BEFORE
THE PUBLIC UTILITIES COMMSSION OF OHIO

In the Matter of the Application of	**)**	
Ohio Power Company to Update Its	**)**	**Case No. 14-1094-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. 13-1406-EL-RDR. In that case the Company's current TCRR rates became effective on December 19, 2013.

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 2014 billing month are $47,619,007 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 32.72%. The increase reflects $57,148,072 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. In Paragraph 16 of the application to the Company's previous TCRR filing in Case No. 13-1406-EL-RDR, the Company explained that it was incorporating into the rates a two-year average forecast of certain costs. The two-year average reflected the anticipated decrease in certain costs due to the termination of the AEP East Power Pool. A significant portion of the under-recovery balance in this filing is the expected differential between actual costs incurred by the Company and forecast costs based on the two-year average method.

13. 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,

[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.

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, 2014, this rate has decreased the outstanding balance to $22,274,488. The Transmission Under-Recovery Rider will terminate when the full amount of the under-recovery has been collected.

14. 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.

15. 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.

16. The Company requests that its proposed updated TCRR rates be made effective on a bills rendered basis beginning on August 28, 2014 – the first day of the September 2014 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.

17. Finally, pursuant to §4901:1-36-06, Ohio Administrative Code, this filing represents the biennial filing in which the Company provides additional information detailing its policies and procedures for minimizing any costs in its TCRR over which it has control. Information relevant to this requirement is included in Appendix A and Attachment L&M, in addition to the information which already is in the required schedules set out in Paragraph 9 above.

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 2014, 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	1.87674	
GS-1, GS-1-TOD	1.90177	
GS-2 Secondary	0.27383	3.94
GS-2 Recreational Lighting, GS-TOD,GS-2-TOD and GS-2-ES	1.89726	
GS-2 Primary	0.26433	3.80
GS-2 Subtransmission and Transmission	0.25906	3.73
GS-3 Secondary	0.27631	5.60
GS-3-ES	1.56854	
GS-3 Primary	0.26672	5.41
GS-3 Subtransmission and Transmission	0.26141	5.30
GS-4 Primary	0.27895	5.32
GS-4 Subtransmission and Transmission	0.27339	5.21
EHG	0.90312	
EHS	1.72021	
SS	1.72021	
OL, AL	0.27338	
SL	0.27338	

Schedule SBS	¢/KWH	$/KW					
		5%	10%	15%	20%	25%	30%
Backup - Secondary	0.28029	0.04	0.07	0.11	0.14	0.18	0.22
- Primary	0.27057	0.03	0.07	0.10	0.14	0.17	0.21
-Subtrans/Trans	0.26518	0.03	0.07	0.10	0.14	0.17	0.20
Backup < 100 KW Secondary		0.40					
Maintenance - Secondary	0.29800						
- Primary	0.28667						
- Subtrans/Trans	0.28128						
GS-2 and GS-3 Breakdown Service		0.50					

TRANSMISSION COST RECOVERY RIDER

Effective ~~December 19, 2013~~Cycle 1 September 2014, 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	~~1.44178~~1.87674	
GS-1, GS-1-TOD	~~1.23027~~1.90177	
GS-2 Secondary	~~0.37253~~0.27383	~~2.14~~3.94
GS-2 Recreational Lighting, GS-TOD,GS-2-TOD and GS-2-ES	~~1.25165~~1.89726	
GS-2 Primary	~~0.35961~~0.26433	~~2.07~~3.80
GS-2 Subtransmission and Transmission	~~0.35244~~0.25906	~~2.02~~3.73
GS-3 Secondary	~~0.37644~~0.27631	~~3.45~~5.60
GS-3-ES	~~1.13004~~1.56854	
GS-3 Primary	~~0.36338~~0.26672	~~3.33~~5.41
GS-3 Subtransmission and Transmission	~~0.35614~~0.26141	~~3.26~~5.30
GS-4 Primary	~~0.37834~~0.27895	~~3.24~~5.32
GS-4 Subtransmission and Transmission	~~0.37081~~0.27339	~~3.18~~5.21
EHG	~~0.70040~~0.90312	
EHS	~~1.10784~~1.72021	
SS	~~1.10784~~1.72021	
OL, AL	~~0.37083~~0.27338	
SL	~~0.37083~~0.27338	

Schedule SBS	¢/KWH	$/KW					
		5%	10%	15%	20%	25%	30%
Backup - Secondary	~~0.38498~~0.28029	0.04	~~0.09~~0.07	~~0.13~~0.11	~~0.17~~0.14	~~0.21~~0.18	~~0.26~~0.22
- Primary	~~0.37162~~0.27057	~~0.04~~0.03	~~0.08~~0.07	~~0.12~~0.10	~~0.16~~0.14	~~0.21~~0.17	~~0.25~~0.21
-Subtrans/Trans	~~0.36422~~0.26518	~~0.04~~0.03	~~0.08~~0.07	~~0.12~~0.10	~~0.16~~0.14	~~0.20~~0.17	~~0.24~~0.20
Backup < 100 KW Secondary		0.40					
Maintenance - Secondary	~~0.40591~~0.29800						
- Primary	~~0.39094~~0.28667						
- Subtrans/Trans	~~0.38354~~0.28128						
GS-2 and GS-3 Breakdown Service		~~0.40~~0.50					

Summary of Total Projected Transmission Costs / Revenues

	Ohio Power Company	
	($)	
NITS	$ 101,241,522	D
Transmission Enhancement Charges	$ 12,983,572	D
Scheduling	$ 1,181,732	E
Point to Point Revenues	$ (1,870,383)	D
Regulation Service	$ 4,566,671	E
Spinning Reserves	$ 49,817	E
Supplemental Reserves - Charges	$ 643,963	E
Net Congestion	$ (8,302,400)	E
Operating Reserves - Charges	$ 4,125,829	E
Load Response Program Subsidies	$ -	E
Net Ancillary Services - Synchronous Condensing	$ 3,304	E
- Reactive Supply - Charges	$ 5,791,203	E
- Blackstart - Charges	$ 9,571,883	E
PJM Administration Fees	$ 5,532,094	E
Net RTO Formation Costs & Expansion Cost Recovery Charge	$ 331,728	E
Phase - In Credit	$ -	O
Net Marginal Losses	$ (2,931,800)	E
Total Transmission Costs	$ 132,918,734	
(Over)/Under Collection	$ 57,148,072	O
Forecast Carrying Costs	$ 2,625,559	O
	$ 192,692,365	

D = Demand, E = Energy, O = Other

Summary of Current versus Proposed Transmission Revenues

Ohio Power Company

	Forecast for September 2014 - May 2015				
	Metered kWh	Current TCRR	Proposed TCRR	Difference	% Difference
RS	7,292,704,967	$105,144,762	$136,865,111	31,720,350	30.17%
GS1	288,062,877	$3,543,951	$5,478,293	1,934,342	54.58%
GS2 Sec	851,459,860	$10,805,313	$16,385,514	5,580,201	51.64%
GS2 RL - GS - TOD	30,941,680	$387,282	$587,044	199,763	51.58%
GS2 Pri	30,206,907	$418,918	$649,461	230,544	55.03%
GS2 Sub/Trans	8,014,212	$179,961	$300,909	120,949	67.21%
GS3 Sec	765,356,768	$9,000,344	$12,047,428	3,047,084	33.86%
GS3 - TOD	0	$0	$0	-	0.00%
GS3 Pri	218,085,391	$2,378,021	$3,157,588	779,567	32.78%
GS3 Sub/Trans	65,613,857	$787,295	$1,071,574	284,280	36.11%
GS4 Pri	0	$0	$0	-	#DIV/0!
GS4/IRP Sub/Trans	1,226,669,787	$12,353,762	$16,141,272	3,787,510	30.66%
EHG	7,936,147	$55,585	$71,673	16,088	28.94%
SS	4,923,174	$54,541	$84,689	30,148	55.28%
OL	64,556,390	$239,394	$176,484	(62,910)	-26.28%
SL	50,124,742	$185,878	$136,970	(48,907)	-26.31%
Total	10,904,656,757	$145,535,005	$193,154,011	47,619,007	32.72%

AEP Ohio

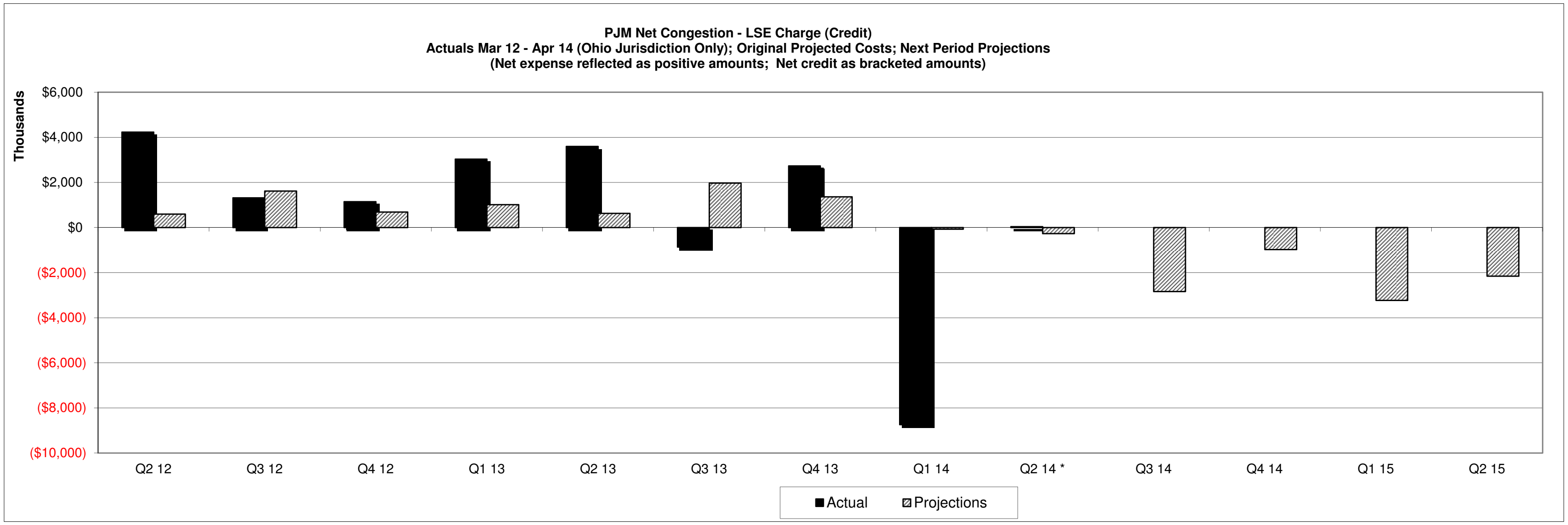
	(12-1046-EL-RDR) May 2013 - Aug 2013 Rates $ kWh	$ Demand	(13-1406-EL-RDR initial) Sep 2013 - Dec 2013 Rates $ kWh	$ Demand	(current) Jan 2014 - Apr 2014 Rates $ kWh	$ Demand	Actual 12 Months Billed 4/30/2014 Metered kWh	Demand	Revenue kWh	Revenue Demand	Forecast September 2014 - May 2015 Metered kWh	Demand	Revenue at Current Rates	Proposed Rates kWh	Demand	Forecast September 2013 - August 2014 Revenue at Proposed Rates	$ Change	% Change
Residential																		
Residential	0.0115708		0.0147657		0.0144178		10,837,253,603		147,903,413.53	-	7,292,704,967		105144761.7	0.0187674		136,865,111.20	31,720,349.52	30%
AL	0.0036987		0.0037978		0.0037083		21,397,703		79,974.24	-	14,878,485		55,173.89	0.0027338		40,674.80	(14,499.09)	-26%
							10,858,651,306	-	147,983,387.77	-	7,307,583,452	-	105,199,935.57			136,905,786.00	31,705,850.43	30%
Commercial																		
GS1	0.0089975		0.0125996		0.0123027		384,581,239	-	4,360,022.83	-	276,327,898		3,399,579.23	0.0190177		5,255,121.07	1,855,541.84	55%
GS2-Sec	0.0051223	1.54	0.0038151	2.19	0.0037253	2.14	1,165,107,442	4,830,009	4,967,019.11	9,326,188.96	794,235,511	3,290,629	10,000,712.27	0.0027383	3.94	15,139,934.58	5,139,222.31	51%
GS2 RL - GS - TOD	0.0113915		0.0128184		0.0125165		42,217,730		516,353.37	-	29,662,208		371,267.03	0.0189726		562,769.21	191,502.18	52%
GS2-Pri	0.0049448	1.49	0.0036828	2.11	0.0035961	2.07	14,849,397	76,121	61,605.01	139,308.47	9,735,437	47,924	134,212.97	0.0026433	3.80	207,846.13	73,633.16	55%
GS2-Sub/Tran	0.0048310	1.45	0.0036094	2.07	0.0035244	2.02	1,586,500	6,490	6,501.53	10,938.62	1,077,055	3,839	11,551.01	0.0025906	3.73	17,110.17	5,559.16	48%
GS3-Sec	0.0046084	2.69	0.0038552	3.54	0.0037644	3.45	1,075,079,753	2,491,896	4,460,992.66	7,852,751.82	692,506,055	1,606,255	8,148,450.27	0.0027631	5.60	10,908,492.66	2,760,042.39	34%
GS3-Pri	0.0044487	2.60	0.0037215	3.42	0.0036338	3.33	274,135,206	587,340	1,106,134.35	1,775,741.77	169,452,371	366,344	1,835,680.91	0.0026672	5.41	2,433,883.38	598,202.47	33%
GS3-Sub/Tran	0.0043463	2.54	0.0036473	3.35	0.0035614	3.26	31,893,404	102,861	119,715.68	322,956.04	24,740,747	82,439	356,861.27	0.0026141	5.30	501,598.94	144,737.67	41%
EHG	0.0083211		0.0071730		0.0070040		10,045,563	-	74,207.02	-	7,770,069		54,421.56	0.0090312		70,173.05	15,751.49	29%
SS	0.0111466		0.0113457		0.0110784		6,533,329	-	73,104.46	-	4,923,174		54,540.89	0.0172021		84,688.92	30,148.03	55%
AL	0.0036987		0.0037978		0.0037083		62,803,398		234,699.82	-	46,059,456		170,802.28	0.0027338		125,917.34	(44,884.94)	-26%
SL	0.0036987		0.0037978		0.0037083		1,031,856	-	3,853.92	-	740,056		2,744.35	0.0026518	0.03	1,962.48	(781.87)	-28%
							3,069,864,817	8,094,717	15,984,209.76	19,427,885.68	2,057,230,036	5,397,430	24,540,824.04			35,309,497.94	10,768,673.90	44%
Industrial																		
GS1	0.0089975		0.0125996		0.0123027		14,882,823.00		169,549.46	-	8,090,808		99,538.79	0.0190177		153,868.57	54,329.78	55%
GS2-Sec	0.0051223	1.54	0.0038151	2.19	0.0037253	2.14	111,441,443.00	552,860.94	473,099.63	1,071,278.80	56,789,822	275,028	800,118.53	0.0027383	3.94	1,239,116.94	438,998.41	55%
GS2 RL - GS - TOD	0.0113915		0.0128184		0.0125165		1,251,156.00		15,254.22	-	631,541		7,904.68	0.0189726		11,981.97	4,077.29	52%
GS2-Pri	0.0049448	1.49	0.0036828	2.11	0.0035961	2.07	44,061,674.00	216,119.15	183,064.77	401,233.15	20,096,594	101,011	281,361.20	0.0026433	3.80	436,961.42	155,600.22	55%
GS2-Sub/Tran	0.0048310	1.45	0.0036094	2.07	0.0035244	2.02	16,013,810.00	150,713.30	68,559.42	268,664.84	6,937,157	71,267	168,409.57	0.0025906	3.73	283,798.99	115,389.42	69%
GS3-Sec	0.0046084	2.69	0.0038552	3.54	0.0037644	3.45	151,537,064.00	349,485.54	625,507.38	1,106,777.62	72,850,712	167,436	851,893.25	0.0027631	5.60	1,138,935.12	287,041.87	34%
GS3-Pri	0.0044487	2.60	0.0037215	3.42	0.0036338	3.33	107,201,665.00	232,504.77	439,128.99	692,239.15	42,770,297	96,985	478,379.22	0.0026672	5.41	638,766.54	160,387.32	34%
GS3-Sub/Tran	0.0043463	2.54	0.0036473	3.35	0.0035614	3.26	75,655,341.00	166,920.48	288,858.37	513,214.54	40,873,110	87,383	430,433.55	0.0026141	5.30	569,975.45	139,541.90	32%
GS4/IRP-Sub/Tran	0.0033770	2.10	0.0037976	3.25	0.0037081	3.18	3,121,973,581	6,055,549	11,173,227.42	16,592,059.57	1,226,669,787	2,454,449	12,353,761.96	0.0027339	5.21	16,141,271.66	3,787,509.70	31%
EHG	0.0083211		0.0071730		0.0070040		276,430.00	-	2,030.90	-	166,078		1,163.21	0.0090312		1,499.88	336.67	29%
AL	0.0036987		0.0037978		0.0037083		6,437,512.00		24,065.29	-	3,515,319		13,035.86	0.0027338		9,610.18	(3,425.68)	-26%
							3,650,732,499	7,724,153	13,462,346	20,645,468	1,479,391,224	3,253,559	15,485,999.82			20,625,786.72	5,139,786.90	33%
Other																		
GS1	0.0089975		0.0125996		0.0123027		3,570,781		38,960.12	-	3,644,170		44,833.14	0.0190177		69,303.74	24,470.60	55%
GS2- Sec	0.0051223	1.54	0.0038151	2.19	0.0037253	2.14	418,627	1,379	1,748.68	2,675.63	434,528	1,338	4,482.66	0.0027383	3.94	6,462.69	1,980.03	44%
GS2 RL - GS - TOD	0.0113915		0.0128184		0.0125165		557,092		6,880.65	-	647,931		8,109.83	0.0189726		12,292.93	4,183.10	52%
AL	0.0036987		0.0037978		0.0037083		98,614		368.72	-	103,129		382.43	0.0027338		281.93	(100.50)	-26%
SL	0.0036987		0.0037978		0.0037083		48,555,255		181,435.58	-	49,384,686		183,133.23	0.0027338		135,007.86	(48,125.37)	-26%
							53,200,369	1,379	229,393.75	2,675.63	54,214,444	1,338	240,941.29			223,349.15	(17,592.14)	-7%
Munis																		
GS2-Pri	0.0049448	1.49	0.0036828	2.11	0.0035961	2.07	514,800	1,394	2,077.77	2,627.07	374,877	964	3,343.41	0.0026433	3.80	4,653.81	1,310.40	39%
GS3-Pri	0.0044487	2.60	0.0037215	3.42	0.0036338	3.33	7,897,800	17,897	30,799.06	55,825.58	5,862,723	12,810	63,960.43	0.0026672	5.41	84,937.80	20,977.37	33%
							8,412,600	19,291	32,876.83	58,452.65	6,237,600	13,774	67,303.84			89,591.61	22,287.77	33%
Total							17,640,861,591	15,839,540	177,692,214	40,134,482	10,904,656,757	8,666,101	145,535,005			193,154,011.42	47,619,006.42	33%

Residential
Commercial
Industrial
Other
Municipal
Total

RS	7,292,704,967	-	105,144,762	136,865,111
GS1	288,062,877	-	3,543,951	5,478,293
GS2 Sec	851,459,860	3,566,995	10,805,313	16,385,514
GS2 RL - GS - TOD	30,941,680	-	387,282	587,044
GS2 Pri	30,206,907	149,899	418,918	649,461
GS2 Sub/Trans	8,014,212	75,107	179,961	300,909
GS3 Sec	765,356,768	1,773,691	9,000,344	12,047,428
GS3 - TOD	-	-	-	-
GS3 Pri	218,085,391	476,139	2,378,021	3,157,588
GS3 Sub/Trans	65,613,857	169,821	787,295	1,071,574
GS4 Pri	-	-	-	-
GS4/IRP Sub/Trans	1,226,669,787	2,454,449	12,353,762	16,141,272
EHG	7,936,147	-	55,585	71,673
SS	4,923,174	-	54,541	84,689
OL	64,556,390	-	239,394	176,484
SL	50,124,742	-	185,878	136,970
Total	10,904,656,757	8,666,101	145,535,005	193,154,011

Ohio Power Company
Summary of Current and Proposed Rates

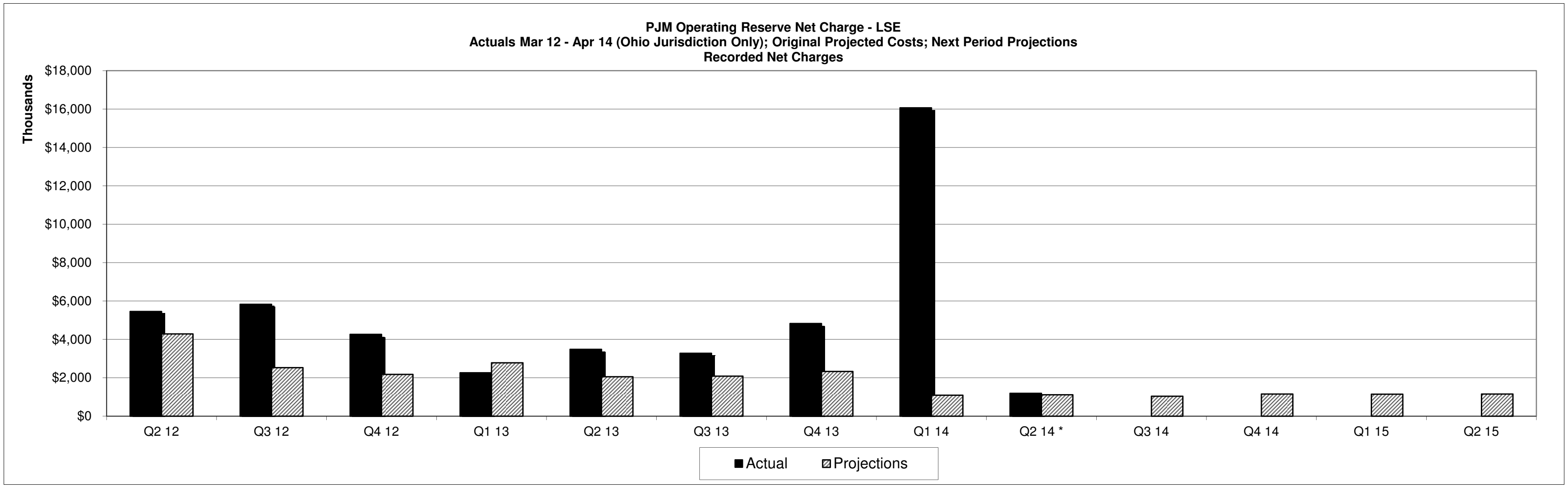
	Forecast for September 2014 - May 2015				Forecast for September 2014 - May 2015			
	Current TCRR Energy Rate	Proposed TCRR Energy Rate	Energy Difference	Energy % Difference	Current TCRR Demand Rate	Proposed TCRR Demand Rate	Demand Difference	Demand % Difference
Residential	$0.0144178	$0.0187674	$0.0043496	30.17%				
GS-1 / GS-1-TOD	$0.0123027	$0.0190177	$0.0067150	54.58%				
GS2-Sec	$0.0037253	$0.0027383	-$0.0009870	-26.49%	$2.14	$3.94	$1.80	84.11%
GS2 RL - GS - TOD / GS2-TOD/LM	$0.0125165	$0.0189726	$0.0064561	51.58%				
GS2-Pri	$0.0035961	$0.0026433	-$0.0009528	-26.50%	$2.07	$3.80	$1.73	83.57%
GS2-Sub/Tran	$0.0035244	$0.0025906	-$0.0009338	-26.50%	$2.02	$3.73	$1.71	84.65%
GS3-Sec	$0.0037644	$0.0027631	-$0.0010013	-26.60%	$3.45	$5.60	$2.15	62.32%
GS3-TOD	$0.0113004	$0.0156854	$0.0043850	38.80%				
GS3-Pri	$0.0036338	$0.0026672	-$0.0009666	-26.60%	$3.33	$5.41	$2.08	62.46%
GS3-Sub/Tran	$0.0035614	$0.0026141	-$0.0009473	-26.60%	$3.26	$5.30	$2.04	62.58%
GS4-Pri	$0.0037834	$0.0027895	-$0.0009939	-26.27%	$3.24	$5.32	$2.08	64.20%
GS4/IRP-Sub/Tran	$0.0037081	$0.0027339	-$0.0009742	-26.27%	$3.18	$5.21	$2.03	63.84%
EHG	$0.0070040	$0.0090312	$0.0020272	28.94%				
SS	$0.0110784	$0.0172021	$0.0061237	55.28%				
EHS	$0.0110784	$0.0172021	$0.0061237	55.28%				
AL	$0.0037083	$0.0027338	-$0.0009745	-26.28%				
SL	$0.0037083	$0.0027338	-$0.0009745	-26.28%				
SBS-Sub/Tran-Backup - 5%	$0.0036422	$0.0026518	-$0.0009904	-27.19%	$0.04	$0.03	-$0.01	-25.00%



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Net Congestion - LSE	583,358	4,237,496	1,316,621	1,146,934	3,035,714	3,597,730	(865,035)	2,736,882	(8,735,781)
Projections - PJM Net Congestion - LSE	200,085	600,507	1,622,588	692,926	1,021,044	633,679	1,975,238	1,362,802	(73,106)

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM Net Congestion - LSE	218,951	(89,632)	(89,632)	39,687	-	-	-	-
Projections - PJM Net Congestion - LSE	(89,632)	(89,632)	(89,632)	(268,896)	(2,836,500)	(972,900)	(3,228,000)	(2,154,000)

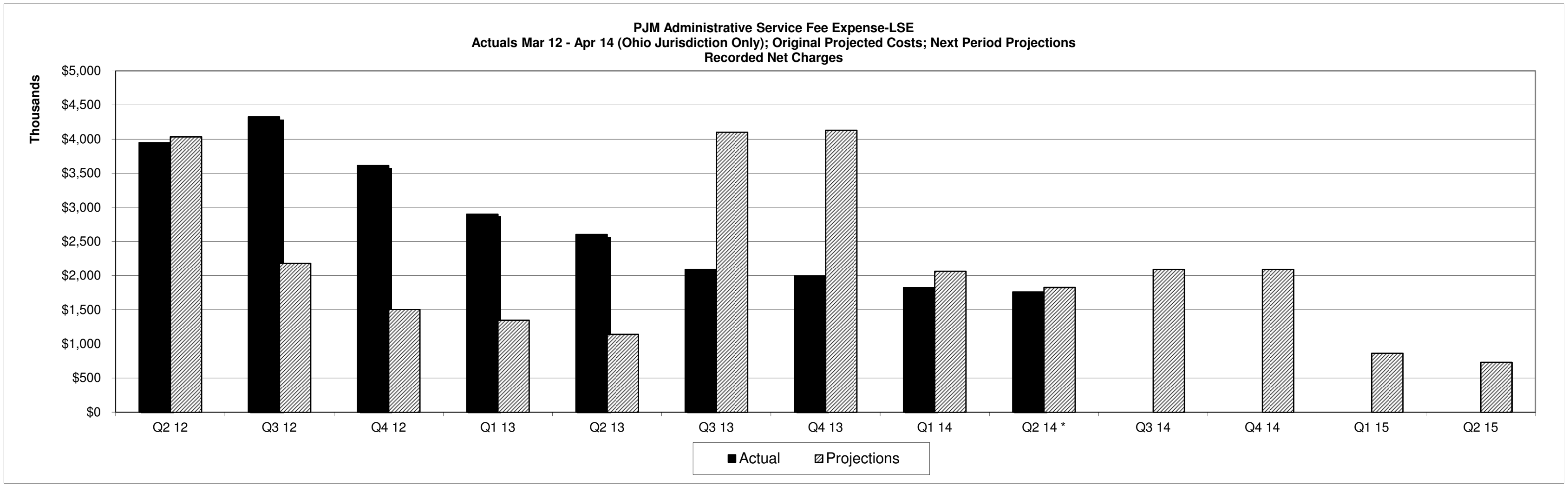
* Q2 14 includes one month of actual and two months projection.



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Operating Reserve-LSE	1,509,298	5,455,714	5,827,255	4,261,516	2,259,627	3,483,706	3,276,084	4,829,466	16,069,741
Projections - PJM Operating Reserve-LSE	1,774,679	4,284,000	2,532,617	2,182,054	2,782,893	2,055,792	2,084,527	2,331,668	1,090,146

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM Operating Reserve-LSE	450,548	372,034	372,034	1,194,616	-	-	-	-
Projections - PJM Operating Reserve-LSE	372,034	372,034	372,034	1,116,102	1,036,483	1,152,641	1,148,352	1,157,466

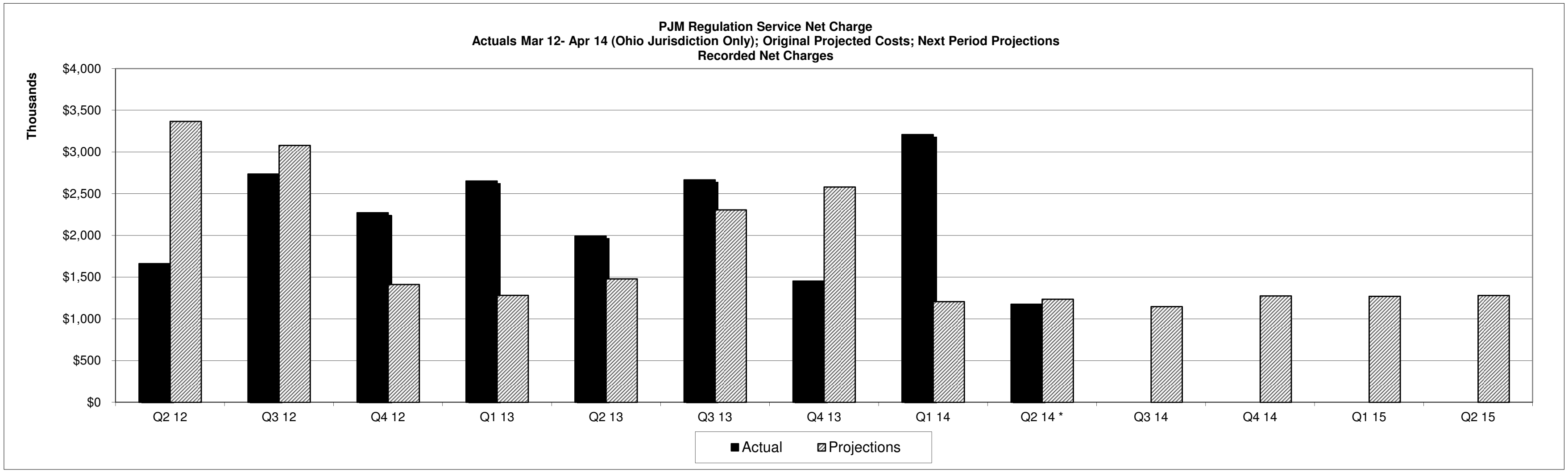
- Q2 14 includes one month of actual and two months projection.



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Administrative Service Fee	1,391,088	3,950,015	4,325,663	3,613,499	2,899,915	2,603,589	2,091,268	2,000,730	1,826,560
Projections - PJM Administrative Service Fee	1,519,940	4,035,434	2,180,794	1,504,976	1,348,533	1,140,822	4,102,419	4,129,814	2,065,382

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM Administrative Service Fee	544,865	609,023	609,023	1,762,911	-	-	-	-
Projections - PJM Administrative Service Fee	609,022	609,023	609,023	1,827,068	2,091,978	2,091,978	865,471	732,321

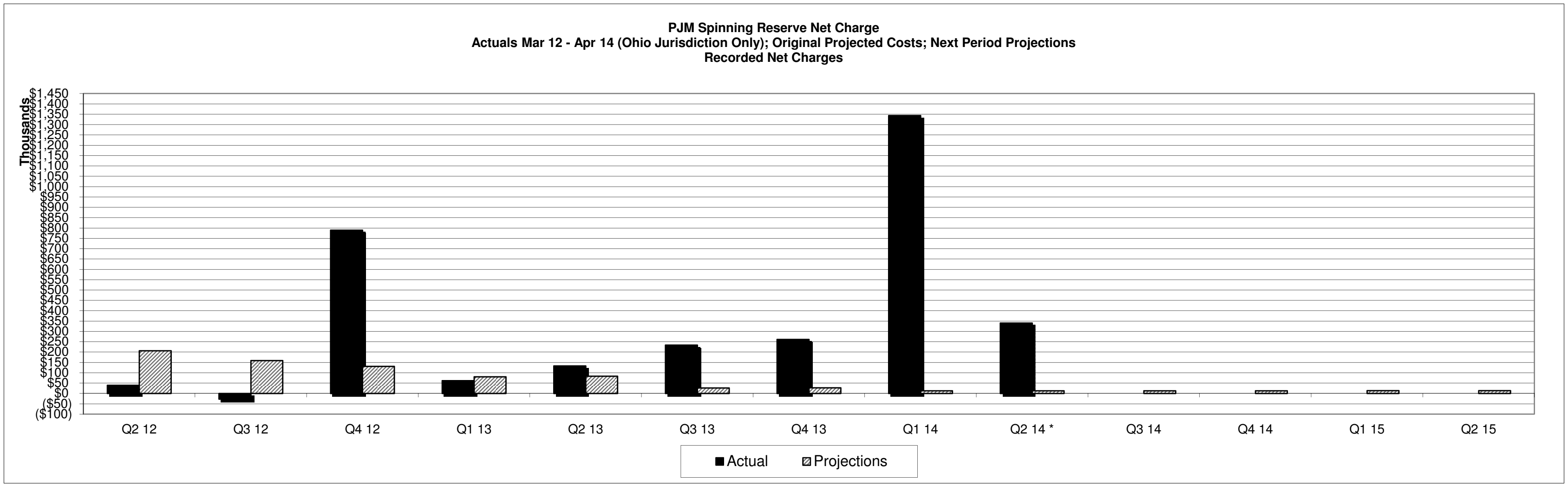
* Q2 14 includes one month of actual and two months projection.



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Regulation Service	527,734	1,662,282	2,736,568	2,273,297	2,652,299	1,993,136	2,666,201	1,453,354	3,209,063
Projections - PJM Regulation Service	1,271,809	3,367,980	3,079,858	1,412,504	1,282,818	1,479,678	2,307,257	2,580,805	1,206,628

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM Regulation Service	352,442	411,786	411,786	1,176,013	-	-	-	-
Projections - PJM Regulation Service	411,785	411,786	411,786	1,235,357	1,147,231	1,275,800	1,271,053	1,281,140

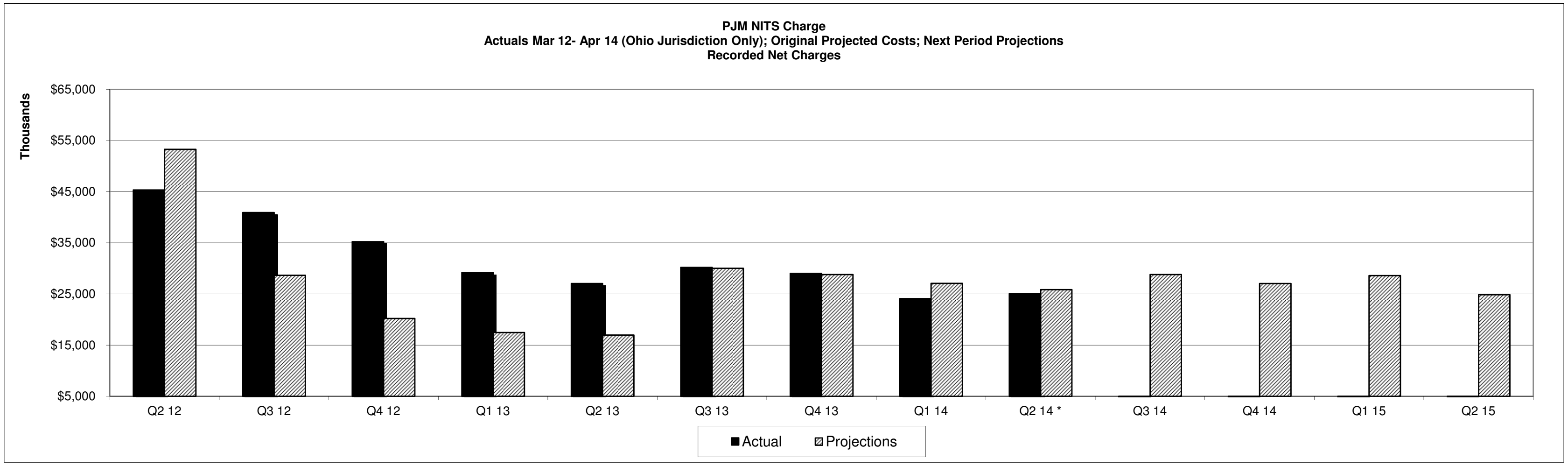
- Q2 14 includes one month of actual and two months projection.



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Spinning Reserve	3,638	39,683	(27,166)	789,548	62,034	133,141	233,916	261,740	1,343,947
Projections - PJM Spinning Reserve	91,399	206,599	158,930	131,461	80,928	83,768	27,065	27,237	13,038

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM Spinning Reserve	331,895	4,346	4,346	340,588	-	-	-	-
Projections - PJM Spinning Reserve	4,346	4,346	4,346	13,038	13,464	13,464	13,733	13,733

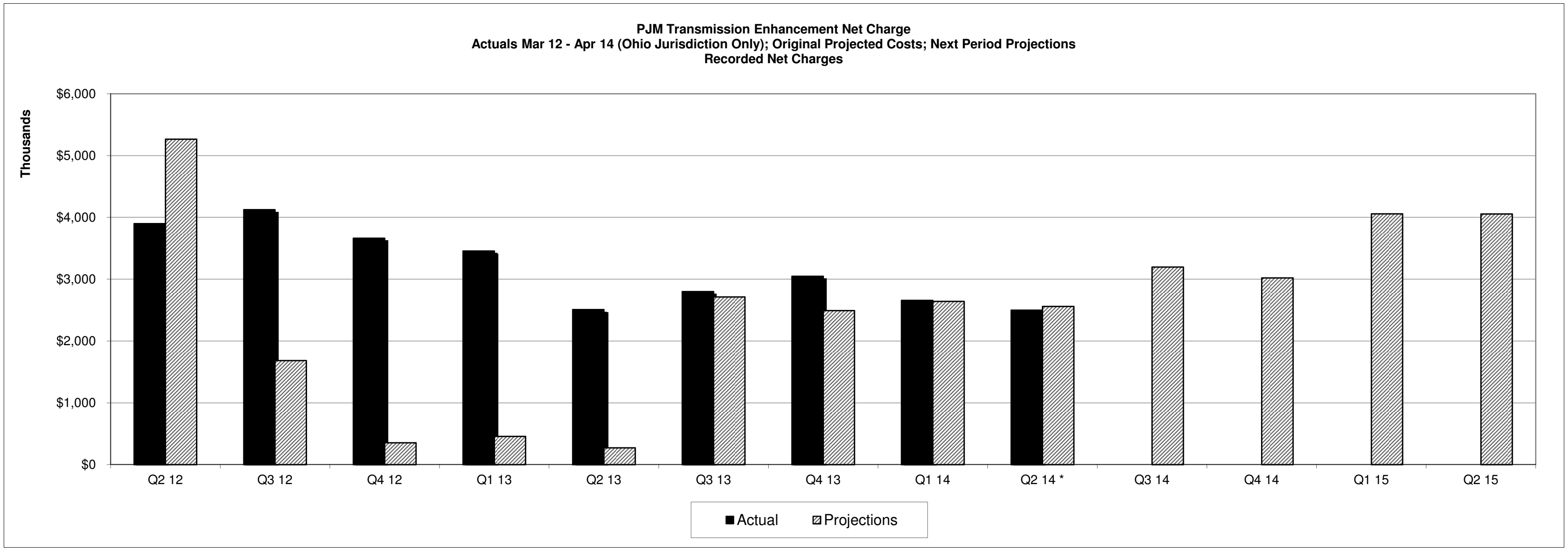
* Q2 14 includes one month of actual and two months projection.



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM NITS	16,399,467	45,335,338	40,926,482	35,241,000	29,202,954	27,054,321	30,208,406	29,040,416	24,094,124
Projections - PJM NITS	18,047,535	53,283,268	28,659,738	20,225,223	17,481,903	16,972,959	30,038,303	28,816,655	27,077,562

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM NITS	7,845,877	8,616,471	8,616,471	25,078,818	-	-	-	-
Projections - PJM NITS	8,616,470	8,616,471	8,616,471	25,849,412	28,796,248	27,064,074	28,599,870	24,869,766

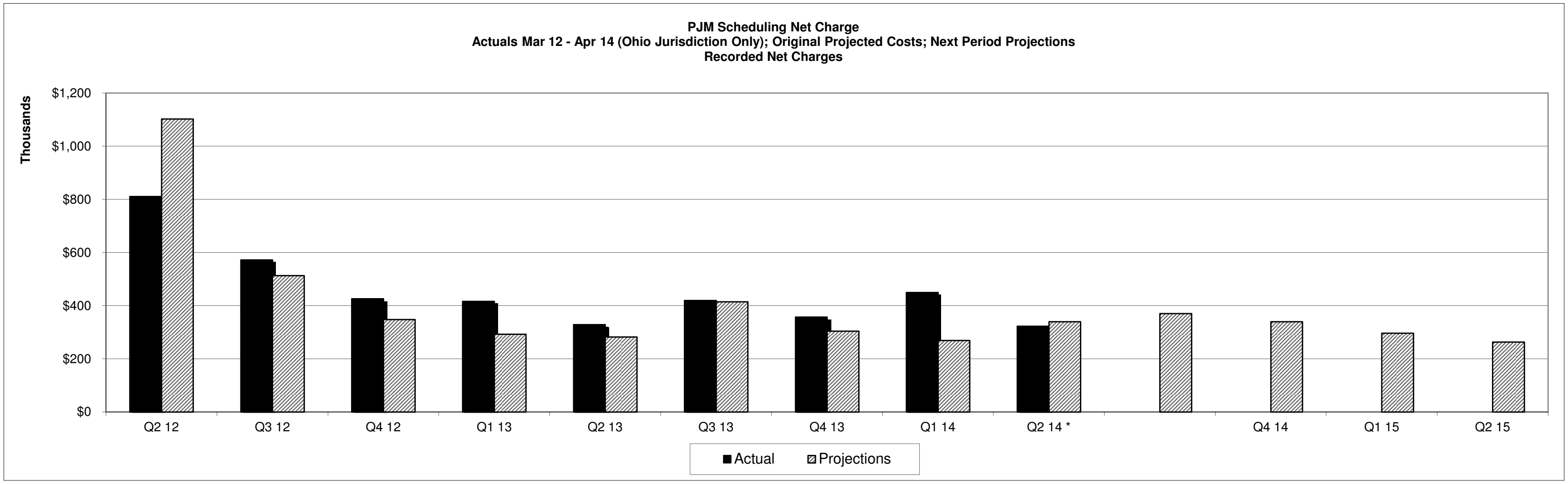
- Q2 14 includes one month of actual and two months projection.



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Transmission Enhancement	1,273,710	3,900,219	4,124,994	3,664,214	3,456,767	2,510,431	2,800,753	3,049,360	2,658,720
Projections - PJM Transmission Enhancement	1,723,169	5,267,188	1,683,797	354,568	457,353	272,274	2,714,914	2,492,843	2,641,540

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM Transmission Enhancement	792,134	853,693	853,693	2,499,520	-	-	-	-
Projections - PJM Transmission Enhancement	853,693	853,693	853,693	2,561,079	3,197,866	3,021,474	4,059,402	4,056,954

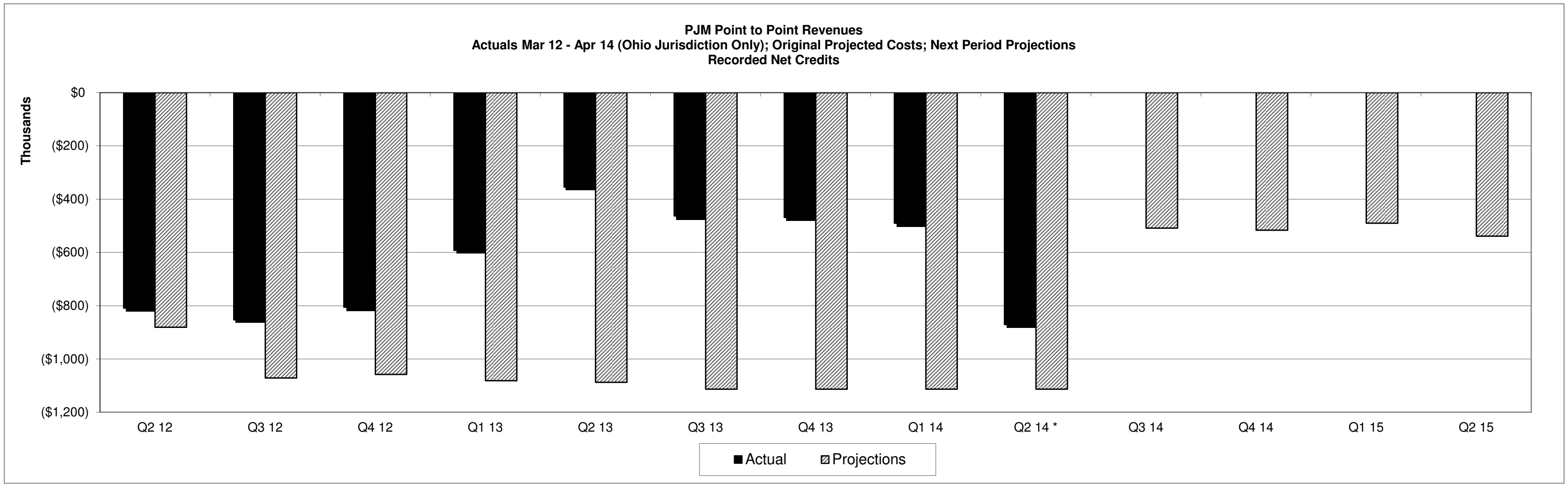
* Q2 14 includes one month of actual and two months projection



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Scheduling	278,242	810,959	572,318	426,477	416,567	328,933	419,988	357,322	449,790
Projections - PJM Scheduling	367,572	1,102,716	513,158	347,905	292,819	282,189	414,930	304,077	269,268

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *		Q4 14	Q1 15	Q2 15
Actual - PJM Scheduling	96,691	113,226	113,226	323,143	-	-	-	-
Projections - PJM Scheduling	113,226	113,226	113,226	339,678	370,622	340,076	296,590	263,454

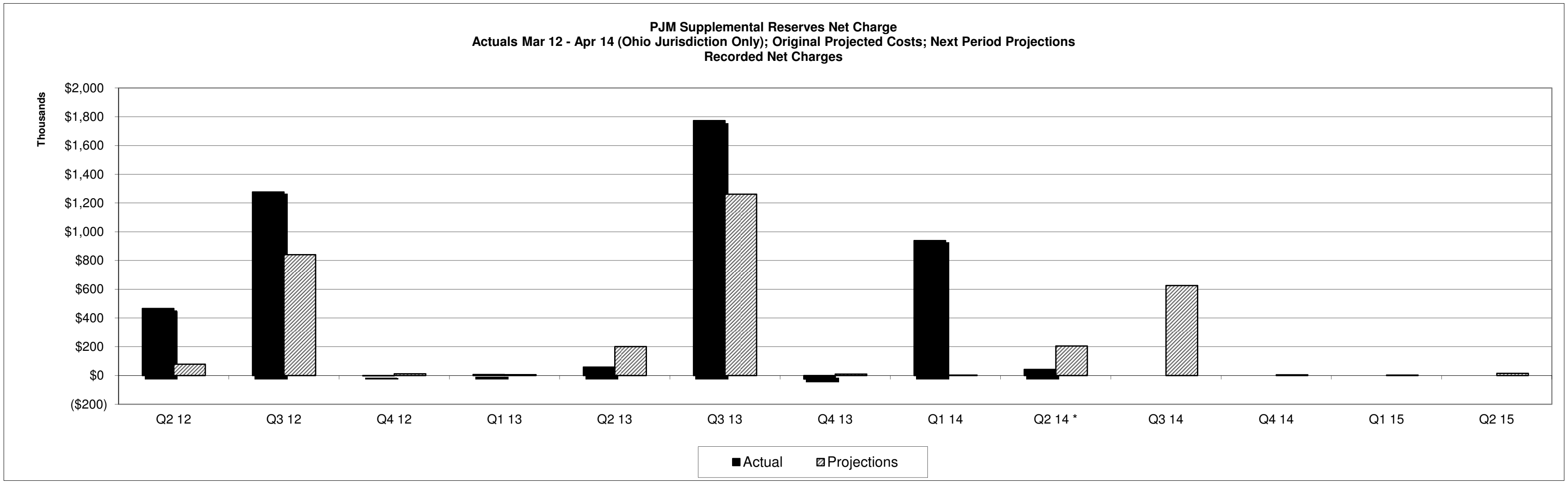
* Q2 14 includes one month of actual and two months projection



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Point to Point	(225,610)	(808,578)	(852,688)	(805,321)	(591,868)	(354,042)	(462,743)	(468,004)	(489,871)
Projections - PJM Point to Point	(293,595)	(880,785)	(1,071,229)	(1,057,813)	(1,081,342)	(1,087,355)	(1,113,000)	(1,113,000)	(1,113,000)

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM Point to Point	(128,679)	(371,000)	(371,000)	(870,679)	-	-	-	-
Projections - PJM Point to Point	(371,000)	(371,000)	(371,000)	(1,113,000)	(508,511)	(516,315)	(489,871)	(538,803)

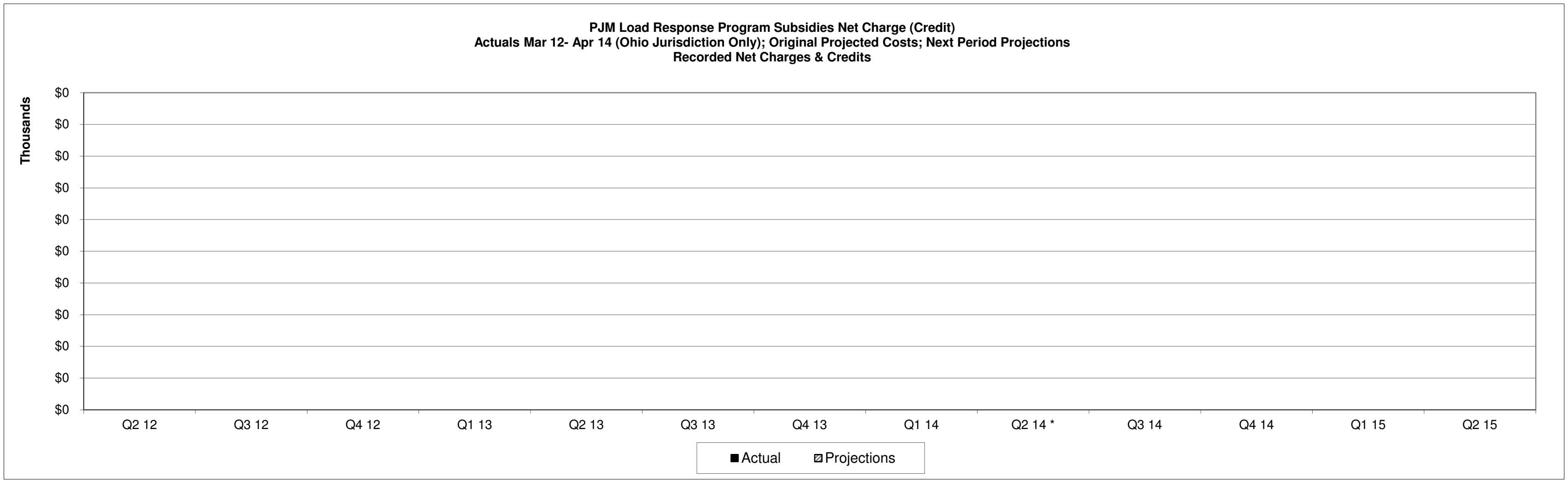
* Q2 14 includes one month of actual and two months projection



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Supplemental Reserves	11,921	466,989	1,276,990	(1,483)	7,475	58,924	1,774,133	(24,073)	939,437
Projections - PJM Supplemental Reserves	7,896	78,896	840,662	12,485	5,918	201,911	1,262,094	10,281	3,280

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM Supplemental Reserves	(93,881)	68,346	68,346	42,812	-	-	-	-
Projections - PJM Supplemental Reserves	68,347	68,346	68,346	205,039	626,786	5,082	3,456	15,551

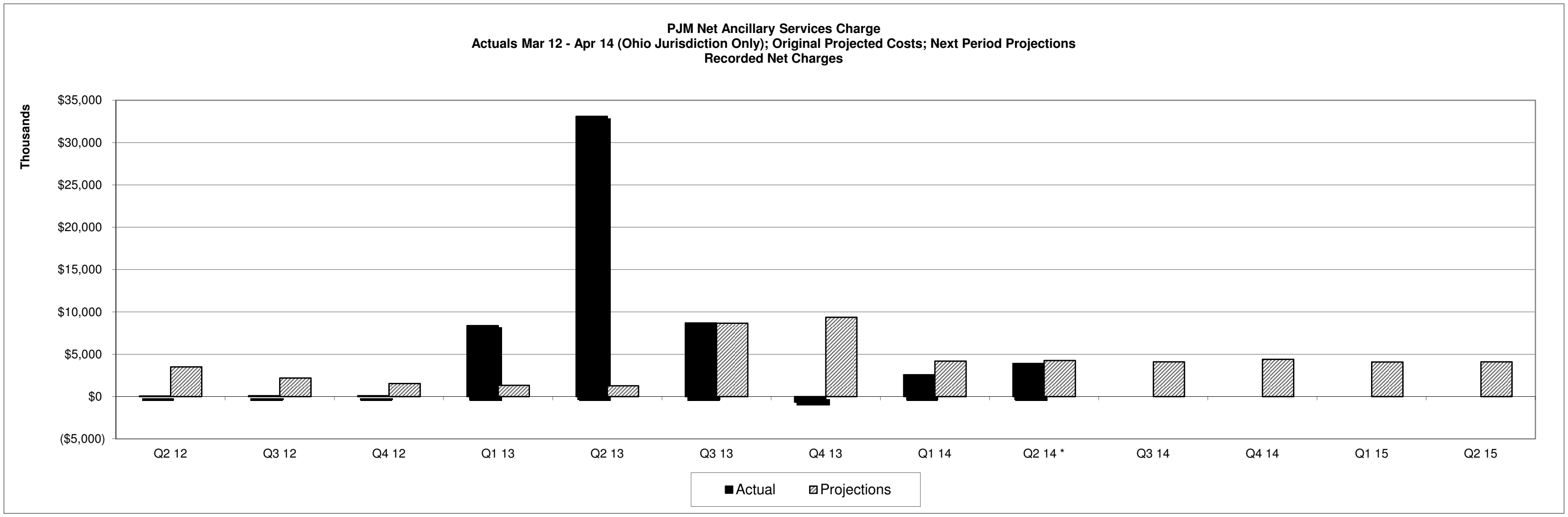
* Q2 14 includes one month of actual and two months projection



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Load Response Program Subsidies	-	-	-	-	-	-	-	-	-
Projections - PJM Load Response Program Subsidies	-	-	-	-	-	-	-	-	-

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM Load Response Program Subsidies	-	-	-	-	-	-	-	-
Projections - PJM Load Response Program Subsidies	-	-	-	-	-	-	-	-

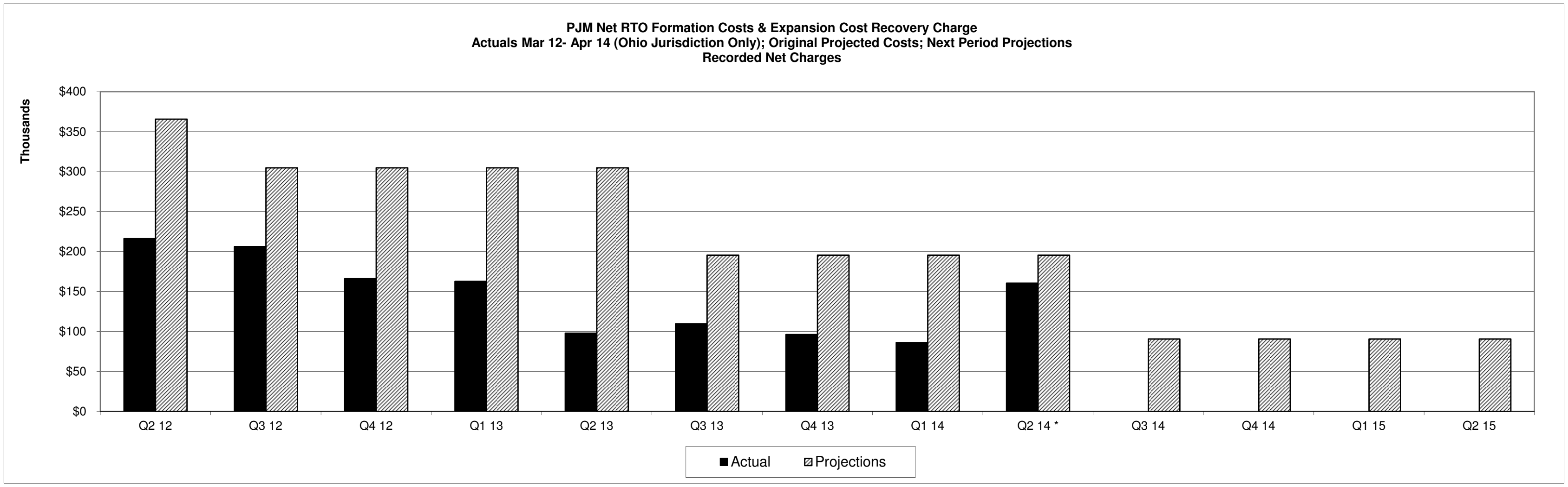
* Q2 14 includes one month of actual and two months projection



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Net Ancillary Services	24,346	67,861	109,466	106,510	8,392,844	33,106,666	8,700,665	(653,664)	2,585,631
Projections - PJM Net Ancillary Services	2,541,506	3,512,673	2,203,724	1,541,174	1,330,641	1,274,654	8,670,684	9,363,111	4,193,401

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM Net Ancillary Services	1,074,686	1,419,046	1,419,046	3,912,778	-	-	-	-
Projections - PJM Net Ancillary Services	1,419,046	1,419,046	1,419,046	4,257,138	4,111,271	4,396,508	4,085,546	4,105,293

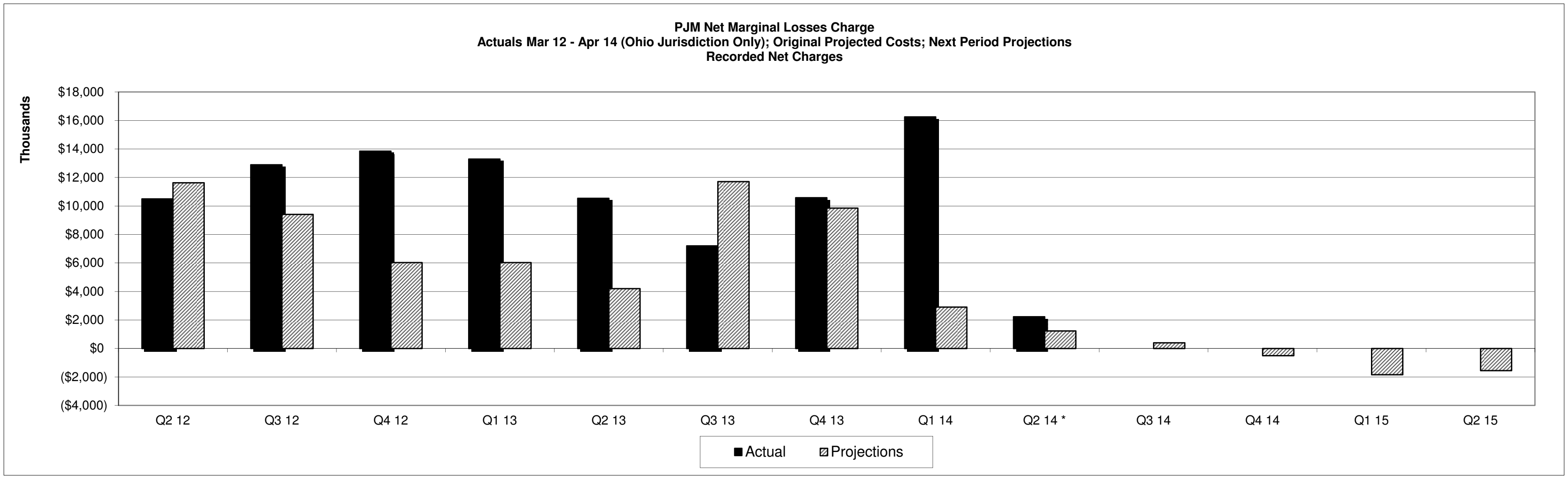
* Q2 14 includes one month of actual and two months projection



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Net RTO Formation Costs & Expansion	77,253	216,134	206,008	165,952	162,555	97,852	109,310	96,203	86,017
Projections - PJM Net RTO Formation Costs &	121,892	365,676	304,836	304,836	304,836	304,836	195,381	195,381	195,381

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM Net RTO Formation Costs & Expansion	30,157	65,127	65,127	160,411	-	-	-	-
Projections - PJM Net RTO Formation Costs &	65,127	65,127	65,127	195,381	90,471	90,471	90,471	90,471

* Q2 14 includes one month of actual and two months projection



	ACTUAL								
	Mar-12	Q2 12	Q3 12	Q4 12	Q1 13	Q2 13	Q3 13	Q4 13	Q1 14
Actual - PJM Net Marginal Losses	2,586,957	10,505,231	12,903,240	13,852,417	13,294,976	10,545,722	7,207,221	10,585,636	16,256,942
Projections - PJM Net Marginal Losses	4,302,277	11,639,611	9,416,001	6,037,829	6,031,678	4,204,822	11,720,197	9,852,241	2,911,098

	FORECAST							
	Apr-14*	May-14*	Jun-14*	Q2 14 *	Q3 14	Q4 14	Q1 15	Q2 15
Actual - PJM Net Marginal Losses	1,410,868	411,527	411,527	2,233,922	-	-	-	-
Projections - PJM Net Marginal Losses	411,528	411,527	411,527	1,234,582	407,800	(496,600)	(1,832,000)	(1,553,000)

* Q2 14 includes one month of actual and two months projection

Ohio Power Company
2014 Typical Bill Comparison
Ohio Power Rate Zone

Tariff	kWh	KW	Current	Proposed	$ Difference	Difference
Residential	100		$22.74	$23.18	$0.44	1.9%
	250		$44.58	$45.67	$1.09	2.5%
	500		$80.96	$83.13	$2.17	2.7%
	750		$117.34	$120.61	$3.27	2.8%
	1,000		$151.06	$155.41	$4.35	2.9%
	1,500		$217.20	$223.72	$6.52	3.0%
	2,000		$283.34	$292.03	$8.69	3.1%
GS-1	375	3	$74.63	$77.15	$2.52	3.4%
Secondary	1,000	3	$148.77	$155.49	$6.72	4.5%
	750	6	$119.12	$124.15	$5.03	4.2%
	2,000	6	$267.34	$280.77	$13.43	5.0%
GS-2	1,500	12	$294.73	$314.85	$20.12	6.8%
	4,000	12	$550.00	$567.65	$17.65	3.2%
	6,000	30	$899.75	$947.83	$48.08	5.3%
	10,000	30	$1,307.83	$1,351.96	$44.13	3.4%
	10,000	40	$1,388.79	$1,450.92	$62.13	4.5%
	14,000	40	$1,796.85	$1,855.04	$58.19	3.2%
	12,500	50	$1,724.78	$1,802.44	$77.66	4.5%
	18,000	50	$2,284.16	$2,356.39	$72.23	3.2%
	15,000	75	$2,182.21	$2,302.40	$120.19	5.5%
	30,000	100	$3,906.41	$4,056.80	$150.39	3.9%
	36,000	100	$4,515.14	$4,659.61	$144.47	3.2%
	30,000	150	$4,311.20	$4,551.59	$240.39	5.6%
	60,000	300	$8,569.20	$9,049.98	$480.78	5.6%
	90,000	300	$11,612.86	$12,064.03	$451.17	3.9%
	100,000	500	$14,246.53	$15,047.83	$801.30	5.6%
	150,000	500	$19,319.29	$20,071.24	$751.95	3.9%
	180,000	500	$22,362.92	$23,085.26	$722.34	3.2%

Ohio Power Company
2014 Typical Bill Comparison
Ohio Power Rate Zone

Tariff	kWh	KW	Current	Proposed	$ Difference	Difference
GS-3	18,000	50	$2,287.86	$2,377.34	$89.48	3.9%
Secondary	30,000	75	$3,624.94	$3,756.15	$131.21	3.6%
	50,000	75	$5,089.77	$5,200.96	$111.19	2.2%
	36,000	100	$4,522.53	$4,701.48	$178.95	4.0%
	30,000	150	$4,999.43	$5,291.89	$292.46	5.9%
	60,000	150	$7,196.64	$7,459.07	$262.43	3.7%
	100,000	150	$10,126.28	$10,348.65	$222.37	2.2%
	120,000	300	$14,340.11	$14,864.95	$524.84	3.7%
	150,000	300	$16,537.36	$17,032.17	$494.81	3.0%
	200,000	300	$20,199.39	$20,644.13	$444.74	2.2%
	180,000	500	$22,399.90	$23,294.67	$894.77	4.0%
	200,000	500	$23,864.72	$24,739.46	$874.74	3.7%
	325,000	500	$33,019.83	$33,769.41	$749.58	2.3%
GS-2	200,000	1,000	$27,407.63	$28,947.07	$1,539.44	5.6%
Primary	300,000	1,000	$37,305.15	$38,749.31	$1,444.16	3.9%
GS-3	360,000	1,000	$43,319.37	$45,051.39	$1,732.02	4.0%
Primary	400,000	1,000	$46,188.56	$47,881.92	$1,693.36	3.7%
	650,000	1,000	$64,121.04	$65,572.75	$1,451.71	2.3%
GS-2						
Subtransmission	1,500,000	5,000	$151,868.86	$159,018.16	$7,149.30	4.7%
GS-3	2,500,000	5,000	$223,326.38	$231,158.13	$7,831.75	3.5%
Subtransmission	3,250,000	5,000	$270,831.74	$277,953.02	$7,121.28	2.6%
GS-4	3,000,000	10,000	$309,125.57	$326,502.97	$17,377.40	5.6%
Subtransmission	5,000,000	10,000	$428,182.43	$443,611.43	$15,429.00	3.6%
	6,500,000	10,000	$517,475.08	$531,442.78	$13,967.70	2.7%
	10,000,000	20,000	$849,744.58	$880,602.58	$30,858.00	3.6%
	13,000,000	20,000	$1,028,329.87	$1,056,265.27	$27,935.40	2.7%
GS-4	25,000,000	50,000	$2,105,343.28	$2,182,488.28	$77,145.00	3.7%
Transmission	32,500,000	50,000	$2,551,510.18	$2,621,348.68	$69,838.50	2.7%

* Typical bills assume 100% Power Factor

Ohio Power Company
2014 Typical Bill Comparison
Columbus Southern Power Rate Zone

Tariff	kWh	KW	Current	Proposed	$ Difference	Difference
Residential						
RR1 Annual	100		$23.81	$24.25	$0.44	1.9%
	250		$45.76	$46.85	$1.09	2.4%
	500		$82.38	$84.55	$2.17	2.6%
RR Annual	750		$126.38	$129.65	$3.27	2.6%
	1,000		$157.39	$161.74	$4.35	2.8%
	1,500		$215.43	$221.95	$6.52	3.0%
	2,000		$273.48	$282.17	$8.69	3.2%
GS-1						
	375	3	$80.26	$82.78	$2.52	3.1%
	1,000	3	$179.61	$186.33	$6.72	3.7%
	750	6	$139.88	$144.91	$5.03	3.6%
	2,000	6	$308.18	$321.61	$13.43	4.4%
GS-2 Secondary						
	1,500	12	$294.95	$315.07	$20.12	6.8%
	4,000	12	$586.79	$604.44	$17.65	3.0%
	6,000	30	$962.54	$1,010.62	$48.08	5.0%
	10,000	30	$1,429.13	$1,473.26	$44.13	3.1%
	10,000	40	$1,508.28	$1,570.41	$62.13	4.1%
	14,000	40	$1,974.87	$2,033.06	$58.19	3.0%
	12,500	50	$1,879.05	$1,956.71	$77.66	4.1%
	18,000	50	$2,518.92	$2,591.15	$72.23	2.9%
	15,000	75	$2,368.54	$2,488.73	$120.19	5.1%
	30,000	150	$4,703.45	$4,943.84	$240.39	5.1%
	60,000	300	$9,373.29	$9,854.07	$480.78	5.1%
	100,000	500	$15,599.72	$16,401.02	$801.30	5.1%
GS-2 Primary						
	250,000	1,000	$35,097.01	$36,588.81	$1,491.80	4.3%

Ohio Power Company
2014 Typical Bill Comparison
Columbus Southern Power Rate Zone

Tariff	kWh	KW	Current	Proposed	$ Difference	% Difference
GS-3 Secondary						
	30,000	75	$3,645.05	$3,776.26	$131.21	3.6%
	50,000	75	$5,101.43	$5,212.62	$111.19	2.2%
	30,000	100	$4,120.67	$4,305.63	$184.96	4.5%
	36,000	100	$4,557.58	$4,736.53	$178.95	3.9%
	60,000	150	$7,256.48	$7,518.91	$262.43	3.6%
	100,000	150	$10,169.22	$10,391.59	$222.37	2.2%
	90,000	300	$12,294.80	$12,849.68	$554.88	4.5%
	120,000	300	$14,479.35	$15,004.19	$524.84	3.6%
	150,000	300	$16,663.92	$17,158.73	$494.81	3.0%
	200,000	300	$20,304.83	$20,749.57	$444.74	2.2%
	150,000	500	$20,468.92	$21,393.73	$924.81	4.5%
	180,000	500	$22,653.45	$23,548.22	$894.77	4.0%
	200,000	500	$24,109.83	$24,984.57	$874.74	3.6%
	325,000	500	$33,212.14	$33,961.72	$749.58	2.3%
GS-3 Primary						
	300,000	1,000	$38,761.73	$40,551.75	$1,790.02	4.6%
	360,000	1,000	$43,002.32	$44,734.34	$1,732.02	4.0%
	400,000	1,000	$45,829.36	$47,522.72	$1,693.36	3.7%
	650,000	1,000	$63,498.45	$64,950.16	$1,451.71	2.3%
GS-4						
	1,500,000	5,000	$152,710.41	$161,399.11	$8,688.70	5.7%
	2,500,000	5,000	$215,226.78	$222,941.28	$7,714.50	3.6%
	3,250,000	5,000	$262,114.07	$269,097.92	$6,983.85	2.7%
	3,000,000	10,000	$283,366.46	$300,743.86	$17,377.40	6.1%
	5,000,000	10,000	$408,399.18	$423,828.18	$15,429.00	3.8%
	6,500,000	10,000	$502,173.73	$516,141.43	$13,967.70	2.8%
	6,000,000	20,000	$544,678.55	$579,433.35	$34,754.80	6.4%
	10,000,000	20,000	$794,744.00	$825,602.00	$30,858.00	3.9%
	13,000,000	20,000	$982,293.09	$1,010,228.49	$27,935.40	2.8%
	15,000,000	50,000	$1,328,614.81	$1,415,501.81	$86,887.00	6.5%
	25,000,000	50,000	$1,953,778.44	$2,030,923.44	$77,145.00	4.0%
	32,500,000	50,000	$2,422,651.16	$2,492,489.66	$69,838.50	2.9%

* Typical bills assume 100% Power Factor

Ohio Power Company
Projected Transmission Cost Recovery Rider Cost / Revenues
July 2014 - May 2015
<Revenue>/ Expense in $

	Forecast Jul-14	Forecast Aug-14	Forecast Sep-14	Forecast Oct-14	Forecast Nov-14	Forecast Dec-14	Forecast Jan-15	Forecast Feb-15	Forecast Mar-15	Forecast Apr-15	Forecast May-15	Forecast TCRR July14-May15
# **NITS (b)** **$3133.05 per MW*Mo.**	27,241,519	27,241,519	27,241,519	27,241,519	27,241,519	27,241,519	26,550,798	26,550,798	26,550,798	26,550,798	26,550,798	296,203,104
Estimated NITS for Shopping	(17,566,125)	(17,555,548)	(17,806,636)	(18,558,023)	(18,390,590)	(17,711,870)	(16,710,534)	(16,934,536)	(17,407,454)	(17,857,907)	(18,462,361)	(194,961,582)
Pt-to-Pt Transm. Revenues	(191,215)	(162,626)	(154,670)	(179,649)	(141,021)	(195,645)	(172,110)	(152,629)	(165,132)	(172,569)	(183,117)	(1,870,383)
Subtotal	**9,484,179**	**9,523,345**	**9,280,213**	**8,503,847**	**8,709,908**	**9,334,004**	**9,668,154**	**9,463,633**	**8,978,212**	**8,520,322**	**7,905,320**	**99,371,139**
TO Scheduling, Sys Contr & Disp	133,910	127,594	109,118	107,415	108,661	124,000	106,803	94,150	95,637	85,434	89,010	1,181,732
Transmission Enhancement Charges (c)	1,087,042	1,065,112	1,045,712	1,026,390	1,008,760	986,324	1,353,164	1,352,702	1,353,536	1,352,706	1,352,124	12,983,572
Net Congestion:												
PJM Implicit Congestion	1,106,400	622,300	177,800	135,600	47,900	767,600	0	0	0	0	0	2,857,600
PJM FTR Revenue & Auction Revenue Rights	(2,693,000)	(1,690,000)	(360,000)	(135,000)	(283,000)	(1,506,000)	(779,000)	(519,000)	(1,930,000)	(376,000)	(889,000)	(11,160,000)
Net Congestion Subtotal	(1,586,600)	(1,067,700)	(182,200)	600	(235,100)	(738,400)	(779,000)	(519,000)	(1,930,000)	(376,000)	(889,000)	(8,302,400)
PJM Operating Reserve (Gross)	312,732	321,667	402,084	379,746	370,811	402,084	419,240	369,113	359,999	419,240	369,113	4,125,829
PJM Ancillary Services (Gross):												
PJM Synchronous Condensing	298	298	298	298	298	298	304	304	304	304	304	3,304
PJM Reactive Supply	521,730	521,730	521,730	521,730	521,730	521,730	532,165	532,165	532,165	532,165	532,165	5,791,203
PJM Blackstart	767,945	789,886	987,358	932,504	910,563	987,358	908,369	799,760	780,013	908,369	799,760	9,571,883
PJM Regulation Charges	346,147	356,037	445,046	420,322	410,432	445,046	464,035	408,553	398,465	464,035	408,553	4,566,671
PJM Spinning Reserve Charges	4,488	4,488	4,488	4,488	4,488	4,488	4,578	4,578	4,578	4,578	4,578	49,817
PJM Supplemental Reserve Charges (d)	533,615	67,761	25,410	1,694	1,694	1,694	1,728	864	864	1,728	6,912	643,963
PJM Ancillary Services Subtotal	2,174,223	1,740,200	1,984,330	1,881,036	1,849,204	1,960,614	1,911,178	1,746,222	1,716,387	1,911,178	1,752,270	20,626,841
PJM Administration Service Fees (a)	738,345	738,345	615,288	656,307	656,307	779,365	316,230	282,942	266,299	233,011	249,655	5,532,094
Amortization of PJM Integration Costs	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	160,909	1,769,999
PJM RTO Formation Cost Recovery	(56,639)	(56,639)	(56,639)	(56,639)	(56,639)	(56,639)	(56,639)	(56,639)	(56,639)	(56,639)	(56,639)	(623,034)
Net Expansion Cost Recovery	(74,112)	(74,112)	(74,112)	(74,112)	(74,112)	(74,112)	(74,112)	(74,112)	(74,112)	(74,112)	(74,112)	(815,237)
Net RTO Formation Costs & Expansion Cost Recovery Charge	30,157	30,157	30,157	30,157	30,157	30,157	30,157	30,157	30,157	30,157	30,157	331,728
			90,471			90,471			90,471			
Net Marginal Losses	357,900	168,300	(118,400)	(170,600)	(265,000)	(61,000)	(688,000)	(531,000)	(613,000)	(469,000)	(542,000)	(2,931,800)
Load Response Program Subsidies	0	0	0	0	0	0	0	0	0	0	0	0
Power Acquisition Rider Adjustment	0	0	0	0	0	0	0	0	0	0	0	0
Phase-In Credit (e)	0	0	0	0	0	0	0	0	0	0	0	0
Total Net RTO Costs - OPCo	**12,731,888**	**12,647,020**	**13,166,302**	**12,414,898**	**12,233,708**	**12,817,147**	**12,337,926**	**12,288,919**	**10,257,227**	**11,707,048**	**10,316,650**	**132,918,734**

	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	July14-May15
2014 - 2015 Forecasted Load (kWh) excluding Shopping Customers												
Residential	901,556,697	928,670,817	843,841,975	641,746,296	674,259,227	883,704,026	1,102,998,939	999,691,502	846,454,084	725,826,058	589,061,345	9,137,810,967
Commercial	256,106,163	258,297,741	254,602,180	224,059,228	210,492,834	233,752,711	248,566,564	231,514,981	220,023,180	216,378,165	217,840,193	2,571,633,940
Industrial	184,027,586	179,204,433	184,919,934	174,866,654	167,210,047	169,322,954	155,655,426	155,745,532	156,753,741	157,237,700	157,679,238	1,842,623,243
Other Ultimates	4,945,979	5,178,495	5,456,873	5,971,381	6,325,307	6,567,075	6,792,738	6,316,802	5,919,142	5,794,507	5,070,619	64,338,918
Municipals	748,500	647,280	658,080	591,120	553,740	743,160	963,660	749,160	742,860	731,760	504,060	7,633,380
Total	1,347,384,925	1,371,998,766	1,289,479,041	1,047,234,678	1,058,841,155	1,294,089,925	1,514,977,327	1,394,017,978	1,229,893,007	1,105,968,190	970,155,454	13,624,040,447
AEP Peak at time of PJM Peak (7/18/2013)	**20604 MW**											
AEP Projected Shopping Percentages	**64.48%**	**64.44%**	**65.37%**	**68.12%**	**67.51%**	**65.02%**	**62.94%**	**63.78%**	**65.56%**	**67.26%**	**69.54%**	
12 CP	0.4220	0.4220	0.4220	0.4220	0.4220	0.4220	0.4113	0.4113	0.4113	0.4113	0.4113	

(a) Includes NERC and RFC Fees
(b) Forecast using 2013/2014 load forecast and current OATT rates
(c) Pursuant to Schedule 12 of the PJM OATT, the Company has begun to incur charges for Required Regional Transmission Enhancements.
(d) Beginning June 1, 2008, the Company is required to comply with PJM's new Supplemental 30-minute Reserve requirement and is a Forecast.
(e) 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-14	Forecast Oct-14	Forecast Nov-14	Forecast Dec-14	Forecast Jan-15	Forecast Feb-15	Forecast Mar-15	Forecast Apr-15	Forecast May-15	Forecast 2014 / 2015 Proposed Rates kWh	Demand	Total
METERED kWh:												
RS	842,160,932	639,925,327	672,389,136	881,919,713	1,101,176,635	998,199,787	844,976,730	724,312,577	587,644,130			7,292,704,967
GS1	30,356,761	27,547,320	28,896,681	35,945,206	39,131,292	35,679,624	35,147,767	32,268,953	23,089,272			288,062,877
GS2 Sec	104,429,848	89,948,418	87,871,280	99,604,029	103,374,911	97,634,365	98,676,745	93,009,766	76,910,498			851,459,860
GS2 RL - GS - TOD	3,383,299	3,078,364	3,011,641	3,846,626	4,259,358	3,872,748	3,748,185	3,152,842	2,588,617			30,941,680
GS2 Pri	4,323,485	2,637,588	3,687,934	3,473,489	4,488,716	3,459,346	3,080,980	2,830,433	2,224,935			30,206,907
GS2 Sub/Trans	267,454	435,782	596,438	774,810	390,645	330,557	3,448,833	336,542	1,433,151			8,014,212
GS3 Sec	103,498,447	84,812,843	79,886,193	82,079,409	87,261,294	77,590,626	78,672,227	76,385,871	95,169,859			765,356,768
GS3 - TOD	-	-	-	-	-	-	-	-	-			-
GS3 Pri	30,082,476	21,490,555	24,480,695	21,384,740	24,543,558	20,781,648	21,220,370	20,303,267	33,798,080			218,085,391
GS3 Sub/Trans	5,419,692	3,981,141	4,832,271	8,284,529	7,698,362	15,727,608	9,600,138	6,055,670	4,014,447			65,613,857
GS4 Pri	-	-	-	-	-	-	-	-	-			-
GS4/IRP Sub/Trans	152,465,049	159,129,938	137,895,698	140,985,640	126,820,676	126,262,680	117,041,559	133,470,475	132,598,071			1,226,669,787
EHG	562,010	514,336	663,663	1,094,188	1,268,387	1,311,962	1,159,965	870,022	491,614			7,936,147
SS	502,063	513,419	519,368	592,708	596,552	603,828	513,572	542,616	539,047			4,923,174
OL	6,914,722	7,565,977	8,100,311	7,914,423	7,635,144	6,692,528	7,079,534	7,123,848	5,529,903			64,556,390
SL	5,112,804	5,653,671	6,009,844	6,190,415	6,331,797	5,870,671	5,526,401	5,305,309	4,123,830			50,124,742
Total	1,289,479,041	1,047,234,678	1,058,841,155	1,294,089,925	1,514,977,327	1,394,017,978	1,229,893,007	1,105,968,190	970,155,454			10,904,656,757
DEMAND:												
RS	-	-	-	-	-	-	-	-	-			-
GS1	-	-	-	-	-	-	-	-	-			-
GS2 Sec	419,611	421,155	420,427	389,135	380,831	368,621	394,404	410,528	362,284			3,566,995
GS2 RL - GS - TOD	-	-	-	-	-	-	-	-	-			-
GS2 Pri	23,406	13,343	18,700	16,832	17,034	15,057	17,470	15,176	12,881			149,899
GS2 Sub/Trans	7,440	4,195	6,942	8,972	6,793	7,387	18,995	5,391	8,991			75,107
GS3 Sec	230,091	209,963	194,603	172,465	182,904	175,293	186,108	187,918	234,345			1,773,691
GS3 - TOD	-	-	-	-	-	-	-	-	-			-
GS3 Pri	62,084	52,001	51,458	44,749	53,632	46,263	48,362	45,260	72,330			476,139
GS3 Sub/Trans	15,494	12,322	16,806	18,852	16,186	41,767	23,029	17,145	8,221			169,821
GS4 Pri	-	-	-	-	-	-	-	-	-			-
GS4/IRP Sub/Trans	262,098	377,969	302,194	285,550	256,464	254,376	229,833	280,179	205,786			2,454,449
EHG	-	-	-	-	-	-	-	-	-			-
SS	-	-	-	-	-	-	-	-	-			-
OL	-	-	-	-	-	-	-	-	-			-
SL	-	-	-	-	-	-	-	-	-			-
Total	1,020,224	1,090,947	1,011,130	936,556	913,845	908,764	918,200	961,597	904,838			8,666,101
REVENUES:												
RS	$ 15,805,171	$ 12,009,735	$ 12,618,996	$ 16,551,340	$ 20,666,222	$ 18,733,615	$ 15,858,016	$ 13,593,464	$ 11,028,552	0.0187674		$ 136,865,111
GS1	577,316	523,887	549,548	683,595	744,187	678,544	668,430	613,681	439,105	0.0190177		$ 5,478,293
GS2 Sec	1,939,227	1,905,655	1,897,101	1,805,937	1,783,545	1,719,718	1,824,157	1,872,169	1,638,005	0.0027383	3.94	$ 16,385,514
GS2 RL - GS - TOD	64,190	58,405	57,139	72,981	80,811	73,476	71,113	59,818	49,113	0.0189726		$ 587,044
GS2 Pri	100,371	57,674	80,808	73,145	76,594	66,362	74,529	65,150	54,828	0.0026433	3.80	$ 649,461
GS2 Sub/Trans	28,443	16,776	27,439	35,474	26,351	28,408	79,787	20,981	37,250	0.0025906	3.73	$ 300,909
GS3 Sec	1,574,486	1,410,140	1,310,509	1,192,600	1,265,375	1,196,032	1,259,584	1,263,403	1,575,298	0.0027631	5.60	$ 12,047,428
GS3 - TOD	-	-	-	-	-	-	-	-	-	0.0156854		$ -
GS3 Pri	416,111	338,644	343,682	299,130	355,614	305,709	318,235	299,012	481,450	0.0026672	5.41	$ 3,157,588
GS3 Sub/Trans	96,287	75,712	101,702	121,572	105,910	262,479	147,152	106,698	54,063	0.0026141	5.30	$ 1,071,574
GS4 Pri	-	-	-	-	-	-	-	-	-	0.0027895	5.32	$ -
GS4/IRP Sub/Trans	1,782,354	2,404,263	1,951,425	1,873,157	1,682,894	1,670,490	1,517,408	1,824,626	1,434,655	0.0027339	5.21	$ 16,141,272
EHG	5,076	4,645	5,994	9,882	11,455	11,849	10,476	7,857	4,440	0.0090312		$ 71,673
SS	8,637	8,832	8,934	10,196	10,262	10,387	8,835	9,334	9,273	0.0172021		$ 84,689
OL	18,903	20,684	22,145	21,636	20,873	18,296	19,354	19,475	15,118	0.0027338		$ 176,484
SL	13,977	15,456	16,430	16,923	17,310	16,049	15,108	14,504	11,274	0.0027338		$ 137,031
Total	$ 22,430,549	$ 18,850,508	$ 18,991,852	$ 22,767,567	$ 26,847,404	$ 24,791,414	$ 21,872,183	$ 19,770,173	$ 16,832,423			$ 193,154,072

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

	SSO Demand	Demand Cost	July 2014 - May 2015 Loss Adjusted KWH Energy	Energy Cost	Net Marginal Loss 100% kWh	Total Cost
Forecast						
RS	1,897.5	$ 80,656,626	7,292,704,967	$ 15,713,297	$ (1,960,699)	$ 94,409,224
GS1	76.1	3,235,687	288,062,877	620,677	(77,448)	$ 3,778,916
GS2	242.1	10,292,949	920,622,659	1,983,628	(247,516)	$ 12,029,061
GS3	217.7	9,252,067	1,049,056,016	2,260,359	(282,047)	$ 11,230,379
GS4/IRP	207.8	8,833,773	1,226,669,787	2,643,056	(329,800)	$ 11,147,030
EHG	0.8	34,474	7,936,147	17,100	(2,134)	$ 49,440
SS/EHS	1.2	49,134	4,923,174	10,608	(1,324)	$ 58,418
OL/SL	0.0	-	114,681,132	247,099	(30,833)	$ 216,266
SBS*	0.0	-	-	-	-	$ -
Total	2,643.2	$ 112,354,711	10,904,656,757	$ 23,495,824	$ (2,931,800)	$ 132,918,734
Reconciliation						
RS		$ 36,271,331	7,292,704,967	$ 7,066,279	$ (881,728)	$ 42,455,882
GS1		$ 1,455,090	288,062,877	279,119	(34,828)	$ 1,699,381
GS2		$ 4,628,745	920,622,659	892,039	(111,308)	$ 5,409,476
GS3		$ 4,160,660	1,049,056,016	1,016,485	(126,837)	$ 5,050,308
GS4/IRP		$ 3,972,553	1,226,669,787	1,188,584	(148,311)	$ 5,012,826
EHG		$ 15,503	7,936,147	7,690	(960)	$ 22,233
SS/EHS		$ 22,096	4,923,174	4,770	(595)	$ 26,271
OL/SL		$ -	114,681,132	111,120	(13,866)	$ 97,255
SBS		$ -	-	-	-	$ -
Total		$ 50,525,977	10,904,656,757	$ 10,566,085	$ (1,318,432)	$ 59,773,631
Total						
RS		$ 116,927,957		$ 22,779,576	$ (2,842,427)	$ 136,865,106
GS1		$ 4,690,777		$ 899,796	$ (112,276)	$ 5,478,297
GS2		$ 14,921,695		$ 2,875,667	$ (358,825)	$ 17,438,537
GS3		$ 13,412,727		$ 3,276,843	$ (408,883)	$ 16,280,687
GS4/IRP		$ 12,806,326		$ 3,831,640	$ (478,111)	$ 16,159,856
EHG		$ 49,976		$ 24,789	$ (3,093)	$ 71,673
SS/EHS		$ 71,230		$ 15,378	$ (1,919)	$ 84,689
OL/SL		$ -		$ 358,219	$ (44,698)	$ 313,521
SBS		$ -		$ -	$ -	$ -
Total		$ 162,880,688		$ 34,061,909	$ (4,250,232)	$ 192,692,365

*Demand imputed based upon contractual forced outage rates

Ohio Power Company

Projected Transmission Cost Recovery Rider Rate Calculations

September 2014 - May 2015

			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	$ 116,927,957	$ 19,937,149	-	7,292,704,967		$ 0.0187674						
GS1	$ 4,690,777	$ 787,520	-	288,062,877		$ 0.0190177						
GS2	$ 14,921,695	$ 2,516,843	3,782,751	919,142,618	$ 3.94	$ 0.0027383	0.9653	$ 3.80	$ 0.0026433	0.9461	$ 3.73	$ 0.0025906
GS3	$ 13,412,727	$ 2,867,960	2,393,977	1,037,952,457	$ 5.60	$ 0.0027631	0.9653	$ 5.41	$ 0.0026672	0.9461	$ 5.30	$ 0.0026141
GS4/IRP	$ 12,806,326	$ 3,353,529	2,322,101	1,160,525,827	$ 5.51	$ 0.0028897	0.9653	$ 5.32	$ 0.0027895	0.9461	$ 5.21	$ 0.0027339
EHG	$ 49,976	$ 21,696	-	7,936,147		$ 0.0090312						
SS/EHS	$ 71,230	$ 13,459	-	4,923,174		$ 0.0172021						
OL/SL	$ -	$ 313,521	-	114,681,132		$ 0.0027338						
Total	$ 162,880,688	$ 29,811,677	8,498,829	10,825,929,199								
				GS-2 Energy only rate		$ 0.0189726						
				GS-3 Energy only rate		$ 0.0156854						

Ohio Power Company
SBS Tariff Rate Design

			AEP Ohio		
			Demand	**Energy**	
GS-2			$ 14,921,695	$ 2,516,843	
GS-3			$ 13,412,727	$ 2,867,960	
GS-4/IRP			$ 12,806,326	$ 3,353,529	
Total			$ 41,140,748	$ 8,738,332	
Demand @ Secondary			57,115,174		
Energy @ Secondary				3,117,620,903	
		Loss			
Forced Outage Rate	15%	Factors			
Secondary		1.0000	$ 0.11	$ 0.0028029	
Primary		0.9653	$ 0.10	$ 0.0027057	
Subtrans/Transmission		0.9461	$ 0.10	$ 0.0026518	
Forced Outage Rate	5%				
Secondary			$ 0.04	$ 0.0028029	
Primary			$ 0.03	$ 0.0027057	
Subtrans/Transmission			$ 0.03	$ 0.0026518	
Forced Outage Rate	10%				
Secondary			$ 0.07	$ 0.0028029	
Primary			$ 0.07	$ 0.0027057	
Subtrans/Transmission			$ 0.07	$ 0.0026518	
Forced Outage Rate	20%				
Secondary			$ 0.14	$ 0.0028029	
Primary			$ 0.14	$ 0.0027057	
Subtrans/Transmission			$ 0.14	$ 0.0026518	
Forced Outage Rate	25%				
Secondary			$ 0.18	$ 0.0028029	
Primary			$ 0.17	$ 0.0027057	
Subtrans/Transmission			$ 0.17	$ 0.0026518	
Forced Outage Rate	30%				
Secondary			$ 0.22	$ 0.0028029	
Primary			$ 0.21	$ 0.0027057	
Subtrans/Transmission			$ 0.20	$ 0.0026518	
Maintenance Energy					
at 15% Forced Outage Rate					
Secondary			$ 0.11		
Primary			$ 0.10		
Subtrans/Transmission			$ 0.10		
Hours at 85% Load Factor			621		
Demand Components per KWH					Total
Secondary			$ 0.0001771	$ 0.0028029	$ 0.0029800
Primary			$ 0.0001610	$ 0.0027057	$ 0.0028667
Subtrans/Transmission			$ 0.0001610	$ 0.0026518	$ 0.0028128
Less than 100 KW*					
Residential & GS-1			$ 121,618,733.816		
GS-2			$ 14,921,695		
Forced Outage Adjustment	15%		$ 20,481,064		
Demand			41,167,292		
			$ 0.50		

* Also Breakdown Service Charge for CSP

Ohio Power Company

	Metered		Loss	Units @ Secondary	
	Energy	Demand	Factor	Energy	Demand
RS	7,292,704,967	-	1.0000	7,292,704,967	-
GS1	288,062,877	-	1.0000	288,062,877	-
GS2 Sec	851,459,860	3,566,995	1.0000	851,459,860	3,566,995
GS2 RL - GS - TOD*	30,941,680	-	1.0000	30,941,680	-
GS2 Pri	30,206,907	149,899	0.9653	29,159,005	144,699
GS2 Sub/Trans	8,014,212	75,107	0.9461	7,582,073	71,057
GS3 Sec	765,356,768	1,773,691	1.0000	765,356,768	1,773,691
GS3-TOD	-	-	1.0000	-	-
GS3 Pri	218,085,391	476,139	0.9653	210,519,835	459,621
GS3 Sub/Trans	65,613,857	169,821	0.9461	62,075,855	160,664
GS4 Pri	-	-	0.9653	-	-
GS4/IRP Sub/Trans	1,226,669,787	2,454,449	0.9461	1,160,525,827	2,322,101
EHG	7,936,147	-	1.0000	7,936,147	-
SS	4,923,174	-	1.0000	4,923,174	-
AL	64,556,390	-	1.0000	64,556,390	-
SL	50,124,742	-	1.0000	50,124,742	-
	10,904,656,757	8,666,101		10,825,929,199	8,498,829

7/18/13 14:00 EST (15:00 EPT) — 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	2.49	1,276,171	3,178.36	1.0932	3,474.58
GS1	1.34	118,395	159.05	1.0932	173.87
GS2	21.09	53,946	1,137.85	1.0874	1,237.32
GS3	194.93	11,901	2,319.84	1.0747	2,493.21
GS4	12,359.04	81	1,001.08	1.0351	1,036.18
IIP	39,203.40	2	78.41	1.0341	81.08
EHG	8.09	434	3.51	1.0932	3.84
SCH	44.83	144	6.46	1.0932	7.06
Joint Service Territory	317,104.99	1	317.10	1.0341	327.92
TOTAL					
Internal Load (At Generation)					8,835.07
Total			8,201.65		8,835.07
Total GS-4					1,445.18

Ohio Power Company
Amount exclude Wheeling Power Company activity
Recorded Transmission Rider Revenues & Transmission Costs
Jan 14 - Apr 14
<Revenue>/ Expense in $

		Dec-13	Jan-14	Feb-14	Mar-14	1st Qtr 2014	Apr-14	May-14	Jun-14	2nd Qtr 2014
	Total Transm. TCRR/ETCRR Revenue-OPCO		(22,808,088)	(21,256,443)	(20,254,911)	(64,319,442)	(13,952,263)			(13,952,263)
	Transmission Costs:									
	Net Congestion:									
1	PJM Implicit Congestion		14,320,216	1,669,597	12,660,054	28,649,867	985,776			985,776
2	PJM FTR Revenue		(20,642,631)	(6,384,634)	(10,358,382)	(37,385,647)	(766,825)			(766,825)
3	Auction Revenue Rights									
	Net Congestion Subtotal		(6,322,415)	(4,715,037)	2,301,672	(8,735,781)	218,951	-	-	218,951
20	**PJM Operating Reserve**		10,087,808	1,818,404	4,163,529	16,069,741	450,548			450,548
	PJM Ancillary Services									
4	PJM Synchronous Condensing		1,390	(0)	-	1,390	(84)			(84)
5	PJM Reactive Supply		540,712	(642,127)	1,618,892	1,517,477	521,841			521,841
6	PJM Blackstart		373,884	343,840	349,041	1,066,764	552,929			552,929
7	PJM Regulation Charges		1,589,033	827,628	792,401	3,209,063	352,442			352,442
8	PJM Spinning Reserve Charges		1,277,737	94,813	(28,602)	1,343,947	331,895			331,895
9	PJM 30 minute Supplemental Market		931,217	4,461	3,760	939,437	(93,881)			(93,881)
	PJM Ancillary Services Subtotal		4,713,972	628,614	2,735,492	8,078,078	1,665,142	-	-	1,665,142
10	**PJM Administration Service Fees**		784,864	598,580	443,115	1,826,560	544,865			544,865
19	**Net Expansion Cost Recovery Charge**		(72,032)	(84,504)	(67,130)	(223,666)	(74,112)			(74,112)
11	Amortization of PJM Integration Costs		160,909	160,909	160,909	482,727	160,909			160,909
12	PJM RTO Formation Cost Recovery		(55,028)	(69,256)	(48,761)	(173,045)	(56,639)			(56,639)
	Net RTO Formation Costs		105,881	91,653	112,148	309,682	104,270	-	-	104,270
13	**PJM Transmission Enhancement Charges**		(176,589)	1,922,650	912,658	2,658,720	792,134			792,134
14	**NITS/TO Charges - LSE**		8,554,144	7,639,891	8,349,879	24,543,914	7,942,568			7,942,568
15	PJM Marginal Losses		9,156,981	4,942,925	2,157,036	16,256,942	1,410,868			1,410,868
	Net Marginal Losses and Fuel Credit		9,156,981	4,942,925	2,157,036	16,256,942	1,410,868	-	-	1,410,868
16	**Pt-to-Pt Transm. Revenues**		(172,110)	(152,629)	(165,132)	(489,871)	(128,679)			(128,679)
17	**PJM Emergency Energy Purchases**		-	-	-	-	-			-
18	**OPCO Phase-In Credits (ER09-1279-000)**		-	-	-	-	-			-
	Total Net RTO Costs - OPCO		26,660,505	12,690,547	20,943,267	60,294,319	12,926,555	-	-	12,926,555
	Monthly OPCo - Net <Over>/Under Recovery		3,852,417	(8,565,897)	688,356	(4,025,123)	(1,025,709)	-	-	(1,025,709)
	Balance to be recovered via Nonbypassable Rates									
	OPCO - Cumul. Net <Over>/Under Recovery	57,756,508	61,608,925	53,043,028	53,731,385		52,705,676	-	-	52,705,676

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

	Ohio Power Company
Cumulative (Over)/Under Recovery on Schedule D-1	52,705,675
Cumulative Carrying Charges	4,442,396
Prior Year (Over)/Under Recovery on Schedule B-1	57,148,072

Monthly Revenues Collected From Each Rate Schedule
March - April 2014

Ohio Power Company

	March 2013	April 2013
Billed:		
RS	14,853,574.32	11,240,969.41
GS1	437,501.43	363,252.50
GS2 Sec	1,226,358.22	1,153,218.06
GS2 RL - GS - TOD	47,212.85	35,941.72
GS2 Pri	46,804.49	52,060.64
GS2 Sub/Trans	49,732.27	17,293.32
GS3 Sec	948,400.41	892,409.48
GS3-TOD	-	-
GS3 Pri	240,520.44	232,403.88
GS3 Sub/Trans	109,176.78	92,506.41
GS4 Pri	-	-
GS4/IRP Sub/Trans	1,145,007.48	2,036,370.88
EHG	8,242.70	5,557.95
EHS	-	-
SS	5,778.55	5,426.81
SL	14,751.09	13,634.72
AL	27,738.54	25,464.18
Shopping	(92.78)	7.38
SBS-Sub/Tran-Backup	-	-
	19,160,706.79	16,166,517.34
Estimated and Unbilled	986,526.82	(2,214,253.92)
Total:	20,147,233.61	13,952,263.42

Ohio Power Company
2014
Example of Carrying Cost Calculation

Schedule D-3a

Line No.	Description Monthly Activity for	Mar-14	Apr-14
1	Monthly (Over)/Under Recovery	688,356	(1,025,709)
2	Cumulative (Over)/Under Rec.	688,356	(337,353)
	Recorded In	Apr-14	May-14
	Accrual of Carrying Charges		
3	Current TCRR Expenditures	688,356	(337,353)
4	Accumulated Carrying Charges	-	3,063
5	Total	688,356	(334,289)
6	Debt Rate	5.340%	5.340%
	Current Month Carrying Cost		
7	Debt Portion (4210041) (4310001)	3,063	(1,488)
	Accumulated		
8	Accumulated Debt	3,063	1,576
	Account 1823154	3,063	(1,488)
	Account 4210041	(3,063)	1,488
	Account 2540104	-	-
	Account 4310001	-	-

6/12/2014

Merged Ohio Companies
Expanded Transmission Cost Recovery Rider Revenues
March 2014

Total Transmission Revenues		Current Month	Prior Month Reversal (4)	Net
(1)	Billed "T" Revenue (incl Republic adjust)	**19,160,706.79**	n/a	19,160,706.79
(2)	Estimated "T" Revenue	**379,598.96**	**(189,781.26)**	189,817.70
(3)	**Estimated** Unbilled "T" Revenue	8,579,241.04	(7,782,531.92)	796,709.12

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 2014 **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 2014	2013
		SALES OF ELECTRICITY										
		RESIDENTIAL										
4400	002	WITHOUT SPACE HEATING	8,959,809.29	7,508,656.32	19.33	622,528,221	649,954,163	4.22-	713,219	766,396	1.44	0.89
4400	001	WITH SPACE HEATING	5,900,379.31	4,617,046.37	27.80	409,546,561	399,295,601	2.57	203,223	214,284	1.44	0.92
		TOTAL RESIDENTIAL	14,860,188.60	12,125,702.69	22.55	1,032,074,782	1,049,249,764	1.64-	916,442	980,680	1.44	1.16
					0.00						0.00	0.00
		COMMERCIAL										
4420	001	OTHER THAN PUBLIC AUTHORITIES	2,484,208.08	3,130,219.52	20.64-	208,837,569	301,031,976	30.63-	89,973	101,771	1.19	0.35
4420	006	PUBLIC AUTHS - SCHOOLS	59,041.28	131,283.42	55.03-	5,414,066	12,583,215	56.97-	497	779	1.09	0.11
4420	007	PUBLIC AUTHS-OTHER THAN SCHOOL	104,268.15	199,043.33	47.62-	9,212,877	19,151,308	51.89-	2,826	3,924	1.13	0.21
		TOTAL COMMERCIAL	2,647,517.51	3,460,546.27	23.49-	223,464,512	332,766,499	32.85-	93,296	106,474	1.18	1.04
					0.00						0.00	0.00
		INDUSTRIAL										
4420	002	EXCLUDING MINE POWER	1,565,343.78	4,443,443.90	64.77-	150,377,078	591,730,566	74.59-	5,084	5,830	1.04	0.32
4420	004	MINE POWER	7,328.14	15,897.69	53.90-	669,020	1,603,209	58.27-	32	39	1.10	0.11
4420	005	ASSOCIATED COMPANIES	53,563.95	53,112.92	0.85	3,053,363	2,970,420	2.79	84	18	1.75	1.79
		TOTAL INDUSTRIAL	1,626,235.87	4,512,454.51	63.96-	154,099,461	596,304,195	74.16-	5,200	5,887	1.06	0.76
		COMMERCIAL AND INDUSTRIAL	4,273,753.38	7,973,000.78	46.40-	377,563,973	929,070,694	59.36-	98,496	112,361	1.13	0.86
		PUBLIC STREET & HIGHWAY LIGHT										
4440	000	PUBLIC STREET & HIGHWAY LIGHT	17,615.64	28,107.91	37.33-	4,157,222	6,157,293	32.48-	1,195	1,599	0.42	0.26
		TOTAL PUBLIC STREET & HIGHWAY LIGHT	17,615.64	28,107.91	37.33-	4,157,222	6,157,293	32.48-	1,195	1,599	0.42	0.46
					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	936.23	563.47	66.15	74,800	49,465	51.22	25	26	1.25	1.14
		TOTAL OTHER SALES TO PUBLIC AUTHS	936.23	563.47	66.15	74,800	49,465	51.22	25	26	1.25	1.14
		ULTIMATE CUSTOMERS	19,152,493.85	20,127,374.85	4.84-	1,413,870,777	1,984,527,216	28.76-	1,016,158	1,094,666	1.35	1.01
		SALES FOR RESALE										
4470	XXX	OTHER ELEC UTILS	8,212.94	6,982.14	17.63	818,100	742,860	10.13	3	3	1.00	0.94
		TOTAL SALES FOR RESALE	8,212.94	6,982.14	17.63	818,100	742,860	10.13	3	3	1.00	0.94
					0.00						0.00	0.00
		TOTAL SALES OF ELECTRICITY	19,160,706.79	20,134,356.99	4.84-	1,414,688,877	1,985,270,076	28.74-	1,016,161	1,094,669	1.35	1.01
		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	19,160,706.79	20,134,356.99	4.84-	1,414,688,877	1,985,270,076	28.74-	1,016,161	1,094,669	1.35	1.01

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: 04/02/2014 04:10:27 PM

March 2014

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
211	G	OH	6	615,991	30.0	5,808.00	14,135.67
211	T	OH	4	160,202	20.0	0.00	1,881.65
211	D	OH	6	615,991	30.0	0.00	14,489.68
Total : 211			6	615,991	30.0	5,808.00	30,507.00
212	G	OH	1	33,414	5.0	1,133.00	1,630.73
212	T	OH	1	33,414	5.0	0.00	170.05
212	D	OH	1	33,414	5.0	0.00	587.22
Total : 212			1	33,414	5.0	1,133.00	2,388.00
213	G	OH	2	259,457	10.0	0.00	1,595.57
213	D	OH	2	259,457	10.0	0.00	7,933.43
Total : 213			2	259,457	10.0	0.00	9,529.00
221	G	OH	21	260,646,480	105.0	3,112,993.00	5,624,161.72
221	T	OH	5	97,060,190	25.0	0.00	375,323.79
221	D	OH	21	260,646,480	105.0	0.00	316,277.49
Total : 221			21	260,646,480	105.0	3,112,993.00	6,315,763.00

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
211	G	OH	16	4,696,077	80.0	8,768.00	27,970.60
211	T	OH	1	218,358	5.0	0.00	2,223.47
211	D	OH	16	4,696,077	80.0	0.00	103,395.93
Total : 211			16	4,696,077	80.0	8,768.00	133,590.00
212	G	OH	1	288,456	5.0	0.00	1,052.65
212	D	OH	1	288,456	5.0	0.00	8,534.35
Total : 212			1	288,456	5.0	0.00	9,587.00
213	G	OH	4	36,943,842	20.0	0.00	80,673.81
213	D	OH	4	36,943,842	20.0	0.00	71,452.19
Total : 213			4	36,943,842	20.0	0.00	152,126.00
216	G	OH	4	1,992,431	20.0	0.00	4,308.13

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

Estimate Billings For MACSS GTD
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March 2014

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
216	D	OH	4	1,992,431	20.0	0.00	30,548.87
Total : 216			4	1,992,431	20.0	0.00	34,857.00
221	G	OH	7	14,960,774	35.0	0.00	28,725.33
221	D	OH	7	14,960,774	35.0	0.00	31,228.67
Total : 221			7	14,960,774	35.0	0.00	59,954.00
	Total G:		62	320,436,922	310.0	3,128,702.00	5,784,254.21
	Total T:		11	97,472,164	55.0	0.00	379,598.96
	Total D:		62	320,436,922	310.0	0.00	584,447.83
	Grand Total :		62	320,436,922	310.0	3,128,702.00	6,748,301.00

6/12/2014

Merged Ohio Companies
Expanded Transmission Cost Recovery Rider Revenues
April 2014

Total Transmission Revenues		Current Month	Prior Month Reversal (4)	Net
(1)	Billed "T" Revenue (incl Republic adjust)	**16,166,517.34**	n/a	16,166,517.34
(2)	Estimated "T" Revenue	**325,656.21**	**(379,598.96)**	(53,942.75)
(3)	**Estimated** Unbilled "T" Revenue	6,418,929.87	(8,579,241.04)	(2,160,311.17)
	Total Amount of Transmission Revenues			**13,952,263.42**

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 2014 **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 2014	2013
		SALES OF ELECTRICITY										
		RESIDENTIAL										
4400	002	WITHOUT SPACE HEATING	7,309,774.29	6,765,933.20	8.04	507,942,912	585,688,654	13.27-	705,432	764,493	1.44	0.87
4400	001	WITH SPACE HEATING	3,937,207.65	3,696,473.13	6.51	273,322,626	319,717,496	14.51-	201,238	214,782	1.44	0.91
		TOTAL RESIDENTIAL	11,246,981.94	10,462,406.33	7.50	781,265,538	905,406,150	13.71-	906,670	979,275	1.44	1.16
					0.00						0.00	0.00
		COMMERCIAL										
4420	001	OTHER THAN PUBLIC AUTHORITIES	2,261,296.36	3,004,998.19	24.75-	182,690,441	279,734,319	34.69-	89,298	101,176	1.24	0.33
4420	006	PUBLIC AUTHS - SCHOOLS	49,716.12	135,961.52	63.43-	4,136,551	12,492,351	66.89-	478	779	1.20	0.11
4420	007	PUBLIC AUTHS-OTHER THAN SCHOOL	98,637.37	193,155.95	48.93-	8,511,425	18,181,397	53.19-	2,962	3,877	1.16	0.20
		TOTAL COMMERCIAL	2,409,649.85	3,334,115.66	27.73-	195,338,417	310,408,067	37.07-	92,738	105,832	1.23	1.07
					0.00						0.00	0.00
		INDUSTRIAL										
4420	002	EXCLUDING MINE POWER	2,435,183.95	4,082,887.84	40.36-	227,715,820	547,508,262	58.41-	5,042	5,727	1.07	0.28
4420	004	MINE POWER	7,375.04	7,239.57	1.87	718,075	748,236	4.03-	31	35	1.03	0.05
4420	005	ASSOCIATED COMPANIES	41,720.54	36,062.56	15.69	2,618,274	2,542,542	2.98	38	17	1.59	1.42
		TOTAL INDUSTRIAL	2,484,279.53	4,126,189.97	39.79-	231,052,169	550,799,040	58.05-	5,111	5,779	1.08	0.75
		COMMERCIAL AND INDUSTRIAL	4,893,929.38	7,460,305.63	34.40-	426,390,586	861,207,107	50.49-	97,849	111,611	1.15	0.87
		PUBLIC STREET & HIGHWAY LIGHT										
4440	000	PUBLIC STREET & HIGHWAY LIGHT	17,396.03	25,701.79	32.32-	3,932,239	5,515,583	28.71-	1,221	1,590	0.44	0.30
		TOTAL PUBLIC STREET & HIGHWAY LIGHT	17,396.03	25,701.79	32.32-	3,932,239	5,515,583	28.71-	1,221	1,590	0.44	0.47
					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	765.77	692.37	10.60	61,180	60,779	0.66	25	26	1.25	1.14
		TOTAL OTHER SALES TO PUBLIC AUTHS	765.77	692.37	10.60	61,180	60,779	0.66	25	26	1.25	1.14
		ULTIMATE CUSTOMERS	16,159,073.12	17,949,106.12	9.97-	1,211,649,543	1,772,189,619	31.63-	1,005,765	1,092,502	1.33	1.01
		SALES FOR RESALE										
4470	XXX	OTHER ELEC UTILS	7,444.22	6,829.25	9.00	706,980	731,760	3.39-	3	3	1.05	0.93
		TOTAL SALES FOR RESALE	7,444.22	6,829.25	9.00	706,980	731,760	3.39-	3	3	1.05	0.93
					0.00						0.00	0.00
		TOTAL SALES OF ELECTRICITY	16,166,517.34	17,955,935.37	9.97-	1,212,356,523	1,772,921,379	31.62-	1,005,768	1,092,505	1.33	1.01
		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	16,166,517.34	17,955,935.37	9.97-	1,212,356,523	1,772,921,379	31.62-	1,005,768	1,092,505	1.33	1.01

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: 05/02/2014 04:05:27 PM

April 2014

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
211	G	OH	18	2,585,108	90.0	12,302.00	34,106.24
211	T	OH	5	279,760	25.0	0.00	2,977.88
211	D	OH	18	2,585,108	90.0	0.00	51,557.88
Total : 211			18	2,585,108	90.0	12,302.00	88,642.00
212	G	OH	4	229,272	20.0	3,795.00	7,308.98
212	T	OH	2	86,895	10.0	0.00	984.85
212	D	OH	4	229,272	20.0	0.00	5,669.17
Total : 212			4	229,272	20.0	3,795.00	13,963.00
213	G	OH	7	679,041	35.0	6,127.00	14,089.60
213	T	OH	1	138,801	5.0	0.00	1,398.39
213	D	OH	7	679,041	35.0	0.00	21,843.01
Total : 213			7	679,041	35.0	6,127.00	37,331.00
216	G	OH	2	950,982	10.0	0.00	5,130.72
216	D	OH	2	950,982	10.0	0.00	15,529.28
Total : 216			2	950,982	10.0	0.00	20,660.00
221	G	OH	24	281,961,508	120.0	4,230,557.00	6,570,593.12
221	T	OH	6	101,353,240	30.0	0.00	316,798.30
221	D	OH	24	281,961,508	120.0	0.00	339,221.58
Total : 221			24	281,961,508	120.0	4,230,557.00	7,226,613.00

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
211	G	OH	20	5,732,096	100.0	0.00	18,501.20
211	D	OH	20	5,732,096	100.0	0.00	136,896.80
Total : 211			20	5,732,096	100.0	0.00	155,398.00
212	G	OH	4	751,860	20.0	16,819.00	27,398.91
212	T	OH	2	337,116	10.0	0.00	3,496.79
212	D	OH	4	751,860	20.0	0.00	19,280.30
Total : 212			4	751,860	20.0	16,819.00	50,176.00

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

Estimate Billings For MACSS GTD
MCSRESTB

Prepared: 05/02/2014 04:05:27 PM

April 2014

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
213	G	OH	4	35,156,306	20.0	0.00	81,627.27
213	D	OH	4	35,156,306	20.0	0.00	72,150.73
Total : 213			4	35,156,306	20.0	0.00	153,778.00
216	G	OH	2	148,800	10.0	0.00	528.36
216	D	OH	2	148,800	10.0	0.00	4,283.64
Total : 216			2	148,800	10.0	0.00	4,812.00
221	G	OH	4	9,912,202	20.0	0.00	22,636.32
221	D	OH	4	9,912,202	20.0	0.00	24,873.68
Total : 221			4	9,912,202	20.0	0.00	47,510.00
	Total G:		89	338,107,175	445.0	4,269,600.00	6,781,920.72
	Total T:		16	102,195,812	80.0	0.00	325,656.21
	Total D:		89	338,107,175	445.0	0.00	691,306.07
	Grand Total :		89	338,107,175	445.0	4,269,600.00	7,798,883.00

PJM Invoice Detail - March 2014 Actual Cycle (Final Invoice from PJM - April 7, 2014)

PJM Billing Line Item	AEPGR Allocated to PSA (SSO_SUPPLY)	PJM Invoice Amount of AEPGR	Reconciled Invoice Allocation Total	Variance (AEPGR Non Allocated to PSA)
PJM Implicit Congestion (5550124)			$ -	$ -
1120A- AEP Aggregate Allocation - Congestion per Transmission Group			$ -	$ -
1210 - Day-Ahead Transmission Implicit Congestion Charge		$41,432,199.00	$ 41,432,199.00	$41,432,199.00
1215 - Balancing Transmission Implicit Congestion Charge		$915,182.40	$ 915,182.40	$ 915,182.40
1410 - Load Reconciliation for Transmission Congestion Charge			$ -	$ -
Grand Total	$4,234,454.99	$42,347,381.40	$ 42,347,381.40	$38,112,926.41
			$ -	$ -
PJM FTR & ARR Revenue (4470101)			$ -	$ -
1500 - Financial Transmission Rights Auction Charge			$ -	$ -
2210 - Transmission Congestion Credit (Target Credit)			$ -	$ -
2210A - Adj. to Transmission Congestion			$ -	$ -
2210A - Adj. to Transmission Congestion			$ -	$ -
2210A - Adj. to Transmission Congestion			$ -	$ -
2210A - Adj. to Transmission Congestion			$ -	$ -
2210A - Adj. to Transmission Congestion			$ -	$ -
2210A - Adj. to Transmission Congestion			$ -	$ -
2510 - Auction Revenue Rights Credit			$ -	$ -
Grand Total	$0.00	$0.00	$ -	$ -
			$ -	$ -
PJM Transmission Implicit Loss Charges (4470207)			$ -	$ -
1120A- AEP Aggregate Allocation - Losses per Transmission Group			$ -	$ -
1220 - Day-Ahead Transmission Implicit Losses Charge		$25,338,085.88	$ 25,338,085.88	$25,338,085.88
1225 - Balancing Transmission Implicit Losses Charge		($31,685.02)	$ (31,685.02)	$ (31,685.02)
1420 - Load Reconciliation for Transmission Losses Charge			$ -	$ -
Grand Total	$4,890,195.54	$25,306,400.86	$ 25,306,400.86	$20,416,205.32
			$ -	$ -
PJM Transmission Implicit Loss Credit (4470208)			$ -	$ -
2220 - Transmission Losses Credit			$ -	$ -
2220A - Adj. to Transmission Losses			$ -	$ -
2420 - Load Reconciliation for Transmission Losses Credit			$ -	$ -
Grand Total			$ -	$ -
			$ -	$ -
PJM Operating Reserve (5550123)			$ -	$ -
			$ -	$ -
1370 - Day-Ahead Operating Reserve Charge			$ -	$ -
1375 - Balancing Operating Reserve Charge		$777,607.41	$ 777,607.41	$ 777,607.41
1375A - Adj. to Balancing Operating Reserve			$ -	$ -
1375A - Adj. to Balancing Operating Reserve			$ -	$ -
1375A - Adj. to Balancing Operating Reserve			$ -	$ -
1375A - Adj. to Balancing Operating Reserve			$ -	$ -
1375A - Adj. to Balancing Operating Reserve			$ -	$ -
1375A - Adj. to Balancing Operating Reserve			$ -	$ -
1375A - Adj. to Balancing Operating Reserve			$ -	$ -
1375A - Adj. to Balancing Operating Reserve			$ -	$ -
1375A - Adj. to Balancing Operating Reserve			$ -	$ -
1375A - Adj. to Balancing Operating Reserve			$ -	$ -
1375A - Adj. to Balancing Operating Reserve			$ -	$ -
1376 - Balancing Operating Reserve for Load Response Charge			$ -	$ -
1378 - Reactive Services Charge			$ -	$ -
1471 - Load Reconciliation for Day Ahead Op Reserve			$ -	$ -
1478 - Load Reconciliation for Balancing Operating Reserve Charge			$ -	$ -
1478A - Adj. to Load Reconciliation for Balancing Operating Reserve Charge			$ -	$ -
1490 - Load Reconciliation for Reactive Services Charge			$ -	$ -
CT Lost Opportunity Credit			$ -	$ -
Grand Total	$246,307.37	$777,607.41	$ 777,607.41	$ 531,300.04
			$ -	$ -
PJM Synchronous Condensing (5550041)			$ -	$ -
1377 - Synchronous Condensing Charge			$ -	$ -
1480 - Load Reconciliation for Synchronous Condensing Charge			$ -	$ -
Grand Total			$ -	$ -
			$ -	$ -
PJM Non Synch Reserve (5550083)			$ -	$ -
1362 - Non Synchronized Reserve Charge			$ -	$ -
1472 - Load Reconciliation for Non Synch Reserve Charge			$ -	$ -
Grand Total			$ -	$ -
			$ -	$ -
PJM Reactive Supply (5550074)			$ -	$ -
1330 - Reactive Supply and Voltage Control from Generation and Other Sources Service Charge			$ -	$ -
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge			$ -	$ -
Grand Total			$ -	$ -
			$ -	$ -
PJM Blackstart (5550076)			$ -	$ -
1380 - Black Start Service Charge			$ -	$ -
1380A - Adj. to Black Start Service			$ -	$ -
1380A - Adj. to Black Start Service			$ -	$ -
1380A - Adj. to Black Start Service			$ -	$ -

Grand Total			$ -	$ -
			$ -	$ -
PJM Regulation Charges (5550078)			$ -	$ -
1340 - Regulation and Frequency Response Service Charge			$ -	$ -
1340A - Adj. to Regulation and Frequency Response Service			$ -	$ -
1460 - Load Reconciliation for Regulation and Frequency Response Service Charge			$ -	$ -
Grand Total			$ -	$ -
			$ -	$ -
PJM Spinning Reserve Charges (5550083)			$ -	$ -
1360 - Synchronized Reserve Tier 2 Charge			$ -	$ -
1360A - Adj Synchronized Reserve Tier 2 Charge			$ -	$ -
1360A - Adj Synchronized Reserve Tier 2 Charge			$ -	$ -
1470 - Load Reconciliation for Synchronized Reserve Charge			$ -	$ -
Grand Total			$ -	$ -
			$ -	$ -
PJM 30 minute Supplemental Reserve Market (DASR) (5550090)			$ -	$ -
1365 - Day-Ahead Scheduling Reserve Charge			$ -	$ -
1365A - Adj. to Day-ahead Scheduling Reserve			$ -	$ -
1365A - Adj. to Day-ahead Scheduling Reserve			$ -	$ -
1365A - Adj. to Day-ahead Scheduling Reserve			$ -	$ -
1365A - Adj. to Day-ahead Scheduling Reserve			$ -	$ -
1475 - Load Reconciliation for Day-Ahead Scheduling Reserve Charge			$ -	$ -
Grand Total			$ -	$ -
			$ -	$ -
PJM Administration Service Fees (5614001,5618001,5757001)			$ -	$ -
1301-PJM Scheduling, System Control and Dispatch Service - Control Area Administration			$ -	$ -
1302-PJM Scheduling, System Control and Dispatch Service - FTR Administration			$ -	$ -
1303-PJM Scheduling, System Control and Dispatch Service - Market Support		$209,684.05	$ 209,684.05	$ 209,684.05
1304-PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$290.86	$ 290.86	$ 290.86
1305-PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.			$ -	$ -
1306-PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center		$24,635.08	$ 24,635.08	$ 24,635.08
1307-PJM Scheduling, System Control and Dispatch Service - Market Support Offset		($29,695.12)	$ (29,695.12)	$ (29,695.12)
1308-PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration			$ -	$ -
1309-PJM Scheduling, System Control and Dispatch Service Refund - FTR Administration			$ -	$ -
1310-PJM Scheduling, System Control and Dispatch Service Refund - Market Support		($32,002.49)	$ (32,002.49)	$ (32,002.49)
1311-PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration		($54.16)	$ (54.16)	$ (54.16)
1311A-PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration			$ -	$ -
1312-PJM Scheduling, System Control and Dispatch Service Refund - Capacity Resource/Obligation Mgmt.			$ -	$ -
1313-PJM Settlement, Inc.		$29,695.12	$ 29,695.12	$ 29,695.12
1314-Market Monitoring Unit (MMU) Funding		$22,009.94	$ 22,009.94	$ 22,009.94
1314A-Adj. to Market Monitoring Unit (MMU) Funding		($5,408.64)	$ (5,408.64)	$ (5,408.64)
1314A-Adj. to Market Monitoring Unit (MMU) Funding			$ -	$ -
1315-FERC Annual Recovery			$ -	$ -
1316-Organization of PJM States, Inc. (OPSI) Funding			$ -	$ -
1317-North American Electric Reliability Corporation (NERC)			$ -	$ -
1318-Reliability First Corporation (RFC)			$ -	$ -
1440-Load Reconciliation for PJM Scheduling, System Control and Dispatch Service			$ -	$ -
1441-Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund			$ -	$ -
1442-Load Reconciliation for Schedule 9-6 - Advanced Second Control Center			$ -	$ -
1444-Load Reconciliation for Market Monitoring Unit (MMU) Funding			$ -	$ -
1445-Load Reconciliation for FERC Annual Recovery			$ -	$ -
1446-Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding			$ -	$ -
1447-Load Reconciliation for North American Electric Reliability Corporation (NERC)			$ -	$ -
1448-Load Reconciliation for Reliability First Corporation (RFC)			$ -	$ -
1304A-PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration			$ -	$ -
1306A-PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center			$ -	$ -
Grand Total	57,878.40	$219,154.64	$ 219,154.64	$ 161,276.24
			$ -	$ -
Expansion Cost Recovery Charge (4561003)			$ -	$ -
1730 - Expansion Cost Recovery Charge			$ -	$ -
Grand Total			$ -	$ -
			$ -	$ -
PJM Customer Payment Defaults (4470208)			$ -	$ -
1999A - Adj. to PJM Customer Defaults			$ -	$ -
Grand Total			$ -	$ -
			$ -	$ -
			$ -	$ -
PJM RTO Formation Cost Recovery (4561002)			$ -	$ -
1720 - RTO Start-up Cost Recovery Charge			$ -	$ -
Grand Total			$ -	$ -
			$ -	$ -
Emergency Load Response Charge (4470203)			$ -	$ -
1245 - Emergency Load Response Charge			$ -	$ -
Grand Total			$ -	$ -
			$ -	$ -
Pt-to-Pt Transm. Revenues (4561005)			$ -	$ -
STTL_ITEM_NME			$ -	$ -
2130 - Firm Point-to-Point Transmission Service Credit			$ -	$ -
2130A - Adj. to Firm Point-to-Point Transmission Service Credit			$ -	$ -
2140 - Non-Firm Point-to-Point Transmission Service Credit			$ -	$ -
2140A - Adj. to Non-Firm Point-to-Point Transmission Service			$ -	$ -
2140A - Adj. to Non-Firm Point-to-Point Transmission Service			$ -	$ -

Grand Total			$ -	$ -

PJM Invoice Detail - March 2014 Actual Cycle (Final Invoice from PJM - April 7, 2014)

PJM Billing Line Item	AEPOPD (Reg Entries)	PJM Amount of OPD	Reconciled Invoice Allocation Total	Variance
PJM Implicit Congestion (4470093)				
1120A- AEP Aggregate Allocation - Congestion per Transmission Group	($356,739.66)	($356,739.66)		
1210 - Day-Ahead Transmission Implicit Congestion Charge	$1,417,975.27	$1,417,975.27		
1215 - Balancing Transmission Implicit Congestion Charge	($1,557,687.15)	($1,557,687.15)		
1410 - Load Reconciliation for Transmission Congestion Charge	7,120,235.93	$7,120,236.04		
Grand Total	$6,623,784.39	$6,623,784.50	$6,623,784.50	$0.11
PJM FTR & ARR Revenue (4470101)				
1500 - Financial Transmission Rights Auction Charge				
2210 - Transmission Congestion Credit (Target Credit)				
2210A - Adj. to Transmission Congestion				
2210A - Adj. to Transmission Congestion				
2210A - Adj. to Transmission Congestion				
2210A - Adj. to Transmission Congestion				
2210A - Adj. to Transmission Congestion				
2210A - Adj. to Transmission Congestion				
2510 - Auction Revenue Rights Credit	(1,094,549.34)	($1,094,549.34)		
Grand Total	($1,094,549.34)	($1,094,549.34)	($1,094,549.34)	$0.00
PJM Transmission Implicit Loss Charges (4470207)				
1120A- AEP Aggregate Allocation - Losses per Transmission Group	$40,522.30	$40,522.30		
1220 - Day-Ahead Transmission Implicit Losses Charge	$182,939.01	$182,939.01		
1225 - Balancing Transmission Implicit Losses Charge	($292,064.40)	($292,064.40)		
1420 - Load Reconciliation for Transmission Losses Charge	929,952.57	$929,952.53		
Grand Total	$861,349.48	$861,349.44	$861,349.44	($0.04)
PJM Transmission Implicit Loss Credit (4470208)				
2220 - Transmission Losses Credit	($1,260,676.16)	($1,260,676.16)		
2220A - Adj. to Transmission Losses	$3.37	$3.37		
2420 - Load Reconciliation for Transmission Losses Credit	$387,553.63	$387,553.52		
Grand Total	$387,553.63	$387,553.52	$387,553.52	($0.11)
PJM Operating Reserve (4470203)				
1370 - Day-Ahead Operating Reserve Charge	113,347.90	$113,347.90		
1375 - Balancing Operating Reserve Charge	$985,017.32	$985,017.32		
1375A - Adj. to Balancing Operating Reserve	$4,670,764.00	$1.54		
1375A - Adj. to Balancing Operating Reserve		$0.85		
1375A - Adj. to Balancing Operating Reserve		$1.26		
1375A - Adj. to Balancing Operating Reserve		$0.06		
1375A - Adj. to Balancing Operating Reserve		$2.68		
1375A - Adj. to Balancing Operating Reserve		$3.18		
1375A - Adj. to Balancing Operating Reserve		$6.35		
1375A - Adj. to Balancing Operating Reserve		$0.60		
1375A - Adj. to Balancing Operating Reserve		$321.53		
1375A - Adj. to Balancing Operating Reserve		$4,657,804.87		
1375A - Adj. to Balancing Operating Reserve		$12,621.08		
1376 - Balancing Operating Reserve for Load Response Charge	($824.60)	($824.72)		
1378 - Reactive Services Charge	2,060.12	$2,060.12		
1471 - Load Reconciliation for Day Ahead Op Reserve	0.00	$0.00		
1478 - Load Reconciliation for Balancing Operating Reserve Charge	(1,168,062.95)	($1,168,062.96)		
1478A - Adj. to Load Reconciliation for Balancing Operating Reserve Charge		$0.00		
1490 - Load Reconciliation for Reactive Services Charge	(3,537.41)	($3,537.45)		
CT Lost Opportunity Credit	(70.06)	($35.03)		
Grand Total	$4,598,694.32	$4,598,729.18	$4,598,729.18	$34.86
PJM Synchronous Condensing (5550041)				
1377 - Synchronous Condensing Charge		$0.00		
1480 - Load Reconciliation for Synchronous Condensing Charge	(84.01)	($83.87)		
Grand Total	($84.01)	($83.87)	($83.87)	$0.14
PJM Non Synch Reserve (5550083)				
1362 - Non Synchronized Reserve Charge	44,941.83	$44,941.83		
1472 - Load Reconciliation for Non Synch Reserve Charge	(6,950.14)	($6,959.39)		
Grand Total	$37,991.69	$37,982.44	$37,982.44	($9.25)
PJM Reactive Supply (5550074)				
1330 - Reactive Supply and Voltage Control from Generation and Other Sources Service Charge	522,724.34	$522,724.29		
1330A - Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service Charge		$0.00		
Grand Total	$522,724.34	$522,724.29	$522,724.29	($0.05)
PJM Blackstart (5550076)				
1380 - Black Start Service Charge	398,048.31	$398,048.18		
1380A - Adj. to Black Start Service	58,451.10	$46,415.91		
1380A - Adj. to Black Start Service		$12,035.19		
1380A - Adj. to Black Start Service		$0.00		

Grand Total	456,499.41	$456,499.28	$456,499.28	($0.13)
PJM Regulation Charges (5550078)				
1340 - Regulation and Frequency Response Service Charge	935,082.47	$935,082.47		
1340A - Adj. to Regulation and Frequency Response Service	27.05	$27.05		
1460 - Load Reconciliation for Regulation and Frequency Response Service Charge	(166,371.73)	($166,371.81)		
Grand Total	768,737.79	$768,737.71	$768,737.71	($0.08)
PJM Spinning Reserve Charges (5550083)				
1360 - Synchronized Reserve Tier 2 Charge	210,332.43	$210,332.46		
1360A - Adj Synchronized Reserve Tier 2 Charge	117.18	$73.67		
1360A - Adj Synchronized Reserve Tier 2 Charge	0.00	$43.51		
1470 - Load Reconciliation for Synchronized Reserve Charge	(92,741.46)	($92,741.54)		
Grand Total	117,708.15	$117,708.10	$117,708.10	($0.05)
PJM 30 minute Supplemental Reserve Market (DASR) (5550090)				
1365 - Day-Ahead Scheduling Reserve Charge	1,117.08	$1,117.08		
1365A - Adj. to Day-ahead Scheduling Reserve	25.08	$25.08		
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	(93,898.69)	($93,898.69)		
Grand Total	(92,756.53)	($92,756.53)	($92,756.53)	$0.00
PJM Administration Service Fees (5614001,5618001,5757001)				
1301-PJM Scheduling, System Control and Dispatch Service - Control Area Administration	271,541.42	$271,541.42		
1302-PJM Scheduling, System Control and Dispatch Service - FTR Administration		$0.00		
1303-PJM Scheduling, System Control and Dispatch Service - Market Support	$60,957.86	$60,957.87		
1304-PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration	2,147.32	$2,147.32		
1305-PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.		$0.00		
1306-PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	$43,868.10	$43,868.17		
1307-PJM Scheduling, System Control and Dispatch Service - Market Support Offset	($8,655.68)	($8,655.68)		
1308-PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration	(40,602.83)	($40,602.83)		
1309-PJM Scheduling, System Control and Dispatch Service Refund - FTR Administration		$0.00		
1310-PJM Scheduling, System Control and Dispatch Service Refund - Market Support	($9,312.88)	($9,312.93)		
1311-PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration	(399.95)	($399.95)		
1311A-PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administratio	(0.01)	($0.01)		
1312-PJM Scheduling, System Control and Dispatch Service Refund - Capacity Resource/Obligation Mg	0	$0.00		
1313-PJM Settlement, Inc.	$8,655.68	$8,655.68		
1314-Market Monitoring Unit (MMU) Funding	$6,404.69	$6,404.70		
1314A-Adj. to Market Monitoring Unit (MMU) Funding	($2,080.13)	($1,122.97)		
1314A-Adj. to Market Monitoring Unit (MMU) Funding		($957.16)		
1315-FERC Annual Recovery	112,660.77	$112,660.77		
1316-Organization of PJM States, Inc. (OPSI) Funding	1,123.42	$1,123.42		
1317-North American Electric Reliability Corporation (NERC)	17,171.96	$17,171.96		
1318-Reliability First Corporation (RFC)	24,393.79	$24,393.79		
1440-Load Reconciliation for PJM Scheduling, System Control and Dispatch Service	(39,374.34)	($39,374.45)		
1441-Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund	5,911.08	$5,910.93		
1442-Load Reconciliation for Schedule 9-6 - Advanced Second Control Center	(3,958.39)	($3,958.42)		
1444-Load Reconciliation for Market Monitoring Unit (MMU) Funding	(780.89)	($780.81)		
1445-Load Reconciliation for FERC Annual Recovery	(13,385.49)	($13,385.40)		
1446-Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding	(133.61)	($133.47)		
1447-Load Reconciliation for North American Electric Reliability Corporation (NERC)	(2,040.11)	($2,040.23)		
1448-Load Reconciliation for Reliability First Corporation (RFC)	(2,898.19)	($2,898.26)		
1304A-PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration	0.06	$0.06		
1306A-PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center		$0.00		
Grand Total	431,213.65	$431,213.52	$431,213.52	($0.13)
Expansion Cost Recovery Charge (4561003)				
1730 - Expansion Cost Recovery Charge	19,415.30	$19,415.39		
Grand Total	19,415.30	$19,415.39	$19,415.39	$0.09
PJM Customer Payment Defaults (4470208)				
1999A - Adj. to PJM Customer Defaults	3,393.67	$3,393.67		
Grand Total	3,393.67	$3,393.67	$3,393.67	$0.00
PJM RTO Formation Cost Recovery (4561002)				
1720 - RTO Start-up Cost Recovery Charge	32,172.11	$32,172.00		
Grand Total	32,172.11	$32,172.00	$32,172.00	($0.11)
Emergency Load Response Charge (4470203)				
1245 - Emergency Load Response Charge	765,286.77	$765,286.63		
Grand Total	765,286.77	$765,286.63	$765,286.63	($0.14)
Pt-to-Pt Transm. Revenues (4561005)				
STTL_ITEM_NME				
2130 - Firm Point-to-Point Transmission Service Credit	(169,135.28)	($169,135.23)		
2130A - Adj. to Firm Point-to-Point Transmission Service Credit		$0.00		
2140 - Non-Firm Point-to-Point Transmission Service Credit	(38,302.27)	($38,302.31)		
2140A - Adj. to Non-Firm Point-to-Point Transmission Service	(701.24)	($701.24)		
2140A - Adj. to Non-Firm Point-to-Point Transmission Service				

Grand Total	(208,138.79)		($208,138.78)	($208,138.78)	$0.01
Grand Total of Dedicated OPD transactions through the Ohio TCRR for March Actual	$14,230,996.03		$14,231,021.15	$14,231,021.15	$25.20

Beginning in January 2014, Ohio Power's SSO load was entered into the OPD account rather than being a portion of the AEPSCG sub account.

PJM Invoice Detail - PPA and Load Reconciliation for AEPSCG March 2014 Actual Cycle (Final Invoice from PJM - April 7, 2014)

Ohio's MLR share is .42538

PJM Billing Line Item	AEPSCG (PPA Entries)		PJM Amount of AEPSCG	Ohio's MLR share	Reconciled Invoice Allocation Total	Variance
PJM Implicit Congestion (4470093)						
Congestion Adjustments	($56,377.23)		($132,533.81)	($56,377.23)		
Grand Total	($56,377.23)		($132,533.81)	($56,377.23)	($56,377.23)	($0.00)
PJM FTR & ARR Revenue (4470101)						
ARR/FTR Adjustments	($11,581.67)		($22,086.31)	($9,395.07)		
Grand Total	($11,581.67)		($22,086.31)	($9,395.07)	($9,395.07)	$2,186.60
PJM Transmission Implicit Loss Charges (4470207)						
Loss Charge Adjustments	(6,238.46)		(14,585.01)	($6,204.17)		
Grand Total	($6,238.46)		($14,585.01)	($6,204.17)	($6,204.17)	$34.29
PJM Transmission Implicit Loss Credit (4470208)						
Loss Credit Adjustments	($3,268.52)		($12,824.09)	($5,455.11)		
Grand Total	($3,268.52)		($12,824.09)	($5,455.11)	($5,455.11)	($2,186.59)
PJM Operating Reserve (4470203)						
Operating Reserve Adjustments	24,464.30		$57,512.23	$24,464.55		
Grand Total	$24,464.30		$57,512.23	$24,464.55	$24,464.55	$0.25
PJM Synchronous Condensing (5550041)						
Grand Total	$0.00		$0.00	$0.00	$0.00	$0.00
PJM Non Synch Reserve (5550083)						
Grand Total	$0.00		$0.00	$0.00	$0.00	$0.00
PJM Reactive Supply (5550074)						
Grand Total	$0.00		$0.00	$0.00	$0.00	$0.00
PJM Blackstart (5550076)						
Grand Total	$0.00		$0.00	$0.00	$0.00	$0.00
PJM Regulation Charges (5550078)						
Regulation Adjustments	1,074.75		$2,526.88	$1,074.88		
Grand Total	1,074.75		$2,526.88	$1,074.88	$1,074.88	$0.13
PJM Spinning Reserve Charges (5550083)						
Spinning Reserve Adjustments	141.69		$333.09	$150.68		
Grand Total	141.69		$333.09	$150.68	$150.68	$8.99
PJM 30 minute Supplemental Reserve Market (DASR) (5550090)						
Grand Total	$0.00		$0.00	$0.00	$0.00	$0.00
PJM Administration Service Fees (5614001,5618001,5757001)						
Admin Fee Adjustments	707.78		$1,663.86	$707.77		
Grand Total	707.78		$1,663.86	$707.77	$707.77	($0.01)
Expansion Cost Recovery Charge (4561003)						
Grand Total	$0.00		$0.00	$0.00	$0.00	$0.00
PJM Customer Payment Defaults (4470208)						
Grand Total	$0.00		$0.00	$0.00	$0.00	$0.00
PJM RTO Formation Cost Recovery (4561002)						
Grand Total	$0.00		$0.00	$0.00	$0.00	$0.00
Emergency Load Response Charge (4470203)						
Grand Total	$0.00		$0.00	$0.00	$0.00	$0.00
Pt-to-Pt Transm. Revenues (4561005)						
Grand Total	$0.00		$0.00	$0.00	$0.00	$0.00
Grand Total of Prior period adjustments from AEPSCG allocated to Ohio Power by frozen MLR through the Ohio TCRR for March Actual	($51,077.36)		($119,993.16)	**($51,033.70)**	($51,033.70)	$43.53

AEPSCG account continues to receive legacy prior period true ups from PJM for charges and credits while the AEP East Pool was in place

Ohio Power is being allocated their portion of the prior period (pre 1/1/2014) and transmission load adjustments in AEPSCG account based on the December 2013 MLR of 42.538%

PJM Invoice Detail - FTR Reconciliation for AEPSCG March 2014 Actual Cycle (Final Invoice from PJM - April 7, 2014)

PJM Billing Line Item	AEPSCG (FTR Entries)	PJM Amount of AEPSCG	FTR's Allocated to OSS	FTR's Allocated to Internal Load	Ohio's NSPL Share of Internal Load FTR's	Reconciled Invoice Allocation Total	Variance
PJM FTR & ARR Revenue (4470101)							
1500 - Financial Transmission Rights Auction Charge	1,365,526.57	3,855,193.79	48,847.94	3,806,345.85	1365526.574		
2210 - Transmission Congestion Credit (Target Credit)	(10,447,665.45)	(28,745,158.83)	377,253.40	(29,122,412.23)	-10447665.39		
2500 - Financial Transmission Rights Auction Credit	(11,079.10)	(36,581.86)	(5,699.35)	(30,882.51)	-11079.10046		
					$0.00		
Grand Total	($9,093,217.98)	($24,926,546.90)	$420,401.99	($25,346,948.89)	($9,093,217.91)	($9,093,217.91)	$0.07
Grand Total of Prior period adjustments from AEPSCG allocated to Ohio Power by frozen MLR through the Ohio TCRR for March Actual	($9,093,217.98)	($24,926,546.90)	$420,401.99	($25,346,948.89)	($9,093,217.91)	($9,093,217.91)	$0.07

AEPSCG account continues to receive all FTR Revenue for the AEP East Pool.
FTR's are allocated between LSE and OSS based on individual FTR's. For January through May 2014 FTR"s, Ohio Power is allocated their share of the AEPSCG FTR's based on the non-CRES portion of the 2013 NSPL peak
Ohio Power's share of the January through May 2014 LSE FTR's is approximately 35.875%

Appendix A
Ohio Power Company
Costs to be Reviewed in Biennial Audit

2014 TCRR Appendix A

		Net Congestion	Regulation	Spinning Reserves
A	**What drives this cost?**	Congestion costs are driven by the difference in Locational Marginal Price (LMP) values between generating sources and load. This difference occurs in hours when congestion exists on the transmission system.	This cost is driven by the Companies' load on the PJM system. The Load Serving Entity (LSE) must secure an amount of regulation service based a percentage of its daily forecasted peak load and on the lowest hourly load in the off-peak hours. The price of regulation, the Regulation Market Clearing Price (RMCP), is influenced by the cost of the "marginal" units in PJM, based upon the most economic means to supply regulation within the PJM footprint.	The LSEs must secure an amount based on a percentage of their daily peak load in the form of spinning reserves service. The Synchronized Reserve Market Clearing Price (SRMCP) is driven by the need for PJM to compensate resources (not necessarily AEP) for synchronized reserves and the manner in which PJM selects the most economic means of supplying synchronized reserves from the resources within the PJM footprint.
B	**Describe the PJM process or markets with which this cost is associated.**	Congestion costs in PJM are a means of applying a financial cost to physical power flow on constrained transmission lines. If there is no congestion on any transmission line in PJM, the LMP would be the same across the entire footprint (not taking marginal losses into account). However, when transmission lines become constrained, LMPs vary across the entire region. Congestion costs are derived by calculating the difference in the LMP value between the generating source and the load. Transmission congestion can be affected by many things, including changes in load or unplanned generation and transmission outages. PJM developed the concept of Financial Transmission Rights (FTRs) to help transmission customers offset the incremental costs associated with congestion. As of June 2007, AEP is annually allocated Auction Revenue Rights (ARRs) which can be converted into FTRs through the annual FTR auction process.	Generating units submit daily bids to PJM for their regulation service. PJM clears the regulation market hourly in real time.	There are 2 cost tiers associated with spinning reserves. Tier 1 reserves are uneconomic MWs on baseload units which are not being used to provide energy during the hour. PJM does not pay any market clearing charges for these Tier 1 reserves unless there is a spinning event. If there is not enough Tier 1 available to provide adequate spinning reserves, PJM clears additional Tier 2 reserves based upon the bids submitted by the owners of generating units (primarily CTs and CCs). When a spinning event occurs (such as a unit trip) PJM will pay both Tier 1 and Tier 2 spinning reserves.
C	**Describe the control the companies have over this cost.**	Congestion costs are driven by the difference in LMP values. PJM uses the bids submitted from each generating unit to dispatch the entire footprint using a security constrained least cost dispatch. AEP is allocated Auction Revenue Rights (ARRs) that are equivalent to the AEP load that occurs at the time of the PJM peak. AEP typically elects to convert the ARRs to FTRs to hedge congestion costs for the planning year. If the LMP at the point of origin (generator, source) is higher than the point of destination (load, sink), the FTR may actually have a negative value, resulting in the FTR holder paying congestion costs to PJM. PJM collects the congestion charges from the Market Participants, then PJM distributes these funds to the FTR holders.	Each LSE is required to bid its generation for regulation service at cost-based rates subjected to the FERC-approved guidelines in PJM Manual 15: Cost Development Guidelines. Each LSE has an obligation to provide Regulation, the cost of which is ultimately determined by the manner in which PJM dispatches all available units to economically meet load requirements and the units available to most economically provide ancillary services.	Generally, PJM has sufficient tier 1 spinning reserves and does not have to clear additional spinning reserves from the Tier 2 market. This allows for the LSE not to have to purchase a significant amount of Tier 2 spinning reserves.
D	**What options do the companies have in incurring this cost -- for example, for Regulation Services the companies have options on how they can fulfill their obligations, such as Self-scheduling, Bilateral, and/or purchasing from the Regulation Market.**	The Company has no options to incurring congestion cost. The use of LMP to manage transmission constraints is an integral part of the PJM market design. See part B and C above. AEP manages congestion cost through ongoing analysis of congestion and prudent use of ARRs/FTRs that are allocated to LSE congestion. In addition, accurate forecasting of LSE load and emphasis on obtaining day-ahead (DA) PJM market awards for offered generation shields AEP from congestion fluctuations in the real-time market.	The AEP Companies bid in an amount for regulation from the Companies' units at least equal to the amount that the LSE must purchase. In that way, the LSE is assured of getting a regulation cost provided at the lower of either AEP's generation or the market. The AEP Companies can fulfill their regulation obligation through self-supply, bi-lateral purchases, and/or purchasing from the Regulation Market as cleared by PJM.	The AEP Companies can fulfill their spinning obligation through self-supply, bi-lateral purchases, and/or purchasing from the Spinning Market as cleared by PJM.
E	**What options have the companies pursued and why?**	The Companies continue to maximize the utilization of FTRs to offset congestion cost exposure for native load customers. For example, if the ARR holder believes that the auction price for the associated FTR is higher than the expected value of the actual FTR when congestion is cleared by the PJM market, the holder may sell the FTR in the auction and lock in the revenues over the next twelve months. The holder of the ARR also has the option to directly convert the ARRs into FTRs and use them in the manner described above. The two methods for managing congestion (FTRs and ARRs) will produce similar results, if the holder of the ARR does not sell the entitlement. AEP's strategy is to convert ARRs to FTRs. Hourly, FTR revenues associated with native load are allocated to offset congestion charges to assure that native load congestion costs are covered (to the extent that FTR revenues exist). Additionally, AEP monitors PJM's load forecast in order to manage load forecast error in the most effective manner.	AEP continually analyzes various products (listed in D above) in the marketplace to ensure its customers benefit by receiving the lower cost of AEP or third-party supply. All units within AEP generation capable of supplying regulation, such as gas units and combined cycle units have been tested and certified with PJM for eligibility within the PJM regulation market.	AEP continually analyzes various products (listed in D above) in the marketplace to ensure its customers benefit by receiving the lower cost of AEP or third-party supply.

Appendix A
Ohio Power Company
Costs to be Reviewed in Biennial Audit

2014 TCRR Appendix A

		Net Congestion	Regulation	Spinning Reserves
F	**Have the companies evaluated the potential impacts of pursuing the other options? If so, provide the expected impacts of pursuing each of those options.**	The Companies continually evaluate their FTR position. Monthly auctions are available for minor purchases or sales throughout the year. However significant adjustments can be made only once a year in the annual auction. Going forward, AEP will maintain the current strategy of converting ARRs to FTRs to fully hedge congestion costs from the AEP generating units to AEP load.	See part E above.	See part E above.
G	**If the companies have not evaluated the other options, please do so and provide the expected impacts of these options.**	See part D above.	See part E above.	See part E above.
H	**Please provide graphically, the monthly cost since AEP began operating in PJM.**	See Schedule B-4	See Schedule B-4	See Schedule B-4
I	**Provide graphically the monthly revenue amounts since AEP began operating in PJM.**	See Schedule B-4	See Schedule B-4	See Schedule B-4
J	**If these costs/revenues (discussed in (h) and (i)) show a decreasing or increasing trend please explain such trend.**	Net Congestion charges have been trending upwards over the last two years due to hotter than normal summer months and FTR revenue deficiencies in the PJM market which have led to the Company not receiving the full value of its FTR positions in PJM. In 1Q14 the PJM system experienced extreme weather conditions and all time high peaks which impacted ancillary services which constrained the system and PJM rates, especially Net Congestion, Regulation, Operating Reserves and Spinning Reserves. FTR pricing was also impacted by the high PJM congestion prices.	AEP would expect regulation costs to rise in the summertime, with the increase in loads and costs. Generally in the summer months, PJM has more of a need to call on more units to provide Automatic Regulation (AR). Regulation charges have been relatively flat over the last two years showing a slight decline over that period. This would be due mainly to lower LMPs in the PJM market. In 1Q14 the PJM system experienced extreme weather conditions and all time high peaks which impacted ancillary services which constrained the system and PJM rates, especially Net Congestion, Regulation, Operating Reserves and Spinning Reserves.	Spinning Reserve charges have been relatively flat over the last two years showing a slight decline over that period. This would be due mainly to lower LMPs in the PJM market. In 1Q14 the PJM system experienced extreme weather conditions and all time high peaks which impacted ancillary services which constrained the system and PJM rates, especially Net Congestion, Regulation, Operating Reserves and Spinning Reserves.
K	**If there are spikes in the trend please explain.**	See part J above.	See part J above.	See part J above.
L	**Provide any internal documents or written policy used to ensure the cost is being minimized.**	See Attachment L&M for a description of actions taken to assist in minimizing costs.	See Attachment L&M for a description of actions taken to assist in minimizing costs.	See Attachment L&M for a description of actions taken to assist in minimizing costs.
M	**Provide the departments/divisions/units/etc. that are involved with managing the cost and what their responsibilities are with regard to ensuring that the costs are minimized.**	Commercial Operations is primarily responsible for strategy development in hedging congestion risk. See Attachment L&M for a description of responsibilities.	Commercial Operations is primarily responsible for monitoring this cost for the appropriate strategy and is responsible for the day-to-day bidding. See Attachment L&M for a description of responsibilities.	Commercial Operations is primarily responsible for monitoring this cost for the appropriate strategy and is responsible for the day-to-day bidding. See Attachment L&M for a description of responsibilities.

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		Net Congestion	Regulation	Spinning Reserves
N	**Provide any additional information that would enhance Staff's investigation.**	On December 31, 2013, based on FERC and PUCO orders, OPCo transferred generation assets to another AEP affiliate. Also at this time, the AEP East Operating Agreement, of which OPCo was a party to, was terminated. In accordance with the PUCO's corporate separation order, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. The Ohio load is entered into PJM on an individual basis	On December 31, 2013, based on FERC and PUCO orders, OPCo transferred generation assets to another AEP affiliate. Also at this time, the AEP East Operating Agreement, of which OPCo was a party to, was terminated. In accordance with the PUCO's corporate separation order, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. The Ohio load is entered into PJM on an individual basis	On December 31, 2013, based on FERC and PUCO orders, OPCo transferred generation assets to another AEP affiliate. Also at this time, the AEP East Operating Agreement, of which OPCo was a party to, was terminated. In accordance with the PUCO's corporate separation order, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. The Ohio load is entered into PJM on an individual basis

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		Operating Reserves	Administrative Costs
A	**What drives this cost?**	Operating Reserve charges in PJM provide for make-whole payments to certain generators called on by PJM after the normal bidding procedure is closed. These make-whole payments occur for operation of units needed even though they are not part of the economic dispatch. For example, after the daily bids are cleared at 1600 Eastern Prevailing Time, PJM may determine that additional generation should be brought on line for the next day for reliability purposes due to changes in weather, generation, or transmission facilities. PJM will call on these units and pay them for their start-up costs as well as their operating costs throughout the time they are kept running. The costs incurred for these expenses are called Operating Reserves. According to the PJM Operating Agreement, generation which is scheduled by PJM under these conditions is guaranteed to be made whole for the day based on their costs.	The cost drivers are PJM costs to administer regional markets and provide control area services. Under the PJM Administrative Cost settlement agreement, various components of the Administrative Costs are defined going forward. Additionally, the Administrative Fees include FERC and NERC fees wherein the cost per MWh are prescribed each year by the FERC.
B	**Describe in detail the PJM process or markets with which this cost is associated.**	The day-ahead operating reserves charges are allocated to LSEs in PJM proportionately by MW based on the cleared day-ahead demand bids plus exports. The real-time, also called "balancing", operating reserves charges are allocated to the LSEs and Generators proportionately by MW based on deviations from day-ahead scheduled quantities, including load variances and by real time load ratio share.	As a Transmission Provider, PJM assesses each of its market participants monthly administration fees to recover PJM operating costs. These fees are filed with the Federal Energy Regulatory Commission (FERC). The seven components of these administration fees are: Control Area Administration Service, Financial Transmission Rights (FTR) Administration Service, Market Support Service, Regulation and Frequency Response Administration Service and Capacity Resource and Obligation Management Service, Market Monitoring Unit, the Advanced Second Control Center and PJM Settlement Inc. PJM also charges FERC, NERC, OPSI and RFC Annual Charge Recovery fees to recover its annual assessment of fees.
C	**Describe the control the companies have over this cost.**	According to the PJM Operating Agreement, the owner of generation which is scheduled by PJM under these conditions is guaranteed to be made whole for the day based on the owner's bids in the market. Since all day ahead and some balancing operating reserve charges are allocated by PJM based on load ratio share, the Company has little control over this cost.	PJM Administrative Fees are established by the FERC and participants do not have the option to avoid paying these fees. The companies retain the right to audit, to participate in the committee and working group processes (AEP is very active in the Finance and Audit Committees), and to seek remedies through the FERC.
D	**What options do the companies have in incurring this cost -- for example, for Regulation Services the companies have options on how they can fulfill their obligations, such as Self-scheduling, Bilateral, and/or purchasing from the Regulation Market.**	For the portion of balancing operating reserve charges that are allocated by PJM based upon real time deviations from day ahead scheduled amounts, the Company attempts to minimize cost risk through accurate communication with PJM regarding unit status, constant attention to unit dispatch and PJM basepoint signals, and prudent management of unplanned operational events minimizes real time deviations and balancing operating reserve charges to the extent possible.	As a member of PJM, AEP does not have the option to avoid PJM Administrative Costs. These costs are not for the actual services, such as regulation service. They are the costs incurred by PJM to administer the systems and processes used for coordinating and tracking control area and market services such as regulation service. The Company is obligated to pay the PJM Administrative Costs based on the billing determinants (e.g., MWhs).
E	**What options have the companies pursued and why?**	AEP continually looks for ways to improve its performance in the PJM market. Emphasis on obtaining day-ahead (DA) PJM market awards for offered generation, as well as accurate load forecasting, shields AEP from fluctuations in the real-time market. AEP continues to work within the PJM stakeholder process for ongoing improvements in prudent and fair allocation of these charges.	AEP is very active in the PJM Finance Committee and reviews the PJM annual budget when it is proposed each year.

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		Operating Reserves	Administrative Costs
F	**Have the companies evaluated the potential impacts of pursuing the other options? If so, provide the expected impacts of pursuing each of those options.**	See part E above.	N/A
G	**If the companies have not evaluated the other options, please do so and provide the expected impacts of these options.**	See part D above.	N/A
H	**Please provide graphically, the monthly cost since AEP began operating in PJM.**	See Schedule B-4	See Schedule B-4
I	**Provide graphically the monthly revenue amounts since AEP began operating in PJM.**	See Schedule B-4	See Schedule B-4
J	**If these costs/revenues (discussed in (h) and (i)) show a decreasing or increasing trend please explain such trend.**	Operating reserve charges will fluctuate with LMPs in the PJM market since units being brought on by PJM for operating reserves are more costly than the "marginal unit" in that hour. In 1Q14 the PJM system experienced extreme weather conditions and all time high peaks which impacted ancillary services which constrained the system and PJM rates, especially Net Congestion, Regulation, Operating Reserves and Spinning Reserves.	No significant change.
K	**If there are spikes in the trend please explain.**	See part J above.	See part J above.
L	**Provide any internal documents or written policy used to ensure the cost is being minimized.**	See Attachment L&M for a description of actions taken to assist in minimizing costs.	See Attachment L&M for a description of actions taken to assist in minimizing costs.
M	**Provide the departments/divisions/units/etc. that are involved with managing the cost and what their responsibilities are with regard to ensuring that the costs are minimized.**	Commercial Operations is primarily responsible for monitoring this cost for the appropriate strategy and is responsible for the day-to-day bidding. See Attachment L&M for a description of responsibilities.	Regulatory Services (RTO and Public Policy) is primarily responsible for monitoring and managing these costs as a member of the PJM Finance Committee as well as the Members Committee. See Attachment L&M also.

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		Operating Reserves	Administrative Costs
N	**Provide any additional information that would enhance Staff's investigation.**	On December 31, 2013, based on FERC and PUCO orders, OPCo transferred generation assets to another AEP affiliate. Also at this time, the AEP East Operating Agreement, of which OPCo was a party to, was terminated. In accordance with the PUCO's corporate separation order, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. The Ohio load is entered into PJM on an individual basis	On December 31, 2013, based on FERC and PUCO orders, OPCo transferred generation assets to another AEP affiliate. Also at this time, the AEP East Operating Agreement, of which OPCo was a party to, was terminated. In accordance with the PUCO's corporate separation order, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. The Ohio load is entered into PJM on an individual basis

American Electric Power Service Corporation
Regulated Commercial Operations

The Commercial Operations group continually strives to minimize the costs associated with operating within PJM. For example, there is a daily morning meeting involving Fuels, Generation and Commercial Operations personnel and others who may have input in the daily and longer-term operations. During this meeting, operational issues are discussed that affect both the real-time, day-ahead and longer-term resource commitment. Topics such as unit outages, weather, load forecasts, transmission outages as well as known or anticipated transmission congestion associated with the dispatch of the generating fleet are discussed.

There is continual interaction among individuals from the morning meeting throughout the day to effectively optimize AEP's system while taking into account fuel markets, operational constraints, environmental constraints, market conditions, system conditions, and regulatory requirements in conjunction with PJM's dispatch signals. With communication being vital to staying informed on all the aspects that may affect the market, information is continually exchanged among all the parties listed above, plus other individuals who may obtain and provide information useful to making economic decisions. For example, throughout the day, various departments within Commercial Operations provide analysis of the market conditions, transmission congestion and potential revised bid and offer strategies. Commercial Operations further refines the intra-day and day-ahead plans after PJM market awards are released based on this analysis. The entire Commercial Operations group works as a team with American Electric Power Service Corporation (AEPSC) Fuels, Generation operations and plant engineering and is responsible for the daily planning and execution necessary to ensure that the proper mix of the AEP system generation fleet and market purchases are utilized for the benefit of the customers on the AEP system. In addition, Commercial Operations continually monitors and reviews PJM market settlement data to ensure billing accuracy from PJM.

By prudently managing the day-ahead and real-time PJM markets, as well as the settlement (reconciliation of the PJM monthly billing of demand bids and generation offers) of those markets, Commercial Operations continually acts to minimize costs of operating in PJM. Within Commercial Operations, groups responsible for prudent coordination of generation relative to the PJM energy market include: RTO Market Operations, Commercial and Financial Analysis, and Energy Trading and Marketing.

RTO Market Operations

The Market Operations group encompasses Real-Time Market Operations (i.e. Generation Dispatch) and Financial and Operational Performance (Production Optimization, Bid Development, Load Forecasting, Financial Performance), as well as Congestion Analysis and RTO Operations. *Generation Dispatch* is responsible for compliance with all North American Electric Reliability Corporation (NERC) policies, such as maintaining Control Area stability and minimizing control imbalances. They are responsible for coordination, with PJM, of the real-time production of energy and ancillary services, to follow PJM basepoint signals, to communicate all real-time changes in AEP generation fleet capabilities with PJM, and for maintaining an accurate flow of information to settlements regarding the production of energy. On an hourly basis, Generation Dispatch coordinates with energy trading to ensure that the impact of unit outages and curtailments are minimized, and that unexpected market events are optimized. Generation Dispatch is expected to have a seamless relationship with the hourly trading desk and others within Commercial Operations to manage the assets of the AEP regulated generation fleet in order to provide maximum reliability of the system's electrical power grid while also achieving the most economical unit operation and dispatch within PJM.

Production Coordination possesses in-depth technical knowledge and experience in power plant operation and is capable of assessing the risk potential of those operations on plant reliability and capability, and imparting this insight to others within Commercial Operations. This group is in constant communication with the generating fleet regarding critical operational issues and works closely with Bid Development and trading in order to optimize unit commitment, de-commitment, and economic dispatch to strategically optimize generation assets within PJM, from immediate decisions to those a month or more away. Both Generation Dispatch and Production Optimization are well aware of position and energy prices, and how the production of energy and ancillary services affect those positions. Production Coordination and Generation Dispatch both provide the critical link to immediately communicate significant issues such as an imminent unit trip to PJM and others.

The *Bid Development* group is the key interface to PJM when providing the day-ahead generation offer of AEP generating assets to PJM, as well as the day-ahead demand bid. Using information provided by Trading, Production Coordination, weather forecasters, load forecasters, and other market information, they formulate a daily bid strategy based on company position, generating capacity, load obligations and trading transactions.

Load Forecasting provides daily the forecast for AEP regulated and individual operating company load for the next 7 days, using statistical models. This group also measures accuracy of load & weather forecasts used in analysis, and provides key insights to Commercial Operations.

RTO Bid and Offer Development develops daily and monthly the fuel and other costs of the generation units, in compliance with PJM cost development guidelines. The group provides daily reporting of the PJM market results as well as key oversight to generation costs and other data significant to the PJM process.

Congestion Analysis provides guidance relative to expected transmission congestion and constantly monitors the status of key transmission constraints affecting energy flow within PJM by simulating generation, PJM load forecast, and expected transmission constraints.

RTO Operations interfaces with PJM in the stakeholder process and ensures that PJM rules and responsibilities are communicated to Commercial Operations and others, and that the impact of these rules are understood and communicated.

Commercial and Financial Analysis

Within Commercial and Financial Analysis, the *Settlements* group processes the PJM monthly bill and provides oversight to costs. The Settlements group ensures that PJM charges are properly allocated to the general ledger.

Energy Trading and Marketing

Energy Trading and Marketing has a key responsibility for optimizing AEP's daily physical position, which is the aggregate balance of load obligation, generating capacity, and trading positions. Within the trading group, Hourly Trading is responsible for managing AEP's intraday financial exposure to the Real Time Location Marginal Price (LMP), in close coordination with Generation Dispatch, Production Coordination and others within Commercial Operations. The Hourly Trading desk is also a key resource for Generation Dispatch and others in making hour-to-hour decisions regarding generating unit liabilities and opportunities. Hourly trading is a 24-hour-a-day responsibility, involving constant evaluation of short-term positions and pricing as conditions change throughout the day to compliment the core business of delivering reliable energy through the PJM RTO. Traders work with market operations to optimize asset and load positions throughout the month and constantly evaluate broker bid/ask spreads and set a price curve relative to current market conditions. These price curves are based on market-based insights from each trader and are used in making economic decisions, both financial and physical, within the PJM footprint.

This summary is not all-inclusive, and others within the above groups, in Commercial Operations, and elsewhere in the Company, provide support and analysis, all with the goal of providing accurate information and decision-making that results in minimizing overall cost within the PJM market.

In addition, AEP continually analyzes available information from the PJM RTO, such as daily market data, monthly billing information, and the yearly State of the Market report, and fully participates in the stakeholder process with PJM. The PJM Open access Transmission Tariff and the PJM Operating Agreement detail, among many other things, the rules and operational responsibilities that AEP is required to follow as a generation-and transmission-owning member of PJM. AEP's compliance with the PJM agreements is enforced through a variety of internal mechanisms. These internal checks and balances built into the systems and processes of the Market Operations group and the external checks and balances arising from the PJM Tariff and the PJM Operating Agreement provide multiple ways to ensure that AEP is operating its generating fleet appropriately. In addition, the PJM market monitor's activities function as another layer of oversight.