS4/IRP	0.0025694	2.507	0.0021548	2.200	0.0033770	2.100	820,881,249	1,523,899	2,342,790	3,482,440	401,005,778	759,284	2,948,693.48	0.0040300	3.450	4,235,584.01	1,286,890.54	44%
AL	0.0033747		0.0033291		0.0036987		2,003,884		7,050	-	1,015,629		3,756.51	0.0040303		4,093.29	336.78	9%
							1,246,918,001	2,570,137	4,104,803.00	5,711,252.77	608,794,110	1,274,085	5,115,350.44			6,793,769.44	1,678,419.01	33%
Joint Service Territory	0.0025694	2.507	0.0021548	2.200	0.0033770	2.100	1,615,299,502	2,274,165	4,614,614	5,201,389	1,440,000,000	2,028,563	9,122,861.63	0.0040300	3.450	12,801,741.25	3,678,879.62	40%
Other																		
GS1	0.0110600		0.0094194		0.0089975		10,284,556		100,818	-	11,250,262		101,224.23	0.0133710		150,427.25	49,203.02	49%
SL	0.0033747		0.0033291		0.0036987		24,381,698		85,876	-	26,600,790		98,388.34	0.0040303		107,209.17	8,820.82	9%
							34,666,254	-	186,693.64	-	37,851,052	-	199,612.57			257,636.42	58,023.84	29%
Total							**12,560,213,653**	**12,500,365**	**93,871,185.13**	**27,012,165.32**	**8,307,852,869**	**6,869,922**	**84,287,518.18**			**112,379,088.03**	**28,091,569.85**	33%

Ohio Power Company
Summary of Current and Proposed Rates

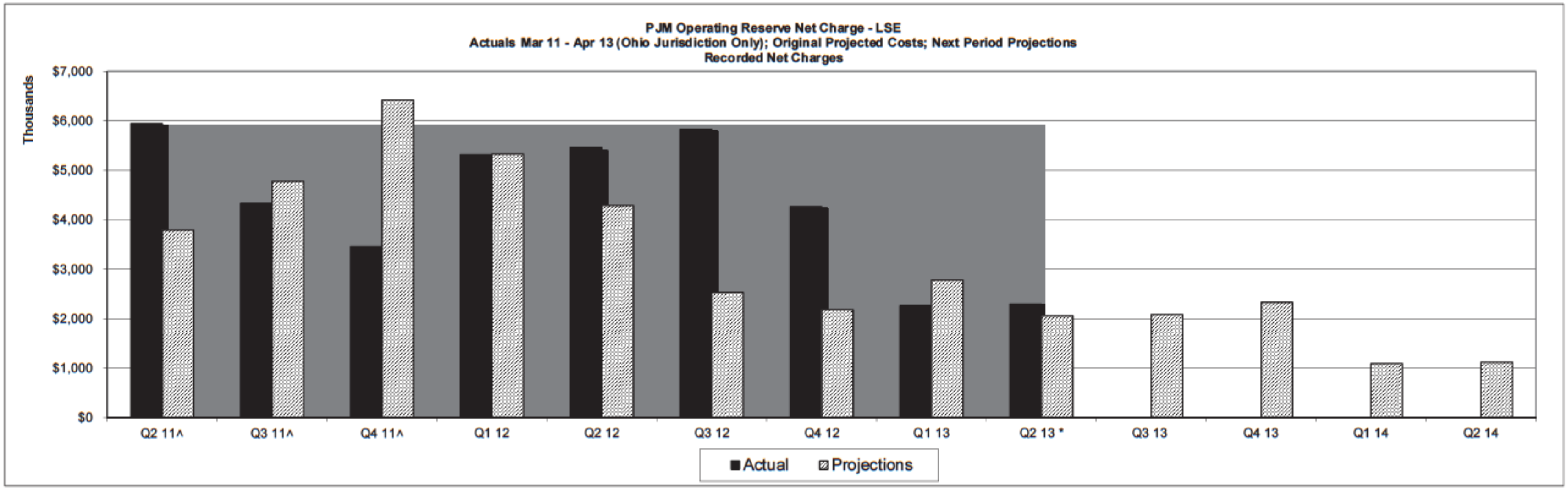
	Forecast for September 2013 - August 2014				Forecast for September 2013 - August 2014			
	Current TCRR Energy Rate	Proposed TCRR Energy Rate	Energy Difference	Energy % Difference	Current TCRR Demand Rate	Proposed TCRR Demand Rate	Demand Difference	Demand % Difference
Residential	$0.0115708	$0.0156698	$0.0040990	35.43%				
GS-1 / GS-1-TOD	$0.0089975	$0.0133710	$0.0043735	48.61%				
GS2-Sec	$0.0051223	$0.0040487	-$0.0010736	-20.96%	$1.54	$2.32	$0.78	50.65%
GS2 RL - GS - TOD / GS2-TOD/LM	$0.0113915	$0.0136033	$0.0022118	19.42%				
GS2-Pri	$0.0049448	$0.0039082	-$0.0010366	-20.96%	$1.49	$2.24	$0.75	50.34%
GS2-Sub/Tran	$0.0048310	$0.0038304	-$0.0010006	-20.71%	$1.45	$2.19	$0.74	51.03%
GS3-Sec	$0.0046084	$0.0040913	-$0.0005171	-11.22%	$2.69	$3.75	$1.06	39.41%
GS3-TOD	$0.0104135	$0.0122816	$0.0018681	17.94%				
GS3-Pri	$0.0044487	$0.0039494	-$0.0004993	-11.22%	$2.60	$3.62	$1.02	39.23%
GS3-Sub/Tran	$0.0043463	$0.0038707	-$0.0004756	-10.94%	$2.54	$3.55	$1.01	39.76%
GS4-Pri	$0.0034566	$0.0041119	$0.0006553	18.96%	$2.15	$3.52	$1.37	63.72%
GS4/IRP-Sub/Tran	$0.0033770	$0.0040300	$0.0006530	19.34%	$2.10	$3.45	$1.35	64.29%
EHG	$0.0083211	$0.0076122	-$0.0007089	-8.52%				
SS	$0.0111466	$0.0120404	$0.0008938	8.02%				
EHS	$0.0111466	$0.0120404	$0.0008938	8.02%				
AL	$0.0036987	$0.0040303	$0.0003316	8.97%				
SL	$0.0036987	$0.0040303	$0.0003316	8.97%				
SBS-Sub/Tran-Backup - 5%	$0.0038013	$0.0039585	$0.0001572	4.14%	$0.12	$0.04	-$0.08	-66.67%



	ACTUAL								
	Mar-11^*	Q2 11^*	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Net Congestion - LSE	(548,514)	2,989,217	5,353,232	4,122,021	3,790,750	4,237,496	1,316,621	1,146,934	3,035,714
Projections - PJM Net Congestion - LSE	-	-	591,384	593,633	600,256	600,507	1,622,588	692,926	1,021,044

	FORECAST							
	Apr-13**	May-13**	Jun-13**	Q2 13 **	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Net Congestion - LSE	252,527	211,226	211,226	674,979	-	-	-	-
Projections - PJM Net Congestion - LSE	211,227	211,226	211,226	633,679	1,975,238	1,362,802	(73,106)	(268,896)

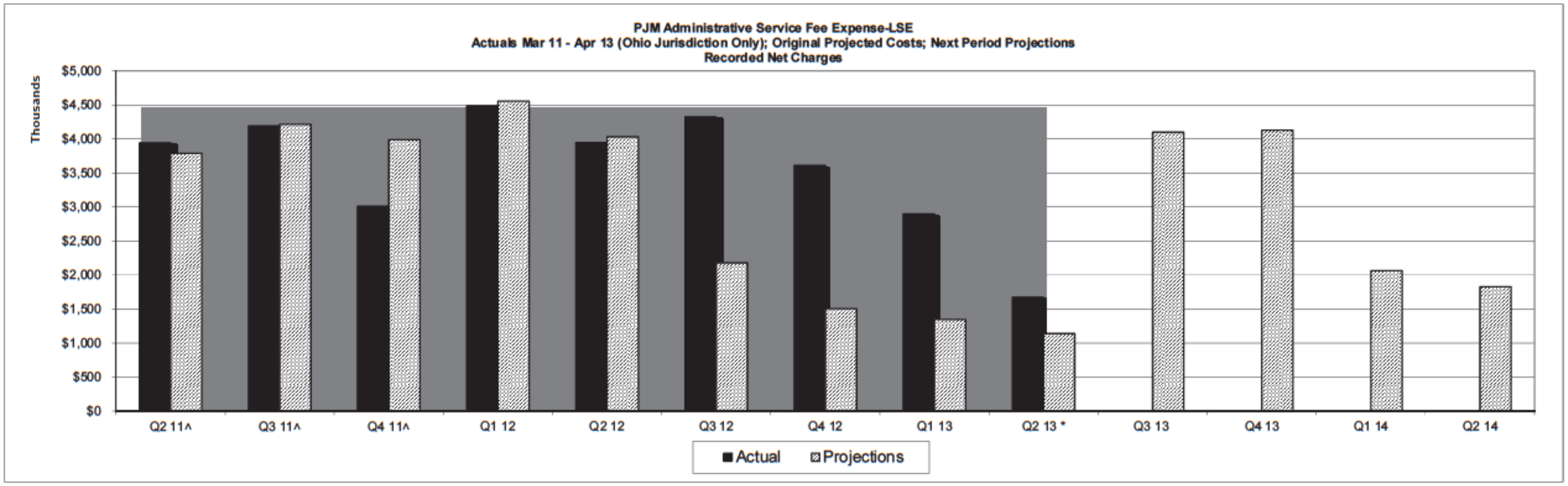
^ For comparability, OPCo & CSP for March 2011 thru Q4 2011 have been combined. OPCo & CSP merger was effective Q1 2012.
* Projected PJM Net Congestion March 2011, and Q2 2011 is $0.
** Q2 13 includes one month of actual and two months projection.



	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Operating Reserve-LSE	2,739,849	5,942,195	4,332,761	3,459,422	5,315,449	5,455,714	5,827,255	4,261,516	2,259,627
Projections - PJM Operating Reserve-LSE	1,367,467	3,791,364	4,774,717	6,421,870	5,324,036	4,284,000	2,532,617	2,182,054	2,782,893

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Operating Reserve-LSE	921,862	685,264	685,264	2,292,390	-	-	-	-
Projections - PJM Operating Reserve-LSE	685,264	685,264	685,264	2,055,792	2,084,527	2,331,668	1,090,146	1,116,102

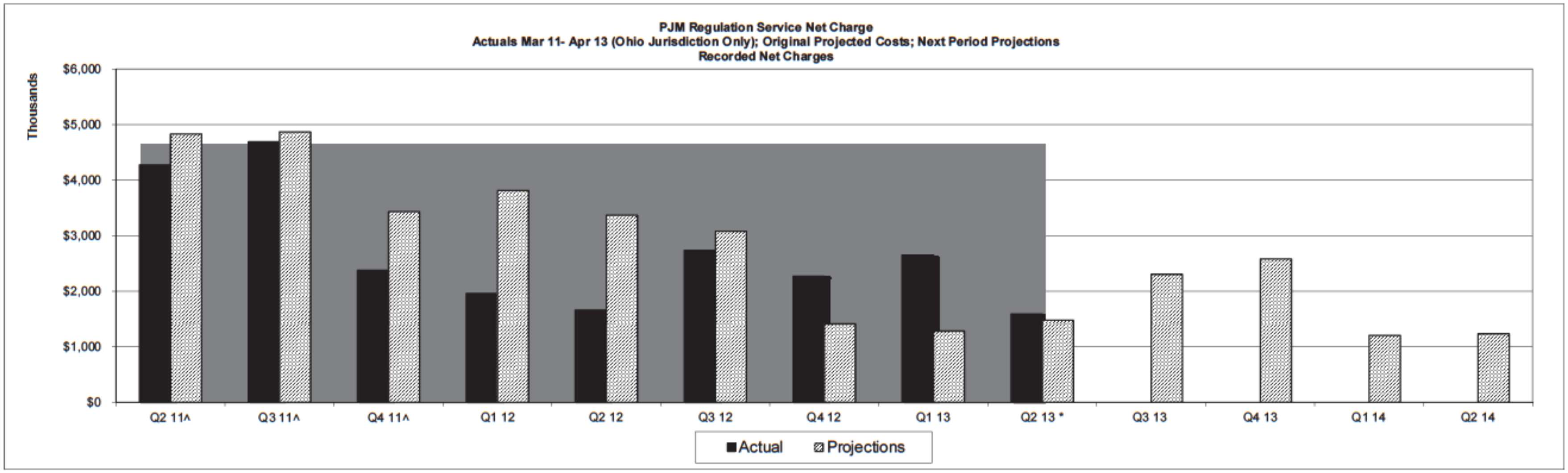
^ For comparability, OPCo & CSP for March 2011 thru Q4 2011 have been combined. OPCo & CSP merger was effective Q1 2012.
* Q2 13 includes one month of actual and two months projection.



	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Administrative Service Fee	1,049,913	3,945,505	4,195,831	3,012,571	4,489,087	3,950,015	4,325,663	3,613,499	2,899,915
Projections - PJM Administrative Service Fee	1,264,448	3,793,344	4,218,380	3,990,762	4,559,821	4,035,434	2,180,794	1,504,976	1,348,533

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Administrative Service Fee	911,742	380,274	380,274	1,672,290	-	-	-	-
Projections - PJM Administrative Service Fee	380,274	380,274	380,274	1,140,822	4,102,419	4,129,814	2,065,382	1,827,068

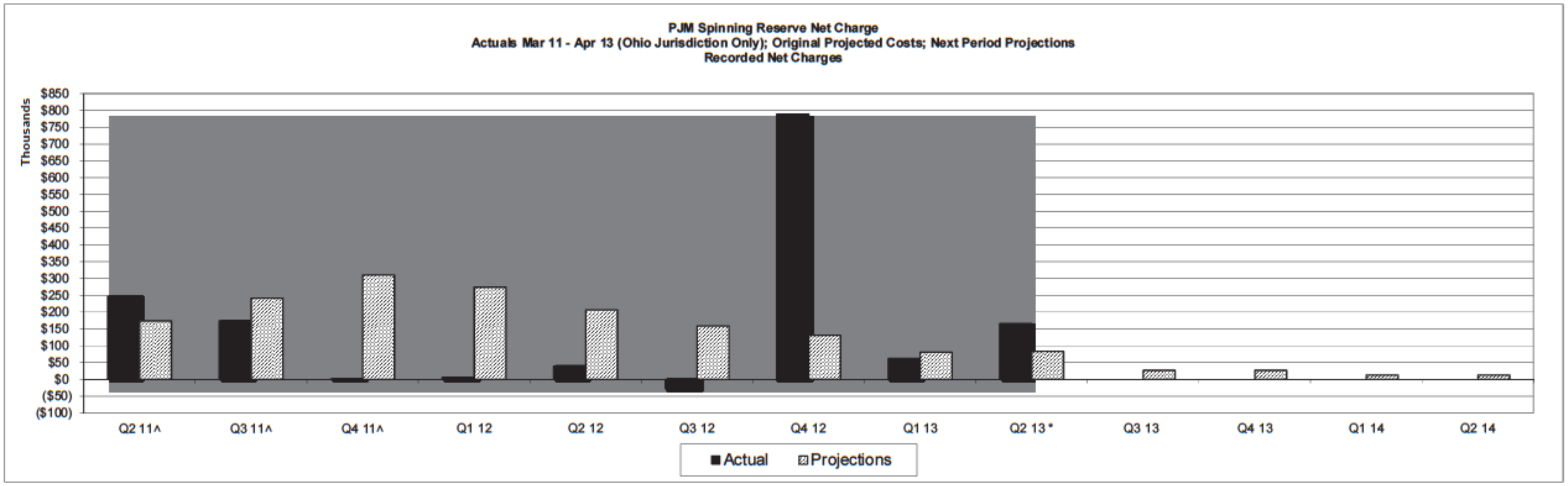
^ For comparability, OPCo & CSP for March 2011 thru Q4 2011 have been combined. OPCo & CSP merger was effective Q1 2012.
* Q2 13 includes one month of actual and two months projection.



	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Regulation Service	864,886	4,275,601	4,687,710	2,375,207	1,958,583	1,662,282	2,736,568	2,273,297	2,652,299
Projections - PJM Regulation Service	1,616,364	4,829,707	4,867,919	3,432,786	3,815,426	3,367,980	3,079,858	1,412,504	1,282,818

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Regulation Service	606,305	493,226	493,226	1,592,757	-	-	-	-
Projections - PJM Regulation Service	493,226	493,226	493,226	1,479,678	2,307,257	2,580,805	1,206,628	1,235,357

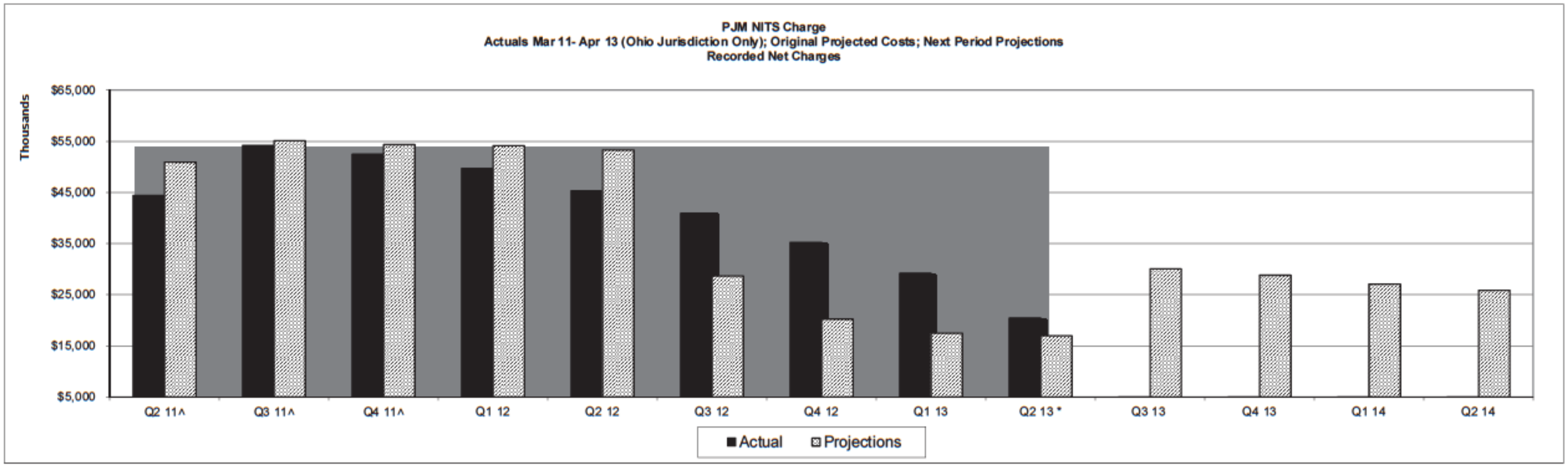
^ For comparability, OPCo & CSP for March 2011 thru Q4 2011 have been combined. OPCo & CSP merger was effective Q1 2012.
* Q2 13 includes one month of actual and two months projection.



	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Spinning Reserve	113,501	246,917	173,889	1,965	6,089	39,683	(27,166)	789,548	62,034
Projections - PJM Spinning Reserve	52,577	174,046	241,554	310,823	274,198	206,599	158,930	131,461	80,928

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Spinning Reserve	110,207	27,923	27,923	166,053	-	-	-	-
Projections - PJM Spinning Reserve	27,922	27,923	27,923	83,768	27,065	27,237	13,038	13,038

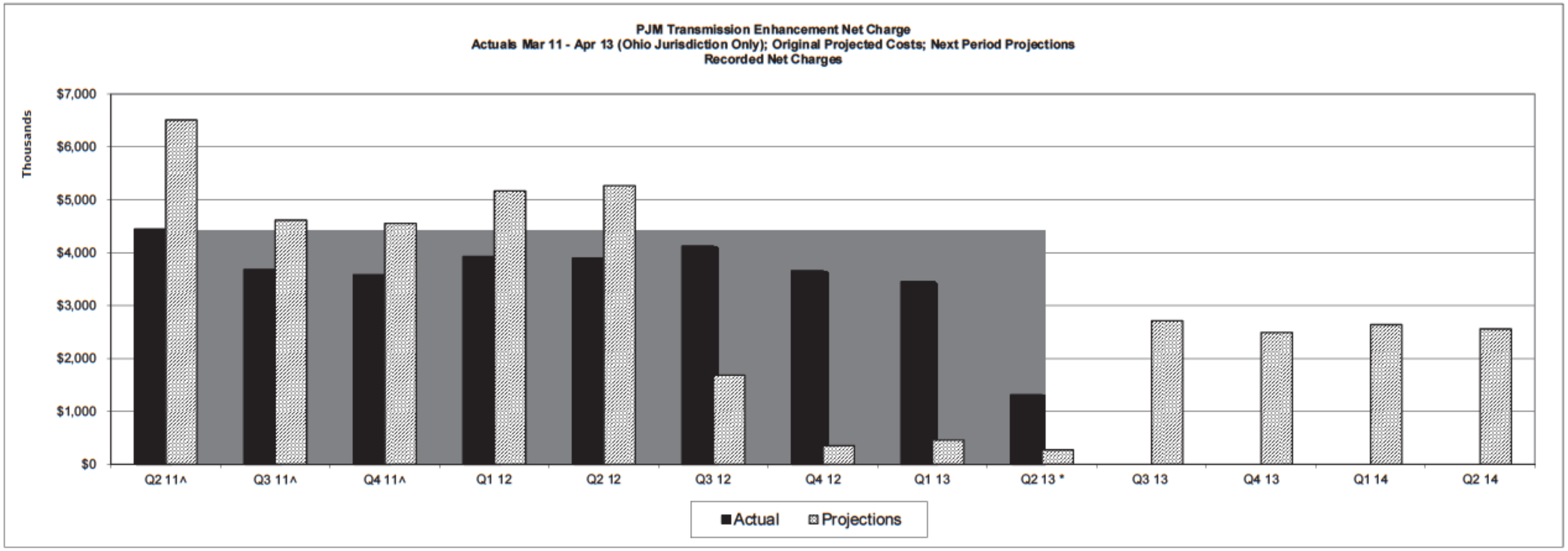
^ For comparability, OPCo & CSP for March 2011 thru Q4 2011 have been combined. OPCo & CSP merger was effective Q1 2012.
* Q2 13 includes one month of actual and two months projection.



	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM NITS	15,466,943	44,435,978	54,229,633	52,504,642	49,733,826	45,335,338	40,926,482	35,241,000	29,202,954
Projections - PJM NITS	18,211,925	50,954,124	55,129,504	54,375,590	54,142,606	53,283,268	28,659,738	20,225,223	17,481,903

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM NITS	9,100,148	5,657,653	5,657,653	20,415,454	-	-	-	-
Projections - PJM NITS	5,657,653	5,657,653	5,657,653	16,972,959	30,038,303	28,816,655	27,077,562	25,849,412

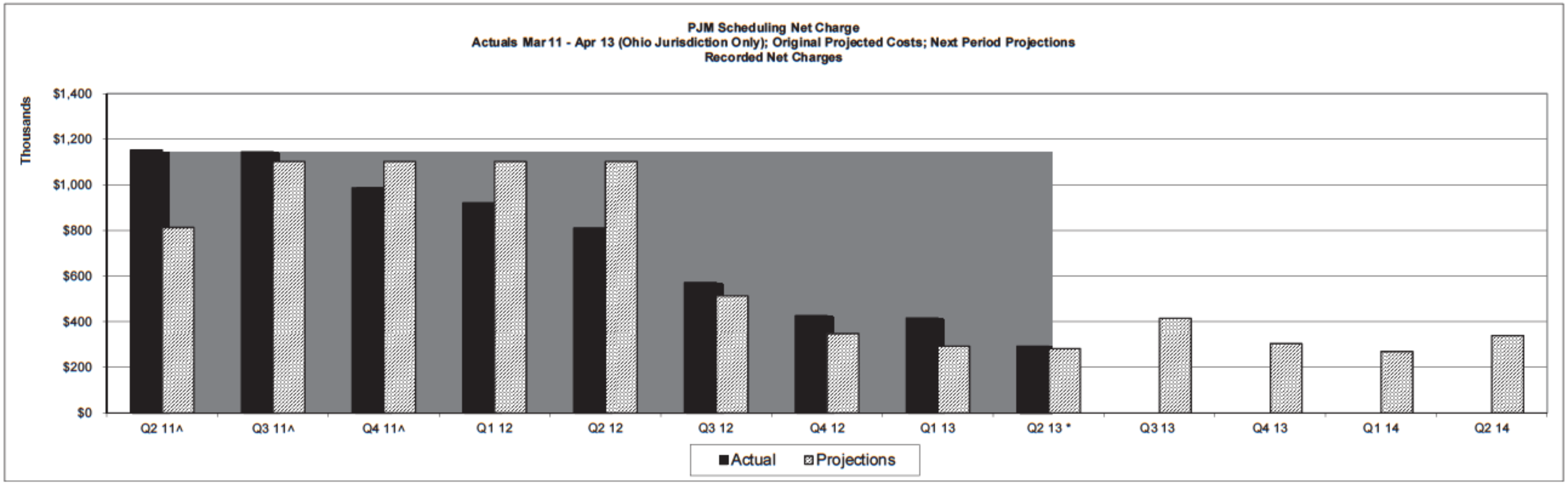
^ For comparability, OPCo & CSP for March 2011 thru Q4 2011 have been combined. OPCo & CSP merger was effective Q1 2012.
* Q2 13 includes one month of actual and two months projection.



	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Transmission Enhancement	1,504,968	4,447,691	3,682,714	3,584,493	3,930,866	3,900,219	4,124,994	3,664,214	3,456,767
Projections - PJM Transmission Enhancement	2,172,132	6,512,058	4,618,263	4,555,106	5,169,506	5,267,188	1,683,797	354,568	457,353

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Transmission Enhancement	1,134,750	90,758	90,758	1,316,266	-	-	-	-
Projections - PJM Transmission Enhancement	90,758	90,758	90,758	272,274	2,714,914	2,492,843	2,641,540	2,561,079

^ For comparability, OPCo & CSP for March 2011 thru Q4 2011 have been combined. OPCo & CSP merger was effective Q1 2012.
* Q2 13 includes one month of actual and two months projection

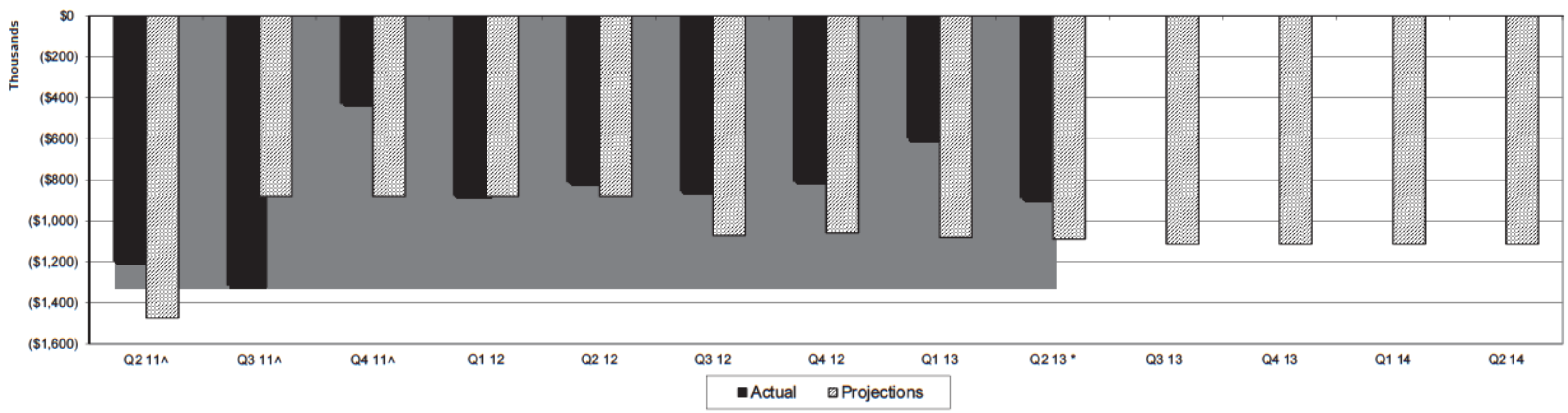


	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Scheduling	414,313	1,153,257	1,145,466	986,740	921,826	810,959	572,318	426,477	416,567
Projections - PJM Scheduling	271,138	813,393	1,102,716	1,102,716	1,102,716	1,102,716	513,158	347,905	292,819

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Scheduling	104,817	94,063	94,063	292,943	-	-	-	-
Projections - PJM Scheduling	94,063	94,063	94,063	282,189	414,930	304,077	269,268	339,678

^ For comparability, OPCo & CSP for March 2011 thru Q4 2011 have been combined. OPCo & CSP merger was effective Q1 2012.
* Q2 13 includes one month of actual and two months projection

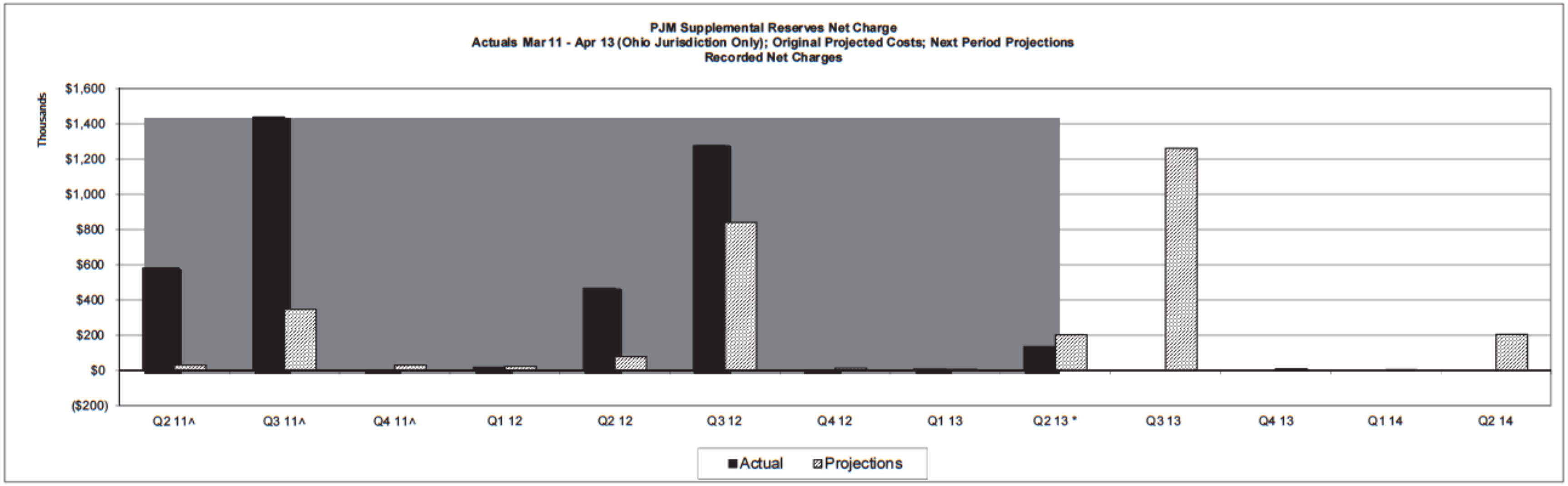
PJM Point to Point Revenues
Actuals Mar 11 - Apr 13 (Ohio Jurisdiction Only); Original Projected Costs; Next Period Projections
Recorded Net Credits



	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Point to Point	(319,955)	(1,194,955)	(1,311,742)	(424,254)	(874,158)	(808,578)	(852,688)	(805,321)	(591,868)
Projections - PJM Point to Point	(478,328)	(1,473,983)	(880,785)	(880,785)	(880,785)	(880,785)	(1,071,229)	(1,057,813)	(1,081,342)

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Point to Point	(160,379)	(362,452)	(362,452)	(885,283)	-	-	-	-
Projections - PJM Point to Point	(362,451)	(362,452)	(362,452)	(1,087,355)	(1,113,000)	(1,113,000)	(1,113,000)	(1,113,000)

^ For comparability, OPCo & CSP for March 2011 thru Q4 2011 have been combined. OPCo & CSP merger was effective Q1 2012.
* Q2 13 includes one month of actual and two months projection



	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Supplemental Reserves	2,521	582,504	1,439,107	(1,239)	17,777	466,989	1,276,990	(1,483)	7,475
Projections - PJM Supplemental Reserves	6,875	30,943	347,907	30,576	23,689	78,896	840,662	12,485	5,918

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Supplemental Reserves	413	67,304	67,304	135,021	-	-	-	-
Projections - PJM Supplemental Reserves	67,303	67,304	67,304	201,911	1,262,094	10,281	3,280	205,039

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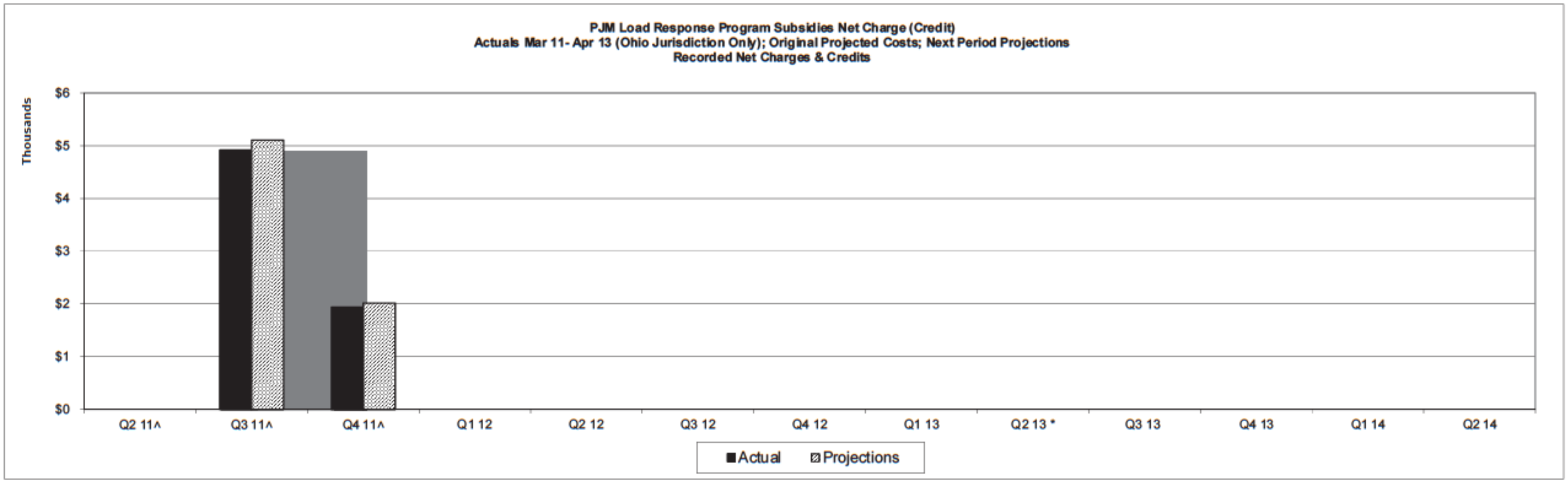
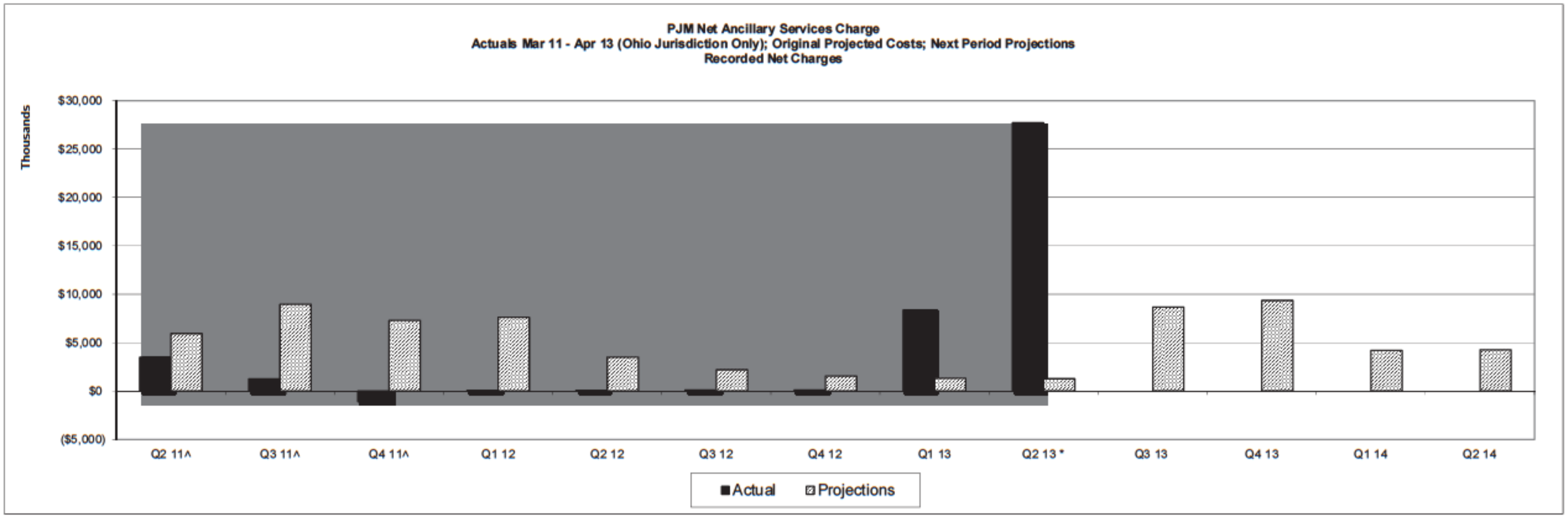


	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Load Response Program Subsidies	-	-	4,919	1,944	-	-	-	-	-
Projections - PJM Load Response Program Subsidies	-	-	5,111	2,020	-	-	-	-	-

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Load Response Program Subsidies	-	-	-	-	-	-	-	-
Projections - PJM Load Response Program Subsidies	-	-	-	-	-	-	-	-

^ For comparability, OPCo & CSP for March 2011 thru Q4 2011 have been combined. OPCo & CSP merger was effective Q1 2012.
* Q2 13 includes one month of actual and two months projection



	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Net Ancillary Services	1,209,277	3,486,456	1,242,722	(1,097,844)	70,140	67,861	109,466	106,510	8,392,844
Projections - PJM Net Ancillary Services	1,696,534	5,939,060	8,968,025	7,297,796	7,624,519	3,512,673	2,203,724	1,541,174	1,330,641

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Net Ancillary Services	26,881,081	424,885	424,885	27,730,851	-	-	-	-
Projections - PJM Net Ancillary Services	424,884	424,885	424,885	1,274,654	8,670,684	9,363,111	4,193,401	4,257,138

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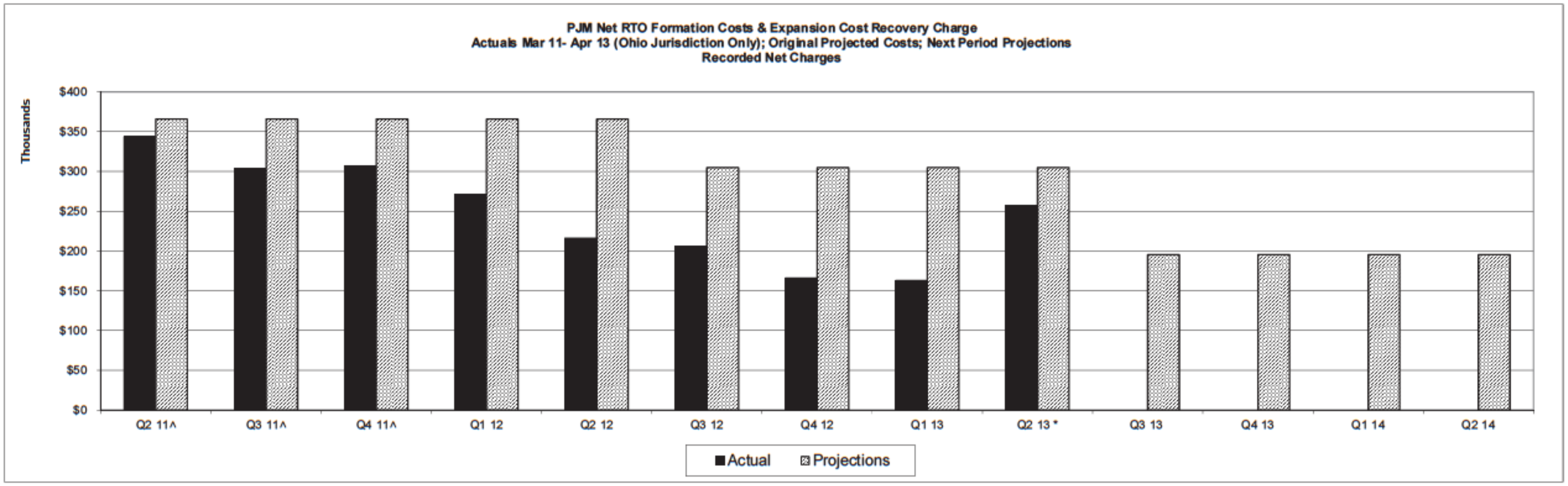
* Q2 13 includes one month of actual and two months projection



	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Net RTO Formation Costs & Expansion	118,240	343,618	303,323	306,497	270,931	216,134	206,008	165,952	162,555
Projections - PJM Net RTO Formation Costs &	122,124	365,676	365,676	365,676	365,676	365,676	304,836	304,836	304,836

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Net RTO Formation Costs & Expansion	53,947	101,612	101,612	257,171	-	-	-	-
Projections - PJM Net RTO Formation Costs &	101,612	101,612	101,612	304,836	195,381	195,381	195,381	195,381

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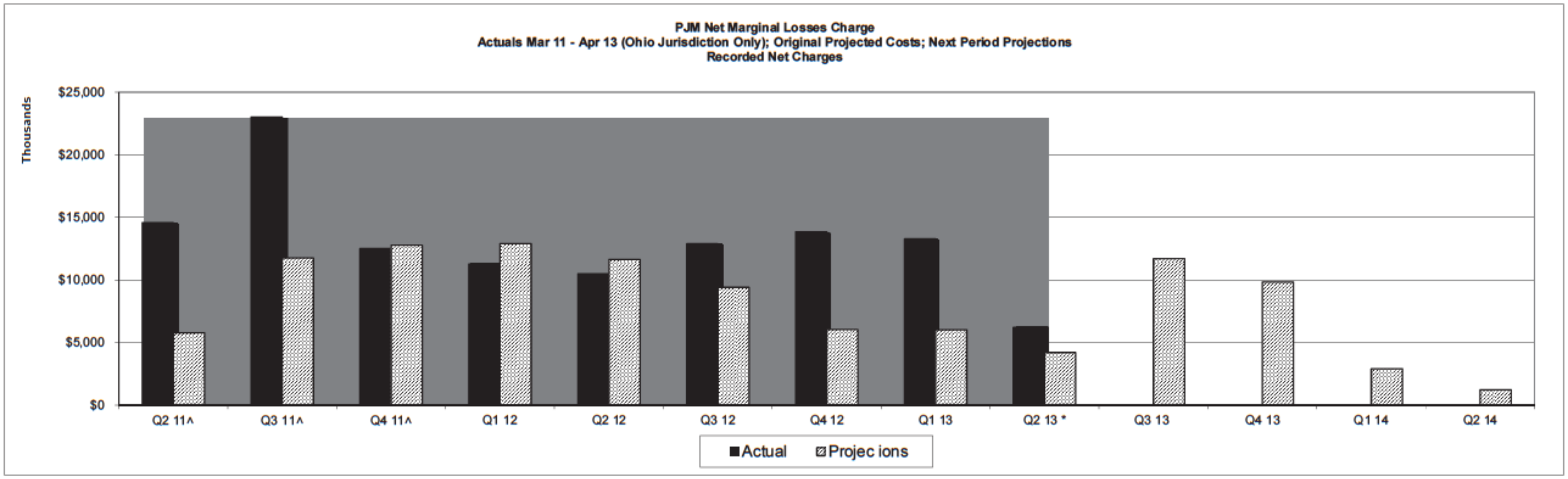
* Q2 13 includes one month of actual and two months projection



	ACTUAL								
	Mar-11^	Q2 11^	Q3 11^	Q4 11^	Q1 12	Q2 12	Q3 12	Q4 12	Q1 13
Actual - PJM Net Marginal Losses	3,745,517	14,595,251	23,028,104	12,513,543	11,277,821	10,505,231	12,903,240	13,852,417	13,294,976
Projections - PJM Net Marginal Losses	2,728,502	5,785,197	11,762,385	12,777,630	12,906,830	11,639,611	9,416,001	6,037,829	6,031,678

	FORECAST							
	Apr-13*	May-13*	Jun-13*	Q2 13 *	Q3 13	Q4 13	Q1 14	Q2 14
Actual - PJM Net Marginal Losses	3,418,987	1,401,607	1,401,607	6,222,201	-	-	-	-
Projections - PJM Net Marginal Losses	1,401,608	1,401,607	1,401,607	4,204,822	11,720,197	9,852,241	2,911,098	1,234,582

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* Q2 13 includes one month of actual and two months projection

Ohio Power Company
2013 Typical Bill Comparison
Ohio Power Rate Zone

Tariff	kWh	KW	Current	Proposed	$ Difference	Difference
Residential	100		$17.97	$18.38	$0.41	2.3%
	250		$37.03	$38.06	$1.03	2.8%
	500		$68.87	$70.91	$2.04	3.0%
	750		$100.67	$103.74	$3.07	3.1%
	1,000		$129.78	$133.88	$4.10	3.2%
	1,500		$186.69	$192.83	$6.14	3.3%
	2,000		$243.59	$251.79	$8.20	3.4%
GS-1	375	3	$57.39	$59.03	$1.64	2.9%
Secondary	1,000	3	$122.04	$126.41	$4.37	3.6%
	750	6	$96.19	$99.47	$3.28	3.4%
	2,000	6	$225.50	$234.24	$8.74	3.9%
GS-2	1,500	12	$257.53	$265.28	$7.75	3.0%
Secondary	4,000	12	$486.43	$491.49	$5.06	1.0%
	6,000	30	$800.99	$817.95	$16.96	2.1%
	10,000	30	$1,166.89	$1,179.56	$12.67	1.1%
	10,000	40	$1,240.02	$1,260.49	$20.47	1.7%
	14,000	40	$1,605.90	$1,622.07	$16.17	1.0%
	12,500	50	$1,541.83	$1,567.41	$25.58	1.7%
	18,000	50	$2,043.22	$2,062.90	$19.68	1.0%
	15,000	75	$1,953.31	$1,995.71	$42.40	2.2%
	30,000	100	$3,499.78	$3,545.57	$45.79	1.3%
	36,000	100	$4,045.27	$4,084.62	$39.35	1.0%
	30,000	150	$3,865.39	$3,950.18	$84.79	2.2%
	60,000	300	$7,689.60	$7,859.18	$169.58	2.2%
	90,000	300	$10,416.97	$10,554.34	$137.37	1.3%
	100,000	500	$12,788.52	$13,071.16	$282.64	2.2%
	150,000	500	$17,334.17	$17,563.13	$228.96	1.3%
	180,000	500	$20,061.52	$20,258.28	$196.76	1.0%

Ohio Power Company
2013 Typical Bill Comparison
Ohio Power Rate Zone

Tariff	kWh	KW	Current	Proposed	$ Difference	Difference
GS-3	18,000	50	$2,021.91	$2,065.60	$43.69	2.2%
Secondary	30,000	75	$3,189.30	$3,253.29	$63.99	2.0%
	50,000	75	$4,369.44	$4,423.09	$53.65	1.2%
	36,000	100	$4,002.63	$4,090.02	$87.39	2.2%
	30,000	150	$4,567.20	$4,710.69	$143.49	3.1%
	60,000	150	$6,337.39	$6,465.37	$127.98	2.0%
	100,000	150	$8,697.63	$8,804.92	$107.29	1.2%
	120,000	300	$12,633.58	$12,889.53	$255.95	2.0%
	150,000	300	$14,403.77	$14,644.21	$240.44	1.7%
	200,000	300	$17,354.06	$17,568.64	$214.58	1.2%
	180,000	500	$19,848.37	$20,285.29	$436.92	2.2%
	200,000	500	$21,028.49	$21,455.07	$426.58	2.0%
	325,000	500	$28,404.26	$28,766.20	$361.94	1.3%
GS-2	200,000	1,000	$24,646.55	$25,189.23	$542.68	2.2%
Primary	300,000	1,000	$33,544.06	$33,983.08	$439.02	1.3%
GS-3	360,000	1,000	$38,480.75	$39,321.00	$840.25	2.2%
Primary	400,000	1,000	$40,807.33	$41,627.61	$820.28	2.0%
	650,000	1,000	$55,348.48	$56,043.93	$695.45	1.3%
GS-2						
Subtransmission	1,500,000	5,000	$136,208.19	$138,407.29	$2,199.10	1.6%
GS-3	2,500,000	5,000	$195,184.04	$199,045.04	$3,861.00	2.0%
Subtransmission	3,250,000	5,000	$234,328.73	$237,833.03	$3,504.30	1.5%
GS-4	3,000,000	10,000	$269,834.29	$285,293.29	$15,459.00	5.7%
Subtransmission	5,000,000	10,000	$363,989.29	$380,754.29	$16,765.00	4.6%
	6,500,000	10,000	$434,605.54	$452,350.04	$17,744.50	4.1%
	10,000,000	20,000	$722,676.79	$756,206.79	$33,530.00	4.6%
	13,000,000	20,000	$863,909.29	$899,398.29	$35,489.00	4.1%
GS-4	25,000,000	50,000	$1,788,641.79	$1,872,466.79	$83,825.00	4.7%
Transmission	32,500,000	50,000	$2,141,393.79	$2,230,116.29	$88,722.50	4.1%

* Typical bills assume 100% Power Factor

Ohio Power Company
2013 Typical Bill Comparison
Columbus Southern Power Rate Zone

Tariff	kWh	KW	Current	Proposed	$ Difference	Difference
Residential						
RR1 Annual	100		$19.09	$19.50	$0.41	2.2%
	250		$38.40	$39.43	$1.03	2.7%
	500		$70.66	$72.70	$2.04	2.9%
RR Annual	750		$110.75	$113.82	$3.07	2.8%
	1,000		$137.29	$141.39	$4.10	3.0%
	1,500		$186.27	$192.41	$6.14	3.3%
	2,000		$235.23	$243.43	$8.20	3.5%
GS-1						
	375	3	$64.28	$65.92	$1.64	2.6%
	1,000	3	$155.84	$160.21	$4.37	2.8%
	750	6	$119.23	$122.51	$3.28	2.8%
	2,000	6	$268.49	$277.23	$8.74	3.3%
GS-2 Secondary						
	1,500	12	$262.20	$269.95	$7.75	3.0%
	4,000	12	$534.02	$539.08	$5.06	1.0%
	6,000	30	$879.76	$896.71	$16.95	1.9%
	10,000	30	$1,314.31	$1,326.97	$12.66	1.0%
	10,000	40	$1,385.69	$1,406.15	$20.46	1.5%
	14,000	40	$1,820.26	$1,836.41	$16.15	0.9%
	12,500	50	$1,728.67	$1,754.24	$25.57	1.5%
	18,000	50	$2,324.50	$2,344.16	$19.66	0.9%
	15,000	75	$2,178.70	$2,221.08	$42.38	2.0%
	30,000	150	$4,335.14	$4,419.90	$84.76	2.0%
	60,000	300	$8,648.10	$8,817.62	$169.52	2.0%
	100,000	500	$14,398.66	$14,681.20	$282.54	2.0%
GS-2 Primary						
	20,000	100	$2,872.91	$2,927.17	$54.26	1.9%
GS-3 Secondary						
	30,000	75	$3,243.62	$3,307.61	$63.99	2.0%
	50,000	75	$4,432.54	$4,486.19	$53.65	1.2%
	30,000	100	$3,722.95	$3,813.44	$90.49	2.4%
	36,000	100	$4,079.62	$4,167.01	$87.39	2.1%

Ohio Power Company
2013 Typical Bill Comparison
Columbus Southern Power Rate Zone

Tariff	kWh	KW	Current	Proposed	$ Difference	Difference
	60,000	150	$6,465.00	$6,592.98	$127.98	2.0%
	100,000	150	$8,842.81	$8,950.10	$107.29	1.2%
	90,000	300	$11,124.45	$11,395.91	$271.46	2.4%
	120,000	300	$12,907.81	$13,163.76	$255.95	2.0%
	150,000	300	$14,691.16	$14,931.60	$240.44	1.6%
	200,000	300	$17,663.41	$17,877.99	$214.58	1.2%
	150,000	500	$18,525.93	$18,978.37	$452.44	2.4%
	180,000	500	$20,309.27	$20,746.19	$436.92	2.2%
	200,000	500	$21,498.18	$21,924.76	$426.58	2.0%
	325,000	500	$28,928.83	$29,290.77	$361.94	1.3%
GS-3 Primary						
	300,000	1,000	$35,107.24	$35,977.45	$870.21	2.5%
	360,000	1,000	$38,584.00	$39,424.25	$840.25	2.2%
	400,000	1,000	$40,901.84	$41,722.12	$820.28	2.0%
	650,000	1,000	$55,388.35	$56,083.80	$695.45	1.3%
GS-4						
	1,500,000	5,000	$137,643.91	$145,373.41	$7,729.50	5.6%
	2,500,000	5,000	$190,795.21	$199,177.71	$8,382.50	4.4%
	3,250,000	5,000	$230,658.70	$239,530.95	$8,872.25	3.9%
	3,000,000	10,000	$251,155.86	$266,614.86	$15,459.00	6.2%
	5,000,000	10,000	$357,458.46	$374,223.46	$16,765.00	4.7%
	6,500,000	10,000	$437,185.41	$454,929.91	$17,744.50	4.1%
	6,000,000	20,000	$478,179.76	$509,097.76	$30,918.00	6.5%
	10,000,000	20,000	$690,784.96	$724,314.96	$33,530.00	4.9%
	13,000,000	20,000	$850,238.86	$885,727.86	$35,489.00	4.2%
	15,000,000	50,000	$1,159,251.46	$1,236,546.46	$77,295.00	6.7%
	25,000,000	50,000	$1,690,764.46	$1,774,589.46	$83,825.00	5.0%
	32,500,000	50,000	$2,089,399.21	$2,178,121.71	$88,722.50	4.3%

* Typical bills assume 100% Power Factor

Ohio Power Company
Projected Transmission Cost Recovery Rider Cost / Revenues
July 2013 - June 2014
<Revenue>/ Expense in $

	Forecast Jul-13	Forecast Aug-13	Forecast Sep-13	Forecast Oct-13	Forecast Nov-13	Forecast Dec-13	Forecast Jan-14	Forecast Feb-14	Forecast Mar-14	Forecast Apr-14	Forecast May-14	Forecast Jun-14	Forecast TCRR July13-Jun14
Total Company													
# **NITS (c)** **$2669.60 per MW*Mo.**	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	321,586,884
Estimated NITS for Shopping	(15,647,581)	(15,816,265)	(16,263,215)	(16,901,301)	(17,036,820)	(16,798,499)	(16,468,388)	(16,694,718)	(17,044,215)	(17,449,841)	(17,815,854)	(17,845,225)	(201,781,922)
Pt-to-Pt Transm. Revenues (b)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(4,452,000)
Subtotal	**10,780,326**	**10,611,642**	**10,164,692**	**9,526,606**	**9,391,087**	**9,629,408**	**9,959,519**	**9,733,189**	**9,383,692**	**8,978,066**	**8,612,053**	**8,582,682**	**115,352,962**
TO Scheduling, Sys Contr & Disp (b)	151,084	145,594	118,252	107,085	98,257	98,736	98,336	73,924	97,009	86,378	134,000	119,300	1,327,953
Transmission Enhancement Charges (b) (d)	930,042	904,741	880,131	855,471	831,620	805,752	891,931	880,260	869,349	856,083	843,367	861,629	10,410,376
Net Congestion:													
PJM Implicit Congestion (b)	849,803	849,803	849,803	849,803	849,803	849,803	849,803	849,803	849,803	849,803	849,803	849,803	10,197,635
PJM FTR Revenue & Auction Revenue Rights (b)	(1,076,250)	(1,076,250)	(1,076,250)	(1,076,250)	(1,076,250)	(1,076,250)	(1,076,250)	(1,076,250)	(1,076,250)	(1,076,250)	(1,076,250)	(1,076,250)	(12,914,998)
Net Congestion Subtotal	(226,447)	(226,447)	(226,447)	(226,447)	(226,447)	(226,447)	(226,447)	(226,447)	(226,447)	(226,447)	(226,447)	(226,447)	(2,717,363)
PJM Operating Reserve (Gross) (b)	476,742	476,742	476,742	476,742	476,742	476,742	476,742	476,742	476,742	476,742	476,742	476,742	5,720,909
PJM Ancillary Services (Gross):													
PJM Synchronous Condensing (b)	383	383	383	383	383	383	383	383	383	383	383	383	4,596
PJM Reactive Supply (b)	657,033	657,033	657,033	657,033	657,033	657,033	657,033	657,033	657,033	657,033	657,033	657,033	7,884,394
PJM Blackstart (b)	1,199,878	1,199,878	1,199,878	1,199,878	1,199,878	1,199,878	1,199,878	1,199,878	1,199,878	1,199,878	1,199,878	1,199,878	14,398,539
PJM Regulation Charges (b)	527,682	527,682	527,682	527,682	527,682	527,682	527,682	527,682	527,682	527,682	527,682	527,682	6,332,185
PJM Spinning Reserve Charges (b)	5,775	5,775	5,775	5,775	5,775	5,775	5,775	5,775	5,775	5,775	5,775	5,775	69,300
PJM Supplemental Reserve Charges (b) (e)	94,484	94,484	94,484	94,484	94,484	94,484	94,484	94,484	94,484	94,484	94,484	94,484	1,133,808
PJM Ancillary Services Subtotal	2,485,235	2,485,235	2,485,235	2,485,235	2,485,235	2,485,235	2,485,235	2,485,235	2,485,235	2,485,235	2,485,235	2,485,235	29,822,822
PJM Administration Service Fees (a) (b)	784,944	784,944	784,944	784,944	784,944	784,944	784,944	784,944	784,944	784,944	784,944	784,944	9,419,327
Amortization of PJM Integration Costs (b)	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	1,930,908
PJM RTO Formation Cost Recovery (b)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(422,616)
Net Expansion Cost Recovery (b)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(726,768)
Net RTO Formation Costs & Expansion Cost Recovery Charge	65,127	65,127	65,127	65,127	65,127	65,127	65,127	65,127	65,127	65,127	65,127	65,127	781,524
Net Marginal Losses (b)	1,027,316	1,027,316	1,027,316	1,027,316	1,027,316	1,027,316	1,027,316	1,027,316	1,027,316	1,027,316	1,027,316	1,027,316	12,327,794
Load Response Program Subsidies (b)	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Acquisition Rider Adjustment (b)	0	0	0	0	0	0	0	0	0	0	0	0	0
Phase-In Credit (f)	(366,667)	0	0	0	0	0	0	0	0	0	0	0	(366,667)
Total Net RTO Costs - OPCo	**16,107,703**	**16,274,895**	**15,775,993**	**15,102,080**	**14,933,881**	**15,146,814**	**15,562,704**	**15,300,290**	**14,962,967**	**14,533,445**	**14,202,338**	**14,176,529**	**182,079,638**
Jurisdictional Allocation	96.830%	96.830%	96.830%	96.830%	96.830%	96.830%	96.830%	96.830%	96.830%	96.830%	96.830%	96.830%	

(a) Includes NERC and RFC Fees
(b) Forecast using actual data and anticipated/known changes
(c) Forecast using 2013/2014 load forecast and current OATT rates
(d) Pursuant to Schedule 12 of the PJM OATT, the Company has begun to incur charges for Required Regional Transmission Enhancements.
(e) Beginning June 1, 2008, the Company is required to comply with PJM's new Supplemental 30-minute Reserve requirement and is a Forecast.
(f) Beginning November 2010, the Company is required to record a Phase-In credit as ordered by the Amended Transmission Agreement. FERC Docket No. ER09-1279-000

Ohio Power Company
Projected Transmission Cost Recovery Rider Cost / Revenues
July 2013 - June 2014
<Revenue>/ Expense in $

	Forecast Jul-13	Forecast Aug-13	Forecast Sep-13	Forecast Oct-13	Forecast Nov-13	Forecast Dec-13	Forecast Jan-14	Forecast Feb-14	Forecast Mar-14	Forecast Apr-14	Forecast May-14	Forecast Jun-14	Forecast TCRR July13-Jun14
Jurisdictional													
NITS (c) **$2669.60 per MW*Mo.**	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	26,798,907	321,586,884
Estimated NITS for Shopping	(15,647,581)	(15,816,265)	(16,263,215)	(16,901,301)	(17,036,820)	(16,798,499)	(16,468,388)	(16,694,718)	(17,044,215)	(17,449,841)	(17,815,854)	(17,845,225)	(201,781,922)
Pt-to-Pt Transm. Revenues (b)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(371,000)	(4,452,000)
Subtotal	**10,780,326**	**10,611,642**	**10,164,692**	**9,526,606**	**9,391,087**	**9,629,408**	**9,959,519**	**9,733,189**	**9,383,692**	**8,978,066**	**8,612,053**	**8,582,682**	**115,352,962**
TO Scheduling, Sys Contr & Disp (b)	151,084	145,594	118,252	107,085	98,257	98,736	98,336	73,924	97,009	86,378	134,000	119,300	1,327,953
Transmission Enhancement Charges (b) (d)	930,042	904,741	880,131	855,471	831,620	805,752	891,931	880,260	869,349	856,083	843,367	861,629	10,410,376
Net Congestion:													
PJM Implicit Congestion (b)	822,864	822,864	822,864	822,864	822,864	822,864	822,864	822,864	822,864	822,864	822,864	822,864	9,874,368
PJM FTR Revenue & Auction Revenue Rights (b)	(1,042,133)	(1,042,133)	(1,042,133)	(1,042,133)	(1,042,133)	(1,042,133)	(1,042,133)	(1,042,133)	(1,042,133)	(1,042,133)	(1,042,133)	(1,042,133)	(12,505,596)
Net Congestion Subtotal	(219,269)	(219,269)	(219,269)	(219,269)	(219,269)	(219,269)	(219,269)	(219,269)	(219,269)	(219,269)	(219,269)	(219,269)	(2,631,228)
PJM Operating Reserve (Gross) (b)	461,630	461,630	461,630	461,630	461,630	461,630	461,630	461,630	461,630	461,630	461,630	461,630	5,539,560
PJM Ancillary Services (Gross):													
PJM Synchronous Condensing (b)	371	371	371	371	371	371	371	371	371	371	371	371	4,452
PJM Reactive Supply (b)	636,205	636,205	636,205	636,205	636,205	636,205	636,205	636,205	636,205	636,205	636,205	636,205	7,634,460
PJM Blackstart (b)	1,161,842	1,161,842	1,161,842	1,161,842	1,161,842	1,161,842	1,161,842	1,161,842	1,161,842	1,161,842	1,161,842	1,161,842	13,942,104
PJM Regulation Charges (b)	510,955	510,955	510,955	510,955	510,955	510,955	510,955	510,955	510,955	510,955	510,955	510,955	6,131,460
PJM Spinning Reserve Charges (b)	5,592	5,592	5,592	5,592	5,592	5,592	5,592	5,592	5,592	5,592	5,592	5,592	67,104
PJM Supplemental Reserve Charges (b) (e)	91,489	91,489	91,489	91,489	91,489	91,489	91,489	91,489	91,489	91,489	91,489	91,489	1,097,868
PJM Ancillary Services Subtotal	2,406,454	2,406,454	2,406,454	2,406,454	2,406,454	2,406,454	2,406,454	2,406,454	2,406,454	2,406,454	2,406,454	2,406,454	28,877,448
PJM Administration Service Fees (a) (b)	760,061	760,061	760,061	760,061	760,061	760,061	760,061	760,061	760,061	760,061	760,061	760,061	9,120,732
Amortization of PJM Integration Costs (b)	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	1,930,908
PJM RTO Formation Cost Recovery (b)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(35,218)	(422,616)
Net Expansion Cost Recovery (b)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(60,564)	(726,768)
Net RTO Formation Costs & Expansion Cost Recovery Charge	65,127	65,127	65,127	65,127	65,127	65,127	65,127	65,127	65,127	65,127	65,127	65,127	781,524
			195,381			195,381			195,381				
Net Marginal Losses (b)	994,750	994,750	994,750	994,750	994,750	994,750	994,750	994,750	994,750	994,750	994,750	994,750	11,937,000
Load Response Program Subsidies (b)	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Acquisition Rider Adjustment (b)	0	0	0	0	0	0	0	0	0	0	0	0	0
Phase-In Credit (f)	(366,667)	0	0	0	0	0	0	0	0	0	0	0	(366,667)
Total Net RTO Costs - OPCo	**15,963,538**	**16,130,730**	**15,631,828**	**14,957,915**	**14,789,716**	**15,002,649**	**15,418,539**	**15,156,126**	**14,818,802**	**14,389,280**	**14,058,173**	**14,032,364**	**180,349,661**

	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	July13-Jun14
2013 - 2014 Forecasted Load (kWh) excluding Shopping Customers													
Residential	877,595,221	904,028,623	805,671,518	610,511,058	609,132,340	817,704,936	973,740,193	869,795,877	739,813,308	611,174,230	511,386,874	567,769,322	8,898,323,500
Commercial	256,319,362	258,267,693	253,848,014	226,653,225	211,358,246	234,446,263	240,017,764	224,132,067	217,614,484	212,276,449	212,613,793	236,725,463	2,784,272,825
Industrial	311,232,636	287,902,729	263,384,862	240,601,218	216,144,191	194,450,000	194,450,000	194,450,000	194,450,000	194,450,000	194,450,000	194,450,000	2,680,415,636
Joint Service Territory	240,000,000	240,000,000	240,000,000	240,000,000	240,000,000	240,000,000	240,000,000	240,000,000	240,000,000	240,000,000	240,000,000	240,000,000	2,880,000,000
Other Ultimates	6,639,364	6,959,088	7,219,422	7,951,928	8,399,577	8,758,935	9,107,611	7,915,668	8,146,033	7,490,681	6,953,305	6,726,168	92,267,781
Municipals	672,000	751,000	705,000	538,000	572,000	740,000	889,000	830,000	715,000	613,000	578,000	627,000	8,230,000
Total	1,692,458,583	1,697,909,133	1,570,828,816	1,326,255,430	1,285,606,355	1,496,100,134	1,658,204,568	1,537,123,612	1,400,738,825	1,266,004,361	1,165,981,972	1,246,297,953	17,343,509,741
AEP Peak at time of PJM Peak (6/29/2012)	**23308.6 MW**												
AEP Projected Shopping Percentages	**58.39%**	**59.02%**	**60.69%**	**63.07%**	**63.57%**	**62.68%**	**61.45%**	**62.30%**	**63.60%**	**65.11%**	**66.48%**	**66.59%**	
12 CP	0.43068	0.43068	0.43068	0.43068	0.43068	0.43068	0.43068	0.43068	0.43068	0.43068	0.43068	0.43068	
WPCo Share of OPCo Peak used in MLR	3.170%	3.170%	3.170%	3.170%	3.170%	3.170%	3.170%	3.170%	3.170%	3.170%	3.170%	3.170%	

(a) Includes NERC and RFC Fees
(b) Forecast using actual data and anticipated/known changes
(c) Forecast using 2013/2014 load forecast and current OATT rates
(d) Pursuant to Schedule 12 of the PJM OATT, the Company has begun to incur charges for Required Regional Transmission Enhancements.
(e) Beginning June 1, 2008, the Company is required to comply with PJM's new Supplemental 30-minute Reserve requirement and is a Forecast.
(f) Beginning November 2010, the Company is required to record a Phase-In credit as ordered by the Amended Transmission Agreement. FERC Docket No. ER09-1279-000

Ohio Power Company
Monthly Projected Cost for Each Rate Schedule

	Forecast Sep-13	Forecast Oct-13	Forecast Nov-13	Forecast Dec-13	Forecast Jan-14	Forecast Feb-14	Forecast Mar-14	Forecast Apr-14	Forecast May-14	Forecast Jun-14	Forecast Jul-14	Forecast Aug-14	Forecast 2013 / 2014 Proposed Rates kWh	Demand	Total
METERED kWh:															
RS	804,174,218	608,749,825	607,512,897	815,923,128	972,030,875	868,282,973	738,460,248	609,982,783	510,278,183	566,800,861	876,341,814	902,769,749			8,881,307,554
GS1	19,648,522	19,459,993	21,443,939	24,783,428	28,517,799	27,441,481	26,687,520	25,294,432	14,933,383	17,678,394	20,281,683	20,158,769			266,329,344
GS2 Sec	88,904,116	81,011,529	78,820,897	78,387,138	85,821,741	84,336,172	81,169,522	78,653,810	63,187,732	80,397,066	93,347,186	93,861,726			987,898,635
GS2 RL - GS - TOD	3,084,766	3,086,839	3,449,907	3,525,479	3,740,988	3,618,121	3,137,215	2,978,156	2,265,458	2,916,161	3,657,870	3,422,864			38,883,822
GS2 Pri	8,208,219	6,447,621	9,685,767	6,361,138	6,670,157	6,685,212	4,523,496	4,341,580	4,259,136	5,554,119	6,775,775	7,339,824			76,852,043
GS2 Sub/Trans	4,598,777	3,057,970	3,633,609	3,232,361	4,824,891	6,347,431	1,343,713	1,858,439	3,083,579	4,180,156	3,916,464	7,753,134			47,830,525
GS3 Sec	114,874,292	107,698,454	107,848,122	101,452,226	110,512,422	101,574,769	94,339,345	93,617,963	87,847,202	103,131,982	113,334,537	116,083,061			1,252,314,373
GS3 - TOD	-	-	-	-	-	-	-	-	-	-	-	-			-
GS3 Pri	76,679,730	67,572,736	67,242,295	53,462,622	54,160,234	48,337,430	36,066,692	36,656,868	46,688,390	56,868,911	73,515,495	79,195,044			696,446,446
GS3 Sub/Trans	15,277,319	9,891,310	12,417,620	6,335,600	13,191,252	8,224,129	6,425,483	5,745,745	7,729,179	10,227,460	14,905,342	15,317,452			125,687,890
GS4 Pri	-	4,921,685	-	-	-	-	-	-	1,537,457	2,038,762	3,097,082	3,310,199			14,905,185
GS4/IRP Sub/Trans	424,299,365	401,261,664	359,674,817	388,097,475	363,501,964	368,146,459	394,783,191	394,218,561	414,508,520	387,131,184	473,384,043	438,551,402			4,807,558,645
EHG	498,418	450,732	565,145	661,921	902,334	991,173	936,259	744,158	405,560	457,933	522,234	547,864			7,683,731
SS	402,611	482,468	474,929	554,484	630,833	685,023	645,270	578,979	401,130	397,677	357,240	266,954			5,877,597
OL	4,242,859	5,353,742	5,599,838	5,736,724	5,866,953	5,655,536	5,418,011	5,213,407	3,167,973	3,112,734	3,607,647	3,697,497			56,672,920
SL	5,935,605	6,808,863	7,236,573	7,586,411	7,832,125	6,797,705	6,802,861	6,119,480	5,689,090	5,404,552	5,414,171	5,633,595			77,261,032
Total	1,570,828,816	1,326,255,430	1,285,606,355	1,496,100,134	1,658,204,568	1,537,123,612	1,400,738,825	1,266,004,361	1,165,981,972	1,246,297,953	1,692,458,583	1,697,909,133			17,343,509,741
DEMAND:															
RS	-	-	-	-	-	-	-	-	-	-	-	-			-
GS1	-	-	-	-	-	-	-	-	-	-	-	-			-
GS2 Sec	349,084	368,713	360,745	308,635	318,219	335,922	318,986	335,839	282,397	325,747	378,580	354,542			4,037,409
GS2 RL - GS - TOD	-	-	-	-	-	-	-	-	-	-	-	-			-
GS2 Pri	36,544	29,538	40,837	25,897	33,621	28,548	19,616	18,631	19,492	24,366	30,067	33,096			340,253
GS2 Sub/Trans	18,832	16,575	18,381	14,587	20,141	20,302	14,070	11,814	11,099	13,853	18,293	27,900			205,847
GS3 Sec	255,220	259,300	258,325	216,864	228,833	233,560	209,891	223,293	210,493	234,025	258,207	259,936			2,847,947
GS3 - TOD	-	-	-	-	-	-	-	-	-	-	-	-			-
GS3 Pri	153,701	140,927	145,024	107,755	103,251	100,170	72,408	74,246	97,120	116,368	150,282	159,075			1,420,327
GS3 Sub/Trans	29,934	20,514	25,650	12,954	24,316	18,296	12,649	11,377	14,802	22,145	30,375	30,164			253,176
GS4 Pri	-	8,390	-	-	-	-	-	-	2,874	3,841	5,599	6,186			26,889
GS4/IRP Sub/Trans	699,676	676,687	591,096	625,796	582,447	660,200	659,047	653,394	647,961	606,421	779,351	725,139			7,907,216
EHG	-	-	-	-	-	-	-	-	-	-	-	-			-
SS	-	-	-	-	-	-	-	-	-	-	-	-			-
OL	-	-	-	-	-	-	-	-	-	-	-	-			-
SL	-	-	-	-	-	-	-	-	-	-	-	-			-
Total	1,542,990	1,520,645	1,440,057	1,312,488	1,310,828	1,396,999	1,306,668	1,328,594	1,286,239	1,346,766	1,650,753	1,596,038			17,039,065
REVENUES:															
RS	$ 12,601,249	$ 9,538,988	$ 9,519,606	$ 12,785,352	$ 15,231,529	$ 13,605,821	$ 11,571,524	$ 9,558,308	$ 7,995,957	$ 8,881,656	$ 13,732,101	$ 14,146,221	0.0156698		$ 139,168,313
GS1	262,720	260,200	286,727	331,379	381,311	366,920	356,839	338,212	199,674	236,378	271,186	269,543	0.0133710		$ 3,561,090
GS2 Sec	1,169,821	1,183,405	1,156,051	1,033,398	1,085,734	1,120,790	1,068,678	1,097,593	910,989	1,081,236	1,256,241	1,202,556	0.0040487	2.32	$ 13,366,494
GS2 RL - GS - TOD	41,963	41,991	46,930	47,958	50,890	49,218	42,676	40,513	30,818	39,669	49,759	46,562	0.0136033		$ 528,948
GS2 Pri	113,937	91,364	129,328	82,871	101,379	90,076	61,618	58,701	60,308	76,286	93,831	102,822	0.0039082	2.24	$ 1,062,520
GS2 Sub/Trans	58,857	48,013	54,172	44,328	62,590	68,775	35,961	32,991	36,119	46,350	55,063	90,798	0.0038304	2.19	$ 634,015
GS3 Sec	1,427,059	1,413,002	1,409,959	1,228,311	1,310,262	1,291,423	1,173,063	1,220,369	1,148,758	1,299,538	1,431,961	1,449,691	0.0040913	3.75	$ 15,803,396
GS3 - TOD	-	-	-	-	-	-	-	-	-	-	-	-	0.0122816		$ -
GS3 Pri	859,237	777,028	790,553	601,217	587,671	553,519	404,560	413,543	535,967	645,851	834,362	888,623	0.0039494	3.62	$ 7,892,130
GS3 Sub/Trans	165,399	111,112	139,121	70,511	137,382	96,785	69,774	62,630	82,465	118,202	165,524	166,371	0.0038707	3.55	$ 1,385,275
GS4 Pri	-	49,770	-	-	-	-	-	-	16,437	21,904	32,443	35,385	0.0041119	3.52	$ 155,939
GS4/IRP Sub/Trans	4,123,808	3,951,655	3,488,771	3,723,029	3,474,356	3,761,321	3,864,690	3,842,909	3,905,936	3,652,291	4,596,500	4,269,092	0.0040300	3.45	$ 46,654,357
EHG	3,794	3,431	4,302	5,039	6,869	7,545	7,127	5,665	3,087	3,486	3,975	4,170	0.0076122		$ 58,490
SS	4,848	5,809	5,718	6,676	7,595	8,248	7,769	6,971	4,830	4,788	4,301	3,214	0.0120404		$ 70,769
OL	17,100	21,577	22,569	23,121	23,646	22,794	21,836	21,012	12,768	12,545	14,540	14,902	0.0040303		$ 228,409
SL	23,922	27,442	29,166	30,576	31,566	27,397	27,418	24,663	22,929	21,782	21,821	22,705	0.0040303		$ 311,385
Total	$ 20,873,714	$ 17,524,788	$ 17,082,972	$ 20,013,766	$ 22,492,780	$ 21,070,631	$ 18,713,534	$ 16,724,079	$ 14,967,041	$ 16,141,963	$ 22,563,607	$ 22,712,656			$ 230,881,529

Ohio Power Company
Projected Transmission Cost Recovery Rider Rate Calculations
July 2011 - June 2012

	SSO Demand	Demand Cost	July 2013 - June 2014 Loss Adjusted KWH Energy	Energy Cost	Net Marginal Loss 100% kWh	Total Cost
Forecast						
RS	2,386.7	$ 80,727,450	8,881,307,554	$ 21,839,971	$ 6,112,729	$ 108,680,150
GS1	57.4	1,942,723	266,329,344	654,929	183,306	$ 2,780,958
GS2	252.9	8,552,452	1,151,465,024	2,831,561	792,518	$ 12,176,531
GS3	386.4	13,070,349	2,074,448,709	5,101,265	1,427,779	$ 19,599,392
GS4/IRP	633.1	21,412,104	4,822,463,830	11,858,892	3,319,152	$ 36,590,149
EHG	0.6	21,493	7,683,731	18,895	5,288	$ 45,676
SS/EHS	1.1	36,766	5,877,597	14,454	4,045	$ 55,265
OL/SL	0.0	-	133,933,952	329,356	92,183	$ 421,539
SBS*	0.0	-	-	-	-	$ -
Total	3,718.2	$ 125,763,338	17,343,509,741	$ 42,649,323	$ 11,937,000	$ 180,349,661
Reconciliation						
RS		$ 22,646,255	8,881,307,554	$ 6,126,709	$ 1,714,787	$ 30,487,751
GS1		$ 544,987	266,329,344	183,725	51,422	$ 780,135
GS2		$ 2,399,197	1,151,465,024	794,330	222,323	$ 3,415,850
GS3		$ 3,666,590	2,074,448,709	1,431,044	400,531	$ 5,498,165
GS4/IRP		$ 6,006,680	4,822,463,830	3,326,743	931,113	$ 10,264,536
EHG		$ 6,029	7,683,731	5,301	1,484	$ 12,813
SS/EHS		$ 10,314	5,877,597	4,055	1,135	$ 15,503
OL/SL		$ -	133,933,952	92,393	25,860	$ 118,253
SBS		$ -	-	-	-	$ -
Total		$ 35,280,052	17,343,509,741	$ 11,964,300	$ 3,348,655	$ 50,593,007
Total						
RS		$ 103,373,705		$ 27,966,680	$ 7,827,516	$ 139,167,901
GS1		$ 2,487,710		$ 838,654	$ 234,729	$ 3,561,093
GS2		$ 10,951,649		$ 3,625,891	$ 1,014,841	$ 15,592,381
GS3		$ 16,736,939		$ 6,532,309	$ 1,828,310	$ 25,097,557
GS4/IRP		$ 27,418,785		$ 15,185,636	$ 4,250,265	$ 46,854,685
EHG		$ 27,522		$ 24,196	$ 6,772	$ 58,490
SS/EHS		$ 47,080		$ 18,508	$ 5,180	$ 70,769
OL/SL		$ -		$ 421,750	$ 118,042	$ 539,792
SBS		$ -		$ -	$ -	$ -
Total		$ 161,043,390		$ 54,613,623	$ 15,285,655	$ 230,942,668

*Demand imputed based upon contractual forced outage rates

Ohio Power Company
Projected Transmission Cost Recovery Rider Rate Calculations
September 2013 - August 2014

			Billing Units @ Secondary		Secondary Rate		Primary Loss	Primary Rate		Subtransmission/ Transmission	Subtrans/Trans Rate	
	Demand Cost	**Energy Cost**	**Demand**	**Energy**	**Demand**	**Energy**	**Factor**	**Demand**	**Energy**	**Loss Factor**	**Demand**	**Energy**
RS	$ 103,373,705	$ 35,794,196	-	8,881,307,554		$ 0.0156698						
GS1	$ 2,487,710	$ 1,073,383	-	266,329,344		$ 0.0133710						
GS2	$ 10,951,649	$ 4,640,732	4,719,518	1,146,219,869	$ 2.32	$ 0.0040487	0.9653	$ 2.24	$ 0.0039082	0.9461	$ 2.19	$ 0.0038304
GS3	$ 16,736,939	$ 8,360,618	4,458,527	2,043,511,137	$ 3.75	$ 0.0040913	0.9653	$ 3.62	$ 0.0039494	0.9461	$ 3.55	$ 0.0038707
GS4/IRP	$ 27,418,785	$ 19,435,901	7,506,803	4,562,715,654	$ 3.65	$ 0.0042597	0.9653	$ 3.52	$ 0.0041119	0.9461	$ 3.45	$ 0.0040300
EHG	$ 27,522	$ 30,968	-	7,683,731		$ 0.0076122						
SS/EHS	$ 47,080	$ 23,688	-	5,877,597		$ 0.0120404						
OL/SL	$ -	$ 539,792	-	133,933,952		$ 0.0040303						
Total	$ 161,043,390	$ 69,899,277	16,684,848	17,047,578,837								
				GS-2 Energy only rate		$ 0.0136033						
				GS-3 Energy only rate		$ 0.0122816						

Ohio Power Company
SBS Tariff Rate Design

			AEP Ohio		
			Demand	**Energy**	
GS-2			$ 10,951,649	$ 4,640,732	
GS-3			$ 16,736,939	$ 8,360,618	
GS-4/IRP			$ 27,418,785	$ 19,435,901	
Total			$ 55,107,373	$ 32,437,251	
Demand @ Secondary			59,601,622		
Energy @ Secondary				7,752,446,660	
		Loss			
Forced Outage Rate	15%	Factors			
Secondary		1.0000	$ 0.14	$ 0.0041841	
Primary		0.9653	$ 0.13	$ 0.0040390	
Subtrans/Transmission		0.9461	$ 0.13	$ 0.0039585	
Forced Outage Rate	5%				
Secondary			$ 0.05	$ 0.0041841	
Primary			$ 0.04	$ 0.0040390	
Subtrans/Transmission			$ 0.04	$ 0.0039585	
Forced Outage Rate	10%				
Secondary			$ 0.09	$ 0.0041841	
Primary			$ 0.09	$ 0.0040390	
Subtrans/Transmission			$ 0.09	$ 0.0039585	
Forced Outage Rate	20%				
Secondary			$ 0.18	$ 0.0041841	
Primary			$ 0.18	$ 0.0040390	
Subtrans/Transmission			$ 0.17	$ 0.0039585	
Forced Outage Rate	25%				
Secondary			$ 0.23	$ 0.0041841	
Primary			$ 0.22	$ 0.0040390	
Subtrans/Transmission			$ 0.22	$ 0.0039585	
Forced Outage Rate	30%				
Secondary			$ 0.28	$ 0.0041841	
Primary			$ 0.27	$ 0.0040390	
Subtrans/Transmission			$ 0.26	$ 0.0039585	
Maintenance Energy					
at 15% Forced Outage Rate					
Secondary			$ 0.14		
Primary			$ 0.13		
Subtrans/Transmission			$ 0.13		
Hours at 85% Load Factor			621		
Demand Components per KWH					Total
Secondary			$ 0.0002254	$ 0.0041841	$ 0.0044095
Primary			$ 0.0002093	$ 0.0040390	$ 0.0042483
Subtrans/Transmission			$ 0.0002093	$ 0.0039585	$ 0.0041678
Less than 100 KW*					
Residential & GS-1			$ 105,861,415.401		
GS-2			$ 10,951,649		
Forced Outage Adjustment	15%		$ 17,521,960		
Demand			40,335,389		
			$ 0.43		

* Also Breakdown Service Charge for CSP

Ohio Power Company

	Metered		Loss	Units @ Secondary	
	Energy	Demand	Factor	Energy	Demand
RS	8,881,307,554	-	1.0000	8,881,307,554	-
GS1	266,329,344	-	1.0000	266,329,344	-
GS2 Sec	987,898,635	4,037,409	1.0000	987,898,635	4,037,409
GS2 RL - GS - TOD*	38,883,822	158,913	1.0000	38,883,822	158,913
GS2 Pri	76,852,043	340,253	0.9653	74,185,984	328,449
GS2 Sub/Trans	47,830,525	205,847	0.9461	45,251,428	194,747
GS3 Sec	1,252,314,373	2,847,947	1.0000	1,252,314,373	2,847,947
GS3-TOD	-	-	1.0000	-	-
GS3 Pri	696,446,446	1,420,327	0.9653	672,286,162	1,371,055
GS3 Sub/Trans	125,687,890	253,176	0.9461	118,910,602	239,524
GS4 Pri	14,905,185	26,889	0.9653	14,388,112	25,957
GS4/IRP Sub/Trans	4,807,558,645	7,907,216	0.9461	4,548,327,542	7,480,847
EHG	7,683,731	-	1.0000	7,683,731	-
SS	5,877,597	-	1.0000	5,877,597	-
AL	56,672,920	-	1.0000	56,672,920	-
SL	77,261,032	-	1.0000	77,261,032	-
	17,343,509,741	17,197,978		17,047,578,837	16,684,848

6/29/12 14:00 EST

Ohio Power Company Class Contribution To PJM Peak

Class	Metered Avg / Cust KW	Number Of Customers	Metered Class MW	Peak Loss Factor	At Generation Class MW
Residential	2.76	1,263,365	3,482.63	1.0932	3,807.21
GS1	1.21	116,939	140.94	1.0932	154.07
GS2	19.40	54,165	1,050.74	1.0874	1,142.60
GS3	200.33	11,670	2,337.83	1.0747	2,512.55
GS4	11,730.18	76	891.49	1.0351	922.75
IIP	99,433.71	3	298.30	1.0341	308.47
EHG	9.35	431	4.03	1.0932	4.40
SCH	37.99	150	5.70	1.0932	6.23
Joint Service Territory	497,690.37	1	497.69	1.0341	514.66
TOTAL					
Internal Load (less WPCo) (At Generation)					9,372.95
Total			8,709.35		9,372.95
Total GS-4					1,745.89

Ohio Power Company
Amount exclude Wheeling Power Company activity
Recorded Transmission Rider Revenues & Transmission Costs
Jan 13 - Apr 13
<Revenue>/ Expense in $

Schedule D1 and D3

	Dec-12	Jan-13	Feb-13	Mar-13	1st Qtr 2013	Apr-13	May-13	Jun-13	2nd Qtr 2013
Total Transm. TCRR/ETCRR Revenue-OPCO		(20,336,709)	(19,491,066)	(19,161,355)	(58,989,131)	(17,280,965)			(17,280,965)
Transmission Costs									
Net Congestion									
PJM Implicit Congestior		5,235,425	3,514,718	1,975,482	**10,725,626**	769,034			**769,034**
PJM FTR Revenue		(3,112,340)	(2,446,655)	(2,130,916)	**(7,689,912)**	(516,507)			**(516,507)**
Auction Revenue Rights									
Net Congestion Subtotal		2 123 085	1 068 063	(155 434)	**3,035,714**	252 527	-	-	**252,527**
PJM Operating Reserve		1,090,615	633,174	535,839	**2,259,627**	921,862			**921,862**
PJM Ancillary Services									
PJM Synchronous Condensing		82	0	(35)	**47**	(1)			**(1)**
PJM Reactive Supply		3,642	3,707	3,718	**11,067**	24,019,281			**24,019,281**
PJM Blackstart		2,420,759	4,277,911	1,683,060	**8,381,730**	2,861,802			**2,861,802**
PJM Regulation Charges		958,915	808,994	884,390	**2,652,299**	606,305			**606,305**
PJM Spinning Reserve Charges		2,993	4,999	54,041	**62,034**	110,207			**110,207**
PJM 30 minute Supplemental Marke		2,465	998	4,012	**7,475**	413			**413**
PJM Ancillary Services Subtotal		3,388,856	5,096,611	2,629,186	**11,114,653**	27,598,007	-	-	**27,598,007**
PJM Administration Service Fees		1,516,440	1,426,498	(43,024)	**2,899,915**	911,742			**911,742**
Net Expansion Cost Recovery Charge		(59,264)	(61,431)	(66,163)	**(186,858)**	(62,460)			**(62,460)**
Amortization of PJM Integration Costs		155,502	155,502	155,502	**466,507**	155,502			**155,502**
PJM RTO Formation Cost Recovery		(35,410)	(34,705)	(46,979)	**(117,094)**	(39,096)			**(39,096)**
Net RTO Formation Costs		120,092	120,798	108,523	**349,413**	116,407	-	-	**116,407**
PJM Transmission Enhancement Charges		1,111,073	529,010	1,816,684	**3,456,767**	1,134,750			**1,134,750**
NITS/TO Charges - LSE		10,739,406	9,176,403	9,703,712	**29,619,521**	9,204,965			**9,204,965**
PJM Marginal Losses		4,752,778	3,891,290	4,650,908	**13,294,976**	3,418,987			**3,418,987**
Net Marginal Losses and Fuel Credit		4,752,778	3,891,290	4,650,908	**13,294,976**	3,418,987	-	-	**3,418,987**
Pt-to-Pt Transm. Revenues		(223,360)	(208,999)	(159,508)	**(591,868)**	(160,379)			**(160,379)**
PJM Emergency Energy Purchases		-	-	-	**-**				**-**
OPCO Phase-In Credits (ER09-1279-000)		(366,667)	(366,667)	(366,667)	**(1,100,000)**	(366,667)			**(366,667)**
Total Net RTO Costs - OPCO		**24,193,055**	**21,304,749**	**18,654,057**	**64,151,861**	**42,969,739**	**-**	**-**	**42,969,739**
Monthly OPCo - Net <Over>/Under Recovery		**3,856,346**	**1,813,683**	**(507,299)**	**5,162,730**	**25,688,774**	**-**	**-**	**25,688,774**
OPCO - Cumul. Net <Over>/Under Recovery - Bypassable Rates Only	**13,456,074**	**17,312,419**	**19,126,102**	**18,618,804**		**44,307,578**	**-**	**-**	**44,307,578**

Reconciliation of Cumulative (Over)/Under Recovery on Schedule D1 to (Over)/Under Recovery on Schedule B-1

	Ohio Power Company
Cumulative (Over)/Under Recovery on Schedule D-1	44,307,578
Cumulative Carrying Charges	1,773,880
(Over)/Under Recovery on Schedule B-1	46,081,458

Monthly Revenues Collected From Each Rate Schedule
March - April 2013

Ohio Power Company

	March 2013	April 2013
Billed:		
RS	12,118,556.23	10,455,874.72
GS1	360,721.15	325,966.65
GS2 Sec	1,423,740.46	1,372,710.14
GS2 RL - GS - TOD	54,399.41	49,205.93
GS2 Pri	90,595.38	78,325.76
GS2 Sub/Trans	48,787.77	42,517.62
GS3 Sec	1,562,624.53	1,533,275.36
GS3-TOD	-	-
GS3 Pri	566,081.72	540,137.10
GS3 Sub/Trans	107,224.70	86,881.94
GS4 Pri	-	-
GS4/IRP Sub/Trans	3,728,823.37	3,407,081.60
EHG	11,980.42	9,083.93
EHS	-	-
SS	10,998.56	9,437.08
SL	19,331.26	17,005.87
AL	30,492.03	28,431.67
SBS-Sub/Tran-Backup	-	-
	20,134,356.99	17,955,935.37
Estimated and Unbilled	(973,001.79)	(674,970.26)
Total:	19,161,355.20	17,280,965.11

Ohio Power Company — Schedule D-3a

2013

Example of Carrying Cost Calculation

Line No.	Description		
	Monthly Activity for	Mar-13	Apr-13
1	Monthly (Over)/Under Recovery	(507,299)	25,688,774
2	Cumulative (Over)/Under Rec.	(507,299)	25,181,475
	Recorded In	Apr-13	May-13
	Accrual of Carrying Charges		
3	Current TCRR Expenditures	(507,299)	25,181,475
4	Accumulated Carrying Charges	-	(2,257)
5	Total	(507,299)	25,179,218
6	Debt Rate	5.340%	5.340%
	Current Month Carrying Cost		
7	Debt Portion (4210041) (4310001)	(2,257)	112,048
	Accumulated		
8	Accumulated Debt	(2,257)	109,790
	Account 1823154		109,790
	Account 4210041		(109,790)
	Account 2540104	(2,257)	2,257
	Account 4310001	2,257	(2,257)

Merged Ohio Companies
Expanded Transmission Cost Recovery Rider Revenues
March 2013

Total Transmission Revenues		Current Month	Prior Month Reversal (4)	Net
(1)	Billed "T" Revenue (incl Republic adjust)	**20,134,356.99**	n/a	20,134,356.99
(2)	Estimated "T" Revenue	**125,087.25**	**(336,585.94)**	(211,498.69)
(3)	**Estimated** Unbilled "T" Revenue	7,733,275.39	(8,494,778.49)	(761,503.10)
	Total Amount of Transmission Revenues			**19,161,355.20**

Source of Data:

(1) Billed Transmission revenues 9 - 1T

(2) Estimated Billed Transmission Revenue - MACSS Report MCSRESTB

(3) **Estimated** Unbilled Transmission Revenues - Calculated from KWH provided by Economic Forecasting.

State : OH Line of Business: TRANSMISSION March 2013 9-1T

FERC ACCT	NO	OPERATING REVENUE ACCOUNTS	OPERATING REVENUES THIS YR	LAST YR	%CHNG	KILOWATT - HOUR SALES THIS YR	LAST YR	%CHNG	CUSTOMERS THIS YR	LAST YR	CENTS PER KWH 2013	2012
		SALES OF ELECTRICITY										
		RESIDENTIAL										
4400	002	WITHOUT SPACE HEATING	7,508,656.32	6,879,868.70	9.14	649,954,163	699,459,883	7.08-	766,396	927,184	1.16	0.91
4400	001	WITH SPACE HEATING	4,617,046.37	3,658,335.74	26.21	399,295,601	373,792,321	6.82	214,284	252,374	1.16	0.91
		TOTAL RESIDENTIAL	12,125,702.69	10,538,204.44	15.06	1,049,249,764	1,073,252,204	2.24-	980,680	1,179,558	1.16	0.98
					0.00						0.00	0.00
		COMMERCIAL										
4420	001	OTHER THAN PUBLIC AUTHORITIES	3,130,219.52	4,880,130.57	35.86-	301,031,976	534,492,691	43.68-	101,771	139,214	1.04	0.56
4420	006	PUBLIC AUTHS - SCHOOLS	131,283.42	958,713.41	86.31-	12,583,215	144,644,444	91.30-	779	1,122	1.04	0.50
4420	007	PUBLIC AUTHS-OTHER THAN SCHOOL	199,043.33	394,181.42	49.50-	19,151,308	48,540,782	60.55-	3,924	6,326	1.04	0.45
		TOTAL COMMERCIAL	3,460,546.27	6,233,025.40	44.48-	332,766,499	727,677,917	54.27-	106,474	146,662	1.04	0.86
					0.00						0.00	0.00
		INDUSTRIAL										
4420	002	EXCLUDING MINE POWER	4,443,443.90	6,454,181.54	31.15-	591,730,566	994,050,921	40.47-	5,830	8,436	0.75	0.41
4420	004	MINE POWER	15,897.69	91,623.22	82.65-	1,603,209	13,592,443	88.21-	39	51	0.99	0.62
4420	005	ASSOCIATED COMPANIES	53,112.92	41,447.63	28.14	2,970,420	2,696,267	10.17	18	37	1.79	1.54
		TOTAL INDUSTRIAL	4,512,454.51	6,587,252.39	31.50-	596,304,195	1,010,339,631	40.98-	5,887	8,524	0.76	0.65
		COMMERCIAL AND INDUSTRIAL	7,973,000.78	12,820,277.79	37.81-	929,070,694	1,738,017,548	46.54-	112,361	155,186	0.86	0.74
		PUBLIC STREET & HIGHWAY LIGHT										
4440	000	PUBLIC STREET & HIGHWAY LIGHT	28,107.91	40,195.60	30.07-	6,157,293	9,315,514	33.90-	1,599	2,375	0.46	0.39
		TOTAL PUBLIC STREET & HIGHWAY LIGHT	28,107.91	40,195.60	30.07-	6,157,293	9,315,514	33.90-	1,599	2,375	0.46	0.43
					0.00						0.00	0.00
		OTHER SALES TO PUBLIC AUTHS										
4450	001	PUBLIC SCHOOLS	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
4450	002	OTHER THAN PUBLIC SCHOOLS	563.47	705.28	20.11-	49,465	75,819	34.76-	26	26	1.14	0.93
		TOTAL OTHER SALES TO PUBLIC AUTHS	563.47	705.28	20.11-	49,465	75,819	34.76-	26	26	1.14	0.93
		ULTIMATE CUSTOMERS	20,127,374.85	23,399,383.11	13.98-	1,984,527,216	2,820,661,085	29.64-	1,094,666	1,337,145	1.01	0.83
		SALES FOR RESALE										
4470	XXX	OTHER ELEC UTILS	6,982.14	4,764.77	46.54	742,860	691,860	7.37	3	3	0.94	0.69
		TOTAL SALES FOR RESALE	6,982.14	4,764.77	46.54	742,860	691,860	7.37	3	3	0.94	0.69
					0.00						0.00	0.00
		TOTAL SALES OF ELECTRICITY	20,134,356.99	23,404,147.88	13.97-	1,985,270,076	2,821,352,945	29.63-	1,094,669	1,337,148	1.01	0.83
		PROVISION FOR REFUND										
		PROVISION FOR REFUND										
4491		PROVISION FOR REVENUE REFUND	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
		TOTAL PROVISION FOR REFUND	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
					0.00						0.00	0.00
		TOTAL PROVISION FOR REFUND	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
		OTHER OPERATING REVENUES										
		OPERATING REVENUE										
4500		FORFEITED DISCOUNTS	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
4510		MISCELLANEOUS SERVICE REVENUES	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
4530		SALES OF WATER AND WATER POWER	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
4540		RENT FROM ELE PROP-NON ASSOC	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
4560		OTHER ELECTRIC REVENUES	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
		TOTAL OPERATING REVENUE	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
					0.00						0.00	0.00
		TOTAL OTHER OPERATING REVENUES	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
		TOTAL OPERATING REVENUES	20,134,356.99	23,404,147.88	13.97-	1,985,270,076	2,821,352,945	29.63-	1,094,669	1,337,148	1.01	0.83

POLRR surcharge revenues are billed as Distribution line of business, but reported as Generation line of business. Line of business changed in BO Universe.

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
211	G	OH	8	1,199,829	40.0	0.00	6,922.78
211	D	OH	8	1,199,829	40.0	0.00	27,578.22
Total : 211			8	1,199,829	40.0	0.00	34,501.00
212	G	OH	2	161,552	10.0	2,073.00	4,160.54
212	T	OH	1	63,529	5.0	0.00	179.89
212	D	OH	2	161,552	10.0	0.00	3,139.57
Total : 212			2	161,552	10.0	2,073.00	7,480.00
213	G	OH	4	339,226	20.0	0.00	2,178.67
213	D	OH	4	339,226	20.0	0.00	11,992.33
Total : 213			4	339,226	20.0	0.00	14,171.00
216	G	OH	1	14,679	5.0	479.00	825.26
216	T	OH	1	14,679	5.0	0.00	36.27
216	D	OH	1	14,679	5.0	0.00	190.47
Total : 216			1	14,679	5.0	479.00	1,052.00
221	G	OH	38	186,560,907	190.0	1,987,363.00	3,849,665.73
221	T	OH	8	66,261,406	40.0	0.00	109,869.09
221	D	OH	38	186,560,907	190.0	0.00	787,194.18
Total : 221			38	186,560,907	190.0	1,987,363.00	4,746,729.00

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
211	G	OH	28	13,266,841	140.0	71,674.00	121,139.57
211	T	OH	6	1,790,740	30.0	0.00	1,616.67
211	D	OH	28	13,266,841	140.0	0.00	296,904.76
Total : 211			28	13,266,841	140.0	71,674.00	419,661.00
212	G	OH	2	537,601	10.0	0.00	2,100.34
212	D	OH	2	537,601	10.0	0.00	20,172.66
Total : 212			2	537,601	10.0	0.00	22,273.00
213	G	OH	2	23,989,872	10.0	0.00	26,271.90

American Electric Power
OHIO POWER COMPANY(Companies 7 & 10)

Estimate Billings For MACSS GTD
MCSRESTB

Prepared: 04/02/2013 05:46:05 PM

March 2013

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
213	D	OH	2	23,989,872	10.0	0.00	31,623.10
Total : 213			2	23,989,872	10.0	0.00	57,895.00
216	G	OH	7	2,753,377	35.0	30,195.00	44,194.76
216	T	OH	2	744,155	10.0	0.00	968.99
216	D	OH	7	2,753,377	35.0	0.00	36,978.25
Total : 216			7	2,753,377	35.0	30,195.00	82,142.00
221	G	OH	4	10,684,394	20.0	201,674.00	335,848.59
221	T	OH	1	5,453,000	5.0	0.00	12,416.34
221	D	OH	4	10,684,394	20.0	0.00	21,465.07
Total : 221			4	10,684,394	20.0	201,674.00	369,730.00
	Total G:		96	239,508,278	480.0	2,293,458.00	4,393,308.14
	Total T:		19	74,327,509	95.0	0.00	125,087.25
	Total D:		96	239,508,278	480.0	0.00	1,237,238.61
	Grand Total :		96	239,508,278	480.0	2,293,458.00	5,755,634.00

Merged Ohio Companies
Expanded Transmission Cost Recovery Rider Revenues
April 2013

Total Transmission Revenues		Current Month	Prior Month Reversal (4)	Net
(1)	Billed "T" Revenue (incl Republic adjust)	**17,955,935.37**	n/a	17,955,935.37
(2)	Estimated "T" Revenue	**23,476.86**	**(125,087.25)**	(101,610.39)
(3)	**Estimated** Unbilled "T" Revenue	7,159,915.52	(7,733,275.39)	(573,359.87)
	Total Amount of Transmission Revenues			**17,280,965.11**

Source of Data:

(1) Billed Transmission revenues 9 - 1T
(2) Estimated Billed Transmission Revenue - MACSS Report MCSRESTB
(3) **Estimated** Unbilled Transmission Revenues - Calculated from KWH provided by Economic Forecasting.

State : OH Line of Business: TRANSMISSION April 2013 9-1T

FERC ACCT	NO	OPERATING REVENUE ACCOUNTS	OPERATING REVENUES THIS YR	LAST YR	%CHNG	KILOWATT - HOUR SALES THIS YR	LAST YR	%CHNG	CUSTOMERS THIS YR	LAST YR	CENTS PER KWH 2013	2012
		SALES OF ELECTRICITY										
		RESIDENTIAL										
4400	002	WITHOUT SPACE HEATING	6,765,933.20	5,982,609.21	13.09	585,688,654	607,164,249	3.54-	764,493	915,200	1.16	0.89
4400	001	WITH SPACE HEATING	3,696,473.13	2,466,601.67	49.86	319,717,496	253,245,240	26.25	214,782	248,913	1.16	0.89
		TOTAL RESIDENTIAL	10,462,406.33	8,449,210.88	23.83	905,406,150	860,409,489	5.23	979,275	1,164,091	1.16	0.98
					0.00						0.00	0.00
		COMMERCIAL										
4420	001	OTHER THAN PUBLIC AUTHORITIES	3,004,998.19	4,640,610.81	35.25-	279,734,319	489,951,485	42.91-	101,176	138,105	1.07	0.53
4420	006	PUBLIC AUTHS - SCHOOLS	135,961.52	185,519.64	26.71-	12,492,351	21,181,080	41.02-	779	1,056	1.09	0.19
4420	007	PUBLIC AUTHS-OTHER THAN SCHOOL	193,155.95	316,489.80	38.97-	18,181,397	38,021,720	52.18-	3,877	6,296	1.06	0.38
		TOTAL COMMERCIAL	3,334,115.66	5,142,620.25	35.17-	310,408,067	549,154,285	43.48-	105,832	145,435	1.07	0.94
					0.00						0.00	0.00
		INDUSTRIAL										
4420	002	EXCLUDING MINE POWER	4,082,887.84	7,420,120.82	44.98-	547,508,262	1,235,452,941	55.68-	5,727	8,331	0.75	0.42
4420	004	MINE POWER	7,239.57	87,589.13	91.73-	748,236	14,249,602	94.75-	35	50	0.97	0.58
4420	005	ASSOCIATED COMPANIES	36,062.56	43,778.40	17.62-	2,542,542	3,178,531	20.01-	17	15	1.42	1.38
		TOTAL INDUSTRIAL	4,126,189.97	7,551,488.35	45.36-	550,799,040	1,252,881,074	56.04-	5,779	8,396	0.75	0.60
		COMMERCIAL AND INDUSTRIAL	7,460,305.63	12,694,108.60	41.23-	861,207,107	1,802,035,359	52.21-	111,611	153,874	0.87	0.70
		PUBLIC STREET & HIGHWAY LIGHT										
4440	000	PUBLIC STREET & HIGHWAY LIGHT	25,701.79	35,593.95	27.79-	5,515,583	7,858,345	29.81-	1,590	2,348	0.47	0.40
		TOTAL PUBLIC STREET & HIGHWAY LIGHT	25,701.79	35,593.95	27.79-	5,515,583	7,858,345	29.81-	1,590	2,326	0.47	0.45
					0.00						0.00	0.00
		OTHER SALES TO PUBLIC AUTHS										
4450	001	PUBLIC SCHOOLS	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
4450	002	OTHER THAN PUBLIC SCHOOLS	692.37	476.05	45.44	60,779	51,669	17.63	26	26	1.14	0.92
		TOTAL OTHER SALES TO PUBLIC AUTHS	692.37	476.05	45.44	60,779	51,669	17.63	26	4	1.14	0.92
		ULTIMATE CUSTOMERS	17,949,106.12	21,179,389.48	15.25-	1,772,189,619	2,670,354,862	33.63-	1,092,502	1,320,361	1.01	0.79
		SALES FOR RESALE										
4470	XXX	OTHER ELEC UTILS	6,829.25	3,825.71	78.51	731,760	547,800	33.58	3	3	0.93	0.70
		TOTAL SALES FOR RESALE	6,829.25	3,825.71	78.51	731,760	547,800	33.58	3	-19	0.93	0.70
					0.00						0.00	0.00
		TOTAL SALES OF ELECTRICITY	17,955,935.37	21,183,215.19	15.24-	1,772,921,379	2,670,902,662	33.62-	1,092,505	1,320,343	1.01	0.79
		PROVISION FOR REFUND										
		PROVISION FOR REFUND										
4491		PROVISION FOR REVENUE REFUND	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
		TOTAL PROVISION FOR REFUND	0.00	0.00	100.00	0	0	100.00	0	-22	0.00	0.00
					0.00						0.00	0.00
		TOTAL PROVISION FOR REFUND	0.00	0.00	100.00	0	0	100.00	0	-22	0.00	0.00
		OTHER OPERATING REVENUES										
		OPERATING REVENUE										
4500		FORFEITED DISCOUNTS	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
4510		MISCELLANEOUS SERVICE REVENUES	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
4530		SALES OF WATER AND WATER POWER	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
4540		RENT FROM ELE PROP-NON ASSOC	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
4560		OTHER ELECTRIC REVENUES	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
		TOTAL OPERATING REVENUE	0.00	0.00	100.00	0	0	100.00	0	-22	0.00	0.00
					0.00						0.00	0.00
		TOTAL OTHER OPERATING REVENUES	0.00	0.00	100.00	0	0	100.00	0	-22	0.00	0.00
		TOTAL OPERATING REVENUES	17,955,935.37	21,183,215.19	15.24-	1,772,921,379	2,670,902,662	33.62-	1,092,505	1,320,343	1.01	0.79

POLRR surcharge revenues are billed as Distribution line of business, but reported as Generation line of business. Line of business changed in BO Universe.

American Electric Power
OHIO POWER COMPANY(Companies 7 & 10)

Estimate Billings For MACSS GTD
MCSRESTB

Prepared: 05/02/2013 03:58:51 PM

April 2013

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
211	G	OH	6	522,639	30.0	3,036.00	8,333.13
211	T	OH	2	79,800	10.0	0.00	311.64
211	D	OH	6	522,639	30.0	0.00	11,449.23
Total : 211			6	522,639	30.0	3,036.00	20,094.00
221	G	OH	17	89,197,322	85.0	151,210.00	789,320.90
221	T	OH	5	4,175,571	25.0	0.00	18,750.70
221	D	OH	17	89,197,322	85.0	0.00	358,683.40
Total : 221			17	89,197,322	85.0	151,210.00	1,166,755.00

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
211	G	OH	20	10,483,171	100.0	39,840.00	103,275.11
211	T	OH	3	886,818	15.0	0.00	3,596.23
211	D	OH	20	10,483,171	100.0	0.00	234,717.66
Total : 211			20	10,483,171	100.0	39,840.00	341,589.00
212	G	OH	5	952,679	25.0	9,065.00	20,356.80
212	T	OH	2	201,787	10.0	0.00	818.29
212	D	OH	5	952,679	25.0	0.00	30,156.91
Total : 212			5	952,679	25.0	9,065.00	51,332.00
213	G	OH	2	31,081,152	10.0	0.00	63,542.76
213	D	OH	2	31,081,152	10.0	0.00	77,101.24
Total : 213			2	31,081,152	10.0	0.00	140,644.00
216	G	OH	4	1,898,860	20.0	0.00	3,743.12
216	D	OH	4	1,898,860	20.0	0.00	31,152.88
Total : 216			4	1,898,860	20.0	0.00	34,896.00
221	G	OH	4	23,130,855	20.0	0.00	56,712.57
221	D	OH	4	23,130,855	20.0	0.00	69,430.43
Total : 221			4	23,130,855	20.0	0.00	126,143.00
	Total G:		58	157,266,678	290.0	203,151.00	1,045,284.39

Total T:	12	5,343,976	60.0	0.00	23,476.86
Total D:	58	157,266,678	290.0	0.00	812,691.75
Grand Total :	58	157,266,678	290.0	203,151.00	1,881,453.00

Schedule D-3c
Narrative
Reconciliation of One Month's Invoice from RTO to Financial Records of the Company
(March 2013 PJM Invoice)

Description of the Reconciliation Process

AEP is represented in the PJM market as a single account. This account, under the name Appalachian Power Company, is comprised of the main account, AEP Generation (AEPSCG), and **seven** sub-accounts associated with serving AEP's native load (Load Serving Entity, or LSE) and off-system sales (OSS). The accounts are listed below.

- AEP Generation (AEPSCG),
- City of Auburn (AEPAUB)
- Buckeye (AEPBCK)
- APCo Dedicated (AEPAPD) (Appalachian Power Company dedicated wind purchases)
- CSP Dedicated (AEPCSD) (Columbus Southern Power dedicated wind purchases)
- IM Dedicated (AEPIMD) (Indiana Michigan Power dedicated wind purchases)
- OPCo Dedicated (AEPOPD) (Ohio Power Company dedicated wind purchases)
- Beech Ridge Energy LLC (BRELLC) (Beech Ridge Wind Farm)

PJM charges and credits associated with serving AEP's LSE and OSS loads are invoiced ("financially settled" or "settled") under these accounts. (Note: PJM does not designate charges/credits for AEP's LSE and OSS responsibilities; this process is completed by AEP). The AEP Generation (AEPSCG) account contains the charge and credit settlement on most of AEP's resources as well as load. AEP has elected to establish additional accounts in order to provide details for market settlement purposes for specific resources and/or entities. These accounts either contain AEP's wind resources, or they contain charge and credit settlement for the load related to the specific entity identified in the account.

In addition to the accounts listed above, another account is invoiced by PJM for credits associated with AEP Transmission (AEPSCT). The charges and credits associated with this account are handled by a separate group from those above because AEP is both a transmission provider and market participant in the PJM energy markets. These are further discussed under a separate heading later in this description.

The PJM invoice is received after AEP's month-end closing process and therefore an estimate is booked for the current month. The following month, the estimate entry is reversed out of the general ledger and a new entry is made reflecting the actual invoice amount. Therefore, the detail provided in Schedule D-3c shows the March 2013 general ledger amounts booked for the March 1, 2013 through March 31, 2013 billing period, as shown on the PJM Billing Statements.

The assignment methodology for PJM costs and credits is detailed in **Schedule D-3c, Summary of March 2013 PJM Invoice Reconciliation, Page 9, PJM Invoice Explanations**. As background, AEP uses the hourly MWh information from PJM to reconstruct the resources (both generation and purchased energy) used to serve the native load requirements and fulfill OSS obligations. The reconstruction of the hourly data is completed by AEP's Power Tracker Application[1]. AEP is able to use the output from Power Tracker to assign certain charges/credits, while other charges/credits are either directly assigned or assigned based on the Load Ratio Share (LRS).

The charges and credits in the accounts AEP elected to establish (those other than the main AEP Generation (AEPSCG) account) are assigned based on the nature of the agreement with the respective participants.

Once the PJM charges and credits have been assigned to either the LSE or OSS, some are then allocated to the AEP East operating companies[2] based upon each company's Member Load Ratio (MLR) percentage. The Member Load Ratio (MLR) is an allocation to the AEP East operating companies based on each member's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding twelve months. Beginning in November 2010, some charges are now allocated to the East operating companies based up a 12 coincident peak methodology[3].

Schedule D-3C, Summary of March 2013 PJM Invoice Reconciliation, Pages 5-8, and demonstrates the settlement of the credits and charges (line items in the March 2013 PJM Invoice) for the PJM accounts listed above and the allocation of each to the OPCo general ledger. **Schedule D-3C, Summary of March 2013 PJM Invoice Reconciliation to General Ledger (GL) Transmission Accounts,** Pages 10-12 shows the reconciliation for the TCRR accounts for AEP Transmission (AEPSCT). As noted earlier, the AEP Transmission accounts (AEPSCT), are settled in a separate process from the PJM accounts listed above.

Description of the PJM Invoice Reconciliation Details

Page 5, **"Summary of March 2013 PJM Invoice to General Ledger (GL) Accounts**", shows a list of the PJM charges that represents Ohio Power Company's (OPCo) TCRR activity for the month, and their FERC-based general ledger account number. The three columns show the total amount allocated from the PJM invoice for each account, the corresponding general

[1] Power Tracker is an internal AEP application used for assigning and reporting the costs and revenues associated with OSS for pool settlements of the Eastern AEP operating companies. Power Tracker calculates costs, demand and energy charges and provides reporting on these results. Using an economic dispatch model, ECR determines the costs associated with OSS on an hourly basis. The Power Tracker process assigns generation and market purchases with the highest price to these sales. Once all OSS activity has been covered by the higher cost generation and market purchases, the remaining lower priced resources are used to source AEP's native load customers.

[2] The AEP East operating companies with generation are: Ohio Power Company, plus Appalachian Power Company (APCo), Kentucky Power (KPCo) and Indiana Michigan Power Company (I&M)

[3] For the 12 CP allocation methodology, all of the East operating companies are utilized. This includes the four generation owning companies mentioned in footnote 2 and the two load only companies, Wheeling Power and Kingsport Power.

ledger total for each account and the variance (if any) for each. This summary illustrates that the March invoice is reconciled for OPCo with a zero variance.

Page 6, "**March 2013 PJM Reconciled Invoice Allocation"** shows the AEP allocation for each of the OPCo activities from Page 5, and that the OPCo portions of each activity, together with the remainder of the AEP East Operating Companies, reconcile with the total from the PJM bills for each activity. The Internal Allocation Column shows the breakdown of the AEP allocations for the LSEs, plus allocations for OSS activities from all of the East Operating Companies if needed to reconcile the TCRR accounts back to the PJM invoice amounts. For each activity/account number, the sum of the LSE Allocation plus the OSS amount is equal to the total from all of the applicable PJM bills for March 2013.

Pages 7 and 8, the **PJM Invoice Detail,** lists, for each of the PJM Invoices, the detail for each Billing Line Item (BLI), consisting of a description of the individual entry, and the total invoice amount included under each account. The sum of each individual BLI entry is equal to the total amount for each account as shown on the Reconciled Invoice Allocations for each of the PJM Invoices.

Page 9, the **PJM Invoice Explanations**, is a list of each activity and the specific PJM Invoice Billing Line Item (BLI) for each activity, described in the "Notes" column. The last column lists the assignment methodology for allocation of each AEPSCG item. The assignment methodology describes for each activity how each billing line item is assigned to determine the amounts reflected in the general ledger.

Description of the AEP Transmission PJM Invoice Reconciliation

Page 10, **"Summary of March 2013 PJM Invoice Reconciliation to General Ledger (GL) Transmission Accounts**" shows a list of the AEP Transmission PJM charges that represent Ohio Power Company (OPCo) TCRR activity for the month, and their FERC-based general ledger account numbers. The three columns for OPCo show the total amount allocated from the PJM invoice by Transmission Settlements for the Network Integration Transmission Service (NITS), Transmission Owner and Dispatch Service, PJM Transmission Enhancements, PJM RTO Formation Cost Recovery, Expansion Cost Recovery, the corresponding general ledger total for each account, and the variance (if any) for each. This summary illustrates that the March invoice for OPCo is reconciled to the general ledger.

Page 11, **March 2013 PJM Transmission Reconciled Invoice Allocation,** illustrates the Internal Allocation to OPCo for activities from Page 10, and that the OPCo portion of each activity, together with the remainder of the AEP East Operating Companies, reconcile with the amounts from the following bills: AEP Transmission (AEPSCT), AEP Generation (AEPSCG), and AEP City of Auburn (AEPAUB). (AEP does not have transmission responsibilities for the other PJM accounts). The Internal Allocation Column shows the breakdown of the Internal Allocation for the Load Serving Entities (LSEs) and Non-Affiliate Wholesale allocation, the Non-Affiliate PJM, and the OSS activities from all of the East Operating Companies. For each activity, the sum of the LSE Allocations and Non-Affiliate Wholesale Allocation, the Non-

Affiliate PJM and OSS for each activity/account number is equal to the total from the AEPSCT, AEPSCG, and AEPAUB PJM invoices for March 2013.

Page 12, **PJM Transmission Invoice Explanations**, is a list of each activity and the specific PJM Invoice Billing Line Item (BLI) for each activity and the assignment methodology for allocation of each item. The assignment methodology described for each activity shows how each billing line item is translated to the total allocated amounts in the general ledger.

*Please note that the reconciliation dollars have not been jurisdictionalized in order to tie to the invoice amount.

Summary of April 2013 PJM Invoice to General Ledger (GL) Accounts

TCRR Activity March 2013

Charge	LSE GL Account	Allocated by Settlements OPCO	GL Amount (Feb Actual Booked in March 2012) OPCO	Variance OPCO
PJM Implicit Congestion	4470093	$2,254,066.27	$2,254,066.27	$ -
PJM FTR & ARR Revenue	4470101	($2,052,461.10)	($2,052,461.10)	$ -
PJM Transmission Implicit Loss Charges	4470207	$6,386,360.84	$6,386,360.84	$ -
PJM Transmission Implicit Loss Credit	4470208	($1,469,757.62)	($1,469,757.62)	$ -
PJM Operating Reserve	4470203	$1,060,985.84	$1,060,985.84	$ -
PJM Ancillary Services				
PJM Synchronous Condensing	5550041	($1.20)	($1.20)	$ -
PJM Reactive Supply	5550074	$3,847.21	$3,847.21	$ -
PJM Blackstart	5550076	$1,969,088.78	$1,969,088.78	$ -
PJM Regulation Charges	5550078	$896,477.98	896,477.98	$ -
PJM Spinning Reserve Charges	5550083	$1,584.67	1,584.67	$ -
PJM 30 minute Supplemental Reserve Market (DASR)	5550090	$4,176.79	$4,176.79	$ -
PJM Administration Service Fees	5614001	$513,767.02	$513,767.02	$ -
	5618001	$102,244.80	$102,244.80	$ -
	5757001	$645,579.26	$645,579.26	$ -
Expansion Cost Recovery Charge	4561003	$36,239.77	$36,239.77	$ -
PJM RTO Formation Cost Recovery	4561002	$61,150.08	$61,150.08	$ -
Real-time Economic Load Response Charge	5550036	$0.00	$0.00	$ -
Pt-to-Pt Transm. Revenues	4561005	($256,211.08)	($256,211.08)	$ -

Reconciled Invoice Allocation

TCRR Activity March 2013

	LSE GL Account	LSE Allocation: OPCO	LSE Allocation: Remaining Operating Cos	OSS Total: All Operating COs	Total
[1]MLR Charges					
PJM Implicit Congestion	4470093	$2,254,066.27	$3,024,283.00	$1,789,880.49	$7,068,229.76
PJM FTR & ARR Revenue	4470101	($2,052,461.10)	($2,753,789.00)	$130,015.94	($4,676,234.14)
PJM Transmission Implicit Loss Charges	4470207	$6,386,360.84	$8,568,587.08	$2,949,301.72	$17,904,249.70
PJM Transmission Implicit Loss Credit	4470208	($1,469,757.62)	($1,971,975.38)	($611,425.16)	($4,053,158.16)
Net Transmission Implicit Losses					$13,851,091.54
PJM Operating Reserve (a)	4470203	$1,060,985.84	$790,775.71	$545,537.71	$2,397,299.26
PJM Ancillary Services (a)					
PJM Synchronous Condensing	5550041	($1.20)	($1.24)	$0.00	($2.44)
PJM Reactive Supply	5550074	$3,847.21	$5,162.12		$9,009.33
PJM Blackstart	5550076	$1,969,088.78	$2,641,928.34	$0.00	$4,611,017.12
PJM Regulation Charges	5550078	$896,477.98	$1,202,805.40	$0.00	$2,099,283.38
PJM Spinning Reserve Charges	5550083	$1,584.67	$1,180.91	$0.00	$2,765.58
PJM 30 minute Supplemental Reserve Market (DASR)	5550090	$4,176.79	$5,603.67	$0.00	$9,780.32
0					
PJM Administration Service Fees (b)					
	5614001	$513,767.02	$689,322.52	$357,880.99	$1,560,970.53
	5618001	$102,244.80	$137,181.76	$75,080.68	$314,507.24
	5757001	$645,579.26	$481,164.77	$354,096.00	$1,480,840.03
PJM Administration Service Fees Sub Total					$3,356,317.80
[2]12 CP Charges					
Expansion Cost Recovery Charge	4561003	$36,239.77	$47,905.83	$0.00	$84,145.60
PJM RTO Formation Cost Recovery	4561002	$61,150.08	$80,834.91		$141,984.99
Real-time Economic Load Response Charge	5550036	$0.00	$0.00	$ -	$ -
Pt-to-Pt Transm. Revenues	4561005	($256,211.08)	($338,687.92)	$ -	($594,899.00)
Total					

[1] Charges in this section are allocated based upon MLR
[2] Charges in this section are allocated based upon 12CP

PJM Invoice Detail - April 2013 Invoices

PJM Billing Line Item	AEPAPD	AEPAUB	AEPCSD	AEPIMD	AEPOPD	AEPSCG	Beech Ridge	AEPSCT	AEPBCK	Total of PJM Bills	Reconciled Invoice Allocation Total	Variance
PJM Implicit Congestion												
1210 - Day-Ahead Transmission Implicit Congestion Charge	$281,012.54	($32,698.89)		$266,368.80	$169,256.93	$8,259,617.65	($8,005.92)			$8,935,551.11		
1215 - Balancing Transmission Implicit Congestion Charge	$21,712.71	$809.99		$17,971.13	$21,409.04	($2,149,878.51)	$5,103.63			($2,082,872.01)		
1410 - Load Reconciliation for Transmission Congestion Charge						$215,550.66				$215,550.66		
Grand Total										$7,068,229.76	$7,068,229.76	$0.00
PJM FTR & ARR Revenue												
1500 - Financial Transmission Rights Auction Charge						$6,927,308.36				$6,927,308.36		
2210 - Transmission Congestion Credit (Target Credit)						($5,090,687.55)				($5,090,687.55)		
2210A - Adj. to Transmission Congestion						$0.02				$0.02		
2210A - Adj. to Transmission Congestion						$24,017.37				$24,017.37		
2210A - Adj. to Transmission Congestion						$96,691.54				$96,691.54		
2210A - Adj. to Transmission Congestion						$36,119.80				$36,119.80		
2210A - Adj. to Transmission Congestion						$70,483.42				$70,483.42		
2210A - Adj. to Transmission Congestion						$25,742.01				$25,742.01		
2510 - Auction Revenue Rights Credit		($29,769.92)				($6,736,139.19)				($6,765,909.11)		
Grand Total										($4,676,234.14)	($4,676,234.14)	$0.00
PJM Transmission Implicit Loss Charges												
1220 - Day-Ahead Transmission Implicit Losses Charge	$230,464.87	($24,312.84)		$203,991.31	$83,655.56	$17,589,654.51	($1,340.11)			$18,082,113.30		
1225 - Balancing Transmission Implicit Losses Charge	$14,171.52	$2,348.51		$1,450.21	$8,098.64	($315,434.47)	$6,810.12			($282,555.47)		
1420 - Load Reconciliation for Transmission Losses Charge						$104,691.87				$104,691.87		
Grand Total										$17,904,249.70	$17,904,249.70	$0.00
PJM Transmission Implicit Loss Credit												
2220 - Transmission Losses Credit		($16,608.21)				($3,740,293.46)			($341,838.59)	($4,098,740.26)		
2220A - Adj. to Transmission Losses										$0.00		
2220A - Adj. to Transmission Losses										$0.00		
2220A - Adj. to Transmission Losses										$0.00		
2220A - Adj. to Transmission Losses										$0.00		
2220A - Adj. to Transmission Losses										$0.00		
2420 - Load Reconciliation for Transmission Losses Credit						$46,054.54			($472.44)	$45,582.10		
Grand Total										($4,053,158.16)	($4,053,158.16)	$0.00
PJM Operating Reserve												
1370 - Day-Ahead Operating Reserve Charge		$3,329.64				$769,663.27				$772,992.91		
1370A - Adj. to Day-ahead Operating Reserve		$121.59				$26,288.60				$26,410.19		
1370A - Adj. to Day-ahead Operating Reserve		$94.27				$23,890.83				$23,985.10		
1370A - Adj. to Day-ahead Operating Reserve		$322.70				$74,445.57				$74,768.27		
1375 - Balancing Operating Reserve Charge	$16,901.83	$4,020.15		$9,241.77	$6,387.00	$902,933.54	$22,179.14			$961,663.43		
1375A - Adj. to Balancing Operating Reserve	$88.20	$9.26	$91.44	$83.17	$57.34	$3,132.94	$33.05			$3,495.40		
1375A - Adj. to Balancing Operating Reserve	$179.62	$53.25		$89.78	$34.10	$7,237.83	$73.32			$7,667.90		
1375A - Adj. to Balancing Operating Reserve	$58.79	$6.83		$21.28	$15.68	$2,297.56	$27.48			$2,427.62		
1375A - Adj. to Balancing Operating Reserve	$37.88	$15.07		$12.53	$8.63	$1,294.06	$1.44			$1,369.61		
1375A - Adj. to Balancing Operating Reserve	$8.42	$1.74		$4.87	$2.44	$301.02	$6.68			$325.17		
1375A - Adj. to Balancing Operating Reserve	($86.60)	$10.00		($77.78)	($60.49)	$757.72	($241.88)			$300.97		
1375A - Adj. to Balancing Operating Reserve	($10.87)	$13.75		($244.12)	($45.28)	$10,443.00	$24.17			$10,180.65		
1376 - Balancing Operating Reserve for Load Response Charge	($3.69)	($0.53)		($2.15)	($1.96)	($159.57)	($4.19)			($172.09)		
1378 - Reactive Services Charge		$2,250.61				$529,955.32				$532,205.93		
1478 - Load Reconciliation for Balancing Operating Reserve Charge						($14,139.87)				($14,139.87)		
1478A - Adj. to Load Reconciliation for Balancing Operating Reserve Charge		$0.01				$722.95				$722.96		
1490 - Load Reconciliation for Reactive Services Charge						($6,904.89)				($6,904.89)		
Grand Total										$2,397,299.26	$2,397,299.26	$0.00
PJM Synchronous Condensing												
1377 - Synchronous Condensing Charge										$0.00		
1480 - Load Reconciliation for Synchronous Condensing Charge						($2.44)				($2.44)		
Grand Total										($2.44)	($2.44)	$0.00
PJM Reactive Supply												
1330 - Reactive Supply and Voltage Control from Generation and Other Sources Service Charge		$8,983.18								$8,983.18		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge		$12.22								$12.22		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge		$10.52								$10.52		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge		$3.41								$3.41		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge										$0.00		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge										$0.00		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge										$0.00		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge										$0.00		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge										$0.00		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge										$0.00		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge										$0.00		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge										$0.00		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge										$0.00		
Grand Total										$9,009.33	$9,009.33	$0.00
PJM Blackstart												
1380 - Black Start Service Charge		$17,237.93				$4,584,575.73				$4,601,813.66		
1380A - Adj. to Black Start Service		0.34				$84.41				$84.75		
1380A - Adj. to Black Start Service		28.38				$6,550.92				$6,579.30		
1380A - Adj. to Black Start Service		9.25				$2,519.42				$2,528.67		
1380A - Adj. to Black Start Service						$10.74				$10.74		
1380A - Adj. to Black Start Service										$0.00		
1380A - Adj. to Black Start Service										$0.00		
Grand Total										$4,611,017.12	$4,611,017.12	$0.00

PJM Regulation Charges										
1340 - Regulation and Frequency Response Service Charge		$9,585.13			$2,123,061.68			$2,132,646.81		
1340A - Adj. to Regulation and Frequency Response Service		($0.05)			$0.01			($0.04)		
1340A - Adj. to Regulation and Frequency Response Service		$0.08			($7.97)			($7.89)		
1340A - Adj. to Regulation and Frequency Response Service		($0.19)			$14.12			$13.93		
1340A - Adj. to Regulation and Frequency Response Service		$0.58			($56.14)			($55.56)		
1340A - Adj. to Regulation and Frequency Response Service					$121.80			$121.80		
1460 - Load Reconciliation for Regulation and Frequency Response Service Charge					($33,435.67)			($33,435.67)		
Grand Total								$2,099,283.38	$2,099,283.38	$0.00
PJM Spinning Reserve Charges										
1360 - Synchronized Reserve Tier 2 Charge		$149.68			$3,623.40			$3,773.08		
1360A - Adj Synchronized Reserve Tier 2 Charge		($0.36)						($0.36)		
1470 - Load Reconciliation for Synchronized Reserve Charge					($1,007.14)			($1,007.14)		
Grand Total								$2,765.58	$2,765.58	$0.00
PJM 30 minute Supplemental Reserve Market (DASR)										
1365 - Day-Ahead Scheduling Reserve Charge		$43.75			$9,807.39			$9,851.14		
1365A - Adj. to Day-ahead Scheduling Reserve								$0.00		
1365A - Adj. to Day-ahead Scheduling Reserve								$0.00		
1365A - Adj. to Day-ahead Scheduling Reserve								$0.00		
1365A - Adj. to Day-ahead Scheduling Reserve								$0.00		
1475 - Load Reconciliation for Day-Ahead Scheduling Reserve Charge					($70.82)			($70.82)		
Grand Total								$9,780.32	$9,780.32	$0.00
PJM Administration Service Fees										
1301-PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$6,365.87			$1,441,928.49			$1,448,294.36		
1302-PJM Scheduling, System Control and Dispatch Service - FTR Administration					$30,233.35			$30,233.35		
1303-PJM Scheduling, System Control and Dispatch Service - Market Support	$2,732.58	$1,444.81	$1,505.24	$1,067.61	$709,314.83	$928.82		$716,993.89		
1304-PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$58.60			$15,519.48			$15,578.08		
1305-PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.					$121,618.65			$121,618.65		
1306-PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	$314.02	$983.30	$172.98	$122.69	$270,642.85	$106.74		$272,342.58		
1307-PJM Scheduling, System Control and Dispatch Service - Market Support Offset	($380.93)	($195.64)	($209.85)	($148.81)	($98,695.46)	($129.48)		($99,760.17)		
1308-PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration								$0.00		
1309-PJM Scheduling, System Control and Dispatch Service Refund - FTR Administration								$0.00		
1310-PJM Scheduling, System Control and Dispatch Service Refund - Market Support								$0.00		
1311-PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration								$0.00		
1311A-PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration					($0.01)			($0.01)		
1312-PJM Scheduling, System Control and Dispatch Service Refund - Capacity Resource/Obligation Mgmt.								$0.00		
1313-PJM Settlement, Inc.	$380.93	$195.64	$209.85	$148.81	$98,695.46	$129.48		$99,760.17		
1314-Market Monitoring Unit (MMU) Funding	$280.60	$146.81	$154.56	$109.63	$72,782.56	$95.36		$73,569.52		
1314A-Adj. to Market Monitoring Unit (MMU) Funding	($38.93)	($19.52)	($23.28)	($16.49)	($9,911.21)	($12.17)		($10,021.60)		
1314A-Adj. to Market Monitoring Unit (MMU) Funding	($29.37)	($17.86)	($14.91)	($10.54)	($8,762.20)	($10.68)		($8,845.56)		
1315-FERC Annual Recovery		$2,238.62			$507,061.12			$509,299.74		
1316-Organization of PJM States, Inc. (OPSI) Funding		$25.97			$5,880.20			$5,906.17		
1317-North American Electric Reliability Corporation (NERC)		$376.22			$84,925.84			$85,302.06		
1318-Reliability First Corporation (RFC)		$538.02			$121,443.96			$121,981.98		
1440-Load Reconciliation for PJM Scheduling, System Control and Dispatch Service					($16,712.88)			($16,712.88)		
1441-Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund								$0.00		
1442-Load Reconciliation for Schedule 9-6 - Advanced Second Control Center					($2,153.79)			($2,153.79)		
1444-Load Reconciliation for Market Monitoring Unit (MMU) Funding					($309.98)			($309.98)		
1444A-Adj. to Load Reconciliation for Market Monitoring Unit (MMU) Funding		($0.76)			$68.80			$68.04		
1444A-Adj. to Load Reconciliation for Market Monitoring Unit (MMU) Funding		$0.01			$9.38			$9.39		
1445-Load Reconciliation for FERC Annual Recovery					($4,815.58)			($4,815.58)		
1446-Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding					($55.84)			($55.84)		
1447-Load Reconciliation for North American Electric Reliability Corporation (NERC)					($809.34)			($809.34)		
1448-Load Reconciliation for Reliability First Corporation (RFC)					($1,157.36)			($1,157.36)		
1304A-PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration					$0.13			$0.13		
1304A-PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration					$0.08			$0.08		
1304A-PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration					$1.83			$1.83		
1306A-PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center					($0.11)			($0.11)		
1306A-PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center								$0.00		
1306A-PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center								$0.00		
1306A-PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center								$0.00		
Grand Total								$3,356,317.80	$3,356,317.80	$0.00
Expansion Cost Recovery Charge										
1730 - Expansion Cost Recovery Charge		$316.20			$83,829.40			$84,145.60		
Grand Total								$84,145.60	$84,145.60	$0.00
PJM RTO Formation Cost Recovery										
1720 - RTO Start-up Cost Recovery Charge		$533.51			$141,451.48			$141,984.99		
Grand Total								$141,984.99	$141,984.99	$0.00
Real-time Economic Load Response Charge										
Pt-to-Pt Transm. Revenues										
STTL_ITEM_NME										
2130 - Firm Point-to-Point Transmission Service Credit		($2,377.35)			($630,270.93)			($632,648.28)		
2130A - Adj. to Firm Point-to-Point Transmission Service Credit		$174.51			$40,555.00			$40,729.51		
2130A - Adj. to Firm Point-to-Point Transmission Service Credit		$157.06			$36,154.79			$36,311.85		
2130A - Adj. to Firm Point-to-Point Transmission Service Credit		$46.78			$12,702.70			$12,749.48		
2140 - Non-Firm Point-to-Point Transmission Service Credit		($174.89)			($46,365.57)			($46,540.46)		
2140A - Adj. to Non-Firm Point-to-Point Transmission Service		($0.37)			($85.23)			($85.60)		
2140A - Adj. to Non-Firm Point-to-Point Transmission Service		($0.40)			($91.15)			($91.55)		
2140A - Adj. to Non-Firm Point-to-Point Transmission Service		($0.10)			($25.90)			($26.00)		
2140A - Adj. to Non-Firm Point-to-Point Transmission Service		($19.67)			($5,278.28)			($5,297.95)		
Grand Total							$0.00	($594,899.00)	($594,899.00)	$0.00

Charge	PJM Invoice BLI #	Notes	Assignment Methodology (AEPSCG)
PJM Implicit Congestion	1210, 1215	Add these line items together plus any prior period adjustments on the invoices to get the total Invoiced congestion by PJM.	1 Power Tracker Dispatch.
PJM FTR & ARR Revenue	2210, 2510, 1500 & 2500	Add these line items together plus any prior period adjustments on the invoices to get the PJM Total.	FTR Target credits are assigned hourly between LSE and OSS. The FTR credits are first used to offset LSE congestion charges, if excess credits remain they are then used to offset OSS congestion charges, if still more excess credits exist they are shared between the LSE and OSS. ARR revenue is assigned directly to the LSE.
PJM Operating Reserve (a)	1378, 1370, 1478,1375, 1376 and 2376	Add these line items together plus any prior period adjustments on the invoices to get the PJM Total.	A LRS is used when there is not adequate market data from PJM to attribute the cause of a charge to any one specific activity or when the use of a more granular approach would not yield a more appropriate allocation.
PJM Synchronous Condensing	1377, 1480	Take these line items plus any prior period adjustments on the invoices to get the PJM Total.	Directly to the LSE. The cost to the PJM pool for synchronous condensing is allocated to participants based upon load. AEP's internal assignment of costs matches that approach by assigning it to LSE.
PJM Reactive Supply	1330	Take this line item plus any prior period adjustments on the invoices to get the PJM Total.	Ancillary Service charges and credits are aggregated and recorded based on the netted result. Since ancillary services are used by loads, PJM charges the load for the service while the generators receive credits for providing the service. If the net amount is a charge, this reflects that the native load customers of AEP purchased all or a portion of the service from PJM (AEP did not receive awards to supply its load requirement). If the net amount is a credit, the effect is AEP supplied all its requirements for its load for that service and was able to sell additional to PJM, thus making a sale to the market. As a result, net charges are recorded to LSE accounts while net credits would be recorded to OSS accounts.
PJM Blackstart	1380	Take this line item plus any prior period adjustments on the invoices to get the PJM Total.	See cell D9
PJM Regulation Charges	1340 and 1460	Take these line items plus any prior period adjustments on the invoices to get the PJM Total.	See cell D9
PJM Spinning Reserve Charges	1360, 1470	Take these line items plus any prior period adjustments on the invoices to get the PJM Total.	See cell D9
PJM 30 minute Supplemental Reserve Market (DASR)	1365 and 1475	Add these line items together plus any prior period adjustments on the invoices to get the PJM Total.	See cell D9
PJM Administration Service Fees (b)	1301, 1302, 1303, 1304, 1305,1306, 1307, 1308, 1309, 1310, 1311, 1312, 1313, 1314, 1315, 1316, 1317, 1318, 1440, 1441, 1442, 1444, 1445, 1446, 1447, 1448	Add these line items together plus any prior period adjustments on the invoices to get the PJM Total.	A LRS is used when there is not adequate market data from PJM to attribute the cause of a charge to any one specific activity or when the use of a more granular approach would not yield a more appropriate allocation.
Net Expansion Cost Recovery Charge	1730	Take this line item plus any prior period adjustments on the invoices to get the PJM Total.	PJM allocates these costs to participants based upon load. AEP's internal assignment of costs matches that approach by assigning it to LSE.
PJM RTO Formation Cost Recovery	1720	Take this line item plus any prior period adjustments on the invoices to get the PJM Total.	PJM allocates these costs to participants based upon load. AEP's internal assignment of costs matches that approach by assigning it to LSE.
PJM Transmission Enhancement Charges	1108	Take this line item plus any prior period adjustments on the invoices to get the PJM Total.	PJM allocates these costs to participants based upon load. AEP's internal assignment of costs matches that approach by assigning it to LSE.
NITS Charges	1100	Take this line item plus any prior period adjustments on the invoices to get the PJM Total.	Assigned by Transmission Settlements
TO Charges	1320	Take this line item plus any prior period adjustments on the invoices to get the PJM Total.	Assigned by Transmission Settlements
PJM Transmission Implicit Loss Charges	1220, 1225	Add these line items together plus any prior period adjustments on the invoices to get the total Invoiced congestion by PJM.	1 Power Tracker Dispatch.
PJM Transmission Implicit Loss Credit	2220 & 2420	Add these line items together plus any prior period adjustments on the invoices to get the PJM Total.	The allocation of this credit is based on the monthly percentage of Implicit Loss Charges allocated to LSE versus OSS. The percentage is applied to the Transmission Loss Credit for assignment to LSE and OSS.
Pt-to-Pt Transm. Revenues	2130 & 2140	Add these line items together plus any prior period adjustments on the invoices to get the PJM Total.	Revenues collected by PJM are distributed to a large degree based upon load. Therefore, the internal allocation of the credit is directly assigned to internal load.

*******Negative amounts in the charge section of the PJM invoice equate to credits.**
Negative amounts in the credit section of the PJM invoice equate to charges.
Prior period adjustments will have an "A" next to the billing line item number.

Footnotes

[1] Due to additional information from PJM, AEP is able to allocate Implicit Congestion and Implicit Losses on a more granular basis. The charges are broken down by their activity type (Internal Load, Generation, Purchases, etc.). Charges related to Internal Load are classified as LSE while all other obligations are considered OSS. The charges associated with resources (generation and purchases) are allocated based on the obligations they served as determined during cost reconstruction. (Ex.: A generation asset is assigned to fill internal load during cost reconstruction. Both the implicit congestion and implicit losses associated with the generation asset and the internal load would be assigned to LSE.)

Summary of March 2013 PJM Invoice to General Ledger (GL) Transmission Accounts

TCRR Activity March 2013

Transmission Account Activity

Charge/Credits	LSE GL Account	Allocated by Settlements Ohio	GL Amount (Actual Booked in April 2013) Ohio	Variance Ohio
PJM NITS Charges	4561035, 5650016	$ 9,573,730.28	$ 9,573,730.28	$ -
Transmission Owner Scheduling, System Control & Dispatch	4561036, 5650015	$ 129,431.21	$ 129,431.21	$ -
PJM Transmission Enhancement	4561060, 5650019, 5650012	$ 1,152,528.82	$ 1,152,528.82	$ -
PJM RTO Formation Cost Recovery	4561002	$ (82,877.87)	$ (82,877.87)	$ -
Expansion Cost Recovery	4561003	$ (92,381.84)	$ (92,381.84)	$ -

March 2013 PJM Transmission Reconciled Invoice Allocation

TCRR Activity March 2013
Transmission Account Activity

Charge/Credit	LSE GL Account	Internal Allocation: LSE & Non-Affiliate Wholesale Allocation – Ohio	LSE & Non-Affiliate Wholesale Allocation – APCO, KY, I&M.KGSPT and WHG	Non-Affiliate PJM – Ohio	Non-Affiliate PJM – APCO, KY and I&M	OSS Total – All Operating COs	Total	PJM Invoices March 2013: AEPSCT	AEPSCG	AEPAUB	Total
Transmission Account Activity											
PJM RTO Formation Cost Recovery	4561002			$ (82,877.87)	$ (117,706.30)		$ (200,584.17)	$ (200,584.17)			$ (200,584.17)
Expansion Cost Recovery	4561003			$ (92,381.84)	$ (118,609.40)		$ (210,991.24)	$ (210,991.24)			$ (210,991.24)
Generation Account Activity											
PJM NITS Charges	4561035, 5650016, 4470150	$ 9,573,730.28	$ 26,407,705.65			$ 2,457,418.96	$ 38,438,854.89		$ 38,294,407.09	$ 144,444.50	$ 38,438,851.59
PJM Transmission Enhancement Charges	4561060, 5650019, 5650012, 4470150	$ 78,671.44	$ 217,003.50	$ 1,073,857.38	$ 2,863,993.94	$ 20,193.67	$ 4,253,719.93		$ 4,237,735.42	$ 15,984.51	$ 4,253,719.93
Network Integration Transmission Service Charge	4470107					$ (3.30)	$ (3.30)				
Transmission Owner Scheduling, System Control & Dispatch	4561036, 5650015, 4470150	$ 129,431.21	$ 383,437.71			$ 35,623.48	$ 548,492.40		$ 548,759.14	$ 2,419.21	$ 551,178.35
PJM Transmission Owner Administrative Services Charges	4470110					$ 2,685.95	$ 2,685.95				
		$ 9,781,832.93	$ 27,008,146.86	$ 898,597.67	$ 2,627,678.24	$ 2,515,918.76	$ 42,832,174.46	$ (411,575.41)	$ 43,080,901.65	$ 162,848.22	$ 42,832,174.46

Difference between Total Internal Allocation and PJM Invoices $ -

PJM Transmission Invoice Explanations

Charge/Credit	PJM Invoice BLI #	Notes	Assignment Methodology
PJM NITS Charges	1100	Take this line item plus any prior period adjustments of the invoices (AEPSCG, AEPAUB) to get the PJM Total.	Allocated to the operating companies based on each companies 12cp or direct assigned.
PJM Transmission Enhancement Charges	1108	Take this line item plus any prior period adjustments of the invoices (AEPSCG, AEPAUB) to get the PJM Total.	Allocated to the operating companies based on each companies 12cp or direct assigned.
Transmission Owner Scheduling, System Control & Dispatch	1320	Take this line item plus any prior period adjustments of the invoices (AEPSCG, AEPAUB) to get the PJM Total.	Allocated to the operating companies based on each companies MWh or direct assigned.
PJM RTO Formation Cost Recovery	2720	This line item is directly from the PJM invoice.	Credits are allocated to the operating companies based on each companies share of the total revenue requirement and charges are allocated by 12cp.
Expansion Cost Recovery	2730	This line item is directly from the PJM invoice.	Credits are allocated to the operating companies based on each companies share of the total revenue requirement and charges are allocated by 12cp.

Footnotes

Negative amounts in the charge section of the PJM invoice equate to credits. Negative amounts in the credit section of the PJM invoice equate to charges.
BLI: Billing Line Item
Charges on the PJM Bill are represented with a Billing Line Item that starts with a "1", and credits start with a "2".