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BEFORE THE
PUBLIC UTILITIES COMMSSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Update Each Company's Transmission Cost Recovery Rider	)))))	**Case No. 10-477-EL-RDR**

APPLICATION

Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO), collectively the Companies, submit this application to update each company's Transmission Cost Recovery Rider (TCRR). In support of their application, CSP and OPCO state the following:

1. Both Companies are electric utilities as that term is defined in §4928.01 (A) (11), Ohio Rev. Code.

2. The Companies are electric utility operating company subsidiaries 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 Companies' application in that docket to combine the transmission component of each Company's Standard Service Tariff with its TCRR.

4. As part of the Commission's approval of that application the Companies are to file an annual update to their TCRR. The Companies indicated that the updates would be filed in November of each year. The update would incorporate any over- or under- recovery deferral balance as of September

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30th of that year into the surcharge for the next calendar year. In addition to the 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. The Companies' most recent TCRR proceeding was in Case No. 09-339-EL-UNC. In that proceeding the Companies' current TCRR rates became effective at the beginning of the July 2009 billing month (June 29, 2009).

6. 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 Companies' TCRR. (§4901:1-36-02 (A)), Ohio Admin. Code.

7. 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.

8. On April 15, 2009, the Commission issued an Entry in Case 08-777-EL-ORD directing the Companies to submit by April 16th of each year their

annual update to their current TCRR rates. The Entry, however, contemplates the new TCRR rates to be effective July 1st of each year.

9. In accordance with the Commission's directive, 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, OPCO's proposed TCRR revenues for the 12-month period beginning with the July 2010 billing month are $16,434,601 lower than the TCRR revenues for that period would be under the current TCRR rates. This represents an average decrease in the TCRR of approximately 8.75%. The decrease reflects $12,735,720 of over-recovery, which itself reflects carrying charges.[1]

11. As reflected in Schedules B-1 and B-2, CSP's proposed TCRR revenues for the 12-month period beginning with the July 2010 billing month are $14,849,303 lower than the TCRR revenues for that period would be under the current TCRR rates. This represents an average decrease in the TCRR of approximately 9.24%. The decrease reflects $13,104,205 of over-recovery, which itself reflects carrying charges.[1]

12. The carrying charges identified in the two prior paragraphs 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. 09-339-EL-UNC.

13. In FERC Docket No. ER08-1328-000, American Electric Power Service Corporation, on behalf of the Companies (and other AEP East operating companies) filed an application to increase their Open Access Transmission Tariff (OATT). The Companies' TCRR filing reflects that current OATT rate. A settlement agreement in that case has been filed with the FERC. Assuming the FERC approves the settlement, any

[1] The slight difference between the Forecast Transmission Cost Net of True-Up on Schedule B-1 and the forecast for TCRR revenues assuming the proposed TCRR on Schedule B-2 is attributable to rounding.

difference between the current OATT rate and the new FERC-approved rate will be reflected in the over-/under-recovery balance in the next-subsequent TCRR filing.

14. The Companies' proposed TCRR, as reflected in Schedule A-1, and supported by Schedule B-1, B-2 and C-3 and their related work papers, are reasonable and should be approved.

15. The Companies request that their proposed updated TCRR rates be made effective on a bills rendered basis beginning on June 29, 2010 – the first day of the July 2010 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 09-339-EL-UNC.

Finally, pursuant to §4901:1-36-06, Ohio Admin. Code, this filing represents the biennial filing in which the Companies provide additional information detailing their policies and procedures for minimizing any costs in their TCRR over which they have control. Information relevant to this requirement which, in addition to that which already is in the required schedules set out in Paragraph 9 above, is included in Appendix A and Attachment L and M.

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

Respectfully submitted,

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P.U.C.O. NO. 19

TRANSMISSION COST RECOVERY RIDER

Effective Cycle 1 July 2010, 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, RS-ES, RS-TOD and RDMS	0.84863	
GS-1	0.69428	
GS-2 Secondary	0.21861	0.93
GS-2 Recreational Lighting, GS-TOD and GS-2-ES	0.59723	
GS-2 Primary	0.21077	0.90
GS-2 Subtransmission and Transmission	0.20570	0.88
GS-3 Secondary	0.19306	1.93
GS-3-ES	0.60546	
GS-3 Primary	0.18614	1.86
GS-3 Subtransmission and Transmission	0.18166	1.82
IRP-D Secondary	0.19227	2.28
GS-4 Primary, IRP-D Primary	0.18538	2.20
GS-4 Subtransmission and Transmission, IRP-D Subtransmission and Transmission	0.18092	2.15
EHG	1.04662	
EHS	0.65074	
SS	0.65074	
OL	0.25326	
SL	0.25326	

Schedule SBS	¢/KWH	$/KW					
		5%	10%	15%	20%	25%	30%
Backup - Secondary	0.19789	0.31	0.61	0.92	1.23	1.53	1.84
- Primary	0.19080	0.30	0.59	0.89	1.18	1.48	1.77
-Subtrans/Trans	0.18620	0.29	0.58	0.87	1.15	1.44	1.73
Backup < 100 KW Secondary		0.52					
Maintenance - Secondary	0.34602						
- Primary	0.33362						
- Subtrans/Trans	0.32558						

Filed pursuant to Orders dated________, 2010 in Case No. 10-XXXX-EL-UNC

Issued: June XX, 2010

Effective: Cycle 1 July 2010

Issued by
Joseph Hamrock, President
AEP Ohio

P.U.C.O. NO. 7

TRANSMISSION COST RECOVERY RIDER

Effective Cycle 1 July 2010, 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, KVA and/or KWH as follows:

Schedule	¢/KWH	$/KW or $/KVA
R-R, R-R-1, RLM, RS-ES, RS-TOD	0.81370	
GS-1	0.67810	
GS-2 Secondary	0.27515	1.094
GS-2-TOD and GS-2-LMTOD	0.72950	
GS-2 Primary	0.26619	1.058
GS-3 Secondary	0.20862	1.605
GS-3-LMTOD	0.57856	
GS-3 Primary	0.20182	1.553
GS-4, IRP-D Subtransmission and Transmission	0.16923	2.807
IRP-D Secondary	0.17833	2.958
IRP-D Primary	0.17252	2.862
SL	0.20578	
AL	0.20578	

Schedule SBS	¢/KWH	$/KW					
		5%	10%	15%	20%	25%	30%
Backup - Secondary	0.20918	0.140	0.280	0.420	0.560	0.700	0.840
- Primary	0.20237	0.135	0.271	0.406	0.542	0.677	0.813
-Subtrans/Trans	0.19851	0.133	0.266	0.399	0.531	0.664	0.797
Backup < 100 KW Secondary		0.420					
Maintenance - Secondary	0.27682						
- Primary	0.26780						
- Subtrans/Trans	0.26270						
GS-2 and GS-3 Breakdown Service		0.420					

P.U.C.O. NO. 19

TRANSMISSION COST RECOVERY RIDER

Effective Cycle 1 July ~~2009~~2010, 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, RS-ES, RS-TOD and RDMS	~~0.88128~~0.84863	
GS-1	~~0.70991~~0.69428	
GS-2 Secondary	~~0.34286~~0.21861	~~1.13~~0.93
GS-2 Recreational Lighting, GS-TOD and GS-2-ES	~~0.79208~~0.59723	
GS-2 Primary	~~0.33057~~0.21077	~~1.09~~0.90
GS-2 Subtransmission and Transmission	~~0.32261~~0.20570	~~1.06~~0.88
GS-3 Secondary	~~0.28372~~0.19306	~~2.00~~1.93
GS-3-ES	~~0.70330~~0.60546	
GS-3 Primary	~~0.27355~~0.18614	~~1.93~~1.86
GS-3 Subtransmission and Transmission	~~0.26697~~0.18166	~~1.88~~1.82
IRP-D Secondary	~~0.26039~~0.19227	~~1.83~~2.28
GS-4 Primary, IRP-D Primary	~~0.25105~~0.18538	~~1.76~~2.20
GS-4 Subtransmission and Transmission, IRP-D Subtransmission and Transmission	~~0.24501~~0.18092	~~1.72~~2.15
EHG	~~1.07606~~1.04662	
EHS	~~0.97905~~0.65074	
SS	~~0.97905~~0.65074	
OL	~~0.42501~~0.25326	
SL	~~0.42501~~0.25326	

Schedule SBS	¢/KWH	$/KW					
		5%	10%	15%	20%	25%	30%
Backup - Secondary	~~0.28326~~0.19789	~~0.28~~0.31	~~0.56~~0.61	~~0.85~~0.92	~~1.13~~1.23	~~1.41~~1.53	~~1.69~~1.84
- Primary	~~0.27310~~0.19080	~~0.27~~0.30	~~0.54~~0.59	~~0.82~~0.89	~~1.09~~1.18	~~1.36~~1.48	~~1.63~~1.77
-Subtrans/Trans	~~0.26653~~0.18620	~~0.27~~0.29	~~0.53~~0.58	~~0.80~~0.87	~~1.06~~1.15	~~1.33~~1.44	~~1.59~~1.73
Backup < 100 KW Secondary		~~0.38~~0.52					
Maintenance - Secondary	~~0.41961~~0.34602						
- Primary	~~0.40456~~0.33362						
- Subtrans/Trans	~~0.39482~~0.32558						

P.U.C.O. NO. 7

TRANSMISSION COST RECOVERY RIDER

Effective Cycle 1 July ~~2009~~2010, 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, KVA and/or KWH as follows:

Schedule	¢/KWH	$/KW or $/KVA
R-R, R-R-1, RLM, RS-ES, RS-TOD	~~0.86702~~0.81370	
GS-1	~~0.83784~~0.67810	
GS-2 Secondary	~~0.46741~~0.27515	~~1.089~~1.094
GS-2-TOD and GS-2-LMTOD	~~0.89556~~0.72950	
GS-2 Primary	~~0.45218~~0.26619	~~1.054~~1.058
GS-3 Secondary	~~0.31836~~0.20862	~~1.684~~1.605
GS-3-LMTOD	~~0.70042~~0.57856	
GS-3 Primary	~~0.30799~~0.20182	~~1.629~~1.553
GS-4, IRP-D Subtransmission and Transmission	~~0.21883~~0.16923	~~2.182~~2.807
IRP-D Secondary	~~0.23060~~0.17833	~~2.299~~2.958
IRP-D Primary	~~0.22309~~0.17252	~~2.224~~2.862
SL	~~0.31603~~0.20578	
AL	~~0.31603~~0.20578	

Schedule SBS	¢/KWH	$/KW					
		5%	10%	15%	20%	25%	30%
Backup - Secondary	~~0.30710~~0.20918	~~0.127~~0.140	~~0.254~~0.280	~~0.381~~0.420	~~0.509~~0.560	~~0.636~~0.700	~~0.763~~0.840
- Primary	~~0.29710~~0.20237	~~0.123~~0.135	~~0.246~~0.271	~~0.369~~0.406	~~0.492~~0.542	~~0.615~~0.677	~~0.736~~0.813
-Subtrans/Trans	~~0.29143~~0.19851	~~0.121~~0.133	~~0.241~~0.266	~~0.362~~0.399	~~0.483~~0.531	~~0.603~~0.664	~~0.724~~0.797
Backup < 100 KW Secondary		~~0.381~~0.420					
Maintenance - Secondary	~~0.36851~~0.27682						
- Primary	~~0.35651~~0.26780						
- Subtrans/Trans	~~0.34971~~0.26270						
GS-2 and GS-3 Breakdown Service		~~0.381~~0.420					

Filed pursuant to Orders dated __________, 2010 in Case No. 10-XXXX-EL-UNC

Issued: June XX, 2010

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Issued by
Joseph Hamrock, President
AEP Ohio

Summary of Total Projected Transmission Costs / Revenues

Ohio Power Company

		July 2010 - June 2011 TCRR	
NITS	$	120,314,326	D
Transmission Enhancement Charges	$	11,908,224	D
Scheduling	$	1,710,672	E
Point to Point Revenues	$	(3,107,364)	D
Regulation Service	$	11,173,537	E
Spinning Reserves	$	324,756	E
Supplemental Reserves - Charges	$	77,003	E
Net Congestion	$	-	E
Operating Reserves - Charges	$	8,774,563	E
Load Response Program Subsidies	$	-	E
Net Ancillary Services - Synchronous Condensing	$	21,617	E
- Reactive Supply - Charges	$	7,386,487	E
- Blackstart - Charges	$	168,841	E
PJM Administration Fees	$	7,991,190	E
Net RTO Formation Costs & Expansion Cost Recovery Charge	$	1,047,936	E
Net Marginal Losses	$	16,233,738	O
Total Transmission Costs	$	184,025,526	
Prior Year under/(over) collection	$	(12,735,720)	O
	$	171,289,806	

D = Demand, E = Energy, O = Other

Summary of Total Projected Transmission Costs / Revenues

Columbus Southern Power Company

		July 2010 - June 2011 TCRR	
NITS	$	104,198,054	D
Transmission Enhancement Charges	$	10,445,260	D
Scheduling	$	1,539,673	E
Point to Point Revenues	$	(2,786,727)	D
Regulation Service	$	9,643,215	E
Spinning Reserves	$	280,709	E
Supplemental Reserves - Charges	$	66,343	E
Net Congestion	$	-	E
Operating Reserves - Charges	$	7,580,380	E
Load Response Program Subsidies	$	-	E
Net Ancillary Services - Synchronous Condensing	$	18,636	E
- Reactive Supply - Charges	$	6,385,504	E
- Blackstart - Charges	$	145,962	E
PJM Administration Fees	$	6,946,867	E
Net RTO Formation Costs & Expansion Cost Recovery Charge	$	416,679	E
Net Marginal Losses	$	14,024,136	O
Total Transmission Costs	$	158,904,691	
Prior Year under/(over) collection	$	(13,104,205)	O
	$	145,800,486	

D = Demand, E = Energy, O = Other

Summary of Current versus Proposed Transmission Revenues

Ohio Power Company

	Forecast for July 2010 - June 2011				
	Metered kWh	Assuming Current TCRR	Assuming Proposed TCRR	Difference	% Difference
RS	7,394,120,528	$65,162,905	$62,748,725	(2,414,180)	-3.70%
GS1	428,415,710	$3,041,366	$2,974,405	(66,961)	-2.20%
GS2 Sec	2,764,242,470	$22,269,177	$16,570,589	(5,698,588)	-25.59%
GS2 RL - GS - TOD	135,793,528	$1,075,593	$811,000	(264,594)	-24.60%
GS2 Pri	377,937,534	$3,045,593	$2,279,717	(765,876)	-25.15%
GS2 Sub/Trans	287,600,981	$2,051,001	$1,524,039	(526,961)	-25.69%
GS3 Sec	2,882,203,645	$20,714,943	$17,663,123	(3,051,820)	-14.73%
GS3 Pri	2,671,894,078	$18,050,470	$15,325,379	(2,725,091)	-15.10%
GS3 Sub/Trans	973,287,263	$6,622,527	$5,663,786	(958,741)	-14.48%
GS4 Pri	263,384,344	$1,499,484	$1,536,084	36,600	2.44%
GS4/IRP Sub/Trans	7,761,475,290	$42,898,750	$43,309,019	410,269	0.96%
EHG	28,219,862	$303,663	$295,355	(8,308)	-2.74%
SS	55,039,508	$538,864	$358,164	(180,700)	-33.53%
EHS	427,477	$4,185	$2,782	(1,403)	-33.53%
OL	62,158,840	$264,181	$157,423	(106,758)	-40.41%
SL	67,339,703	$286,200	$170,545	(115,656)	-40.41%
SBS-Sub/Tran-Backup	343,607	$65,716	$69,885	4,169	6.34%
Total	26,153,884,368	$187,894,619	$171,460,018	(16,434,601)	-8.75%

Columbus Southern Power Company

	Forecast for July 2010 - June 2011				
	Metered kWh	Assuming Current TCRR	Assuming Proposed TCRR	Difference	% Difference
RS	7,483,861,009	$64,886,572	$60,896,177	(3,990,395)	-6.15%
GS1	366,779,994	$3,073,030	$2,487,135	(585,894)	-19.07%
GS2 Sec	1,699,313,197	$15,533,982	$12,301,737	(3,232,245)	-20.81%
GS2-TOD/LM *	13,905,374	$124,531	$101,440	(23,091)	-18.54%
GS2 Pri	65,097,383	$676,661	$557,037	(119,624)	-17.68%
GS3 Sec	4,797,522,054	$34,922,176	$28,735,609	(6,186,567)	-17.72%
GS3-TOD/LM	5,924,388	$41,496	$34,276	(7,219)	-17.40%
GS3 Pri	2,617,306,301	$16,855,508	$13,666,414	(3,189,095)	-18.92%
GS4/IRP	3,863,836,016	$24,202,227	$26,796,247	2,594,019	10.72%
SL	41,471,266	$131,062	$85,340	(45,722)	-34.89%
AL	58,127,884	$183,702	$119,616	(64,086)	-34.89%
SBS-Sub/Tran-Backup	1,253,134	$21,004	$21,620	616	2.93%
Total	21,014,398,000	$160,651,949	$145,802,646	(14,849,303)	-9.24%

Ohio Power Company

	Actual 12 Months 2/28/2010				Forecast July 2010 - June 2011			Forecast July 2010 - June 2011				
			Revenue				Revenue at Current	Proposed Rates		Revenue at Proposed		
	Metered kWh	Demand	kWh	Demand	Metered kWh	Demand	Rates	kWh	Demand	Rates	$ Change	% Change
Residential												
Residential	7,319,864,147		62,743,892.88	-	7,394,100,143		65,162,725.74	0.0084863		62748552.05	(2,414,173.69)	-4%
GS1	15,966		126.99	-	14,947		106.11	0.0069428		103.78	(2.33)	-2%
GS2-Sec	6,895	65	23.64	73.96	6,488	-	22.24	0.0021861	0.93	14.18	(8.06)	0%
OL	14,638,981		63,799.56	-	14,230,421		60,480.71	0.0025326		36,039.97	(24,440.74)	-40%
	7,334,525,989	65	62,807,843.07	73.96	7,408,352,000	-	65,223,334.80			62,784,709.97	(2,438,624.83)	-4%
Commercial												
Residential	20,593		180.62	-	20,385		179.65	0.0084863		172.99	(6.66)	-4%
GS1	348,813,153	-	2,671,417.37	-	399,038,029		2,832,810.87	0.0069428		2,770,441.23	(62,369.64)	-2%
GS2-Sec	2,122,300,142	8,399,348	7,669,478.66	10,772,131.14	2,229,162,366	8,838,596	17,630,519.39	0.0021861	0.93	13,093,065.98	(4,537,453.41)	-26%
GS2 RL - GS - TOD	106,031,563		913,093.25	-	124,416,186		986,475.73	0.0059723		743,050.79	(242,424.94)	-25%
GS2-Pri	59,840,713	259,362	209,166.17	318,083.20	61,751,293	268,011	496,263.21	0.0021077	0.90	371,363.07	(124,900.14)	-25%
GS2-Sub/Tran	17,194,884	121,074	57,442.53	143,614.96	16,904,488	119,290	180,983.02	0.0020670	0.88	139,747.78	(41,235.24)	-23%
GS3-Sec	2,114,839,589	4,522,858	6,316,899.07	9,030,590.03	2,191,015,953	4,691,298	15,598,945.76	0.0019306	1.93	13,284,179.86	(2,314,765.90)	-15%
GS3-Pri	750,162,394	1,448,440	2,159,512.95	2,790,769.73	775,598,335	1,498,906	5,014,537.05	0.0018614	1.86	4,231,663.16	(782,873.89)	-16%
GS3-Sub/Tran	32,626,709	65,884	91,841.02	123,626.28	33,437,718	67,863	216,475.66	0.0018166	1.82	183,890.15	(32,585.51)	-15%
GS4/IRP-Sub/Tran	-		-	-	-		-	0.0018092	2.15	-	-	0%
EHG	22,300,536		215,406.77	-	26,798,682		288,369.90	0.0104662		280,480.37	(7,889.53)	-3%
EHS	399,120		3,505.12	-	427,477		4,185.22	0.0065074		2,781.77	(1,403.45)	-34%
SS	48,172,657		416,365.10	-	55,039,508		538,864.30	0.0065074		358,164.09	(180,700.21)	-34%
OL	37,899,731		165,163.25	-	40,273,971		171,168.41	0.0025326		101,997.86	(69,170.55)	-40%
SBS-Sub/Tran-5%	316,204	226,667	1,705.68	50,400.00	343,607	240,000	65,715.81	0.0018620	0.29	69,884.56	4,168.75	6%
	5,660,817,988	15,043,634	20,891,179.56	23,229,214.34	5,954,228,000	15,723,763	44,024,493.98			35,630,883.65	(8,393,610.33)	-19%
Industrial												
GS1	17,594,040		136,082.13	-	22,275,777		158,137.97	0.0069428		154,656.26	(3,481.71)	-2%
GS2-Sec	463,664,245	2,147,241	1,675,421.98	2,751,561.24	533,372,282	2,476,476	4,627,138.57	0.0021861	0.93	3,469,128.23	(1,158,010.34)	-25%
GS2 RL - GS - TOD	8,116,005		69,393.88	-	10,833,584		85,810.65	0.0059723		64,701.41	(21,109.24)	-25%
GS2-Pri	277,487,838	1,210,417	966,966.79	1,490,760.08	315,898,013	1,378,675	2,546,359.17	0.0021077	0.90	1,906,204.62	(640,154.55)	-25%
GS2-Sub/Tran	236,206,953	818,360	804,797.31	987,752.45	270,696,493	940,305	1,870,017.72	0.0020570	0.88	1,384,291.47	(485,726.25)	-26%
GS3-Sec	611,495,937	1,392,734	1,827,050.14	2,780,733.77	690,172,371	1,575,281	5,108,718.61	0.0019306	1.93	4,372,738.69	(735,979.92)	-14%
GS3-Pri	1,680,256,500	3,596,008	4,834,992.13	6,928,377.31	1,869,774,603	4,051,795	12,989,443.61	0.0018614	1.86	11,053,965.94	(1,935,477.67)	-15%
GS3-Sub/Tran	838,285,244	1,846,814	2,365,230.74	3,465,848.46	939,849,544	2,072,838	6,406,051.39	0.0018166	1.82	5,479,895.48	(926,155.91)	-14%
GS4-Pri	236,121,600	426,367	624,229.41	711,350.96	263,384,344	476,283	1,499,483.75	0.0018538	2.20	1,536,083.69	36,599.84	2%
GS4/IRP-Sub/Tran	5,692,158,227	10,557,244	14,919,022.69	17,177,966.07	6,489,475,290	12,094,335	37,094,084.05	0.0018092	2.15	37,743,579.12	649,495.07	2%
EHG	1,045,042		10,005.55	-	1,421,180		15,292.75	0.0104662		14,874.35	(418.40)	-3%
OL	6,339,398		27,644.49	-	7,412,519		31,503.95	0.0025326		18,772.95	(12,731.00)	-40%
	10,068,773,029	21,995,185	28,250,837.14	36,294,350.34	11,434,366,000	25,065,969	72,432,042.19			67,198,892.11	(5,233,150.08)	-7%
Joint Service Territory	1,697,598,240	2,239,610	4,500,607.12	3,591,157.62	1,272,000,000	1,518,204	5,804,666.04	0.0018092	2.15	5,565,439.95	(239,226.09)	-4%

Ohio Power Company

	Actual 12 Months 2/28/2010				Forecast July 2010 - June 2011			Forecast July 2010 - June 2011				
			Revenue				Revenue at Current	Proposed Rates		Revenue at Proposed		
	Metered kWh	Demand	kWh	Demand	Metered kWh	Demand	Rates	kWh	Demand	Rates	$ Change	% Change
Other												
GS1	6,676,201		51,445.41	-	7,086,956		50,311.01	0.0069428		49,203.32	(1,107.69)	-2%
GS2- Sec	1,710,347	5,097	6,243.09	6,548.20	1,701,334	5,012	11,497.03	0.0021861	0.93	8,380.68	(3,116.35)	-27%
GS2 RL - GS - TOD	517,908		4,615.61	-	543,758		4,307.00	0.0059723		3,247.49	(1,059.51)	-25%
GS3-Sec	1,026,080	2,238	3,061.08	4,467.44	1,015,321	2,199	7,278.45	0.0019306	1.93	6,204.04	(1,074.41)	-15%
OL	236,255		1,029.99	-	241,928		1,028.22	0.0025326		612.71	(415.51)	-40%
SL	65,856,372		287,123.78	-	67,339,703		286,200.47	0.0025326		170,544.53	(115,655.94)	-40%
	76,023,163	7,335	353,518.96	11,015.64	77,929,000	7,211	360,622.18			238,192.76	(122,429.42)	-34%
Munis												
GS2-Pri	471,600	1,193	1,637.29	1,453.24	488,228	1,245	2,970.91	0.0021077	0.90	2,149.48	(821.43)	-28%
GS3-Pri	6,412,500	14,539	18,422.92	28,017.00	6,521,140	14,845	46,488.85	0.0018614	1.86	39,749.59	(6,739.26)	-14%
	6,884,100	15,732	20,060.21	29,470.24	7,009,368	16,090	49,459.76			41,899.07	(7,560.69)	-15%
Total	24,844,622,509	39,301,562	116,824,046.06	63,155,282.14	26,153,884,368	42,331,257	187,894,618.95			171,460,017.51	(16,434,601.44)	-9%
					368							
Recap												
Residential	7,334,525,989	65	62,807,843.07	73.96	7,408,352,000	-	65,223,334.80			62,784,709.97	(2,438,624.83)	-4%
Commercial	5,660,817,988	15,043,634	20,891,179.56	23,229,214.34	5,954,228,000	15,723,763	44,024,493.98			35,630,883.65	(8,393,610.33)	-19%
Industrial	10,068,773,029	21,996,185	28,250,837.14	38,294,350.34	11,434,366,000	25,065,989	72,432,042.19			67,198,892.11	(5,233,150.08)	-7%
Joint Service Territory	1,697,598,240	2,239,610	4,500,607.12	3,591,157.62	1,272,000,000	1,518,204	5,804,666.04			5,565,439.95	(239,226.09)	-4%
Other	76,023,163	7,335	353,518.96	11,015.64	77,929,000	7,211	360,622.18			238,192.76	(122,429.42)	-34%
Munis	6,884,100	15,732	20,060.21	29,470.24	7,009,000	16,090	49,459.76			41,899.07	(7,560.69)	-15%
Total	24,844,622,509	39,301,562	116,824,046.06	63,155,282.14	26,153,884,000	42,331,257	187,894,618.95			171,460,017.51	(16,434,601.44)	-9%
RS	7,319,884,740	-	62,744,073.50	-	7,394,120,528	-	65,162,905.39			62,748,725.04	(2,414,180.35)	-4%
GS1	373,099,360	-	2,859,071.90	-	428,415,710	-	3,041,365.96			2,974,404.59	(66,961.37)	-2%
GS2 Sec	2,587,681,629	10,551,752	9,351,167.37	13,530,314.54	2,764,242,470	11,320,085	22,269,177.23			16,570,589.07	(5,698,588.16)	-26%
GS2 RL - GS - TOD *	114,665,476	-	987,102.74	-	135,793,528	556,100 *	1,075,593.38			810,999.69	(264,593.69)	-25%
GS2 Pri	337,800,151	1,470,972	1,177,770.25	1,810,296.52	377,937,534	1,647,931	3,045,593.29			2,279,717.16	(765,876.13)	-25%
GS2 Sub/Trans	253,403,837	939,434	862,239.84	1,131,367.41	287,600,981	1,059,595	2,051,000.74			1,524,039.25	(526,961.49)	-26%
GS3 Sec	2,727,361,606	5,917,829	8,147,010.29	11,815,791.24	2,882,203,645	6,268,777	20,714,942.82			17,663,122.59	(3,051,820.23)	-15%
GS3 Pri	2,436,831,394	5,058,987	7,012,928.00	9,747,163.04	2,671,894,078	5,565,546	18,050,469.51			15,325,378.69	(2,725,090.82)	-15%
GS3 Sub/Trans	870,811,953	1,912,698	2,447,071.76	3,589,474.74	973,287,263	2,140,501	6,622,527.05			5,663,785.63	(958,741.42)	-14%
GS4 Pri	236,121,600	426,367	624,229.41	711,350.96	263,384,344	476,283	1,499,483.75			1,536,083.59	36,599.84	2%
GS4/IRP Sub/Trans	7,389,756,467	12,796,854	19,419,629.71	20,769,123.69	7,761,475,290	13,612,539	42,898,750.09			43,309,019.06	410,268.97	1%
EHG	23,345,578	-	225,414.32	-	28,219,862	-	303,662.65			295,354.72	(8,307.93)	-3%
SS	48,172,657	-	416,365.10	-	55,039,508	-	538,864.30			358,164.09	(180,700.21)	-34%
EHS	399,120	-	3,505.12	-	427,477	-	4,185.22			2,781.77	(1,403.45)	-34%
OL	59,114,365	-	257,637.29	-	62,158,840	-	264,181.29			157,423.48	(106,757.81)	-40%
SL	65,856,372	-	287,123.78	-	67,339,703	-	286,200.47			170,544.53	(115,655.94)	-40%
SBS-Sub/Tran-Backup	316,204	226,667	1,705.68	50,400.00	343,607	240,000	65,716			69,885	4,169	6%
Total	24,844,622,509	39,301,562	116,824,046.06	63,155,282.14	26,153,884,368	42,887,356	187,894,618.95			171,460,017.51	(16,434,601.44)	-9%

Columbus Southern Power
Excludes Shopping Customers

	Actual 12 Months 2/28/2010				Forecast July 2010 - June 2011			Forecast July 2010 - June 2011				
			Revenue				Revenue at Current	Proposed Rates		Revenue at Proposed		
	Metered kWh	Demand	kWh	Demand	Metered kWh	Demand	Rates	kWh	Demand	Rates	$ Change	% Change
Residential												
Residential	7,297,878,230		63,724,194	-	7,483,848,112		64,886,459.90	0.0081370		60,896,072.08	(3,990,387.81)	-6%
GS1	25,495		220	-	23,859		199.90	0.0067810		161.79	(38.11)	-19%
GS2-Sec	-	-	-	-	-	-	-	0.0027515	1.094	-	-	0%
AL	11,310,745		37,796	-	11,622,029		36,729.10	0.0020578		23,915.81	(12,813.29)	-35%
	7,309,214,470	-	63,762,210.48	-	7,495,494,000	-	64,923,388.90			60,920,149.69	(4,003,239.21)	-6%
Commercial												
Residential	12,040		104	-	12,897		111.82	0.0081370		104.95	(6.88)	-6%
GS1	328,036,021		2,908,228	-	343,694,594		2,879,610.79	0.0067810		2,330,593.04	(549,017.74)	-19%
GS2-Sec	1,483,592,719	5,854,937	7,279,926	6,720,830	1,556,205,684	6,177,195	14,000,826.12	0.0027515	1.094	11,039,751.05	(2,961,075.07)	-21%
GS2-TOD/LM	12,661,488		118,820	-	13,276,645		118,900.32	0.0072950		96,853.12	(22,047.20)	-19%
GS2-Pri	20,193,879	91,807	94,577	101,360	21,101,587	96,309	196,926.73	0.0026619	1.058	158,065.12	(38,861.61)	-20%
GS3-Sec	4,082,691,833	9,835,831	13,748,626	16,365,762	4,286,709,601	10,340,598	31,060,735.58	0.0020862	1.605	25,539,593.23	(5,521,142.35)	-18%
GS3-LM-TOD	5,606,400		39,946	-	5,924,388		41,495.60	0.0057856		34,276.14	(7,219.46)	-17%
GS3-Pri	1,501,401,088	3,089,545	4,891,684	4,973,923	1,577,190,012	3,249,602	10,151,188.52	0.0020182	1.553	8,229,716.17	(1,921,472.36)	-19%
GS4/IRP	869,608,133	1,614,422	2,018,903	3,304,565	914,530,590	1,699,863	5,710,368.71	0.0016923	2.807	6,319,176.01	608,807.30	11%
SL	241,009		797		253,378		800.75	0.0020578		521.40	(279.35)	-35%
AL	41,657,114		139,134	-	43,783,624		138,369.39	0.0020578		90,097.94	(48,271.45)	-35%
	8,345,701,724	20,486,542	31,240,745.04	31,466,459.94	8,762,683,000	21,563,566	64,299,334.33			53,838,748.17	(10,460,586.16)	-16%
Industrial												
GS1	8,340,033		74,139	-	9,594,429		80,385.96	0.0067810		65,059.82	(15,326.14)	-19%
GS2-Sec	124,319,077	686,015	610,454	790,489	143,107,613	793,624	1,533,155.85	0.0027515	1.094	1,261,985.47	(271,170.38)	-18%
GS2-TOD/LM	566,600		5,088	-	628,730		5,630.65	0.0072950		4,586.58	(1,044.07)	-19%
GS2-Pri	37,967,573	230,231	181,188	256,717	43,996,796	266,408	479,734.04	0.0026619	1.058	398,971.89	(80,762.15)	-17%
GS3-Sec	442,845,136	1,148,475	1,492,818	1,910,766	510,812,453	1,327,326	3,861,440.34	0.0020862	1.605	3,196,015.96	(665,424.38)	-17%
GS3-Pri	902,069,985	1,861,993	2,938,499	2,997,743	1,040,116,289	2,149,069	6,704,319.63	0.0020182	1.553	5,436,697.43	(1,267,622.20)	-19%
GS4/IRP	1,463,612,440	3,228,265	3,382,967	6,597,630	1,677,305,426	3,726,095	11,800,786.03	0.0016923	2.807	13,297,651.71	1,496,865.68	13%
AL	2,355,812		7,881	-	2,722,231		8,603.07	0.0020578		5,601.81	(3,001.26)	-35%
SBS-Sub/Tran-10%	1,072,195	72,000	3,241	16,248	1,253,134	72,000	21,004.01	0.0019851	0.266	21,620.07	616.06	3%
	2,983,137,851	7,226,979	8,696,293.53	12,569,593.25	3,429,536,000	8,334,542	24,495,059.58			23,688,190.74	(806,868.84)	-3%
Joint Service Territory	1,697,785,064	2,389,005	3,998,150	4,807,119	1,272,000,000	1,790,813	6,691,072.46	0.0016923	2.807	7,179,418.84	488,346.38	7%
Other												
GS1	13,544,745		120,478	-	13,467,112		112,832.85	0.0067810		91,320.49	(21,512.36)	-19%
SL	41,691,889		139,553	-	41,217,888		130,260.89	0.0020578		84,818.17	(45,442.72)	-35%
	55,236,634	-	260,031.25	-	54,685,000	-	243,093.74			176,138.66	(66,955.09)	-28%
Total	**20,391,075,743**	**30,102,526**	**107,957,430.07**	**48,843,171.74**	**21,014,398,000**	**31,688,922**	**160,651,949.02**			**145,802,646.10**	**(14,849,302.92)**	-9%
Recap												
Residential	7,309,214,470	-	63,762,210.48	-	7,495,494,000	-	64,923,388.90			60,920,149.69	(4,003,239.21)	-6%
Commercial	8,345,701,724	20,486,542	31,240,745.04	31,466,459.94	8,762,683,000	21,563,566	64,299,334.33			53,838,748.17	(10,460,586.16)	-16%
Industrial	2,983,137,851	7,226,979	8,696,293.53	12,569,593.25	3,429,536,000	8,334,542	24,495,059.58			23,688,190.74	(806,868.84)	-3%
Joint Service Territory	1,697,785,064	2,389,005	3,998,149.77	4,807,118.55	1,272,000,000	1,790,813	6,691,072.46			7,179,418.84	488,346.38	7%
Other	55,236,634	-	260,031.25	-	54,685,000	-	243,093.74			176,138.66	(66,955.09)	-28%
Total	20,391,075,743	30,102,526	107,957,430.07	48,843,171.74	21,014,398,000	31,688,922	160,651,949.02			145,802,646.10	(14,849,302.92)	-9%

Columbus Southern Power
Excludes Shopping Customers

	Actual 12 Months 2/28/2010				Forecast July 2010 - June 2011			Forecast July 2010 - June 2011				
			Revenue				Revenue	Proposed Rates		Revenue		
	Metered kWh	Demand	kWh	Demand	Metered kWh	Demand	at Current Rates	kWh	Demand	at Proposed Rates	$ Change	% Change
RS	7,297,890,270	-	63,724,296.87	-	7,483,861,009	-	64,886,571.72			60,896,177.03	(3,990,394.69)	-6%
GS1	349,946,294	-	3,103,065.65	-	366,779,994	-	3,073,029.50			2,487,135.14	(585,894.36)	-19%
GS2 Sec	1,607,911,796	6,540,953	7,890,379.71	7,511,319.38	1,699,313,197	6,970,819	15,533,981.98			12,301,736.52	(3,232,245.46)	-21%
GS2-TOD/LM *	13,217,088	-	123,907.53	-	13,905,374	57,042 *	124,530.97			101,439.71	(23,091.26)	-19%
GS2 Pri	58,161,452	322,038	275,764.10	358,076.35	65,097,383	362,717	676,660.77			557,037.01	(119,623.75)	-18%
GS3 Sec	4,525,536,969	10,984,306	15,241,443.70	18,276,528.23	4,797,522,054	11,667,924	34,922,175.92			28,735,609.19	(6,186,566.73)	-18%
GS3-TOD/LM	5,606,400	-	39,945.78	-	5,924,388	14,409 *	41,495.60			34,276.14	(7,219.46)	-17%
GS3 Pri	2,403,471,073	4,951,538	7,830,183.35	7,971,866.39	2,617,306,301	5,398,690	16,855,508.16			13,666,413.60	(3,189,094.56)	-19%
GS4/IRP	4,031,005,637	7,231,692	9,400,039.64	14,709,333.39	3,863,836,016	7,216,771	24,202,227.20			26,796,246.56	2,594,019.36	11%
SL	41,932,898	-	140,349.92	-	41,471,266	-	131,061.64			85,339.57	(45,722.07)	-35%
AL	55,323,671	-	184,810.89	-	58,127,884	-	183,701.55			119,615.56	(64,085.99)	-35%
SBS-Sub/Tran-Backup	1,072,195	72,000	3,240.93	16,248.00	1,253,134	72,000	21,004.01			21,620.07	616.06	3%
Total	20,391,075,743	30,102,526	107,957,430.07	48,843,171.74	21,014,398,000	31,760,372	180,651,949.02			145,802,646.10	(14,849,302.92)	-8%

* Impute demand based upon GS2 Sec or GS3 Sec ratio

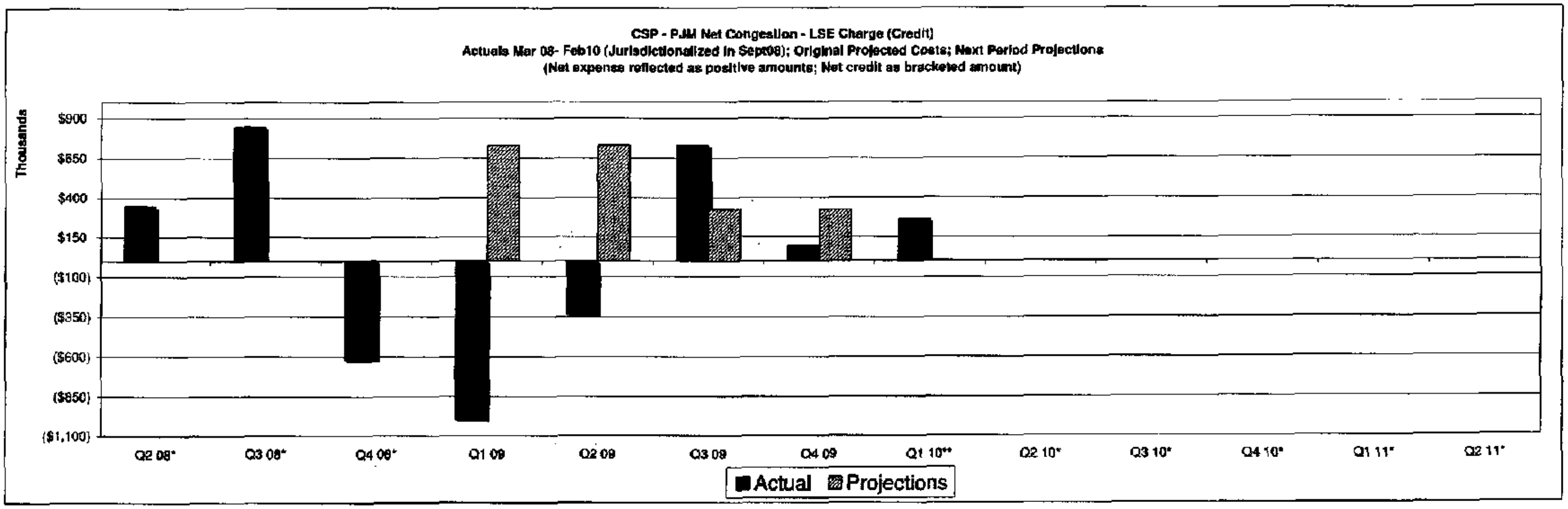
Summary of Current and Proposed Rates

Ohio Power Company

	Forecast for July 2010 - June 2011				Forecast for July 2010 - June 2011			
	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	$0.0088128	$0.0084863	-$0.0003265	-3.70%				
GS1	$0.0070991	$0.0069428	-$0.0001563	-2.20%				
GS2-Sec	$0.0034286	$0.0021861	-$0.0012425	-36.24%	$1.13	$0.93	-$0.20	-17.70%
GS2 RL - GS - TOD	$0.0079208	$0.0059723	-$0.0019485	-24.60%				
GS2-Pri	$0.0033057	$0.0021077	-$0.0011980	-36.24%	$1.09	$0.90	-$0.19	-17.43%
GS2-Sub/Tran	$0.0032261	$0.0020570	-$0.0011691	-36.24%	$1.06	$0.88	-$0.18	-16.98%
GS3-Sec	$0.0028372	$0.0019306	-$0.0009066	-31.95%	$2.00	$1.93	-$0.07	-3.50%
GS3-Pri	$0.0027355	$0.0018614	-$0.0008741	-31.95%	$1.93	$1.86	-$0.07	-3.63%
GS3-Sub/Tran	$0.0026697	$0.0018166	-$0.0008531	-31.95%	$1.88	$1.82	-$0.06	-3.19%
GS4-Pri	$0.0025105	$0.0018538	-$0.0006567	-26.16%	$1.76	$2.20	$0.44	25.00%
GS4/IRP-Sub/Tran	$0.0025105	$0.0018092	-$0.0007013	-27.93%	$1.72	$2.15	$0.43	25.00%
EHG	$0.0107606	$0.0104662	-$0.0002944	-2.74%				
SS	$0.0097905	$0.0065074	-$0.0032831	-33.53%				
EHS	$0.0097905	$0.0065074	-$0.0032831	-33.53%				
OL	$0.0042501	$0.0025326	-$0.0017175	-40.41%				
SL	$0.0042501	$0.0025326	-$0.0017175	-40.41%				
SBS-Sub/Tran-Backup - 5%	$0.0026653	$0.0018620	-$0.0008033	-30.14%	$0.27	$0.29	$0.02	6.86%

Columbus Southern Power Company

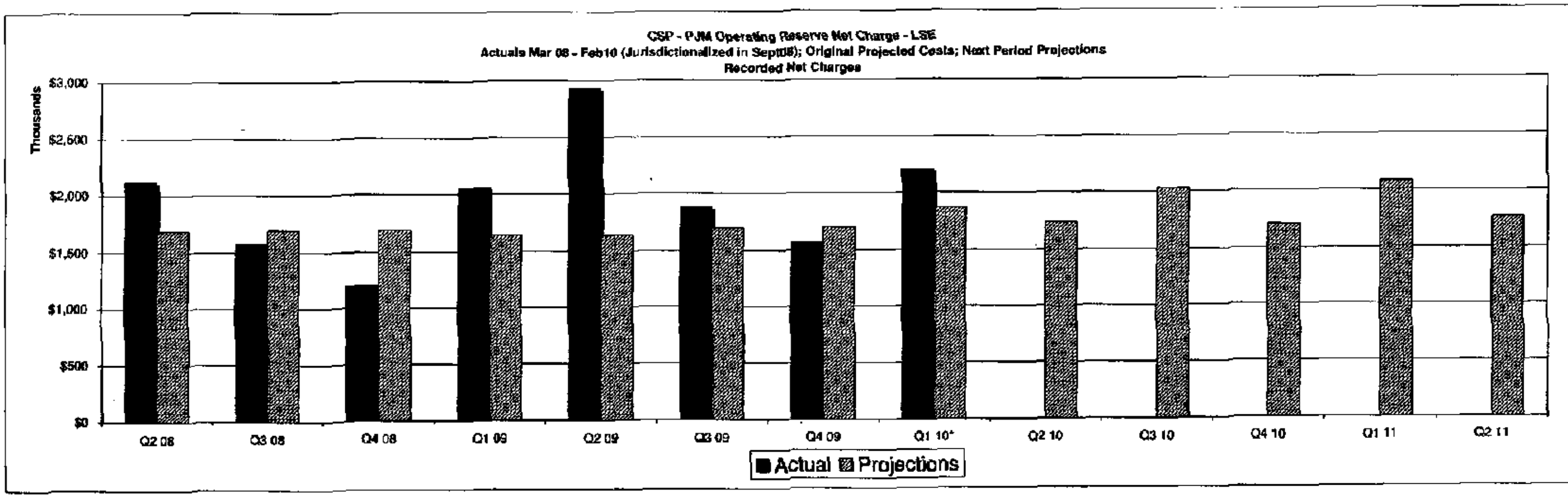
	Forecast for July 2010 - June 2011				Forecast for July 2010 - June 2011			
	Current TCRR Energy Rate	Proposed TCRR Energy Rate	Difference	% Difference	Current TCRR Demand Rate	Proposed TCRR Demand Rate	Demand Difference	Demand % Difference
RS	$0.0086702	$0.0081370	-$0.0005332	-6.15%				
GS1	$0.0083784	$0.0067810	-$0.0015974	-19.07%				
GS2-Sec	$0.0046741	$0.0027515	-$0.0019226	-41.13%	$1.089	$1.094	$0.005	0.46%
GS2-TOD/LM	$0.0089556	$0.0072950	-$0.0016606	-18.54%				
GS2-Pri	$0.0045218	$0.0026619	-$0.0018599	-41.13%	$1.054	$1.058	$0.004	0.38%
GS3-Sec	$0.0031836	$0.0020862	-$0.0010974	-34.47%	$1.684	$1.605	-$0.079	-4.69%
GS3-LM-TOD	$0.0070042	$0.0057856	-$0.0012186	-17.40%				
GS3-Pri	$0.0030799	$0.0020182	-$0.0010617	-34.47%	$1.629	$1.553	-$0.076	-4.67%
GS4/IRP	$0.0021883	$0.0016923	-$0.0004960	-22.67%	$2.182	$2.807	$0.625	28.64%
SL	$0.0031603	$0.0020578	-$0.0011025	-34.89%				
AL	$0.0031603	$0.0020578	-$0.0011025	-34.89%				
SBS-Sub/Tran-Backup - 10%	$0.0029143	$0.0019851	-$0.0009292	-31.88%	$0.241	$0.266	$0.025	10.26%



	ACTUAL									
	Mar-08*	Q2 08*	Q3 08*	Q4 08*	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10**	Feb-10**
Actual - PJM Net Congestion - LSE	223,424	347,251	844,794	(615,957)	(993,074)	(337,569)	728,376	94,537	178,288	81,996
Projections - PJM Net Congestion - LSE	0	0	0	0	729,081	729,081	322,832	322,832	0	0

	2010 FORECAST									
	Mar-10**	Q1 10**	Apr-10*	May-10*	Jun-10*	Q2 10*	Q3 10*	Q4 10*	Q1 11*	Q2 11*
Actual - PJM Net Congestion - LSE	0	260,284								
Projections - PJM Net Congestion - LSE	0	0	0	0	0	0	0	0	0	0

* Projected PJM Net Congestion in 2008, 2010 and 2011 is $0.
** Q1 10 includes two months of actual and one month projection.

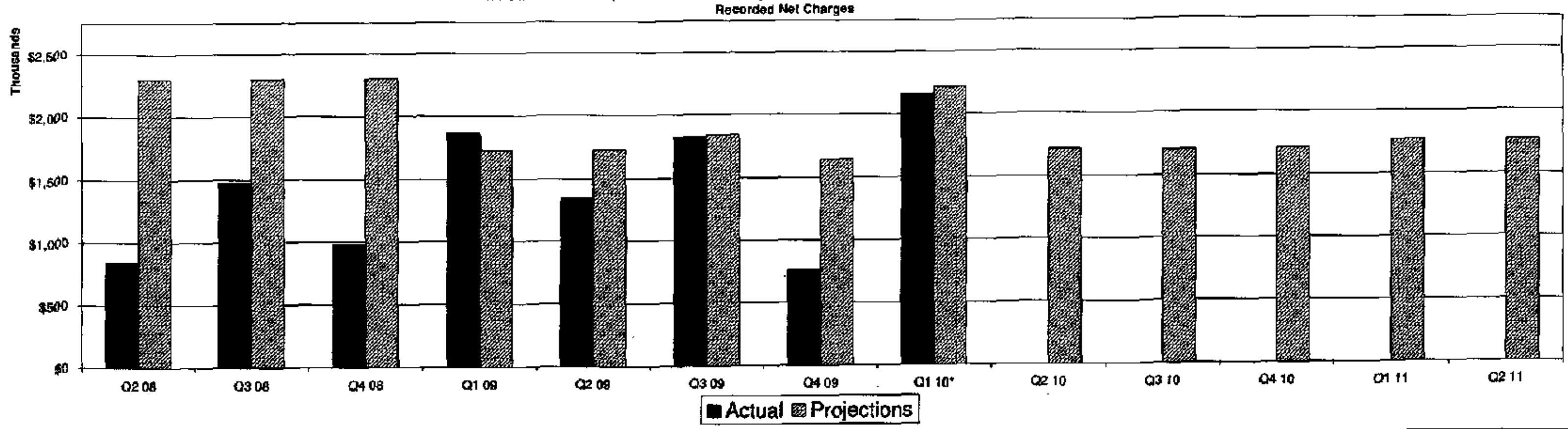


	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Operating Reserve-LSE	372,075	2,121,906	1,576,149	1,200,028	2,051,963	2,928,526	1,882,428	1,567,051	789,182	790,709
Projections - PJM Operating Reserve-LSE	564,362	1,693,065	1,693,065	1,693,065	1,640,655	1,640,655	1,700,904	1,700,904	623,798	623,798

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Operating Reserve-LSE	623,798	2,203,688								
Projections - PJM Operating Reserve-LSE	623,798	1,871,394	578,368	578,368	578,368	1,735,105	2,031,739	1,707,646	2,075,271	1,765,722

* Q1 10 includes two months of actual and one month projection.

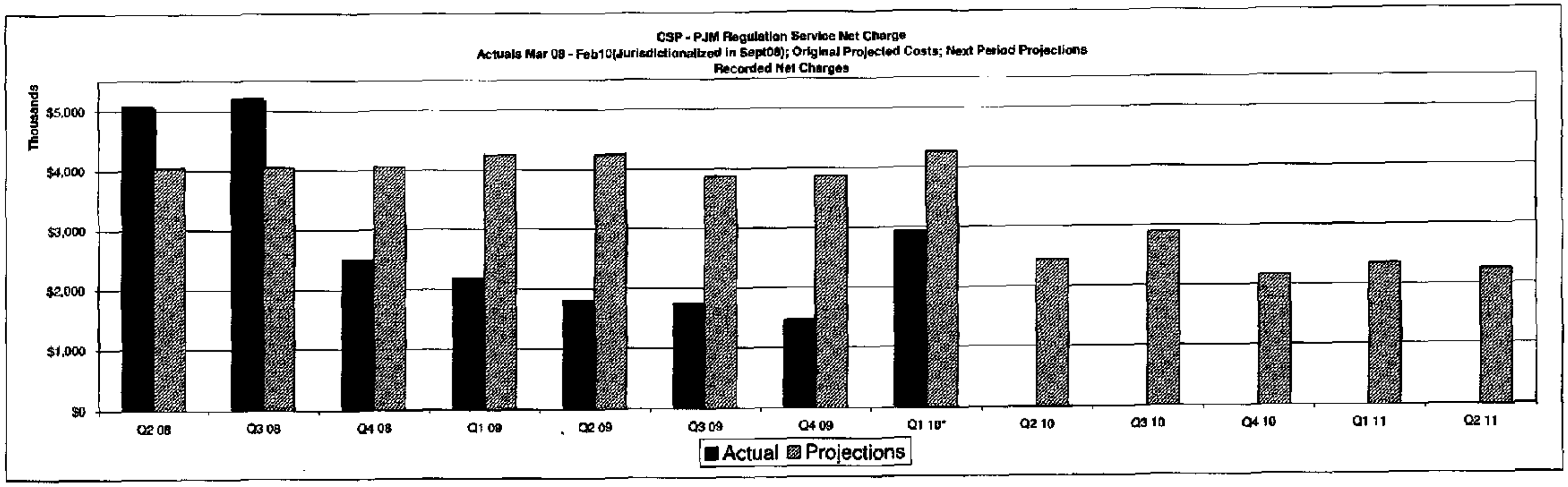
CSP - PJM Administrative Service Fee Expense-LSE
Actuals Mar 08 - Feb10 (Jurisdictionalized in Sept08); Original Projected Costs; Next Period Projections
Recorded Net Charges



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Admin Service Fee	1,140,678	844,208	1,477,024	982,542	1,863,792	1,349,187	1,828,773	761,719	733,660	687,492
Projections - PJM Admin Service Fee	767,196	2,301,588	2,301,588	2,301,588	1,731,633	1,731,633	1,843,199	1,643,199	736,945	736,945

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Admin Service Fee	736,945	2,158,097								
Projections - PJM Admin Service Fee	736,945	2,210,835	571,667	571,667	571,667	1,715,000	1,700,239	1,714,584	1,766,022	1,766,022

* Q1 10 includes two months of actual and one month projection.

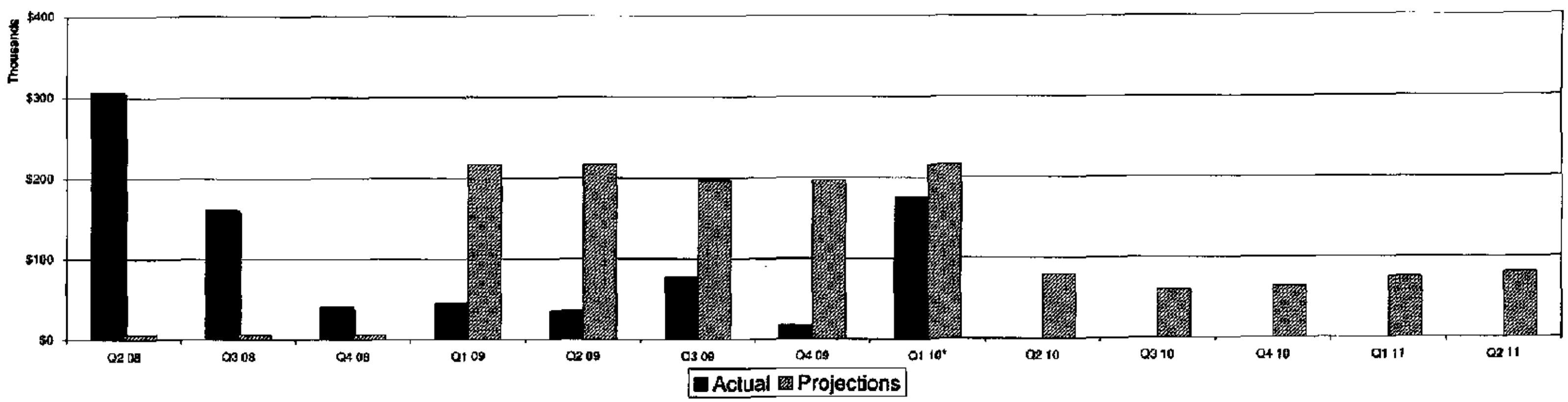


	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Regulation Service Charge	1,187,358	5,090,108	5,211,246	2,505,038	2,182,170	1,800,966	1,743,698	1,455,345	853,998	661,128
Projections - PJM Regulation Service Charge	1,349,545	4,048,635	4,048,635	4,048,635	4,244,583	4,244,583	3,877,362	3,877,362	1,422,002	1,422,002

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Regulation Service Charge	1,422,002	2,937,128								
Projections - PJM Regulation Service Charge	1,422,002	4,266,006	814,303	814,303	814,303	2,442,908	2,891,275	2,182,416	2,340,222	2,249,302

* Q1 10 includes two months of actual and one month projection.

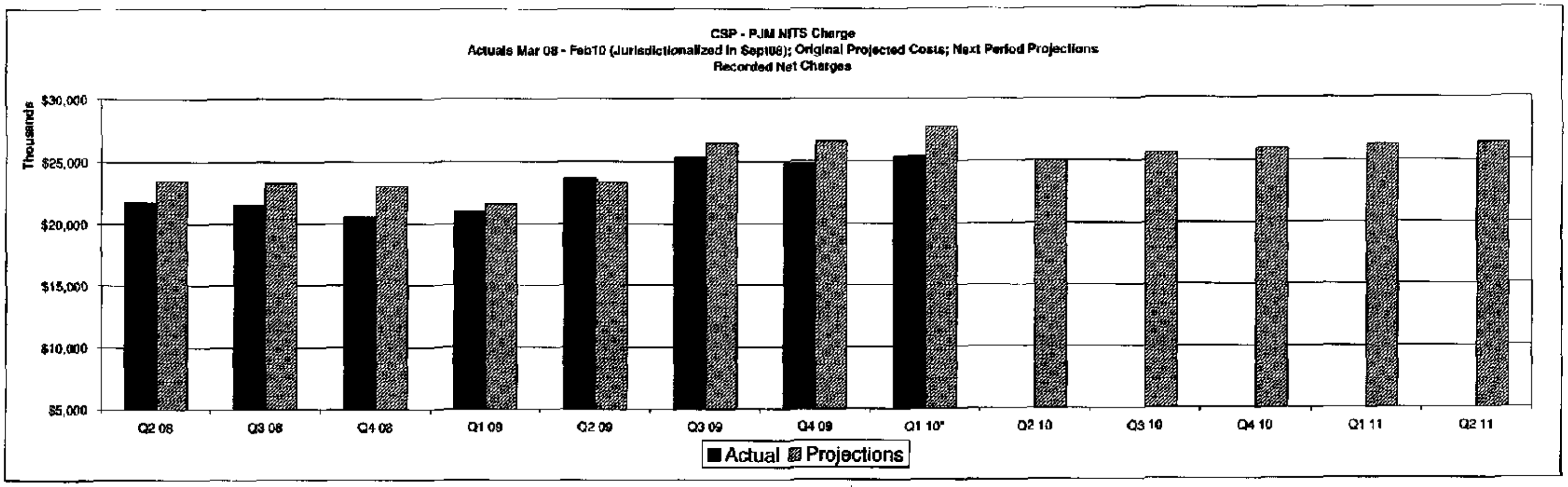
CSP - PJM Spinning Reserve Net Charge
Actuals Mar 06 - Feb10 (Jurisdictionalized in Sept08); Original Projected Costs; Next Period Projections
Recorded Net Charges



	ACTUAL									
	Mar-06	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Spinning Reserve	108,125	307,220	161,062	40,936	44,567	36,169	77,203	17,591	80,429	23,215
Projections - PJM Spinning Reserve	1,996	5,988	5,988	5,988	216,831	216,831	196,722	196,722	72,148	72,148

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Spinning Reserve	72,148	175,792								
Projections - PJM Spinning Reserve	72,148	216,444	26,550	26,550	26,550	79,651	60,615	64,139	74,898	81,057

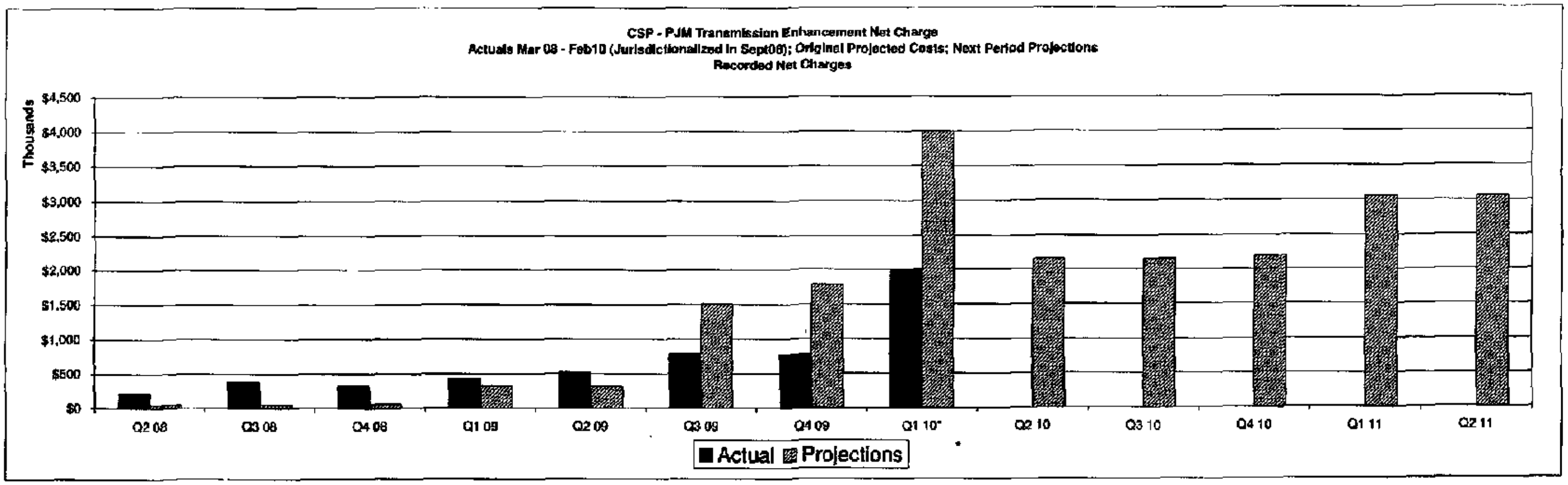
* Q1 10 includes two months of actual and one month projection.



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM NITS	7,398,677	21,728,121	21,811,146	20,567,949	20,962,961	23,606,806	25,368,949	24,827,128	8,428,351	7,892,398
Projections - PJM NITS	7,655,149	23,479,815	23,278,164	23,050,911	21,613,791	23,321,916	26,465,318	26,586,612	9,250,856	9,250,856

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM NITS	9,250,856	25,371,604								
Projections - PJM NITS	9,250,856	27,752,588	8,345,798	8,345,796	8,345,796	25,037,388	25,613,678	25,968,633	26,230,518	26,385,225

* Q1 10 includes two months of actual and one month projection.

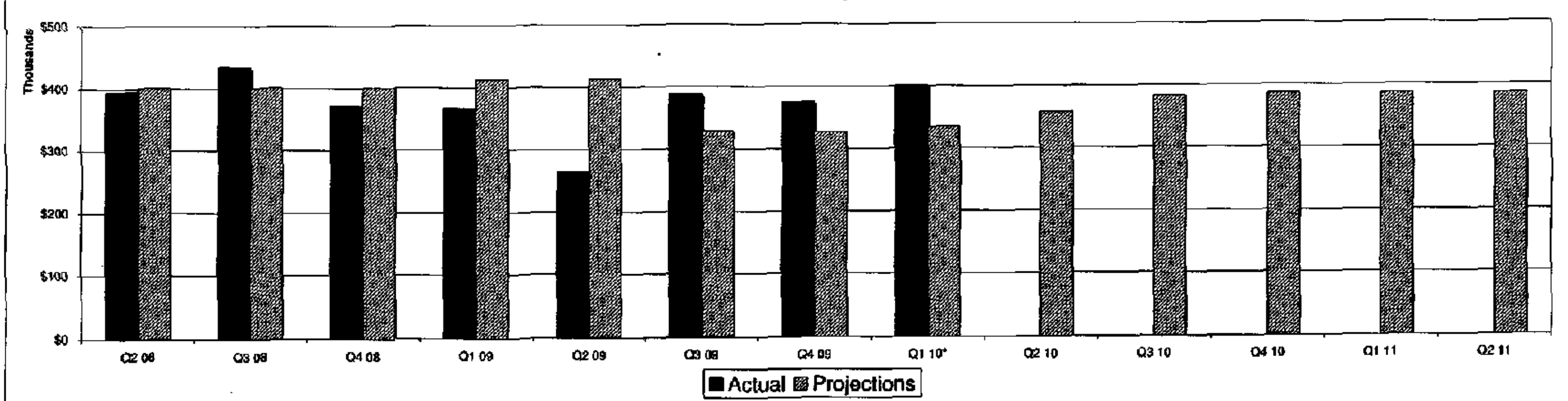


	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Transmission Enhancement	15,193	222,043	360,389	318,451	433,394	518,492	789,135	775,492	319,913	340,101
Projections - PJM Transmission Enhancement	16,368	49,074	49,074	49,074	318,303	318,303	1,508,148	1,780,890	1,334,055	1,334,055

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Transmission Enhancement	1,334,055	1,994,069								
Projections - PJM Transmission Enhancement	1,334,055	4,002,165	719,308	719,308	719,308	2,157,923	2,154,145	2,186,409	3,053,880	3,050,826

* Q1 10 includes two months of actual and one month projection.

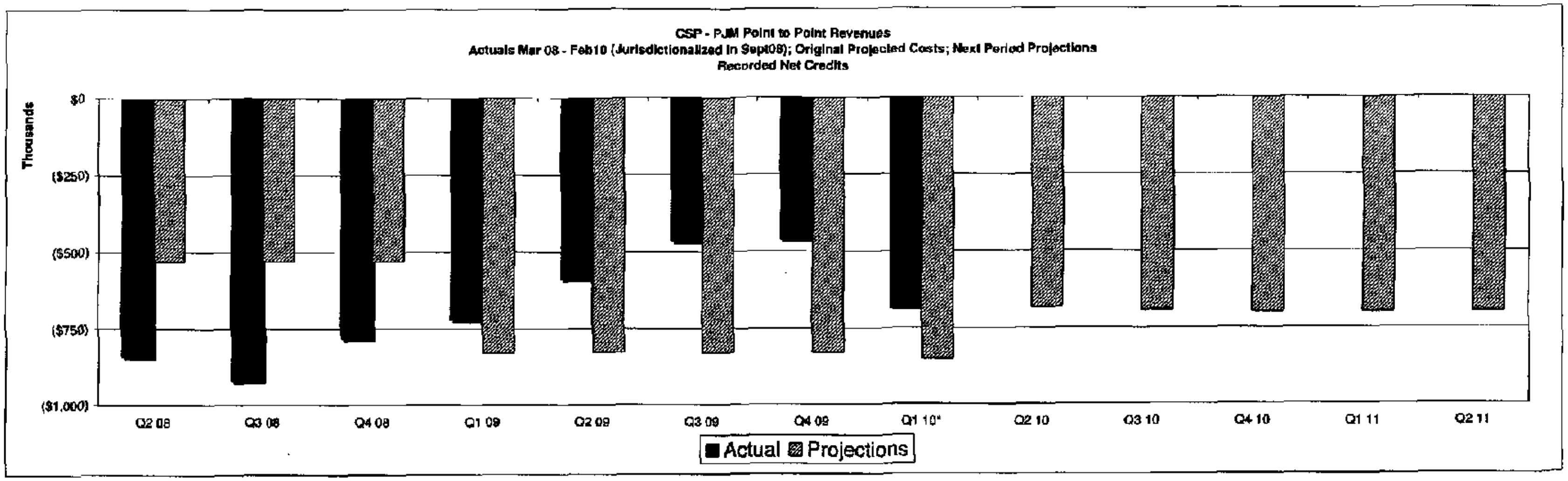
CSP - PJM Scheduling Net Charge
Actuals Mar 08 - Feb10 (Jurisdictionalized in Sept08); Original Projected Costs; Next Period Projections)
Recorded Net Charges



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Scheduling	126,150	394,587	434,834	371,684	368,183	263,345	388,437	375,935	151,996	138,119
Projections - PJM Scheduling	133,662	400,986	400,986	400,986	412,791	412,791	328,943	328,943	111,590	111,590

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Scheduling	111,590	401,705								
Projections - PJM Scheduling	111,590	334,770	119,168	119,168	119,168	357,505	382,498	385,725	385,725	385,726

* Q1 10 includes two months of actual and one month projection.

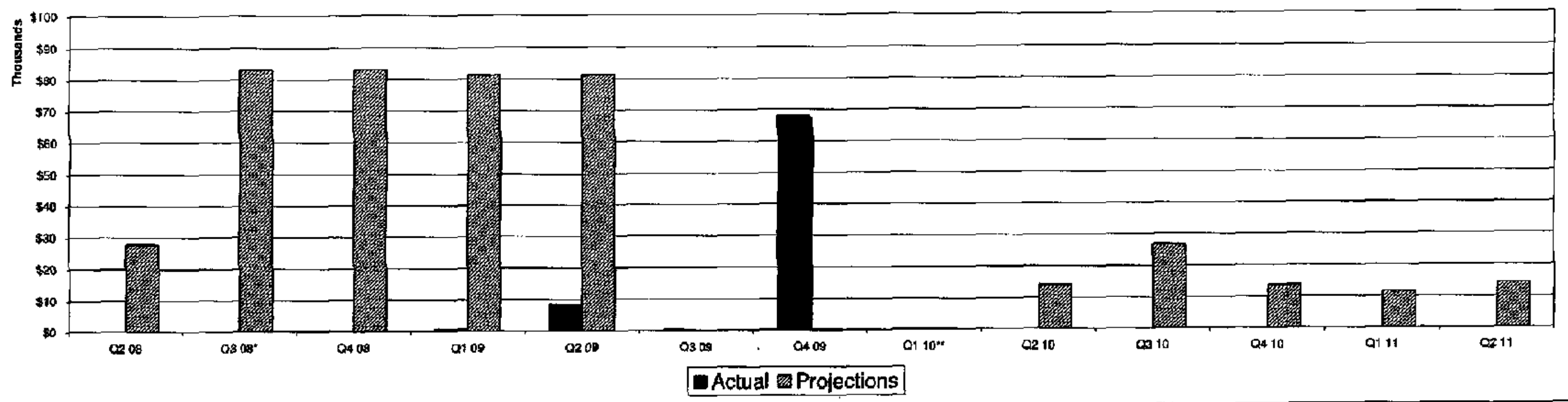


	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Point to Point	(279,193)	(839,558)	(918,638)	(761,412)	(720,612)	(589,514)	(465,318)	(460,643)	(170,735)	(228,822)
Projections - PJM Point to Point	(176,722)	(530,166)	(530,166)	(530,166)	(828,629)	(828,629)	(829,958)	(829,958)	(283,274)	(283,274)

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Point to Point	(283,274)	(682,831)								
Projections - PJM Point to Point	(283,274)	(849,822)	(227,268)	(227,268)	(227,268)	(681,804)	(692,301)	(698,142)	(698,142)	(698,142)

* Q1 10 includes two months of actual and one month projection.

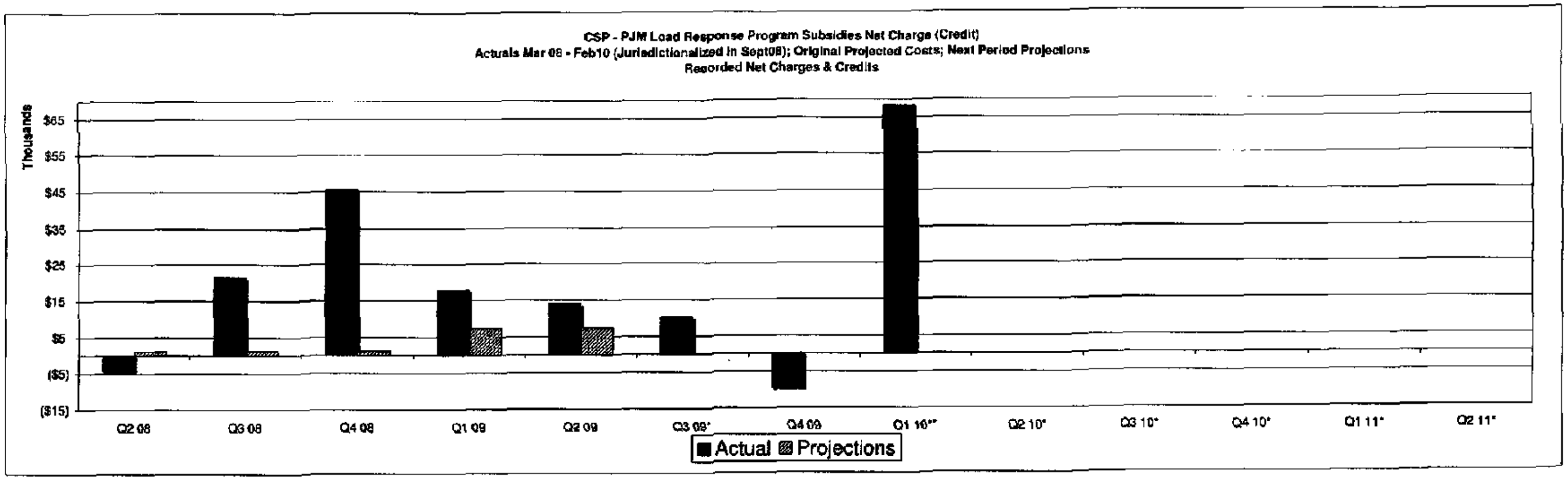
CSP - PJM Supplemental Reserves Net Charge
Actuals Mar 08 - Feb10 (Jurisdictionalized in Sept08); Original Projected Costs; Next Period Projections
Recorded Net Charges



	ACTUAL									
	Mar-08	Q2 08	Q3 08*	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10**	Feb-10**
Actual - PJM Supplemental Reserves	0	0	62	374	837	8,367	365	69,048	44	43
Projections - PJM Supplemental Reserves	0	27,695	83,085	83,085	81,303	81,303	108	108	40	40

	2010 FORECAST									
	Mar-10**	Q1 10**	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Supplemental Reserves	40	127								
Projections - PJM Supplemental Reserves	40	120	4,720	4,720	4,720	14,160	26,671	13,898	11,565	14,411

* Actual Supplemental Reserves charges started in Q3 08
** Q1 10 includes two months of actual and one month projection.

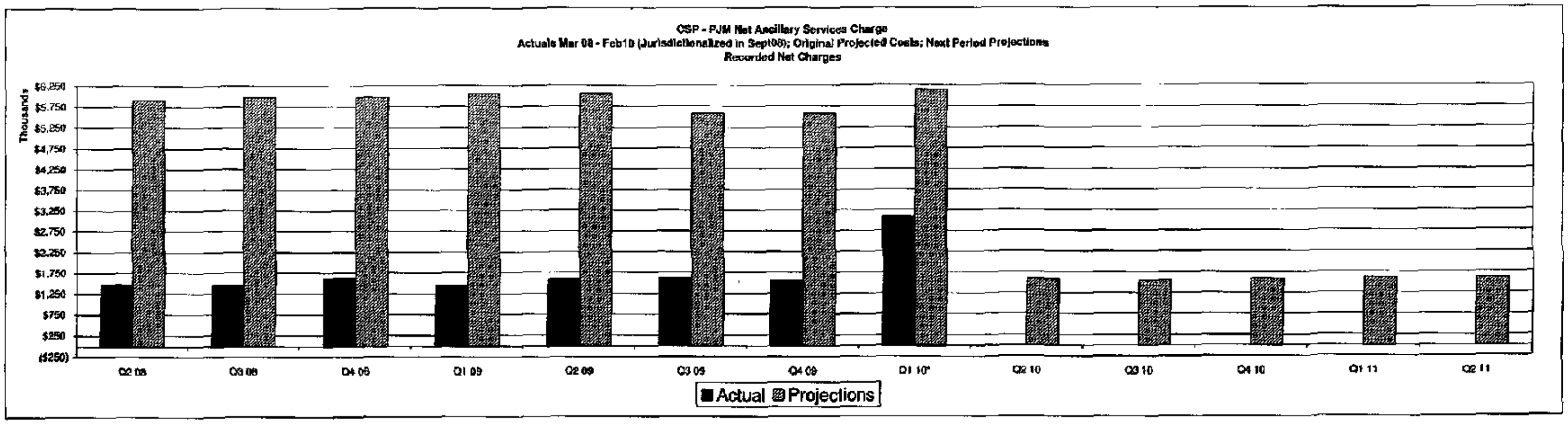


	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09*	Q4 09	Jan-10**	Feb-10**
Actual - PJM Load Response Program Subsidies	42	(4,132)	21,425	45,578	17,791	14,051	10,245	(9,823)	51,292	17,142
Projections - PJM Load Response Program Subsidies	414	1,242	1,242	1,242	7,431	7,431	0	0	0	0

	2010 FORECAST									
	Mar-10**	Q1 10**	Apr-10*	May-10*	Jun-10*	Q2 10*	Q3 10*	Q4 10*	Q1 11*	Q2 11*
Actual - PJM Load Response Program Subsidies	0	68,434								
Projections - PJM Load Response Program Subsidies	0	0	0	0	0	0	0	0	0	0

* Projected PJM Load Response Program Subsidies is $0 for Q3 09 through Q2 11 due to the lack of insight into the expected magnitude.

** Q1 10 includes two months of actual and one month projection.

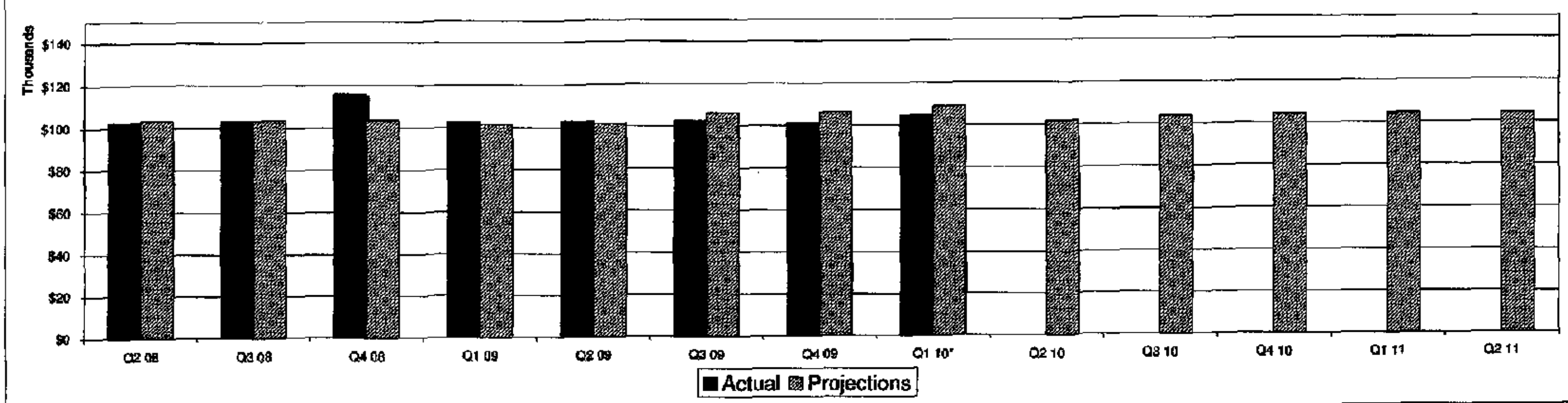


	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Net Ancillary Services	548,673	1,475,826	1,458,863	1,632,364	1,454,359	1,590,292	1,609,264	1,573,354	541,556	496,863
Projections - PJM Net Ancillary Services	1,963,499	5,918,192	5,973,582	5,973,582	6,061,024	6,051,024	5,584,850	5,584,550	2,048,143	2,048,143

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Net Ancillary Services	2,048,143	3,086,362								
Projections - PJM Net Ancillary Services	2,048,143	6,144,429	529,230	529,230	529,230	1,587,689	1,560,587	1,587,936	1,619,549	1,617,432

* Q1 10 includes two months of actual and one month projection.

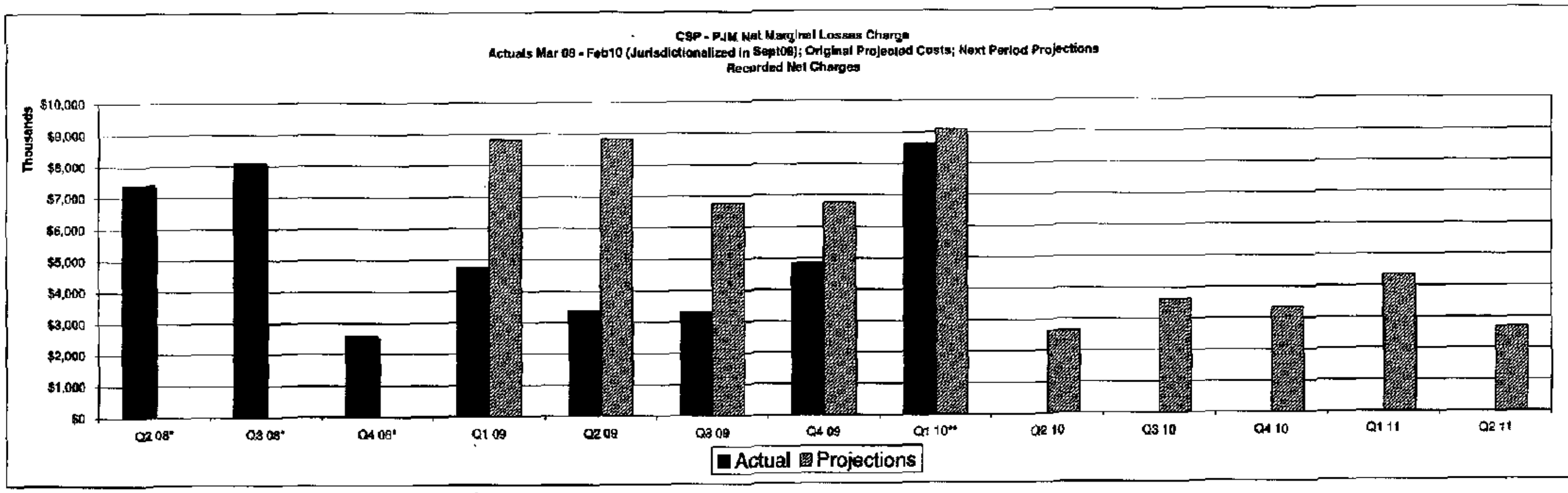
CSP - PJM Net RTO Formation Costs & Expansion Cost Recovery
Actuals Mar 08 - Feb10(Jurisdictionalized in Sept08); Original Projected Costs; Next Period Projections
Recorded Net Charges



	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
	35,338	102,413	103,352	116,210	102,583	102,533	102,500	101,355	35,132	33,167
	34,511	103,533	103,533	103,533	101,406	101,406	106,437	106,437	36,329	36,329

	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Net RTO Formation Costs & Expansion Cost Recovery	36,329	104,628								
	36,329	106,987	33,976	33,976	33,976	101,928	103,515	104,388	104,388	104,388

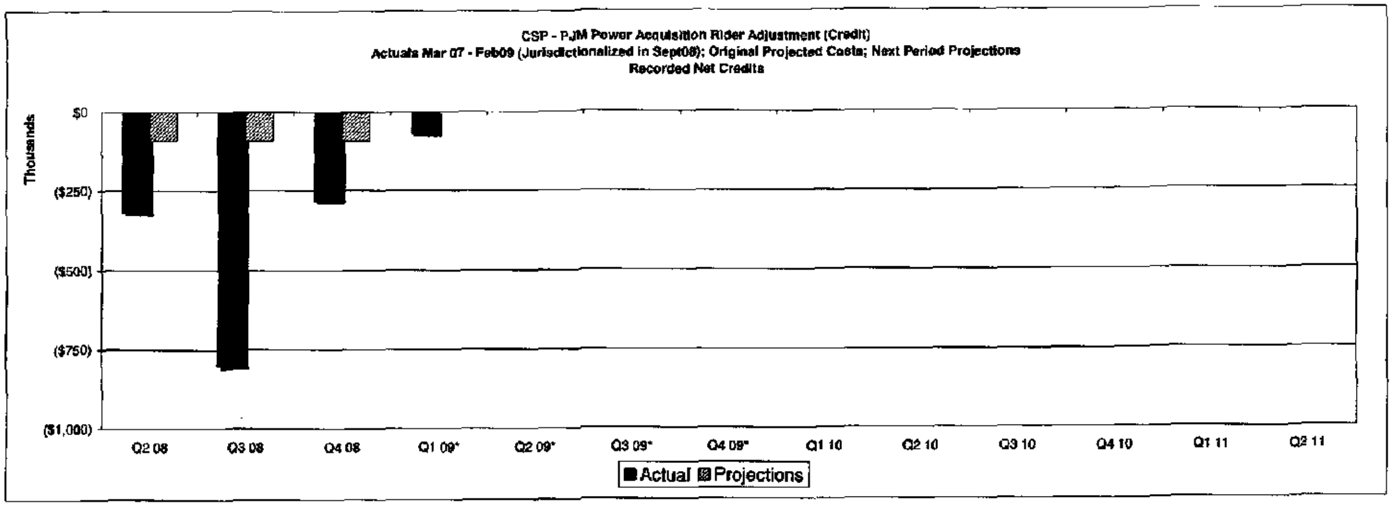
* Q1 10 includes two months of actual and one month projection.



	ACTUAL									
	Mar-08*	Q2 08*	Q3 08*	Q4 08*	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10**	Feb-10**
Actual - PJM Net Marginal Losses	1,473,766	7,421,943	8,114,035	2,584,528	4,787,073	3,383,814	3,334,408	4,856,062	3,301,830	2,278,792
Projections - PJM Net Marginal Losses	0	0	0	0	8,832,027	8,832,027	6,777,153	6,777,153	3,028,064	3,028,064

	2010 FORECAST									
	Mar-10**	Q1 10**	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Net Marginal Losses	3,028,064	8,608,687								
Projections - PJM Net Marginal Losses	3,028,064	9,084,192	882,525	882,525	882,525	2,647,576	3,612,521	3,355,242	4,362,079	2,694,295

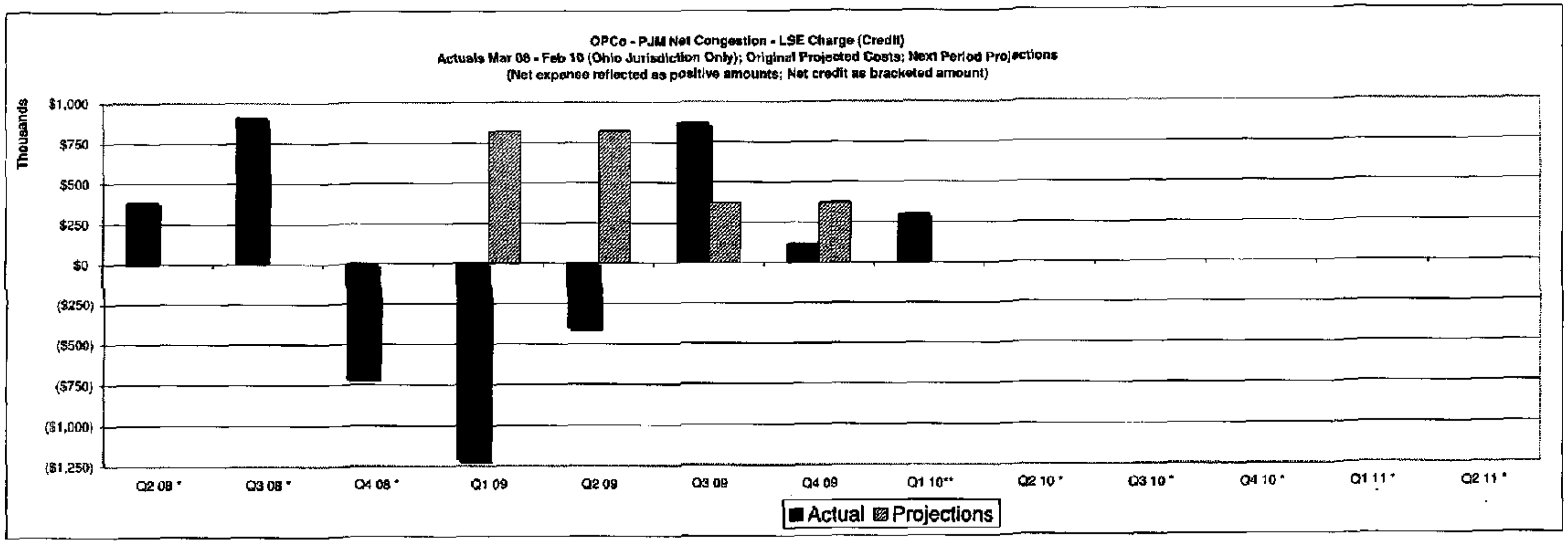
* Collection of Marginal Losses began in 2008. No projections until 2009.
** Q1 10 includes two months of actual and one month projection.



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09*	Q2 09*	Q3 09*	Q4 09*	Jan-10	Feb-10
Actual - PJM Power Acquisition Rider	(628,439)	(317,949)	(802,169)	(280,524)	(69,706)	0	0	0	0	0
Projections - PJM Power Acquisition Rider	(29,435)	(89,496)	(91,878)	(91,878)	0	0	0	0	0	0

	2010 FORECAST									
	Mar-10	Q1 10	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Power Acquisition Rider	0	0	0	0	0	0	0	0	0	0
Projections - PJM Power Acquisition Rider	0	0	0	0	0	0	0	0	0	0

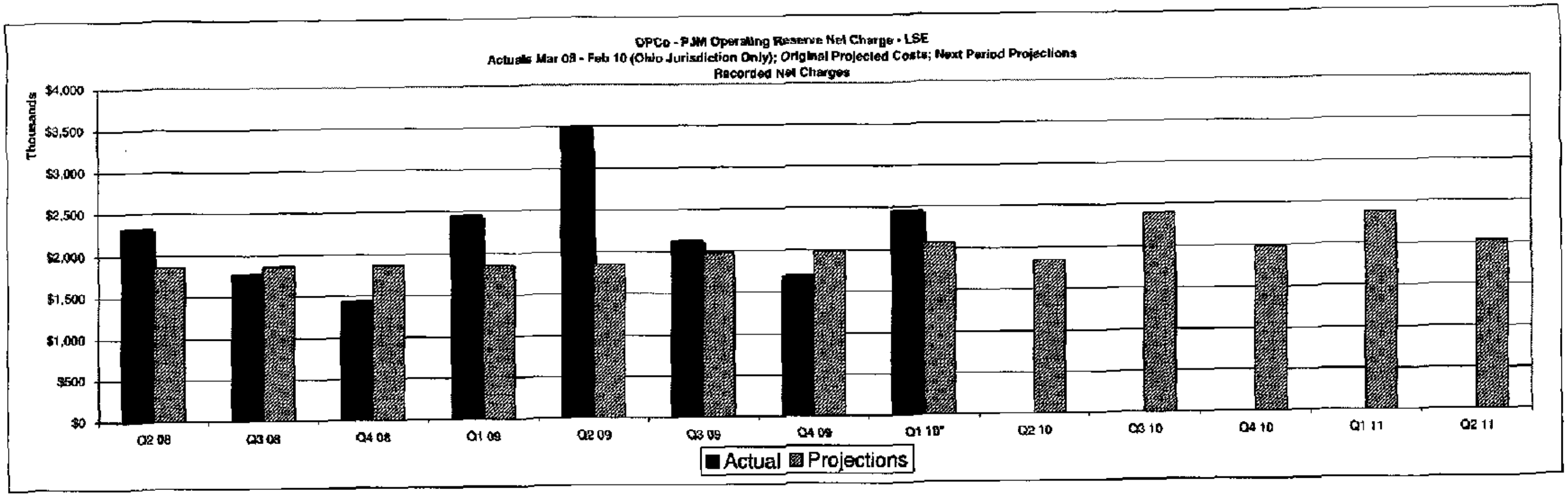
* Power Acquisition Rider Adjustment ceased beginning in 2009.



	ACTUAL									
	Mar-08*	Q2 08 *	Q3 08 *	Q4 08 *	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10**	Feb-10**
Actual - PJM Net Congestion - LSE	245,161	381,037	910,309	(713,702)	(1,212,166)	(403,470)	869,734	119,804	208,322	91,324
Projections - PJM Net Congestion - LSE	0	0	0	0	819,558	819,558	375,315	375,315	0	0

	2010 FORECAST									
	Mar-10**	Q1 10**	Apr-10 *	May-10 *	Jun-10 *	Q2 10 *	Q3 10 *	Q4 10 *	Q1 11 *	Q2 11 *
Actual - PJM Net Congestion - LSE	0	299,646								
Projections - PJM Net Congestion - LSE	0	0	0	0	0	0	0	0	0	0

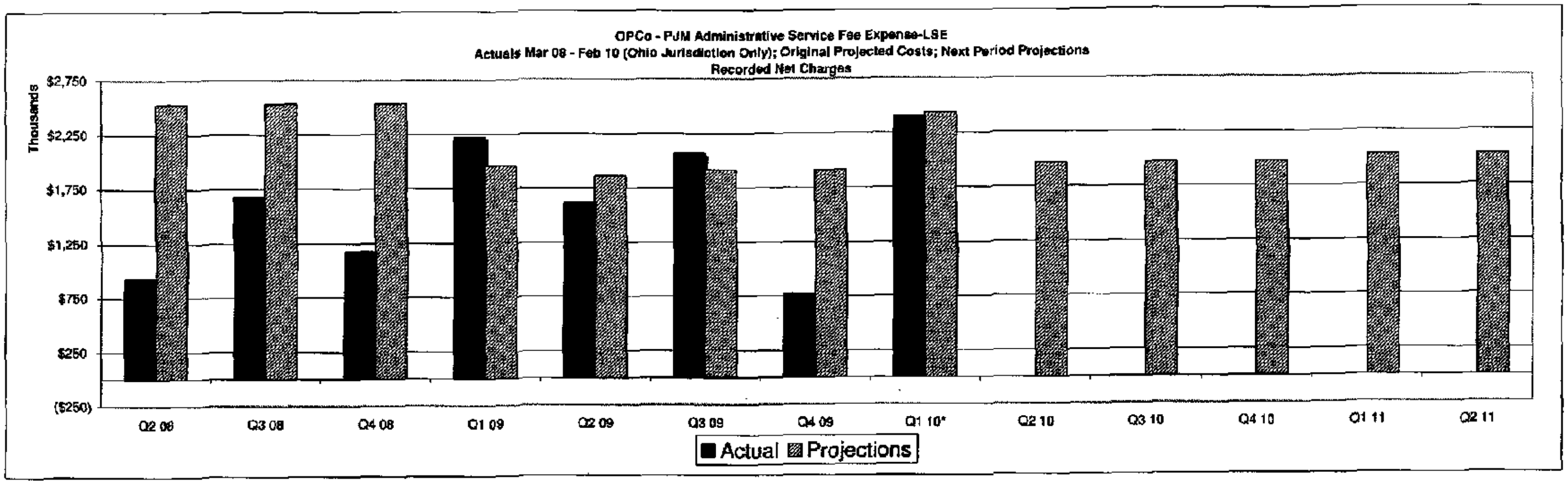
* Projected PJM Net Congestion in 2008, 2010 and 2011 at $0.
** Q1 10 includes two months of actual and one month projection.



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Operating Reserve-LSE	408,274	2,327,679	1,774,049	1,434,297	2,450,133	3,500,238	2,130,456	1,692,226	886,634	879,187
Projections - PJM Operating Reserve-LSE	620,987	1,862,961	1,862,961	1,862,961	1,852,167	1,852,167	1,978,635	1,978,635	688,388	688,386

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Operating Reserve-LSE	688,386	2,454,207								
Projections - PJM Operating Reserve-LSE	688,386	2,065,158	614,089	614,089	614,089	1,842,267	2,390,870	1,977,545	2,380,707	2,025,641

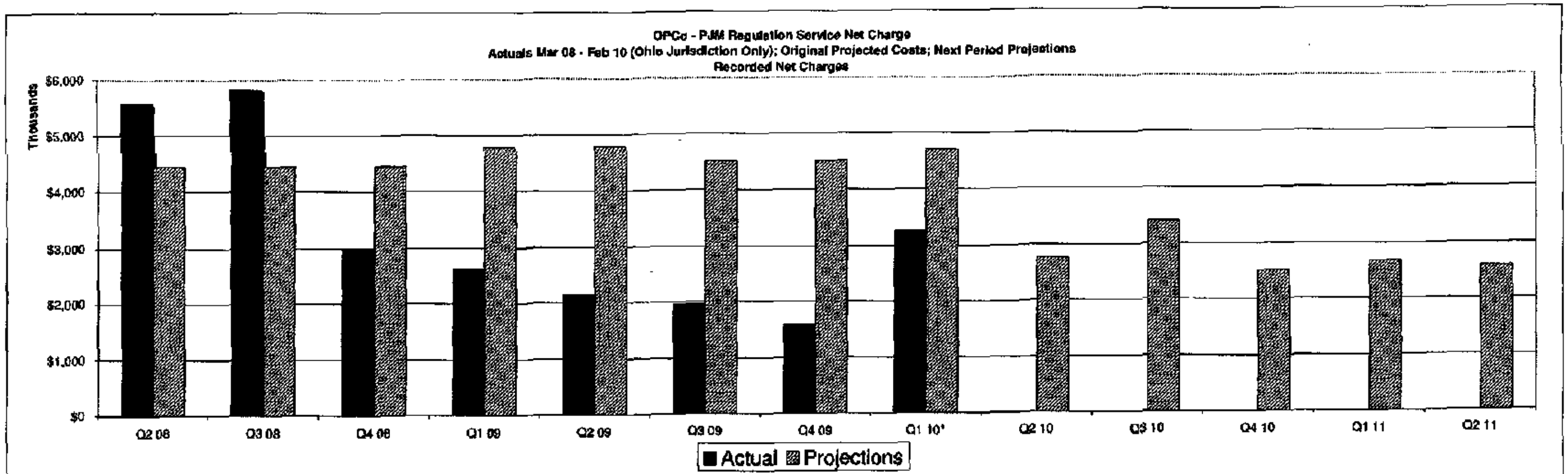
* Q1 10 includes two months of actual and one month projection



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Administrative Service Fee	1,251,655	926,342	1,674,327	1,174,363	2,227,536	1,611,383	2,060,507	766,948	824,256	763,558
Projections - PJM Administrative Service Fee	844,182	2,532,546	2,532,546	2,532,546	1,955,880	1,855,880	1,911,510	1,911,510	813,249	813,249

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Administrative Service Fee	813,249	2,401,063								
Projections - PJM Administrative Service Fee	813,249	2,439,747	655,942	655,942	655,941	1,967,825	1,968,273	1,968,273	2,027,322	2,027,322

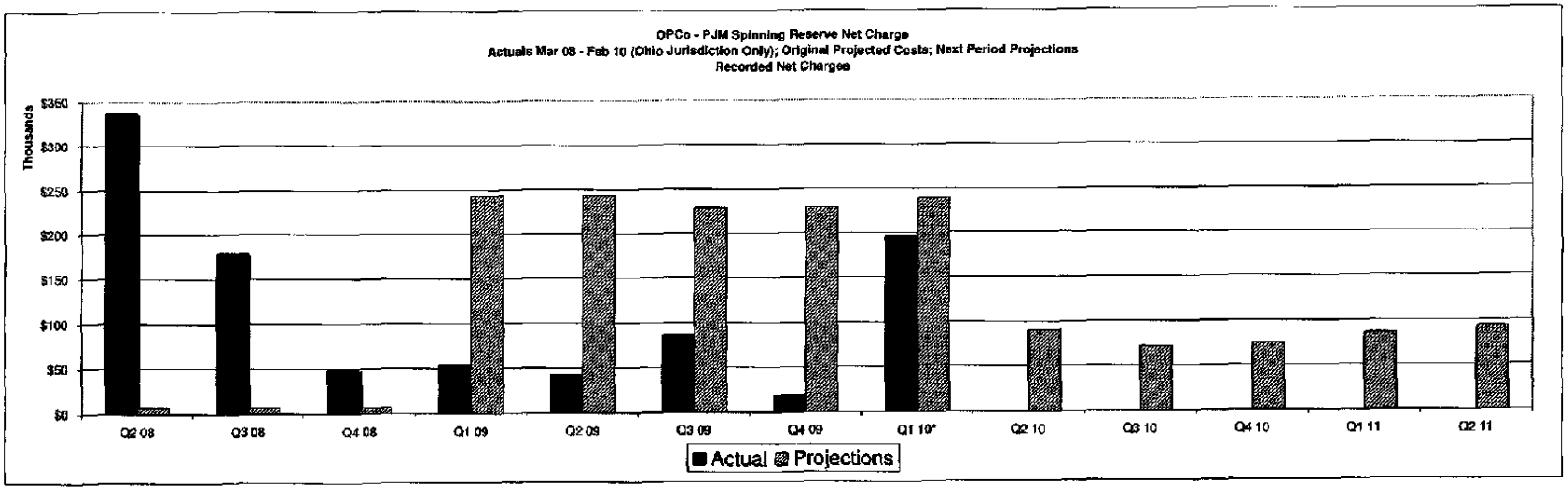
* Q1 10 includes two months of actual and one month projection



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Regulation Service	1,302,878	5,585,329	5,831,440	2,994,069	2,620,128	2,162,654	1,965,408	1,587,998	959,455	735,435
Projections - PJM Regulation Service	1,484,935	4,454,904	4,454,904	4,454,904	4,791,192	4,791,192	4,510,479	4,510,479	1,569,237	1,569,237

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Regulation Service	1,569,237	3,264,127								
Projections - PJM Regulation Service	1,569,237	4,707,711	921,350	921,350	921,350	2,764,051	3,404,264	2,504,191	2,684,657	2,580,405

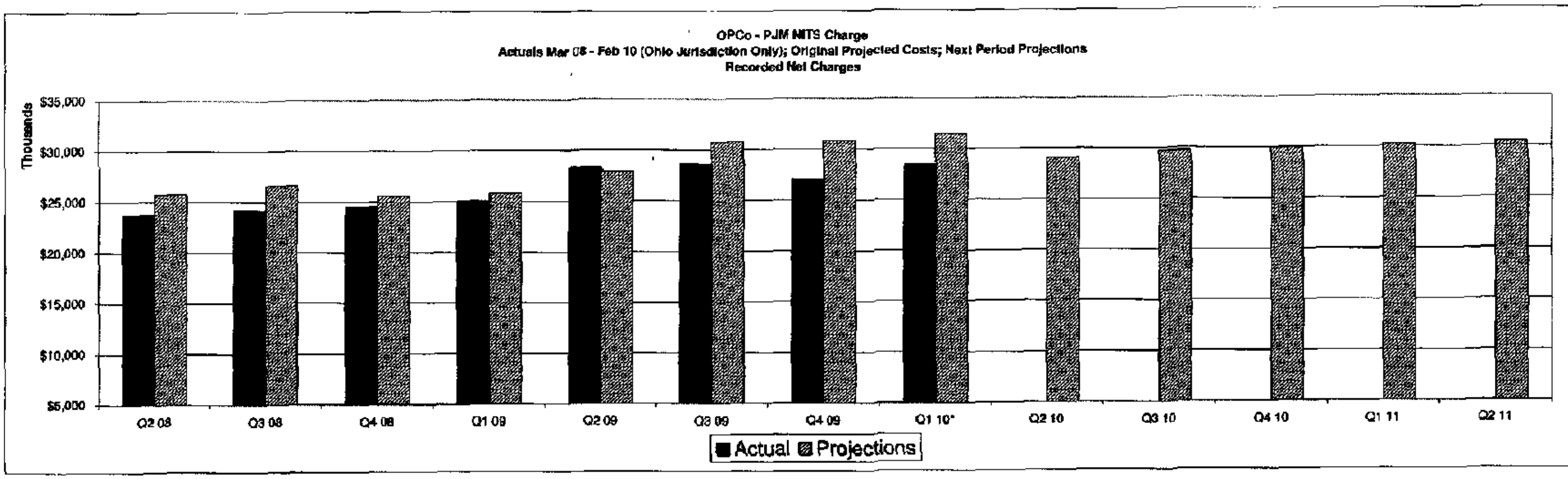
* Q1 10 includes two months of actual and one month projection



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Spinning Reserve	118,644	337,110	178,826	46,928	53,269	43,230	86,036	18,489	90,361	25,795
Projections - PJM Spinning Reserve	2,196	6,588	6,588	6,588	244,071	244,071	228,846	228,846	79,618	79,618

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Spinning Reserve	79,618	195,774								
Projections - PJM Spinning Reserve	79,618	238,854	30,040	30,040	30,040	90,121	71,568	74,277	65,922	92,989

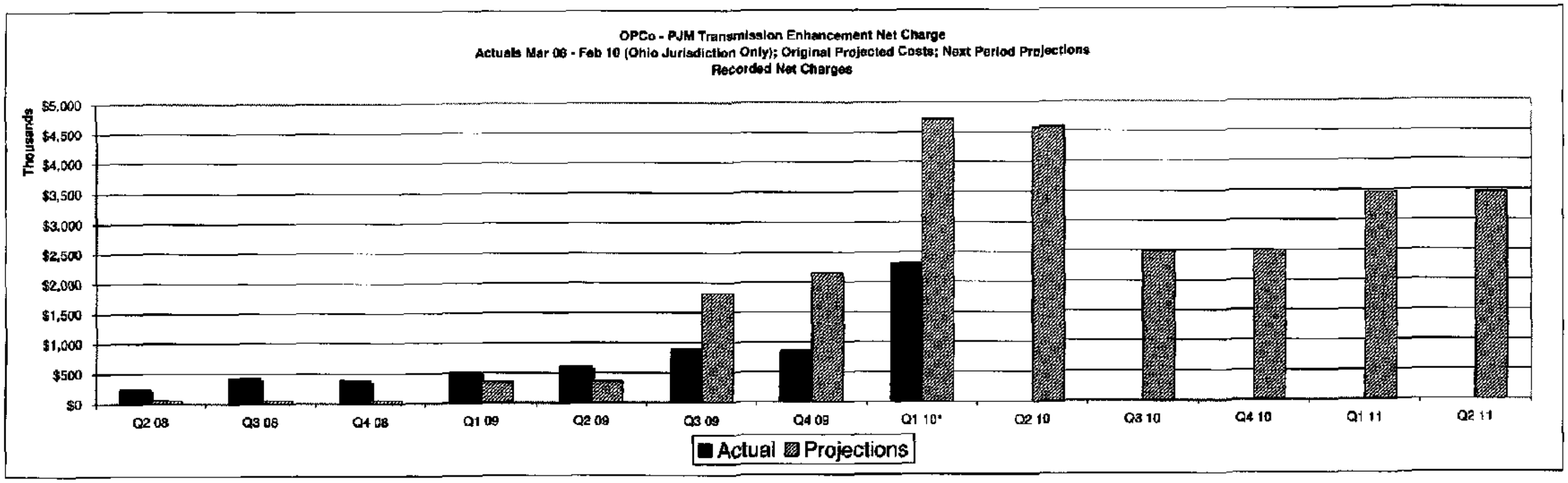
* Q1 10 includes two months of actual and one month projection



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM NITS	8,118,500	23,842,069	24,256,875	24,583,223	25,065,376	28,306,019	28,581,292	27,099,362	9,469,133	8,541,388
Projections - PJM NITS	8,390,800	25,736,229	26,613,819	25,561,515	25,833,097	27,874,947	30,815,533	30,876,813	10,492,238	10,492,238

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM NITS	10,492,238	28,502,759								
Projections - PJM NITS	10,492,238	31,476,713	9,692,165	9,692,165	9,692,165	29,076,495	29,699,457	29,944,335	30,246,061	30,424,473

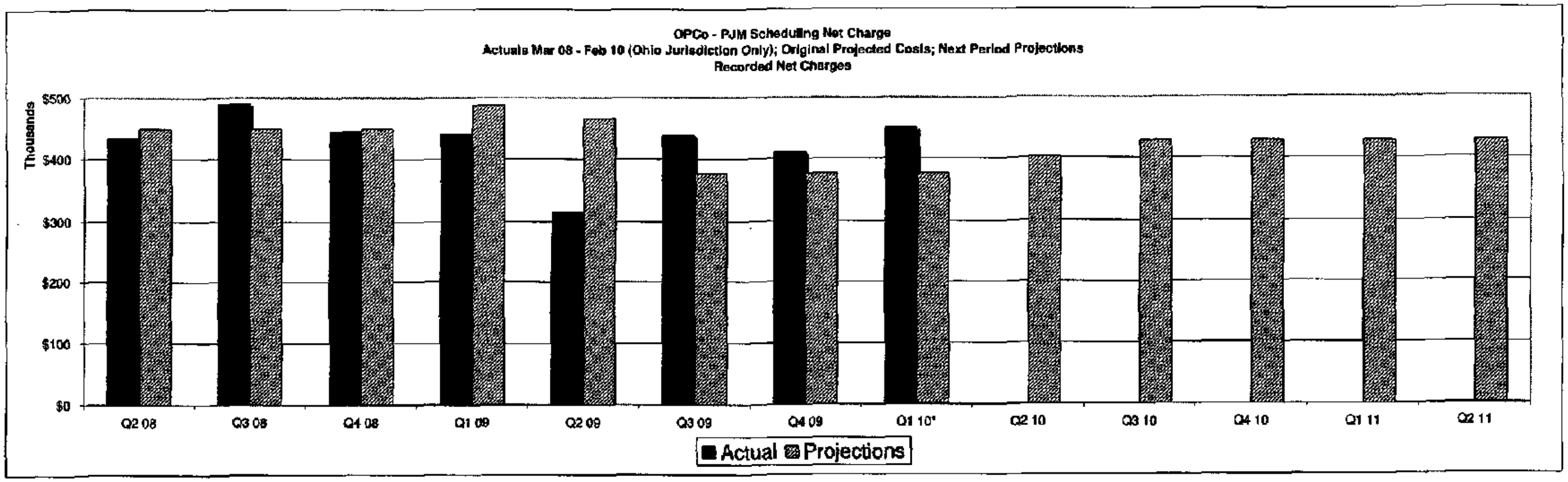
* Q1 10 includes two months of actual and one month projection



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Transmission Enhancement	16,571	243,646	427,254	380,618	518,001	619,713	888,886	853,232	359,417	377,666
Projections - PJM Transmission Enhancement	17,999	53,997	53,997	53,997	357,807	357,807	1,819,710	2,148,795	1,572,022	1,572,022

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Transmission Enhancement	1,572,022	2,309,105								
Projections - PJM Transmission Enhancement	1,572,022	4,716,066	1,524,703	1,524,703	1,524,703	4,574,109	2,488,780	2,493,525	3,464,687	3,461,232

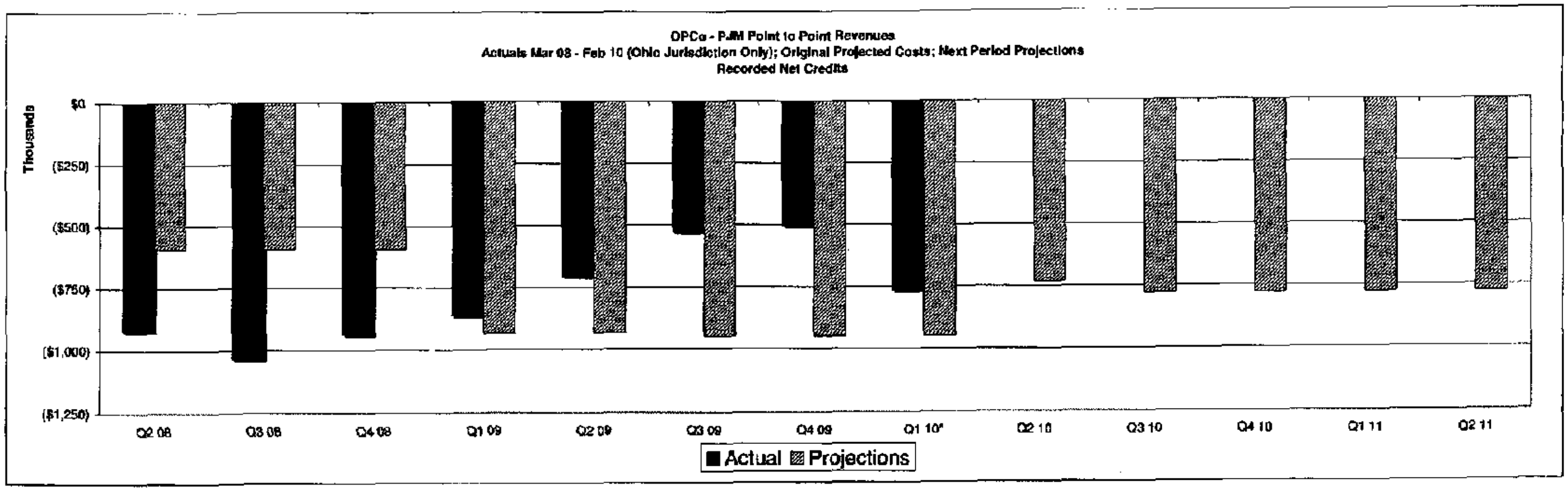
* Q1 10 includes two months of actual and one month projection



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Scheduling	138,423	432,977	489,847	444,244	439,964	315,473	438,080	410,697	170,765	153,369
Projections - PJM Scheduling	149,531	448,593	448,593	448,593	488,323	466,323	376,503	376,503	125,501	125,501

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Scheduling	125,501	449,635								
Projections - PJM Scheduling	125,501	376,503	134,263	134,263	134,263	402,790	427,668	427,668	427,668	427,668

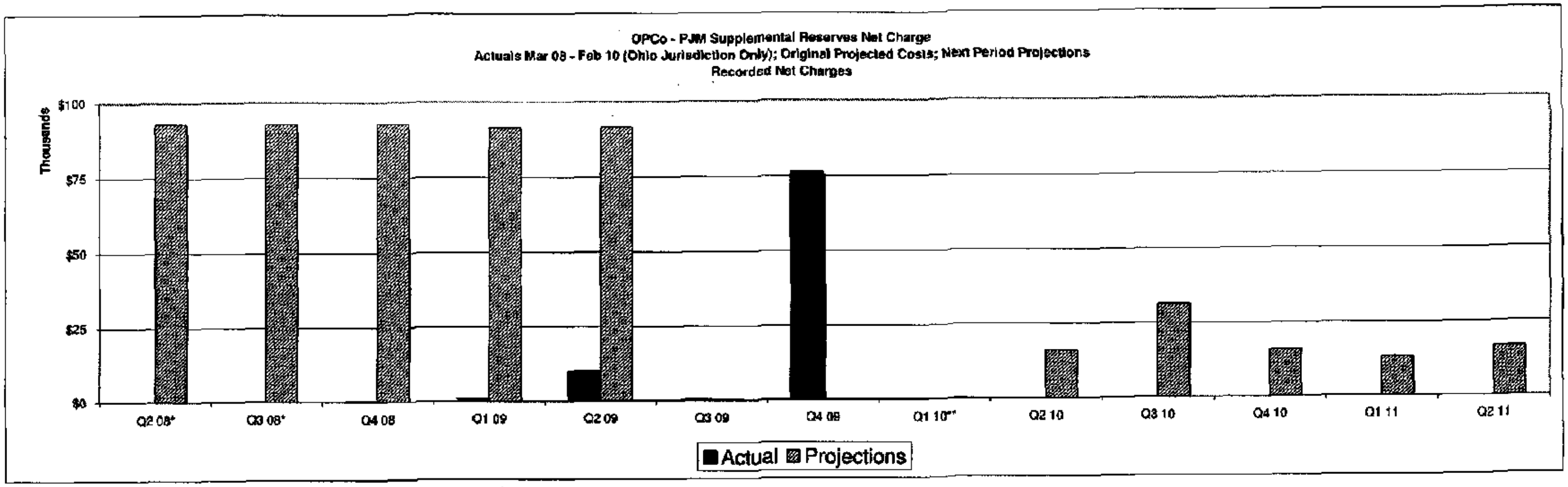
* Q1 10 includes two months of actual and one month projection



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Point to Point	(306,356)	(921,236)	(1,033,953)	(933,959)	(861,291)	(704,800)	(526,246)	(503,148)	(191,818)	(254,836)
Projections - PJM Point to Point	(197,585)	(592,755)	(592,755)	(592,755)	(933,591)	(931,591)	(948,582)	(948,582)	(316,194)	(316,194)

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Point to Point	(316,194)	(762,848)								
Projections - PJM Point to Point	(316,194)	(948,582)	(243,884)	(243,884)	(243,884)	(731,651)	(776,841)	(776,841)	(776,841)	(776,841)

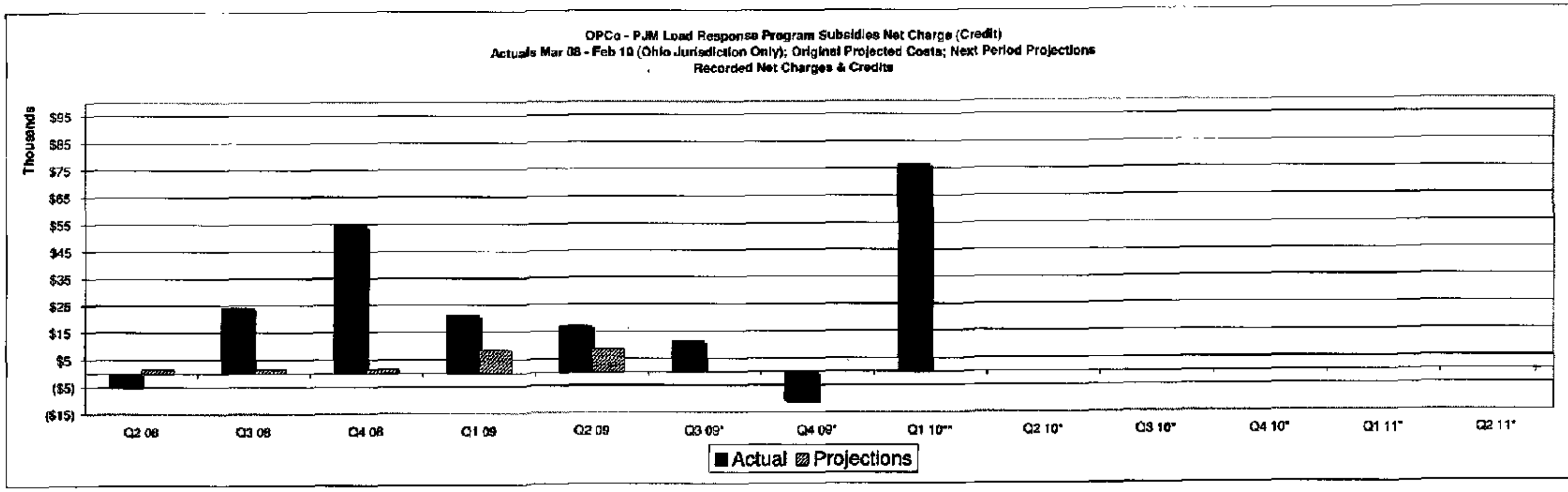
* Q1 10 includes two months of actual and one month projection



	ACTUAL									
	Mar-10*	Q2 08*	Q3 08*	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10**	Feb-10**
Actual - PJM Supplemental Reserves	0	0	74	448	1,000	9,999	412	76,519	50	48
Projections - PJM Supplemental Reserves	0	92,889	92,889	92,889	91,401	91,401	126	126	43	43

	2010 FORECAST									
	Mar-10**	Q1 10**	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Supplemental Reserves	43	141								
Projections - PJM Supplemental Reserves	43	129	5,341	5,341	5,341	16,022	31,345	15,860	13,266	16,532

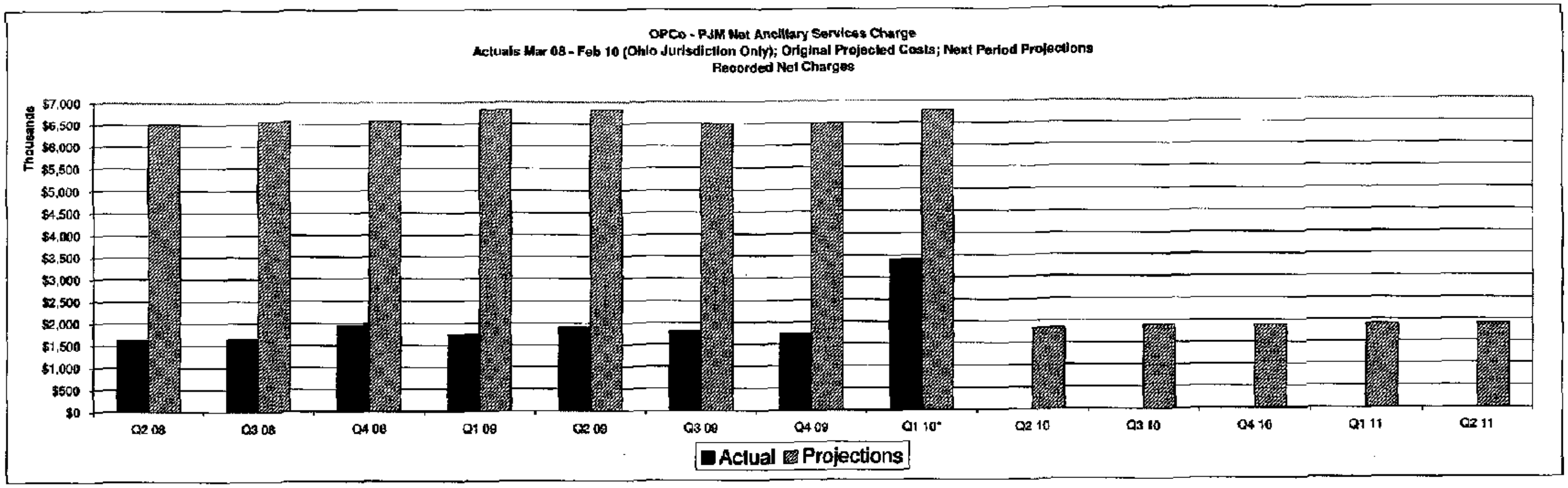
* Actual Supplemental Reserves charges started in Q3 08
** Q1 10 includes two months of actual and one month projection.



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09*	Q4 09*	Jan-10*	Feb-10*
Actual - PJM Load Response Program Subsidies	48	(4,534)	24,225	54,476	21,284	16,795	11,379	(10,546)	57,626	19,035
Projections - PJM Load Response Program Subsidies	494	1,481	1,481	1,481	8,391	8,391	-	-	-	-

	2010 FORECAST									
	Mar-10**	Q1 10**	Apr-10*	May-10*	Jun-10*	Q2 10*	Q3 10*	Q4 10*	Q1 11*	Q2 11*
Actual - PJM Load Response Program Subsidies	-	76,660								
Projections - PJM Load Response Program Subsidies	-	-	0	0	0	0	0	0	0	0

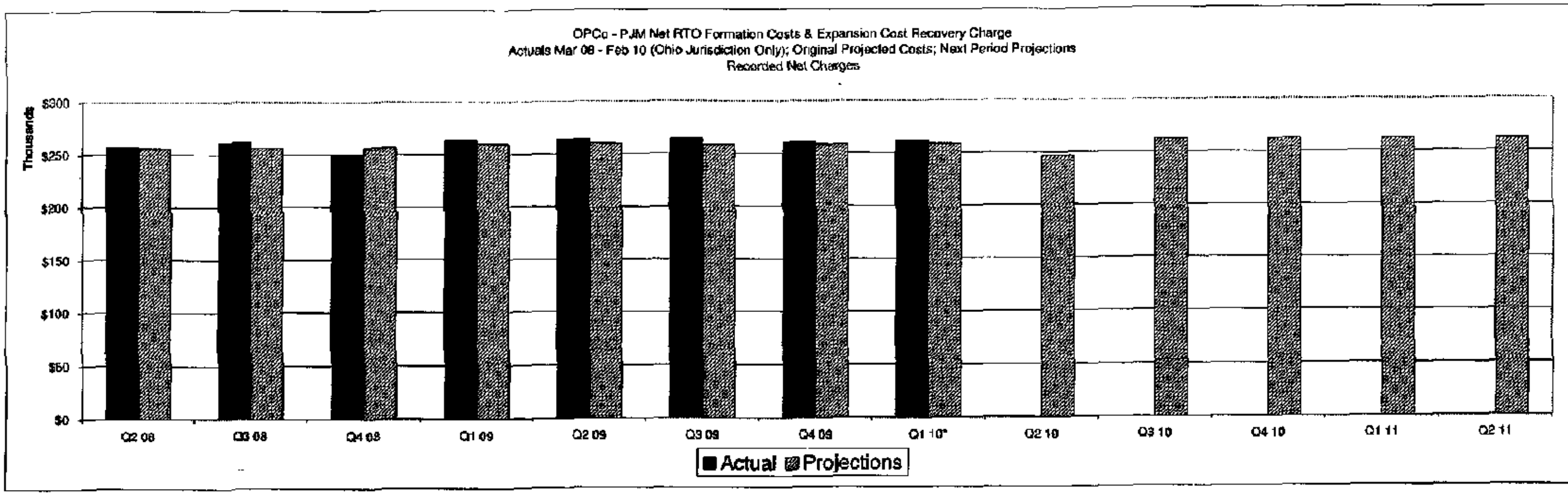
* Projected PJM Load Response Program Subsidies is $0 for Q3 09 through Q2 11 due to the lack of insight into the expected magnitude.
** Q1 10 includes two months of actual and one month projection.



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Net Ancillary Services	602,053	1,619,411	1,644,698	1,951,034	1,738,283	1,900,751	1,812,539	1,724,298	608,430	551,148
Projections - PJM Net Ancillary Services	2,180,530	6,512,553	6,574,479	6,574,479	6,829,833	6,829,833	6,496,542	6,496,542	2,260,206	2,260,206

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Net Ancillary Services	2,260,206	3,419,784								
Projections - PJM Net Ancillary Services	2,260,206	6,780,618	614,162	614,162	614,162	1,842,486	1,884,077	1,886,567	1,905,212	1,901,088

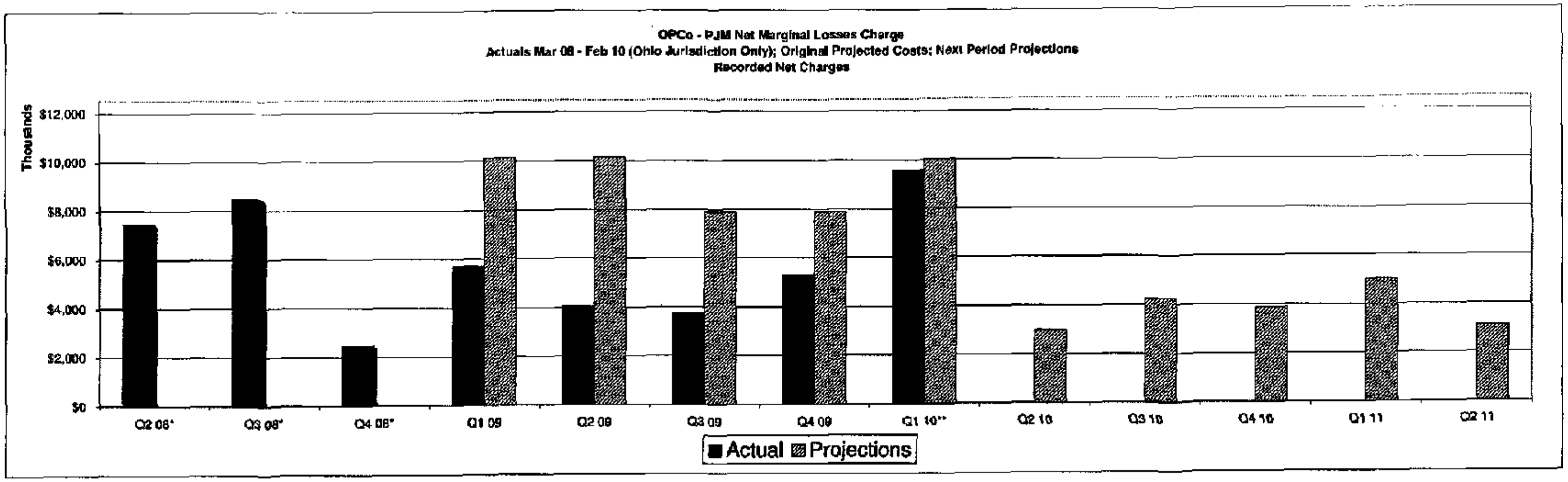
* Q1 10 includes two months of actual and one month projection



	ACTUAL									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10*	Feb-10*
Actual - PJM Net RTO Formation Costs & Expansion Cost Recovery	88,676	256,992	261,675	250,201	264,156	264,020	263,929	260,788	90,624	85,234
Projections - PJM Net RTO Formation Costs & Expansion Cost Recovery	85,423	256,266	256,266	256,266	259,800	259,800	258,510	258,510	86,170	86,170

	2010 FORECAST									
	Mar-10*	Q1 10*	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Net RTO Formation Costs & Expansion Cost Recovery	86,170	262,027								
Projections - PJM Net RTO Formation Costs & Expansion Cost Recovery	86,170	258,510	82,247	82,247	82,247	246,741	261,984	261,984	261,984	261,984

* Q1 10 includes two months of actual and one month projection

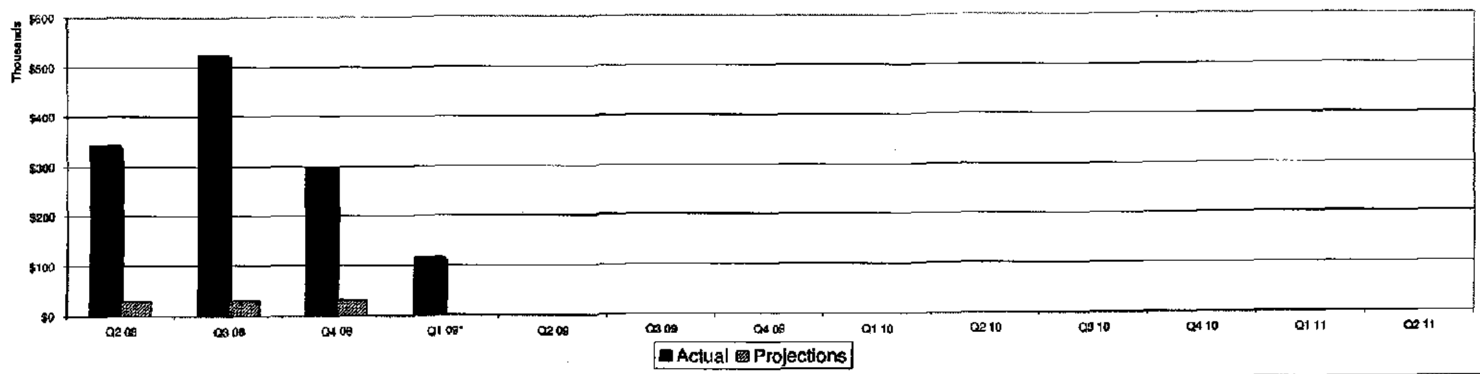


	ACTUAL									
	Mar-08*	Q2 08*	Q3 08*	Q4 08*	Q1 09	Q2 09	Q3 09	Q4 09	Jan-10**	Feb-10**
Actual - PJM Net Marginal Losses	1,342,708	7,461,516	8,493,408	2,469,951	5,696,284	4,044,408	3,751,536	5,309,163	3,709,658	2,630,927
Projections - PJM Net Marginal Losses	0	0	0	0	10,138,650	10,138,650	7,883,783	7,883,783	3,341,591	3,341,591

	2010 FORECAST									
	Mar-10**	Q1 10**	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Net Marginal Losses	3,341,591	9,582,078								
Projections - PJM Net Marginal Losses	3,341,591	10,024,773	998,541	998,541	998,541	2,995,624	4,253,206	3,885,546	5,004,083	3,090,903

* Collection of Marginal Losses began in 2008. No projections until 2009.
** Q1 10 includes two months of actual and one month projection.

OPCo - PJM Power Acquisition Rider Adjustment Charge
Actuals Mar 08 - Feb 10 (Ohio Jurisdiction Only); Original Projected Costs; Next Period Projections
Recorded Net Charges



	ACTUALS									
	Mar-08	Q2 08	Q3 08	Q4 08	Q1 09*	Q2 09	Q3 09	Q4 09	Jan-10	Feb-10
Actual - PJM Power Acquisition Rider Adjustment	306,070	342,413	525,142	299,994	115,208	0	0	0	0	0
Projections - PJM Power Acquisition Rider Adjustment	9,792	29,779	30,585	30,585	0	0	0	0	0	0

	2010 FORECAST									
	Mar-10	Q1 10	Apr-10	May-10	Jun-10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11
Actual - PJM Power Acquisition Rider Adjustment	0	0	0	0	0	0	0	0	0	0
Projections - PJM Power Acquisition Rider Adjustment	0	0	0	0	0	0	0	0	0	0

* Power Acquisition Rider Adjustment ceased beginning in 2009.

Typical Bill Comparison

Ohio Power Company

Tariff	kWh	KW	Current	Proposed	Difference
Residential					
	100		$14.13	$14.10	-0.2%
	250		$28.62	$28.54	-0.3%
	500		$52.83	$52.66	-0.3%
	750		$77.02	$76.77	-0.3%
	1,000		$98.85	$98.53	-0.3%
	1,500		$141.35	$140.86	-0.4%
	2,000		$183.82	$183.16	-0.4%
GS-1 Secondary					
	375	3	$45.17	$45.11	-0.1%
	1,000	3	$95.31	$95.15	-0.2%
	750	6	$75.24	$75.13	-0.2%
	2,000	6	$175.50	$175.19	-0.2%
GS-2 Secondary					
	1,500	12	$180.77	$176.51	-2.4%
	4,000	12	$352.29	$344.92	-2.1%
	6,000	30	$566.04	$552.59	-2.4%
	10,000	30	$840.10	$821.67	-2.2%
	10,000	40	$882.71	$862.28	-2.3%
	14,000	40	$1,156.77	$1,131.38	-2.2%
	12,500	50	$1,096.62	$1,071.09	-2.3%
	18,000	50	$1,471.77	$1,439.41	-2.2%
	15,000	75	$1,374.44	$1,340.80	-2.5%
	30,000	100	$2,513.38	$2,456.10	-2.3%
	36,000	100	$2,921.08	$2,856.35	-2.2%
	30,000	150	$2,730.79	$2,663.51	-2.5%
	60,000	300	$5,426.06	$5,291.51	-2.5%
	90,000	300	$7,464.76	$7,292.94	-2.3%
	100,000	500	$9,018.32	$8,794.07	-2.5%
	150,000	500	$12,416.15	$12,129.78	-2.3%
	180,000	500	$14,454.83	$14,131.18	-2.2%

Typical Bill Comparison

Ohio Power Company

Tariff	kWh	KW	Current	Proposed	Difference
GS-3 Secondary					
	18,000	50	$1,486.01	$1,466.19	-1.3%
	30,000	75	$2,319.84	$2,287.39	-1.4%
	50,000	75	$3,043.60	$2,993.02	-1.7%
	36,000	100	$2,949.57	$2,909.93	-1.3%
	30,000	150	$3,535.93	$3,498.23	-1.1%
	60,000	150	$4,621.56	$4,556.67	-1.4%
	100,000	150	$6,069.09	$5,967.93	-1.7%
	120,000	300	$9,207.65	$9,077.86	-1.4%
	150,000	300	$10,293.29	$10,136.30	-1.5%
	200,000	300	$12,102.68	$11,900.36	-1.7%
	180,000	500	$14,597.19	$14,399.00	-1.4%
	200,000	500	$15,320.96	$15,104.64	-1.4%
	325,000	500	$19,844.46	$19,514.82	-1.7%
GS-2 Primary					
	200,000	1,000	$16,884.48	$16,454.88	-2.5%
	300,000	1,000	$23,538.85	$22,989.45	-2.3%
GS-3 Primary					
	360,000	1,000	$27,799.90	$27,415.22	-1.4%
	400,000	1,000	$29,233.22	$28,813.58	-1.4%
	650,000	1,000	$38,191.41	$37,553.24	-1.7%
GS-2 Subtransmission					
	1,500,000	5,000	$112,798.87	$110,145.22	-2.4%
GS-3 Subtransmission					
	2,500,000	5,000	$157,107.79	$154,675.04	-1.6%
	3,250,000	5,000	$182,713.11	$179,640.53	-1.7%
GS-4 Subtransmission					
	3,000,000	10,000	$218,562.08	$220,939.38	1.1%
	5,000,000	10,000	$278,850.47	$279,945.97	0.4%
	6,500,000	10,000	$324,066.77	$324,200.92	0.0%
	10,000,000	20,000	$556,020.70	$558,211.70	0.4%
	13,000,000	20,000	$646,453.29	$646,721.59	0.0%
GS-4 Transmission					
	25,000,000	50,000	$1,337,128.42	$1,342,605.92	0.4%
	32,500,000	50,000	$1,562,900.88	$1,563,571.63	0.0%

Typical Bill Comparison

Columbus Southern Power Company

Tariff	kWh	KW	Current	Proposed	Difference
Residential					
RR1	100		$16.56	$17.11	3.3%
	250		$33.38	$34.76	4.1%
	500		$61.43	$64.20	4.5%
RR Winter	750		$96.55	$96.15	-0.4%
	1,000		$115.87	$115.34	-0.5%
	1,500		$149.05	$148.25	-0.5%
	2,000		$182.21	$181.14	-0.6%
RR Summer	750		$96.55	$96.15	-0.4%
	1,000		$126.93	$126.40	-0.4%
	1,500		$187.75	$186.95	-0.4%
	2,000		$248.56	$247.49	-0.4%
GS-1					
	375	3	$57.59	$56.99	-1.0%
	1,000	3	$140.94	$139.34	-1.1%
	750	6	$107.60	$106.41	-1.1%
	2,000	6	$243.19	$239.99	-1.3%
GS-2 Secondary					
	1,500	12	$219.47	$219.48	0.0%
	4,000	12	$463.35	$463.28	0.0%
	6,000	30	$751.29	$751.24	0.0%
	10,000	30	$1,141.13	$1,140.95	0.0%
	10,000	40	$1,192.82	$1,192.69	0.0%
	14,000	40	$1,582.66	$1,582.38	0.0%
	12,500	50	$1,488.16	$1,487.97	0.0%
	18,000	50	$2,022.50	$2,022.14	0.0%
	15,000	75	$1,861.00	$1,860.86	0.0%
	30,000	150	$3,702.09	$3,701.83	0.0%
	60,000	300	$7,384.28	$7,383.74	0.0%
	100,000	500	$12,293.87	$12,292.97	0.0%

Typical Bill Comparison

Columbus Southern Power Company

Tariff	kWh	KW	Current	Proposed	Difference
GS-2 Primary					
	200,000	1,000	$23,527.51	$23,159.53	-1.6%
GS-3 Secondary					
	30,000	75	$2,790.46	$2,751.62	-1.4%
	50,000	75	$3,778.14	$3,717.35	-1.6%
	30,000	100	$3,180.64	$3,139.82	-1.3%
	36,000	100	$3,476.92	$3,429.51	-1.4%
	60,000	150	$5,437.50	$5,359.80	-1.4%
	100,000	150	$7,412.82	$7,291.23	-1.6%
	90,000	300	$9,246.11	$9,123.65	-1.3%
	120,000	300	$10,727.61	$10,572.22	-1.4%
	150,000	300	$12,209.13	$12,020.82	-1.5%
	200,000	300	$14,678.27	$14,435.09	-1.7%
	150,000	500	$15,311.61	$15,107.50	-1.3%
	180,000	500	$16,793.09	$16,556.06	-1.4%
	200,000	500	$17,780.76	$17,521.78	-1.5%
	325,000	500	$23,953.68	$23,557.53	-1.7%
GS-3 Primary					
	300,000	1,000	$28,993.88	$28,599.37	-1.4%
	360,000	1,000	$31,886.99	$31,428.78	-1.4%
	400,000	1,000	$33,815.73	$33,315.05	-1.5%
	650,000	1,000	$45,870.35	$45,104.24	-1.7%
GS-4					
	1,500,000	5,000	$125,300.51	$128,232.76	2.3%
	2,500,000	5,000	$167,492.32	$169,928.57	1.5%
	3,250,000	5,000	$199,136.21	$201,200.46	1.0%
	3,000,000	10,000	$230,873.86	$236,738.99	2.5%
	5,000,000	10,000	$315,257.51	$320,130.64	1.5%
	6,500,000	10,000	$378,545.23	$382,674.36	1.1%
	6,000,000	20,000	$442,006.20	$453,735.82	2.7%
	10,000,000	20,000	$610,773.47	$620,519.09	1.6%
	13,000,000	20,000	$737,348.91	$745,606.53	1.1%
	15,000,000	50,000	$1,075,424.73	$1,104,749.73	2.7%
	25,000,000	50,000	$1,497,342.90	$1,521,707.90	1.6%
	32,500,000	50,000	$1,813,781.53	$1,834,426.53	1.1%

Ohio Power Company
Projected Transmission Cost Recovery Rider Cost / Revenues
July 2010 - June 2011
<Revenue>/ Expense in $

	Forecast Jul-10	Forecast Aug-10	Forecast Sep-10	Forecast Oct-10	Forecast Nov-10	Forecast Dec-10	Forecast Jan-11	Forecast Feb-11	Forecast Mar-11	Forecast Apr-11	Forecast May-11	Forecast Jun-11	Forecasted ETCRR July10-Jun11
Total Company													
# NITS (d) **$2111.60 per MW/Mo**	10,253,621	10,758,753	10,636,664	10,636,664	10,636,664	10,636,664	10,636,664	10,767,644	10,807,216	10,807,216	10,807,216	10,807,216	128,212,202
Pt-to-Pt Transm. Revenues (b)	(275,945)	(275,945)	(275,945)	(275,945)	(275,945)	(275,945)	(275,945)	(275,945)	(275,945)	(275,945)	(275,945)	(275,945)	(3,311,342)
Subtotal	9,977,676	10,482,808	10,360,719	10,360,719	10,360,719	10,360,719	10,360,719	10,511,699	10,531,271	10,531,271	10,531,271	10,531,271	124,900,860
TO Scheduling, Sys Contr & Disp (b)	151,913	151,913	151,913	151,913	151,913	151,913	151,913	151,913	151,913	151,913	151,913	151,913	1,822,961
Transmission Enhancement Charges (c) (e)	879,691	886,725	885,736	885,736	885,736	885,736	1,233,038	1,229,606	1,229,480	1,229,480	1,229,480	1,229,480	12,689,923
Net Congestion:													
PJM Implicit Congestion (b)	2,316,993	2,881,700	1,700,186	1,249,160	1,191,748	1,305,826	2,400,841	1,315,853	598,365	788,986	777,982	1,511,437	18,019,057
PJM FTR Revenue & Auction Revenue Rights (b)	(2,316,993)	(2,881,700)	(1,700,186)	(1,249,160)	(1,191,748)	(1,305,826)	(2,400,841)	(1,315,853)	(598,365)	(788,986)	(777,982)	(1,511,437)	(18,019,057)
Net Congestion Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM Operating Reserve (Gross) (c)	885,702	1,023,307	638,594	638,594	638,594	830,172	990,399	902,226	644,362	644,362	741,016	773,234	9,350,560
PJM Ancillary Services (Gross):													
PJM Synchronous Condensing (c)	2,541	3,586	2,417	2,730	1,705	1,555	2,527	1,579	1,038	852	737	1,771	23,038
PJM Reactive Supply (c)	647,123	654,203	653,208	653,208	653,208	653,208	661,574	659,195	659,108	659,108	659,108	659,108	7,871,361
PJM Blackstart (c)	14,792	14,954	14,931	14,931	14,931	14,931	15,122	15,068	15,066	15,066	15,066	15,066	179,925
PJM Regulation Charges (c)	1,328,356	1,448,878	850,519	768,509	874,743	1,025,323	930,953	1,076,344	853,592	586,487	941,401	1,221,694	11,907,008
PJM Spinning Reserve Charges (c)	38,317	19,335	20,614	4,683	28,942	45,527	29,342	33,468	28,762	26,584	26,870	43,858	346,072
PJM Supplemental Reserve Charges (c) (f)	6,520	21,845	3,037	4,118	4,563	8,221	8,027	3,792	2,318	3,583	3,018	11,017	82,058
PJM Ancillary Services Subtotal	2,037,649	2,162,802	1,544,726	1,448,180	1,578,092	1,748,765	1,647,546	1,789,436	1,559,883	1,291,670	1,646,000	1,952,715	20,409,463
PJM Administration Service Fees (a) (c)	699,159	699,159	699,159	699,159	699,159	699,159	720,134	720,134	720,134	720,134	720,134	720,134	8,515,758
Amortization of PJM Integration Costs (b)	129,521	129,521	129,521	129,521	129,521	129,521	129,521	129,521	129,521	129,521	129,521	129,521	1,554,255
PJM RTO Formation Cost Recovery (b)	(5,973)	(5,973)	(5,973)	(5,973)	(5,973)	(5,973)	(5,973)	(5,973)	(5,973)	(5,973)	(5,973)	(5,973)	(71,681)
Net Expansion Cost Recovery (b)	(30,488)	(30,488)	(30,488)	(30,488)	(30,488)	(30,488)	(30,488)	(30,488)	(30,488)	(30,488)	(30,488)	(30,488)	(365,860)
Net RTO Formation Costs & Expansion Cost Recovery Charge	93,059	93,059	93,059	93,059	93,059	93,059	93,059	93,059	93,059	93,059	93,059	93,059	1,116,714
Net Marginal Losses (c)	1,674,635	1,708,187	1,149,579	1,150,063	1,340,186	1,850,359	2,726,842	1,496,897	1,109,130	993,233	977,370	1,323,198	17,299,378
Load Response Program Subsidies (b)	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Acquisition Rider Adjustment (c)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net RTO Costs - OPCo	16,399,485	17,207,960	15,823,485	16,437,424	15,747,458	16,419,852	17,923,349	16,894,970	16,039,233	16,666,122	16,092,243	16,776,005	196,105,617
Jurisdictional Allocation	93.840%	93.840%	93.840%	93.840%	93.840%	93.840%	93.840%	93.840%	93.840%	93.840%	93.840%	93.840%	

(a) Includes NERC and RFC Fees
(b) Forecast using 12 months actual data through February 2010
(c) Forecast using February 2009 actual and anticipated/known changes
(d) Forecast using 2010/2011 load forecast and current OATT rates
(e) Pursuant to Schedule 12 of the PJM OATT, the Company has begun to incur charges for Required Regional Transmission Enhancements.
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Ohio Power Company
Projected Transmission Cost Recovery Rider Cost / Revenues
July 2010 - June 2011
<Revenue>/ Expense in $

	Forecast Jul-10	Forecast Aug-10	Forecast Sep-10	Forecast Oct-10	Forecast Nov-10	Forecast Dec-10	Forecast Jan-11	Forecast Feb-11	Forecast Mar-11	Forecast Apr-11	Forecast May-11	Forecast Jun-11	Forecasted ETCRR July10-Jun11
Jurisdictional													
NITS (d) $2111.60 per MW/Mo	9,821,998	10,098,014	9,981,445	9,981,445	9,981,445	9,981,445	9,981,445	10,123,125	10,141,491	10,141,491	10,141,491	10,141,491	120,314,326
Pt-to-Pt Transm. Revenues (b)	(258,947)	(258,947)	(258,947)	(258,947)	(258,947)	(258,947)	(258,947)	(258,947)	(258,947)	(258,947)	(258,947)	(258,947)	(3,107,364)
Subtotal	9,563,051	9,839,067	9,722,498	9,722,498	9,722,498	9,722,498	9,722,498	9,864,178	9,882,544	9,882,544	9,882,544	9,882,544	117,206,962
TO Scheduling, Sys Contr & Disp (b)	142,556	142,556	142,556	142,556	142,556	142,556	142,556	142,556	142,556	142,556	142,556	142,556	1,710,672
Transmission Enhancement Charges (c) (e)	825,502	832,103	831,175	831,175	831,175	831,175	1,157,081	1,153,862	1,153,744	1,153,744	1,153,744	1,153,744	11,908,224
Net Congestion:													
PJM Implicit Congestion (b)	2,174,286	2,704,187	1,595,436	1,172,212	1,118,337	1,226,387	2,252,949	1,234,796	581,505	721,616	730,059	1,418,333	16,909,083
PJM FTR Revenue & Auction Revenue Rights (b)	(2,174,286)	(2,704,187)	(1,595,436)	(1,172,212)	(1,118,337)	(1,226,387)	(2,252,949)	(1,234,796)	(581,505)	(721,616)	(730,059)	(1,418,333)	(16,909,083)
Net Congestion Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM Operating Reserve (Gross) (c)	831,143	960,271	599,256	599,256	599,256	779,033	929,390	846,648	604,669	604,669	695,369	725,603	8,774,583
PJM Ancillary Services (Gross):													
PJM Synchronous Condensing (c)	2,384	3,365	2,288	2,582	1,600	1,459	2,371	1,482	974	799	691	1,662	21,617
PJM Reactive Supply (c)	607,280	613,906	612,971	612,971	612,971	612,971	620,821	618,589	618,507	618,507	618,507	618,507	7,386,487
PJM Blackstart (c)	13,881	14,033	14,011	14,011	14,011	14,011	14,191	14,140	14,138	14,138	14,138	14,138	168,841
PJM Regulation Charges (c)	1,246,530	1,359,627	798,127	721,159	820,859	962,163	873,606	1,010,041	801,010	550,369	883,411	1,146,825	11,173,537
PJM Spinning Reserve Charges (c)	34,080	18,144	19,344	4,395	27,159	42,723	27,535	31,397	26,990	24,928	26,904	41,157	324,756
PJM Supplemental Reserve Charges (c) (f)	7,996	20,500	2,850	3,864	4,282	7,714	7,533	3,558	2,175	3,362	2,832	10,338	77,003
PJM Ancillary Services Subtotal	1,912,130	2,029,574	1,449,571	1,358,972	1,480,882	1,641,041	1,546,057	1,679,207	1,463,794	1,212,103	1,546,483	1,832,427	19,152,241
PJM Administration Service Fees (a) (c)	656,091	656,091	656,091	656,091	656,091	656,091	675,774	675,774	675,774	675,774	675,774	675,774	7,991,190
Amortization of PJM Integration Costs (b)	121,543	121,543	121,543	121,543	121,543	121,543	121,543	121,543	121,543	121,543	121,543	121,543	1,458,516
PJM RTO Formation Cost Recovery (b)	(5,605)	(5,605)	(5,605)	(5,605)	(5,605)	(5,605)	(5,605)	(5,605)	(5,605)	(5,605)	(5,605)	(5,605)	(67,260)
Net Expansion Cost Recovery (b)	(28,610)	(28,610)	(28,610)	(28,610)	(28,610)	(28,610)	(28,610)	(28,610)	(28,610)	(28,610)	(28,610)	(28,610)	(343,320)
Net RTO Formation Costs & Expansion Cost Recovery Charge	87,328	87,328	87,328	87,328	87,328	87,328	87,328	87,328	87,328	87,328	87,328	87,328	1,047,936
Net Marginal Losses (c)	1,571,478	1,602,963	1,078,765	1,079,219	1,257,630	1,548,697	2,558,587	1,404,888	1,040,808	932,050	917,164	1,241,689	16,233,738
Load Response Program Subsidies (b)	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Acquisition Rider Adjustment (c)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net RTO Costs - OPCo	15,389,879	16,147,853	14,667,240	14,477,995	14,777,416	15,608,419	16,819,271	15,854,441	15,051,217	14,890,768	15,100,962	15,741,665	184,025,626
2010 - 2011 Forecasted Load (MWH)													
Residential	716,266	718,119	550,821	446,890	500,993	761,049	846,838	674,966	680,950	485,068	470,298	546,484	7,408,352
Commercial	554,802	533,726	505,593	486,056	414,707	508,683	515,103	462,358	497,428	456,435	489,019	530,520	5,954,228
Industrial	929,377	931,238	916,893	979,011	923,494	950,664	910,518	942,553	1,002,344	971,358	1,001,495	975,623	11,434,366
Joint Service Territory	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	1,272,000
Other Ultimates	4,821	5,494	5,879	7,366	7,612	8,607	8,303	6,798	6,847	5,899	5,344	4,861	77,929
Municipals	638	681	487	398	460	731	764	679	661	560	422	526	7,009
Total	2,311,804	2,295,258	2,085,273	2,025,821	1,953,266	2,335,734	2,387,526	2,193,350	2,294,230	2,035,350	2,072,578	2,163,996	26,153,884
AEP Peak at time of PJM Peak (1/16/2009)	22,068 MW												
MLR Forecast for July 2010 - June 2011	0.22004	0.23088	0.22626	0.22626	0.22626	0.22626	0.22626	0.23150	0.23192	0.23192	0.23192	0.23192	
WPCo Share of OPCo Peak used in MLR	6.160%	6.160%	6.160%	6.160%	6.160%	6.160%	6.160%	6.160%	6.160%	6.160%	6.160%	6.160%	

(a) Includes NERC and RFC Fees
(b) Forecast using 12 months actual data through February 2010
(c) Forecast using February 2009 actual and anticipated/known changes
(d) Forecast using 2010/2011 load forecast and current OATT rates
(e) Pursuant to Schedule 12 of the PJM OATT, the Company has begun to incur charges for Required Regional Transmission Enhancements.
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Columbus Southern Power
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July 2010 - June 2011
<Revenue>/ Expense in $

	Forecast Jul-10	Forecast Aug-10	Forecast Sep-10	Forecast Oct-10	Forecast Nov-10	Forecast Dec-10	Forecast Jan-11	Forecast Feb-11	Forecast Mar-11	Forecast Apr-11	Forecast May-11	Forecast Jun-11	Forecasted ETCRR July10-Jun11
Total Company													
# NITS (d) **$2111.80 per MW/Mo**	8,609,146	8,564,411	8,656,211	8,656,211	8,656,211	8,656,211	8,656,211	8,779,232	8,795,075	8,795,075	8,795,075	8,795,075	104,414,144
Pt-to-Pt Transm. Revenues (b)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(2,792,567)
Subtotal	8,376,432	8,331,697	8,423,497	8,423,497	8,423,497	8,423,497	8,423,497	8,546,518	8,562,361	8,562,361	8,562,361	8,562,361	101,621,577
TO Scheduling, Sys Contr & Disp (b)	128,575	128,575	128,575	128,575	128,575	128,575	128,575	128,575	128,575	128,575	128,575	128,575	1,542,899
Transmission Enhancement Charges (c) (e)	718,152	725,215	728,803	728,803	728,803	728,803	1,019,870	1,017,068	1,016,942	1,016,942	1,016,942	1,016,942	10,463,283
Net Congestion:													
PJM Implicit Congestion (c)	1,858,791	2,315,656	1,377,688	1,012,227	965,705	1,058,145	1,963,913	1,076,386	489,456	829,022	636,382	1,236,340	14,617,712
PJM FTR Revenue & Auction Revenue Rights (c)	(1,858,791)	(2,315,656)	(1,377,688)	(1,012,227)	(965,705)	(1,058,145)	(1,963,913)	(1,076,386)	(489,456)	(829,022)	(636,382)	(1,236,340)	(14,617,712)
Net Congestion Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM Operating Reserve (Gross) (c)	709,784	822,302	517,469	517,469	517,469	872,710	810,156	738,033	527,081	527,081	606,144	632,498	7,598,197
PJM Ancillary Services (Gross):													
PJM Synchronous Condensing (c)	2,036	2,862	1,958	2,213	1,382	1,260	2,067	1,292	849	687	602	1,449	18,687
PJM Reactive Supply (c)	518,591	525,700	529,312	529,312	529,312	529,312	541,174	539,231	539,144	539,144	539,144	539,144	6,396,518
PJM Blackstart (c)	11,854	12,017	12,099	12,099	12,099	12,098	12,370	12,326	12,324	12,324	12,324	12,324	146,258
PJM Regulation Charges (c)	1,064,518	1,164,279	689,197	622,743	708,827	830,846	761,529	850,464	698,229	479,748	770,057	999,497	9,669,935
PJM Spinning Reserve Charges (c)	29,104	15,537	16,704	3,795	23,452	36,892	24,002	27,369	23,527	21,729	23,452	35,876	281,438
PJM Supplemental Reserve Charges (c) (f)	6,827	17,554	2,461	3,337	3,898	6,661	6,567	3,102	1,886	2,931	2,488	9,012	68,514
PJM Ancillary Services Subtotal	1,632,931	1,737,969	1,251,731	1,173,498	1,278,769	1,417,070	1,347,709	1,463,783	1,275,969	1,056,573	1,348,047	1,597,301	16,561,350
PJM Administration Service Fees (a) (c)	571,528	571,528	571,528	571,528	571,528	571,528	588,674	588,674	588,674	588,674	588,674	588,674	6,961,212
Amortization of PJM Integration Costs (b)	47,686	47,686	47,686	47,686	47,686	47,686	47,686	47,686	47,686	47,686	47,686	47,686	572,230
PJM RTO Formation Cost Recovery (b)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(25,211)
Net Expansion Cost Recovery (b)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(129,463)
Net RTO Formation Costs & Expansion Cost Recovery Charge	34,796	34,796	34,796	34,796	34,796	34,796	34,796	34,796	34,796	34,796	34,796	34,796	417,555
Net Marginal Losses (c)	1,342,019	1,372,653	931,534	931,926	1,085,987	1,337,329	2,230,339	1,224,483	807,257	812,454	799,478	1,082,362	14,057,822
Load Response Program Subsidies (c)	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Acquisition Rider Adjustment (c)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net RTO Costs - CSP	13,514,217	13,724,736	12,687,933	12,619,092	12,769,424	13,314,307	14,583,818	13,741,930	13,841,685	12,727,457	13,086,917	13,643,509	159,243,894
Jurisdictional Allocation	97.49%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

(a) Includes NERC and RFC Fees
(b) Forecast using 12 months actual data through February 2010
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(f) Beginning June 1, 2008, the Company is required to comply with PJM's new Supplemental 30-minute Reserve requirement and is a Forecast.

Columbus Southern Power
Projected Transmission Cost Recovery Rider Cost / Revenues
July 2010 - June 2011
<Revenue>/ Expense in $

	Forecast Jul-10	Forecast Aug-10	Forecast Sep-10	Forecast Oct-10	Forecast Nov-10	Forecast Dec-10	Forecast Jan-11	Forecast Feb-11	Forecast Mar-11	Forecast Apr-11	Forecast May-11	Forecast Jun-11	Forecasted ETCRR July10-Jun11
Jurisdictional													
NITS (d) $2111.60 per MW/Mo	8,393,056	8,564,411	8,656,211	8,656,211	8,656,211	8,656,211	8,656,211	8,779,232	8,795,075	8,795,075	8,795,075	8,795,075	104,198,054
Pt-to-Pt Transm. Revenues (b)	(226,873)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(232,714)	(2,786,727)
Subtotal	8,168,183	8,331,697	8,423,497	8,423,497	8,423,497	8,423,497	8,423,497	8,546,518	8,562,361	8,562,361	8,562,361	8,562,361	101,411,327
TO Scheduling, Sys Contr & Disp (b)	125,348	128,575	128,575	128,575	128,575	128,575	128,575	128,575	128,575	128,575	128,575	128,575	1,539,673
Transmission Enhancement Charges (c) (e)	700,127	725,215	728,803	728,803	728,803	728,803	1,019,870	1,017,068	1,016,942	1,016,942	1,016,942	1,016,942	10,445,260
Net Congestion:													
PJM Implicit Congestion (c)	1,810,186	2,315,656	1,377,689	1,012,227	985,705	1,058,145	1,963,913	1,076,386	489,456	629,022	636,382	1,236,340	14,571,107
PJM FTR Revenue & Auction Revenue Rights (c)	(1,810,186)	(2,315,656)	(1,377,689)	(1,012,227)	(985,705)	(1,058,145)	(1,963,913)	(1,076,386)	(489,456)	(629,022)	(636,382)	(1,236,340)	(14,571,107)
Net Congestion Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM Operating Reserve (Gross) (c)	691,968	822,302	517,469	517,469	517,469	672,710	810,158	738,033	527,081	527,081	606,144	632,498	7,580,380
PJM Ancillary Services (Gross):													
PJM Synchronous Condensing (c)	1,985	2,882	1,958	2,213	1,382	1,280	2,067	1,292	849	697	602	1,449	18,636
PJM Reactive Supply (c)	505,575	525,700	529,312	529,312	529,312	529,312	541,174	539,231	539,144	539,144	539,144	539,144	6,385,504
PJM Blackstart (c)	11,557	12,017	12,098	12,098	12,098	12,098	12,370	12,326	12,324	12,324	12,324	12,324	145,962
PJM Regulation Charges (c)	1,037,799	1,164,279	689,197	622,743	708,827	830,846	761,529	880,464	698,229	479,748	770,057	999,497	9,643,216
PJM Spinning Reserve Charges (c)	28,374	15,537	18,704	3,795	23,452	38,892	24,002	27,369	23,527	21,729	23,452	35,876	280,709
PJM Supplemental Reserve Charges (c) (f)	6,656	17,554	2,461	3,337	3,698	6,661	6,567	3,102	1,898	2,931	2,468	9,012	66,343
PJM Ancillary Services Subtotal	1,591,946	1,737,969	1,251,731	1,173,498	1,278,770	1,417,070	1,347,709	1,463,784	1,275,969	1,056,573	1,348,047	1,597,302	16,540,369
PJM Administration Service Fees (a) (c)	557,163	571,528	571,528	571,528	571,528	571,528	588,674	588,674	588,674	588,674	588,674	588,674	6,946,867
Amortization of PJM Integration Costs (b)	46,489	47,686	47,686	47,686	47,686	47,686	47,686	47,686	47,686	47,686	47,686	47,686	571,036
PJM RTO Formation Cost Recovery (b)	(2,048)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(25,159)
Net Expansion Cost Recovery (b)	(10,518)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(10,789)	(129,197)
Net RTO Formation Costs & Expansion Cost Recovery Charge	33,923	34,796	34,796	34,796	34,796	34,796	34,796	34,796	34,796	34,796	34,796	34,796	416,679
Net Marginal Losses (c)	1,308,334	1,372,653	931,534	931,926	1,085,987	1,337,329	2,230,339	1,224,483	907,257	812,454	798,478	1,082,362	14,024,136
Load Response Program Subsidies (c)	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Acquisition Rider Adjustment (c)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net RTO Costs - CSP	13,175,012	13,724,736	12,587,933	12,510,093	12,769,425	13,314,308	14,583,816	13,741,931	13,041,655	12,727,456	13,086,017	13,643,510	158,904,691

2010 - 2011 Forecasted Load (MWH) excluding Shopping Customers	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	July10-Jun11
Residential	761,965	710,624	604,135	450,976	537,511	740,642	832,667	687,654	659,227	465,540	451,631	572,723	7,495,494
Commercial	827,098	784,501	751,430	721,325	695,497	721,627	734,941	668,372	701,556	662,498	715,480	778,358	8,762,683
Industrial	273,875	277,965	267,054	262,637	289,911	280,316	278,915	276,698	291,960	300,419	307,263	302,323	3,429,536
Joint Service Territory	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	106,000	1,272,000
Other Ultimates	4,540	4,360	4,533	4,899	4,499	4,203	5,034	3,913	4,788	5,051	4,504	4,563	54,685
Total	1,973,478	1,883,450	1,733,152	1,565,836	1,633,418	1,852,788	1,957,557	1,742,637	1,763,529	1,559,508	1,584,878	1,763,967	21,014,398

AEP Peak at time of PJM Peak (1/16/2009) **22,668 MW**

	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
MLR Forecast for 2010 - 2011	0.16475	0.16379	0.18576	0.18576	0.18576	0.18576	0.18576	0.18840	0.18874	0.18874	0.18874	0.18874
Westerville Share of CSP Peak used in MLR	2.510%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%

(a) Includes NERC and RFC Fees
(b) Forecast using 12 months actual data through February 2010
(c) Forecast using February 2009 actual and anticipated/known changes
(d) Forecast using 2010/2011 load forecast and current OATT rates
(e) Pursuant to Schedule 12 of the PJM OATT, the Company has begun to incur charges for Required Regional Transmission Enhancements.
(f) Beginning June 1, 2006, the Company is required to comply with PJM's new Supplemental 30-minute Reserve requirement and is a Forecast.

Ohio Power Company
Monthly Projected Cost for Each Rate Schedule

	Forecast July 2010	Forecast August 2010	Forecast September 2010	Forecast October 2010	Forecast November 2010	Forecast December 2010	Forecast January 2011	Forecast February 2011	Forecast March 2011	Forecast April 2011	Forecast May 2011	Forecast June 2011	Forecast 2010 / 2011 Proposed Rates kWh	Forecast 2010 / 2011 Proposed Rates Demand	Forecast 2010 / 2011 Total
METERED kWh:															
RS	715,098,142	716,786,125	549,474,681	445,412,780	499,567,092	759,318,883	845,390,827	673,914,574	679,657,637	494,126,191	489,342,774	546,004,021			7,394,120,526
GS1	33,821,582	32,808,873	30,076,690	28,939,153	26,695,207	35,293,204	39,785,564	35,155,157	38,424,587	30,857,285	31,090,187	67,468,221			428,415,710
GS2 Sec	245,303,843	245,504,508	229,753,100	220,553,946	195,619,713	239,396,002	244,649,064	224,622,488	235,475,178	211,117,470	222,988,805	249,258,353			2,764,242,470
GS2 RL - GS - TOD	10,880,960	10,752,283	9,666,480	9,089,934	8,815,889	11,161,747	12,404,364	11,057,790	10,432,364	8,397,386	8,539,324	24,595,017			135,793,528
GS2 Pri	27,890,791	32,549,890	28,591,769	31,583,549	31,040,331	33,153,152	28,419,592	34,945,579	32,297,503	31,830,363	31,139,688	34,495,326			377,937,534
GS2 Sub/Trans	19,942,530	28,762,688	19,385,996	25,658,248	24,963,352	23,168,868	23,028,926	23,108,921	22,818,602	23,350,344	28,538,279	24,874,227			287,600,981
GS3 Sec	271,869,496	269,327,677	245,972,486	241,132,986	211,750,286	242,922,603	236,505,531	214,659,210	239,374,030	228,778,195	247,717,958	232,193,189			2,882,203,645
GS3 Pri	224,588,381	246,788,171	211,674,349	226,324,738	210,830,721	223,876,001	242,965,596	200,195,079	220,452,231	216,082,808	230,744,028	217,371,975			2,671,894,078
GS3 Sub/Trans	76,529,886	91,212,491	73,791,034	79,915,459	82,000,695	82,906,953	82,218,712	78,682,313	82,561,174	84,442,774	81,519,492	79,526,281			973,287,263
GS4 Pri	22,729,079	25,389,837	20,660,565	20,892,904	21,806,541	23,134,961	21,771,834	19,724,845	20,955,244	20,773,856	23,079,965	22,464,711			263,384,344
GS4/IRP Sub/Trans	649,706,131	581,258,143	651,011,275	676,167,157	622,248,996	640,130,605	589,146,318	661,253,045	693,328,740	669,297,850	682,546,873	643,381,158			7,761,475,290
EHG	1,774,865	1,671,683	1,578,674	1,489,641	1,487,737	2,304,586	3,172,638	2,902,769	2,930,822	1,953,976	1,671,225	5,383,546			28,219,862
SS	3,223,103	2,727,777	3,761,268	4,035,883	3,786,379	4,498,761	4,590,471	4,350,964	5,880,279	4,775,209	4,869,210	8,740,204			55,039,508
EHS	16,088	14,343	23,141	31,154	32,321	54,560	57,756	44,474	50,975	33,904	28,955	40,835			427,477
OL	4,323,135	4,967,863	4,715,997	5,752,015	5,809,258	6,764,821	6,129,399	4,870,416	5,655,605	4,516,615	4,290,809	4,362,905			62,158,840
SL	4,108,696	4,733,647	5,137,496	6,541,454	6,810,139	7,648,663	7,289,406	5,878,327	5,900,643	5,016,775	4,470,427	3,806,029			67,339,703
SBS-Sub/Tran-Backup	-	-	-	-	1,343	3,829	-	4,048	334,386	-	-	-			343,607
Total	2,311,804,368	2,295,256,000	2,085,273,000	2,025,521,000	1,963,266,000	2,336,734,000	2,387,526,000	2,193,360,000	2,294,230,000	2,035,350,000	2,072,578,000	2,163,996,000			26,163,884,368
DEMAND:															
RS	-	-	-	-	-	-	-	-	-	-	-	-			-
GS1	-	-	-	-	-	-	-	-	-	-	-	-			-
GS2 Sec	1,000,984	1,015,072	933,708	973,299	850,072	910,306	887,983	841,857	961,838	900,571	992,665	1,071,741			11,320,085
GS2 RL - GS - TOD	-	-	-	-	-	-	-	-	-	-	-	-			-
GS2 Pri	129,295	148,309	128,771	142,635	136,903	135,722	127,799	135,651	137,831	136,549	137,803	140,682			1,647,931
GS2 Sub/Trans	83,879	101,711	70,043	90,546	87,887	85,879	86,672	81,292	86,329	78,881	98,875	105,602			1,059,595
GS3 Sec	593,813	696,286	531,729	542,879	471,513	485,739	460,677	447,542	546,659	513,447	566,228	512,265			6,268,777
GS3 Pri	488,580	532,338	443,509	480,412	438,648	436,264	444,702	395,281	480,080	461,510	498,709	465,532			5,565,548
GS3 Sub/Trans	173,177	205,804	184,158	177,273	174,989	166,269	169,011	163,256	187,770	195,395	181,264	183,224			2,140,501
GS4 Pri	40,060	46,259	38,503	40,889	38,601	37,710	37,728	36,755	41,116	39,127	42,899	38,918			476,283
GS4/IRP Sub/Trans	1,153,549	1,027,365	1,022,827	1,186,822	880,191	1,087,589	1,003,478	1,166,332	1,265,607	1,147,819	1,364,026	1,206,036			13,812,539
EHG	-	-	-	-	-	-	-	-	-	-	-	-			-
SS	-	-	-	-	-	-	-	-	-	-	-	-			-
EHS	-	-	-	-	-	-	-	-	-	-	-	-			-
OL	-	-	-	-	-	-	-	-	-	-	-	-			-
SL	-	-	-	-	-	-	-	-	-	-	-	-			-
SBS-Sub/Tran-Backup	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000			240,000
Total	3,693,356	3,693,144	3,351,248	3,654,766	3,198,774	3,364,418	3,218,049	3,287,946	3,729,229	3,495,300	3,903,066	3,751,977			42,331,257
REVENUES:															
RS	$ 6,068,537	$ 6,062,862	$ 4,683,007	$ 3,779,906	$ 4,239,476	$ 6,443,789	$ 7,174,240	$ 5,719,041	$ 5,767,779	$ 4,193,295	$ 3,982,984	$ 4,633,809	0.0084863		$ 62,748,726
GS1	234,816	227,785	208,816	200,919	185,339	245,034	276,223	244,075	252,889	214,236	215,863	468,418	0.0069428		2,974,405
GS2 Sec	1,467,173	1,480,714	1,370,612	1,387,321	1,218,211	1,369,928	1,342,052	1,273,974	1,409,282	1,299,055	1,410,645	1,541,622	0.0021861	0.93	16,570,589
GS2 RL - GS - TOD	64,964	64,216	57,731	54,288	52,651	66,661	74,083	66,040	62,306	50,152	50,999	146,889	0.0059723		811,000
GS2 Pri	176,161	202,083	176,157	194,941	168,637	192,027	174,919	195,741	192,121	191,783	189,566	206,502	0.0021077	0.90	2,278,717
GS2 Sub/Trans	114,835	148,670	101,515	132,459	128,690	123,232	123,642	119,072	124,867	117,447	145,713	144,096	0.0020670	0.88	1,524,039
GS3 Sec	1,670,930	1,670,796	1,501,111	1,513,286	1,318,826	1,406,463	1,345,704	1,278,177	1,517,188	1,432,632	1,571,084	1,436,943	0.0019306	1.93	17,663,123
GS3 Pri	1,326,808	1,449,520	1,218,936	1,314,848	1,206,325	1,228,174	1,279,401	1,107,828	1,303,299	1,260,626	1,357,105	1,270,508	0.0018614	1.86	15,325,379
GS3 Sub/Trans	454,206	540,261	432,818	467,812	467,388	451,289	456,959	436,390	491,722	509,017	477,989	477,934	0.0018166	1.82	5,663,788
GS4 Pri	130,312	148,838	118,607	128,686	125,346	128,849	123,361	117,426	129,300	124,590	136,504	127,264	0.0018538	2.20	1,536,084
GS4/IRP Sub/Trans	3,655,576	3,260,448	3,378,887	3,778,607	3,233,184	3,496,441	3,223,361	3,703,954	3,975,425	3,678,705	4,169,453	3,756,980	0.0018092	2.15	43,309,019
EHG	18,573	17,496	16,502	16,591	16,571	24,120	33,205	30,381	29,628	20,451	17,491	56,345	0.0104662		295,355
SS	20,974	17,751	24,476	26,263	24,639	29,279	29,872	28,313	36,964	31,074	31,686	56,876	0.0065074		358,164
EHS	96	93	151	203	210	356	376	289	332	221	188	266	0.0065074		2,782
OL	10,949	12,582	11,944	14,568	14,713	17,133	15,523	12,336	14,323	11,439	10,867	11,049	0.0025326		157,423
SL	10,406	11,988	13,011	16,567	17,247	19,368	18,461	14,887	14,944	12,705	11,322	9,639	0.0025326		170,545
SBS-Sub/Tran-Backup	5,770	5,770	5,770	5,770	5,773	5,778	5,770	5,776	6,393	5,770	5,770	5,770	0.0018620	0.29	69,885
Total	$ 15,430,099	$ 15,341,674	$ 13,288,053	$ 13,032,037	$ 12,444,228	$ 15,244,914	$ 15,697,183	$ 14,353,704	$ 15,328,960	$ 13,153,197	$ 13,785,269	$ 14,350,909			$ 171,460,018

Columbus Southern Power
Excludes Shopping Customers
Monthly Projected Cost for Each Rate Schedule

	Forecast July 2010	Forecast August 2010	Forecast September 2010	Forecast October 2010	Forecast November 2010	Forecast December 2010	Forecast January 2011	Forecast February 2011	Forecast March 2011	Forecast April 2011	Forecast May 2011	Forecast June 2011	Forecast 2010 / 2011 Proposed Rates KWh	Demand	Total
METERED kWh:															
RS	760,858,401	709,545,936	603,200,159	450,100,451	536,457,123	739,555,654	831,759,906	687,021,558	658,267,668	484,670,926	460,703,322	571,719,906			7,483,861,009
GS1	32,194,876	30,647,783	29,544,300	28,256,531	28,460,010	31,605,753	36,003,511	32,222,726	31,620,958	28,333,327	27,924,991	29,766,250			366,779,994
GS2 Sec	163,031,191	153,853,700	147,583,287	134,978,214	125,963,635	137,205,594	148,602,170	134,619,636	143,831,209	125,036,627	134,336,723	150,273,311			1,699,313,197
GS2-TOD/LM *	1,192,003	1,127,758	1,126,975	1,091,844	1,114,130	1,544,383	1,292,409	1,158,450	1,132,731	945,809	1,006,177	1,172,706			13,905,374
GS2 Pri	5,461,425	4,694,550	5,081,351	5,473,908	5,617,287	5,718,719	5,785,617	5,095,087	6,042,961	5,403,382	4,942,906	5,779,991			65,097,363
GS3 Sec	442,064,156	419,921,367	404,122,336	394,383,024	381,153,968	398,360,443	402,736,681	383,058,060	388,635,142	374,683,557	398,443,030	429,990,290			4,797,522,054
GS3-TOD/LM	863,213	843,671	790,291	724,552	442,318	308,343	161,462	143,201	199,166	328,097	489,616	630,456			5,924,368
GS3 Pri	226,466,331	238,505,270	216,692,972	218,307,832	210,067,084	218,423,962	206,540,169	188,613,321	209,264,372	212,592,356	232,139,355	238,513,276			2,617,306,301
GS4/IRP	333,865,530	315,868,405	314,633,673	324,250,427	334,772,042	311,702,022	316,205,811	323,476,709	315,949,973	319,283,475	326,375,433	327,452,517			3,863,836,018
SL	3,431,329	3,174,766	3,552,174	3,549,787	3,388,287	3,164,015	3,950,633	2,915,271	3,798,135	3,559,446	3,519,057	3,468,366			41,471,266
AL	5,041,945	5,136,525	4,624,482	4,739,058	5,199,822	4,999,112	4,510,662	4,495,328	4,779,612	4,682,096	4,943,530	4,976,913			58,127,884
SBS-Sub/Tran-Backup	27,601	130,289	-	1,372	762,493	-	7,770	17,652	7,075	-	54,881	224,020			1,253,134
Total	1,973,478,000	1,883,450,000	1,733,152,000	1,565,836,000	1,633,418,000	1,852,768,000	1,967,557,000	1,742,637,000	1,763,529,000	1,559,508,000	1,584,878,000	1,763,967,000			21,014,398,000
DEMAND:															
RS	-	-	-	-	-	-	-	-	-	-	-	-			-
GS1	-	-	-	-	-	-	-	-	-	-	-	-			-
GS2 Sec	614,303	585,178	565,687	565,900	856,298	511,732	492,469	483,024	564,560	526,844	595,009	609,616			6,970,819
GS2-TOD/LM *	-	4,289	4,320	4,578	7,574	5,760	4,283	4,157	4,446	3,985	-	-			43,392
GS2 Pri	30,695	27,169	28,615	30,726	31,066	31,373	26,955	27,000	31,607	33,313	32,844	31,342			362,717
GS3 Sec	1,052,698	1,020,715	973,001	1,004,059	979,332	909,398	869,654	855,639	985,664	934,791	1,030,300	1,062,374			11,687,924
GS3-TOD/LM	-	2,051	1,903	1,845	1,136	704	349	338	505	819	1,266	1,543			12,469
GS3 Pri	475,639	480,709	461,271	465,990	451,544	424,833	390,209	379,804	434,737	438,371	495,901	499,684			5,398,690
GS4/IRP	636,000	597,528	592,301	601,958	618,575	556,568	536,766	541,283	607,865	618,768	653,803	653,359			7,216,771
SL	-		-	-	-	-	-	-	-	-	-	-			-
AL	-	-	-	-	-	-	-	-	-	-	-	-			-
SBS-Sub/Tran-Backup	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000			72,000
Total	2,815,336	2,723,629	2,633,097	2,681,052	2,951,546	2,446,368	2,328,685	2,297,545	2,635,384	2,662,890	2,815,121	2,854,118			31,744,771
REVENUES:															
RS	$ 6,191,106	$ 5,773,575	$ 4,608,240	$ 3,662,467	$ 4,365,152	$ 6,017,764	$ 6,766,030	$ 5,590,294	$ 5,356,324	$ 3,943,767	$ 3,687,373	$ 4,652,086	0.0081370	-	$ 60,896,177
GS1	218,313	207,822	200,340	191,601	192,987	215,675	244,140	218,502	214,422	192,128	189,359	201,845	0.0067810	-	2,487,135
GS2 Sec	1,120,628	1,083,514	1,024,937	990,487	1,263,379	937,358	947,640	898,834	1,013,360	920,402	1,020,563	1,080,616	0.0027515	1.094	12,301,737
GS2-TOD/LM *	8,698	8,227	8,221	7,965	8,128	11,256	9,428	8,451	8,263	6,800	7,340	8,556	0.0072950	-	101,440
GS2 Pri	47,013	41,230	43,601	47,079	47,842	48,416	43,920	42,129	49,526	49,629	47,906	48,546	0.0026619	1.058	557,037
GS3 Sec	2,611,794	2,514,287	2,404,746	2,434,234	2,366,991	2,290,643	2,235,985	2,131,184	2,392,762	2,262,004	2,484,853	2,586,106	0.0020862	1.606	28,736,609
GS3-TOD/LM	4,994	4,881	4,572	4,192	2,559	1,784	934	829	1,152	1,896	2,833	3,648	0.0057856	-	34,276
GS3 Pri	1,193,683	1,227,893	1,168,123	1,164,271	1,125,265	1,100,689	1,022,833	970,494	1,097,434	1,109,823	1,238,637	1,257,377	0.0020182	1.563	13,666,414
GS4/IRP	2,350,254	2,211,806	2,195,043	2,238,416	2,302,674	2,069,760	2,047,431	2,066,801	2,240,960	2,277,205	2,387,549	2,388,128	0.0016923	2.807	26,706,247
SL	7,061	6,533	7,310	7,306	6,972	6,511	8,130	5,999	7,816	7,325	7,242	7,137	0.0020578	-	85,340
AL	10,376	10,570	9,516	9,752	10,700	10,267	9,282	9,250	9,835	9,635	10,173	10,239	0.0020578	-	119,616
SBS-Sub/Tran-Backup	1,649	1,853	1,594	1,697	3,148	1,594	1,610	1,629	1,608	1,594	1,703	2,039	0.0019651	0.266	21,620
Total	$ 13,765,588	$ 13,072,192	$ 11,968,443	$ 10,759,369	$ 11,715,937	$ 12,731,654	$ 13,339,363	$ 11,944,408	$ 12,393,593	$ 10,802,310	$ 11,065,542	$ 12,246,318			$ 146,802,646

Ohio Power Company
Projected Transmission Cost Recovery Rider Rate Calculations
July 2010 - June 2011

	(at Generation at time of PJM 2009 Peak) Demand	NITS, Trans Enh & Pt to Pt Revenue Demand Cost	July 2010 - June 2011 Loss Adjusted KWH Energy	Energy Cost	Base Generation Revenue	Net Marginal Loss Cost	Total Cost
Forecast July 2010 - June 2011							
RS	1,603.3	51,172,393.1	7,394,120,528	$ 11,213,878	$ 180,352,132	$ 5,027,858	$ 67,414,129
GS1	68.7	2,191,625	428,415,710	649,733	12,705,972	$ 354,217	$ 3,195,575
GS2	450.5	14,379,230	3,535,041,263	5,361,222	105,512,864	$ 2,941,488	$ 22,681,941
GS3	884.9	26,241,762	6,374,119,318	9,666,951	127,469,702	$ 3,553,601	$ 41,462,313
GS4/IRP	1,019.0	32,521,618	7,557,073,383	11,461,012	148,847,665	$ 4,149,576	$ 48,132,206
EHG	8.3	263,386	28,219,862	42,798	399,289	$ 11,131	$ 317,316
SS/EHS	8.3	266,110	55,466,985	84,121	1,346,978	$ 37,551	$ 387,782
OL/SL	0.0	-	129,498,543	196,397	5,594,256	$ 155,957	$ 352,353
SBS*	2.5	79,062	323,315	490	84,616	$ 2,359	$ 81,911
Total	4,045.5	$ 129,115,186	25,502,278,907	$ 38,676,602	$ 582,313,474	$ 16,233,738	$ 184,025,526
2009 Reconciliation							
RS	1,603.3	$ (3,541,450)	7,394,120,528	$ (776,071)	180,352,132	(347,959)	$ (4,665,480)
GS1	68.7	(151,674)	428,415,710	(44,966)	12,705,972	(24,514)	$ (221,154)
GS2	450.5	(995,133)	3,535,041,263	(371,030)	105,512,864	(203,569)	$ (1,569,732)
GS3	884.9	(1,954,507)	6,374,119,318	(669,014)	127,469,702	(245,931)	$ (2,869,452)
GS4/IRP	1,019.0	(2,250,700)	7,557,073,383	(793,174)	148,847,665	(287,177)	$ (3,331,050)
EHG	8.3	(18,228)	28,219,862	(2,962)	399,289	(770)	$ (21,960)
SS/EHS	8.3	(18,416)	55,466,985	(5,822)	1,346,978	(2,599)	$ (26,837)
OL/SL	0.0	-	129,498,543	(13,592)	5,594,256	(10,793)	$ (24,385)
SBS	2.5	(5,472)	323,315	(34)	84,616	(163)	$ (5,669)
Total	4,045.5	$ (8,935,580)	25,502,278,907	$ (2,676,663)	$ 582,313,474	$ (1,123,476)	$ (12,735,720)
Total 2010							
RS		$ 47,630,943		$ 10,437,808		$ 4,679,898	$ 62,748,649
GS1		2,039,951		604,767		329,703	$ 2,974,421
GS2		13,384,097		4,990,192		2,737,919	$ 21,112,208
GS3		26,287,255		8,997,937		3,307,670	$ 38,592,861
GS4/IRP		30,270,918		10,667,838		3,862,399	$ 44,801,156
EHG		245,158		39,836		10,361	$ 295,355
SS/EHS		247,693		78,299		34,952	$ 360,945
OL/SL		-		182,805		145,164	$ 327,968
SBS		73,591		456		2,196	$ 76,243
Total		$ 120,179,606		$ 35,999,939		$ 15,110,262	$ 171,289,806

*Demand imputed based upon contractual forced outage rates

Ohio Power Company
Projected Transmission Cost Recovery Rider Rate Calculations
July 2010 - June 2011

			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	$ 47,630,943	$15,117,706	-	7,394,120,528		$0.0084863						
GS1	$ 2,039,951	$ 934,470	-	428,415,710		$0.0069428						
GS2	$ 13,384,097	$ 7,728,111	14,462,058	3,535,041,263	$ 0.93	$0.0021861	0.9641	$ 0.90	$0.0021077	0.9409	$ 0.88	$0.0020570
GS3	$ 26,287,255	$12,305,607	13,648,891	6,374,119,318	$ 1.93	$0.0019306	0.9641	$ 1.86	$0.0018614	0.9409	$ 1.82	$0.0018166
GS4/IRP	$ 30,270,918	$14,530,237	13,267,876	7,557,073,383	$ 2.28	$0.0019227	0.9641	$ 2.20	$0.0018538	0.9409	$ 2.15	$0.0018092
EHG	$ 245,158	$ 50,197	-	28,219,862		$0.0104662						
SS/EHS	$ 247,693	$ 113,251	-	55,466,985		$0.0065074						
OL/SL	$ -	$ 327,968	-	129,498,543		$0.0025326						
SBS-Backup	$ 73,591	$ 2,652	240,000	323,315								
Total	$ 120,179,606	$51,110,200	41,618,824	25,502,278,907								

GS-2 Energy only rate	$0.0059723
GS-3 Energy only rate	$0.0060546

Columbus Southern Power Company
Projected Transmission Cost Recovery Rider Rate Calculations
July 2010 - June 2011

	(at Generation at time of PJM 2009 Peak) **Demand**	NITS, Trans Enh & Pt to Pt Revenue **Demand Cost**	July 2010 - June 2011 Loss Adjusted **KWH Energy**	**Energy Cost**	Base Generation **Revenue**	Net Marginal Loss **Cost**	**Total Cost**
Forecast July 2010 - June 2011							
RR/RR-1	1,509.4	$ 49,798,326	7,483,861,009	$ 11,922,294	$ 145,727,722	$ 4,649,053	$ 66,369,673
GS-1	48.3	1,594,516	366,779,994	584,305	16,670,892	$ 531,840	$ 2,710,661
GS-2	266.6	8,795,282	1,776,195,226	2,829,598	78,268,563	$ 2,496,949	$ 14,121,830
GS-3	896.4	29,575,565	7,335,486,730	11,685,923	156,505,913	$ 4,992,902	$ 46,254,391
GS-4/IRP	669.3	22,081,911	3,666,690,671	5,841,285	40,281,812	$ 1,285,083	$ 29,208,279
AL/SL	0.0	-	99,599,150	158,668	2,028,181	$ 64,704	$ 223,372
SBS-Backup*	0.3	10,987	1,189,195	1,894	112,968	$ 3,604	$ 16,485
Total	3,390.3	$ 111,856,587	20,729,801,976	$ 33,023,968	$ 439,596,051	$ 14,024,136	$ 158,904,691
Reconciliation 2009							
RR/RR-1	1,509.4	$ (4,106,660)	7,483,861,009	$ (983,182)	145,727,722	$ (383,388)	$ (5,473,229)
GS-1	48.3	(131,493)	366,779,994	(48,185)	16,670,892	(43,859)	$ (223,537)
GS-2	266.6	(725,310)	1,776,195,226	(233,345)	78,268,563	(205,913)	$ (1,164,568)
GS-3	896.4	(2,438,973)	7,335,486,730	(963,689)	156,505,913	(411,744)	$ (3,814,406)
GS-4/IRP	669.3	(1,821,003)	3,666,690,671	(481,706)	40,281,812	(105,975)	$ (2,408,685)
AL/SL	0.0	-	99,599,150	(13,085)	2,028,181	(5,336)	$ (18,421)
SBS-Backup*	0.3	(906)	1,189,195	(156)	112,968	(297)	$ (1,359)
Total	3,390.3	$ (9,224,345)	20,729,801,976	$ (2,723,348)	$ 439,596,051	$ (1,156,512)	$ (13,104,205)
Total 2010							
RR/RR-1		$ 45,691,667		$ 10,939,112		$ 4,265,665	$ 60,896,444
GS-1		1,463,023		536,120		487,982	$ 2,487,124
GS-2		8,069,972		2,596,253		2,291,036	$ 12,957,262
GS-3		27,136,592		10,722,234		4,581,159	$ 42,439,985
GS-4/IRP		20,260,908		5,359,578		1,179,108	$ 26,799,595
AL/SL		-		145,583		59,368	$ 204,951
SBS-Backup*		10,081		1,738		3,307	$ 15,126
Total		$ 102,632,242		$ 30,300,620		$ 12,867,624	$ 145,800,486

*Demand imputed based upon contractual forced outage rates

Columbus Southern Power Company
Projected Transmission Cost Recovery Rider Rate Calculations
July 2010 - June 2011

			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
RR/RR-1	$ 45,691,667	$ 15,204,777	-	7,483,861,009		$ 0.0081370						
GS-1	$ 1,463,023	$ 1,024,102	-	366,779,994		$ 0.0067810						
GS-2	$ 8,069,972	$ 4,887,289	7,378,761	1,776,195,226	$ 1.094	$ 0.0027515	0.9674	$ 1.058	$ 0.0026619			
GS-3	$ 27,136,592	$ 15,303,393	16,905,146	7,335,486,730	$ 1.605	$ 0.0020862	0.9674	$ 1.553	$ 0.0020182			
GS-4/IRP	$ 20,260,908	$ 6,538,686	6,848,548	3,666,690,671	$ 2.958	$ 0.0017833	0.9674	$ 2.862	$ 0.0017252	0.9490	$ 2.807	$ 0.0016923
AL/SL	$ -	$ 204,951	-	99,599,150		$ 0.0020578						
SBS-Backup	$ 10,081	$ 5,045	72,000	1,189,195								
Total	$102,632,242	$43,168,244	31,204,456	20,729,801,976								

GS-2 Energy only rate	$ 0.0072950
GS-3 Energy only rate	$ 0.0057856

SBS Tariff Rate Design

			OPCo				CSP		
			Demand	Energy			Demand	Energy	
GS-2			$ 13,384,097	$ 7,728,111			$ 8,069,972	$ 4,887,289	
GS-3			$ 26,287,255	$ 12,305,607			$ 27,136,592	$ 15,303,393	
GS-4/IRP			$ 30,270,918	$ 14,530,237			$ 20,260,906	$ 6,538,686	
Total			$ 69,942,270	$ 34,563,955			$ 55,467,472	$ 26,729,369	
Demand @ Secondary			11,405,095				19,808,671		
Energy @ Secondary				17,466,233,963				12,778,372,627	
Forced Outage Rate	15%	Loss Factors				Loss Factors			
Secondary*		1.0000	$ 0.92	$ 0.0019789		1.0000	$ 0.420	$ 0.0020918	
Primary		0.9641	$ 0.89	$ 0.0019080		0.9674	$ 0.406	$ 0.0020237	
Subtrans/Transmission		0.9409	$ 0.87	$ 0.0018620		0.9490	$ 0.399	$ 0.0019851	
Forced Outage Rate	5%								
Secondary			$ 0.31	$ 0.0019789			$ 0.140	$ 0.0020918	
Primary			$ 0.30	$ 0.0019080			$ 0.135	$ 0.0020237	
Subtrans/Transmission			$ 0.29	$ 0.0018620			$ 0.133	$ 0.0019851	
Forced Outage Rate	10%								
Secondary			$ 0.61	$ 0.0019789			$ 0.280	$ 0.0020918	
Primary			$ 0.59	$ 0.0019080			$ 0.271	$ 0.0020237	
Subtrans/Transmission			$ 0.58	$ 0.0018620			$ 0.266	$ 0.0019851	
Forced Outage Rate	20%								
Secondary			$ 1.23	$ 0.0019789			$ 0.560	$ 0.0020918	
Primary			$ 1.18	$ 0.0019080			$ 0.542	$ 0.0020237	
Subtrans/Transmission			$ 1.15	$ 0.0018620			$ 0.531	$ 0.0019851	
Forced Outage Rate	25%								
Secondary			$ 1.53	$ 0.0019789			$ 0.700	$ 0.0020918	
Primary			$ 1.48	$ 0.0019080			$ 0.677	$ 0.0020237	
Subtrans/Transmission			$ 1.44	$ 0.0018620			$ 0.664	$ 0.0019851	
Forced Outage Rate	30%								
Secondary			$ 1.84	$ 0.0019789			$ 0.840	$ 0.0020918	
Primary			$ 1.77	$ 0.0019080			$ 0.813	$ 0.0020237	
Subtrans/Transmission			$ 1.73	$ 0.0018620			$ 0.797	$ 0.0019851	
Maintenance Energy									
at 15% Forced Outage Rate									
Secondary			$ 0.92				$ 0.420		
Primary			$ 0.89				$ 0.406		
Subtrans/Transmission			$ 0.87				$ 0.399		
Hours at 85% Load Factor			621				621		
Demand Components per KWH					Total				Total
Secondary			$ 0.0014813	$ 0.0019789	$ 0.0034602		$ 0.0006764	$ 0.0020918	$ 0.0027682
Primary			$ 0.0014282	$ 0.0019080	$ 0.0033362		$ 0.0006543	$ 0.0020237	$ 0.0026780
Subtrans/Transmission			$ 0.0013938	$ 0.0018620	$ 0.0032558		$ 0.0006419	$ 0.0019851	$ 0.0026270
Less than 100 KW									
Residential & GS-1			$ 49,670,894						
GS-2							$ 8,069,972		
Forced Outage Adjustment	15%		$ 7,450,634				$ 1,210,496		
Demand			14,432,639				2,881,967		
			$ 0.52				$ 0.420		

* Also Breakdown Service Charge for CSP

Columbus Southern Power Company

	Metered		Loss	Units @ Secondary	
	Energy	Demand	Factor	Energy	Demand
RS	7,483,861,009	-	1.0000	7,483,861,009	-
GS1	366,779,994	-	1.0000	366,779,994	-
GS2 Sec	1,699,313,197	6,970,819	1.0000	1,699,313,197	6,970,819
GS2-TOD/LM *	13,905,374	57,042	1.0000	13,905,374	57,042
GS2 Pri	65,097,383	362,717	0.9674	62,976,655	350,900
GS3 Sec	4,797,522,054	11,667,924	1.0000	4,797,522,054	11,667,924
GS3-TOD/LM*	5,924,388	14,409	1.0000	5,924,388	14,409
GS3 Pri	2,617,306,301	5,398,690	0.9674	2,532,040,288	5,222,813
GS4/IRP	3,863,836,016	7,216,771	0.9490	3,666,690,671	6,848,548
SL	41,471,266	-	1.0000	41,471,266	-
AL	58,127,884	-	1.0000	58,127,884	-
SBS-Sub/Tran-Backup	1,253,134	72,000	0.9490	1,189,195	72,000
				-	-
Total	21,014,398,000	31,760,372		20,729,801,976	31,204,456

Ohio Power

	Metered		Loss	Units @ Secondary	
	Energy	Demand	Factor	Energy	Demand
RS	7,394,120,528	-	1.0000	7,394,120,528	-
GS1	428,415,710	-	1.0000	428,415,710	-
GS2 Sec	2,764,242,470	11,320,085	1.0000	2,764,242,470	11,320,085
GS2 RL - GS - TOD*	135,793,528	556,100	1.0000	135,793,528	556,100
GS2 Pri	377,937,534	1,647,931	0.9641	364,388,181	1,588,852
GS2 Sub/Trans	287,600,981	1,059,595	0.9409	270,617,083	997,022
GS3 Sec	2,882,203,645	6,268,777	1.0000	2,882,203,645	6,268,777
GS3 Pri	2,671,894,078	5,565,546	0.9641	2,576,104,609	5,366,017
GS3 Sub/Trans	973,287,263	2,140,501	0.9409	915,811,063	2,014,097
GS4 Pri	263,384,344	476,283	0.9641	253,941,811	459,207
GS4/IRP Sub/Trans	7,761,475,290	13,612,539	0.9409	7,303,131,571	12,808,668
EHG	28,219,862	-	1.0000	28,219,862	-
SS	55,039,508	-	1.0000	55,039,508	-
EHS	427,477	-	1.0000	427,477	-
OL	62,158,840	-	1.0000	62,158,840	-
SL	67,339,703	-	1.0000	67,339,703	-
SBS-Sub/Tran-Backup	343,607	240,000	0.9409	323,315	240,000
Total	26,153,884,368	42,887,356		25,502,278,907	41,618,824

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Ohio Power Company Class Contribution To PJM Peak

Class	Metered Avg / Cust KW	Number Of Customers	Metered Class MW	Adjusted Load	Peak Loss Factor	At Generation Class MW
Residential	2.41	608645	1465.5	1,465.5	1.0941	1603.3
GS1	0.97	64765	62.8	62.8	1.0941	68.7
GS2	13.80	29931	413.0	413.0	1.0900	450.1
GS3	142.94	5732	819.3	819.3	1.0800	884.9
GS4	12032.34	40	481.3	481.3	1.0670	513.5
IIP	38058.76	6	228.4	228.4	1.0341	236.1
EHG	15.06	501	7.5	7.5	1.0941	8.3
SCH	37.92	201	7.6	7.6	1.0941	8.3
Joint Service Territory	260425.96	1	260.4	260.4	1.0341	269.3
Joint Service Territory TOTAL	382.28	1	0.4	0.4	1.0341	0.4
Internal Load (less WPCo) (At Generation)						4043.0
Total			3,746.2	3,746.2		4,043.0
Total GS-2						450.5
Total GS-4						1,019.0

1/16/09 08:00 EST

Columbus Southern Power Company Class Contribution To PJM Peak

Class	Metered Avg / Cust KW	Number Of Customers	Metered Class MW	Adjusted Load	Peak Loss Factor	At Generation Class MW
Residential	2.11	666122	1403.3	1,403.3	1.0756	1509.4
GS1	0.88	50928	44.9	44.9	1.0756	48.3
GS2	10.19	24446	249.1	249.1	1.0700	266.6
GS3	152.58	5569	849.7	849.7	1.0550	896.4
GS4/IRP	9282.09	32	297.0	297.0	1.0400	308.9
Joint Service Territory	259120.82	1	259.1	259.1	1.0341	268.0
Joint Service Territory	380.37	1	0.4	0.4	1.0341	0.4
Westerville	89001.97	1	89.0	89.0	1.0341	92.0
Total			3,192.6	3,192.6		3,390.0

Total GS-4	669.3
Internal Load (At Generation)	3390.0

Schedule D-1 and D-3
Page 1 of 2

Ohio Power Company
Amounts are recorded as 94.229% due to Wheeling Activity
Reconciliation Adjustment & Monthly Over and Under Recovery
Jan 10 - Feb 10
<Revenue>/ Expense in $

	Dec-09	Jan-10	Feb-10	Mar-10	1st Qtr 2010
Total Transm. TCRR/ETCRR Revenue-OPCO		(17,991,295)	(15,476,047)		(33,467,342)
Transmission Costs:					
Net Congestion:					
PJM Implicit Congestion		9,685,017	2,093,924		11,778,941
PJM FTR Revenue		(9,476,695)	(2,002,600)		(11,479,295)
Net Congestion Subtotal		208,322	91,324	-	299,646
PJM Operating Reserve		886,634	879,187		1,765,821
PJM Ancillary Services					
PJM Synchronous Condensing		5,226	1,862		7,088
PJM Reactive Supply		591,061	537,912		1,128,973
PJM Blackstart		12,142	11,374		23,516
PJM Regulation Charges		959,455	735,435		1,694,890
PJM Spinning Reserve Charges		90,361	25,795		116,156
PJM 30 Minute Supplemental Market		50	48		98
PJM Ancillary Services Subtotal		1,658,295	1,312,426	-	2,970,721
PJM Administration Service Fees		824,256	763,558		1,587,814
					-
Net Expansion Cost Recovery Charge		(27,369)	(31,658)		(59,027)
					-
Amortization of PJM Integration Costs		121,987	121,987		243,974
PJM RTO Formation Cost Recovery		(3,994)	(5,096)		(9,090)
Net RTO Formation Costs		117,993	116,891	-	234,884
Load Response Program Subsidies		359,417	377,666		737,083
Prior Year Amortization of ETCRR Charges		(690,775)	(694,081)		(1,384,856)
NITS/TO Charges - LSE		9,639,898	8,694,757		18,334,655
Net PJM Marginal Losses		3,709,559	2,530,927		6,240,486
Pt-to-Pt Transm. Revenues		(191,818)	(254,836)		(446,654)
PJM Emergency Energy Purchases		57,626	19,035		76,661
Total Net RTO Costs - OPCO		16,552,038	13,805,196	-	30,357,234
Monthly OPCo - Net <Over>/Under Recovery		(1,439,257)	(1,670,851)	-	(3,110,108)
Amortization of prior period liability		(667,584)	(667,584)		(1,335,168)
OPCO - Cumul. Net <Over>/Under Recovery	(13,432,149)	(14,203,822)	(15,207,089)	-	(15,207,089)

Columbus Southern Power Company
Amounts are recorded at 97.66% due to City of Westerville
Reconciliation Adjustment & Monthly Over and Under Recovery
Jan 10 - Feb 10
<Revenue>/ Expense in $

	Dec-09	Jan-10	Feb-10	Mar-10	1st Qtr 2010
Total Transm. TCRR/ETCRR Revenue-CSP		(14,633,702)	(13,380,776)		(28,014,478)
Transmission Costs:					
Net Congestion:					
PJM Implicit Congestion		8,620,506	1,885,225		10,505,731
PJM FTR Revenue		(8,442,218)	(1,803,229)		(10,245,447)
Net Congestion Subtotal		178,288	81,996	-	260,284
PJM Operating Reserve		789,182	790,709		1,579,891
PJM Ancillary Services					
PJM Synchronous Condensing		4,652	1,677		6,329
PJM Reactive Supply		526,096	484,739		1,010,835
PJM Blackstart		10,808	10,248		21,056
PJM Regulation Charges		853,998	661,128		1,515,126
PJM Spinning Reserve Charges		80,429	23,215		103,644
PJM 30 Minute Supplemental Reserve Market		44	43		87
PJM Ancillary Services Subtotal		1,476,027	1,181,050	-	2,657,077
PJM Administration Service Fees		733,660	687,492		1,421,152
Net Expansion Cost Recovery Charge		(9,982)	(11,545)		(21,527)
Amortization of PJM Integration Costs		46,570	46,570		93,140
PJM RTO Formation Cost Recovery		(1,457)	(1,858)		(3,315)
Net RTO Formation Costs		45,113	44,712	-	89,825
Load Response Program Subsidies		319,913	340,101		660,014
Prior Year Amortization of ETCRR Charges		(1,270,270)	(1,276,355)		(2,546,625)
NITS/TO Charges - LSE		8,580,346	7,830,517		16,410,863
Net PJM Marginal Losses		3,301,830	2,278,792		5,580,622
Pt-to-Pt Transm. Revenues		(170,735)	(228,822)		(399,557)
PJM Emergency Energy Purchases		51,292	17,142		68,434
Total Net RTO Costs - CSP		14,024,664	11,735,789	-	25,760,453
Monthly CSP - Net <Over>/Under Recovery		(609,038)	(1,644,987)	-	(2,254,025)
Amortization of prior period liability		(1,222,997)	(1,222,997)	-	(2,445,994)
CSP - Cumul. Net <Over>/Under Recovery	(17,930,432)	(17,316,473)	(17,738,462)	-	(17,738,462)

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

	Columbus Southern Power Company	Ohio Power Company
Cumulative (Over)/Under Recovery on Schedule D-1	(17,738,462)	(15,207,089)
Amortization of 2009 (Over)/Under Recovery from March - June 2010	4,891,989	2,670,335
Cumulative Carrying Charges	(257,732)	(198,966)
Prior Year (Over)/Under Recovery on Schedule B-1	(13,104,205)	(12,735,720)

Monthly Revenues Collected From Each Rate Schedule
January - February 2010

Ohio Power Company

	January 2010	February 2010
Billed:		
RS	7,917,585.63	7,198,810.86
GS1	285,091.46	256,673.69
GS2 Sec	1,808,541.88	1,750,513.50
GS2 RL - GS - TOD	99,110.85	90,139.54
GS2 Pri	215,663.73	254,150.91
GS2 Sub/Trans	153,719.80	155,111.69
GS3 Sec	1,576,708.31	1,525,355.25
GS3 Pri	1,434,268.43	1,277,276.97
GS3 Sub/Trans	491,746.00	488,726.66
GS4 Pri	110,374.91	108,792.41
GS4/IRP Sub/Trans	3,046,370.60	3,539,822.25
EHG	34,519.74	32,211.65
SS	574.11	450.36
EHS	45,629.57	44,059.48
OL	26,495.87	21,951.92
SL	29,678.21	22,731.66
SBS-Sub/Tran-Backup	-	10,809.59
	17,276,079.10	16,777,588.39
Estimated and Unbilled	715,216.01	(1,301,541.38)
Total:	17,991,295.11	15,476,047.01

Columbus Southern Power Company

	January 2010	February 2010
Billed:		
RS	7,480,077.09	6,736,846.20
GS1	302,866.60	273,153.09
GS2 Sec	1,233,272.48	1,162,834.95
GS2-TOD/LM	11,644.41	10,458.55
GS2 Pri	52,880.16	51,327.13
GS3 Sec	2,750,727.46	2,613,856.36
GS3-TOD/LM	1,140.28	1,011.41
GS3 Pri	1,250,479.49	1,200,943.46
GS4/IRP	1,925,068.61	1,943,885.13
SL	11,484.27	10,398.93
AL	14,483.97	14,704.92
SBS-Sub/Tran-Backup	1,487.40	1,496.90
	15,035,592.22	14,020,917.03
Unbilled and Estimated:	(401,890.01)	(640,141.13)
Total:	14,633,702.21	13,380,775.90

Ohio Power Company
2010
Example of Carrying Cost Calculation

Line No.	Description		
	Monthly Activity for	Jan-10	Feb-10
1	Monthly (Over)/Under Recovery	(1,439,257)	(1,670,851)
2	Cumulative (Over)/Under Rec.	(1,439,257)	(3,110,108)
	Recorded In	Feb-10	Mar-10
	Accrual of Carrying Charges		
3	Current TCRR Expenditures	(1,439,257)	(3,110,108)
4	Accumulated Carrying Charges	-	(6,851)
5	Total	(1,439,257)	(3,116,959)
6	Debt Rate	5.710%	5.710%
	Current Month Carrying Cost		
7	Debt Portion (4210041) (4310001)	(6,851)	(14,837)
	Accumulated		
8	Accumulated Debt	(6,851)	(21,688)
	Account 2540104	(6,851)	(14,837)
	Account 4310001	6,851	14,837

Line No.	Description Monthly Activity for	Jan-10	Feb-10
1	Monthly (Over)/Under Recovery	(609,038)	(1,644,987)
2	Cumulative (Over)/Under Rec.	(609,038)	(2,254,025)
	Recorded In	Feb-10	Mar-10
	Accrual of Carrying Charges		
3	Current TCRR Expenditures	(609,038)	(2,254,025)
4	Accumulated Carrying Charges	-	(2,911)
5	Total	(609,038)	(2,256,936)
6	Debt Rate	5.730%	5.730%
	Current Month Carrying Cost		
7	Debt Portion (4210041) (4310001)	(2,911)	(10,788)
	Accumulated		
8	Accumulated Debt	(2,911)	(13,699)
	Account 2540104	(2,911)	(10,788)
	Account 4310001	2,911	10,788

Ohio Power Company
Expanded Transmission Cost Recovery Rider Revenues
Jan 2010

Total Transmission Revenues	Current Month	Prior Month Reversal (4)	Net	
(1) Billed "T" Revenue	17,276,079.10	n/a	17,276,079 10	
(2) Estimated "T" Revenue	305,957.85	(2,609.32)	303,348 53	
(3) **Estimated** Unbilled T ' Revenue	8,669,457.24	(8,257,589.76)	411,867.48	**3rd W/D**
Total Amount of Transmission Revenues			**17,991,295.11**	

Source of Data:

(1) Billed Transmission revenues 9 - **1T**

(2) Estimated Billed Transmission Revenue - MACSS Report MCSRESTB

(3) **Estimated** Unbilled Transmission Revenues - Calculated from KWH

1,121,533,925 Est Unbilled KWH on Unbilled Kwh Calc SS for Board Est
0.00773 9-1T Cents/Kwh
8,669,457 24

American Electric Power OPERATING REVENUES, KILOWATT HOUR SALES, CUSTOMER REALIZATION(CENTS PER KWH), AVG REV AND KWH USE Prepared: 02/09/2010 01:45:38 PM

OHIO POWER COMPANY 1 MONTH BILLED - MCSR0194 - FINAL Page: 1 of 1

State : OH Line of Business: TRANSMISSION January 2010 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 2010	2009
		SALES OF ELECTRICITY										
		RESIDENTIAL										
4400	002	WITHOUT SPACE HEATING	4,692,457.00	4,354,568.83	7.76	533,037,351	543,581,032	1.94-	456,978	458,256	0.88	0.80
4400	001	WITH SPACE HEATING	3,231,736.23	2,999,905.82	7.73	366,921,055	374,310,592	1.97-	151,710	150,798	0.88	0.80
		TOTAL RESIDENTIAL	7,924,193.23	7,354,474.65	7.75	899,958,406	917,891,624	1.95-	608,688	609,053	0.88	0.80
					0.00						0.00	0.00
		COMMERCIAL										
4420	001	OTHER THAN PUBLIC AUTHORITIES	2,847,863.59	3,414,605.48	16.60-	412,909,258	416,957,254	0.97-	83,499	83,175	0.69	0.82
4420	006	PUBLIC AUTHS - SCHOOLS	322,407.44	376,087.34	14.27-	44,871,699	44,569,646	0.68	1,687	1,723	0.72	0.84
4420	007	PUBLIC AUTHS-OTHER THAN SCHOOL	432,618.02	513,325.20	15.72-	65,191,277	66,983,272	2.88-	7,444	7,448	0.66	0.77
		TOTAL COMMERCIAL	3,602,889.05	4,304,018.03	16.29-	522,972,232	528,510,172	1.05-	92,630	92,346	0.69	0.81
					0.00						0.00	0.00
		INDUSTRIAL										
4420	002	EXCLUDING MINE POWER	5,599,783.64	7,047,277.38	20.54-	940,662,355	1,125,839,801	16.52-	7,133	7,180	0.60	0.63
4420	004	MINE POWER	93,600.45	92,807.55	0.75	15,678,522	15,364,062	2.05	64	88	0.60	0.60
4420	005	ASSOCIATED COMPANIES	14,185.51	18,917.41	25.01-	2,355,242	2,613,538	9.88-	23	22	0.60	0.72
		TOTAL INDUSTRIAL	5,707,469.60	7,159,002.34	20.28-	958,696,119	1,144,817,421	16.26-	7,220	7,289	0.60	0.63
		COMMERCIAL AND INDUSTRIAL	9,310,358.55	11,463,020.37	18.78-	1,481,668,351	1,673,327,593	11.45-	99,850	99,614	0.63	0.69
		PUBLIC STREET & HIGHWAY LIGHT										
4440	000	PUBLIC STREET & HIGHWAY LIGHT	35,729.98	42,310.29	15.56-	7,884,331	8,423,720	6.40-	2,515	2,504	0.45	0.50
		TOTAL PUBLIC STREET & HIGHWAY LIGHT	35,729.98	42,310.29	15.55-	7,884,331	8,423,720	6.40-	2,515	2,504	0.45	0.50
					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	551.97	867.09	36.34-	69,687	84,411	17.44-	26	26	0.79	1.03
		TOTAL OTHER SALES TO PUBLIC AUTHS	551.97	867.09	36.34-	69,687	84,411	17.44-	26	26	0.79	1.03
		ULTIMATE CUSTOMERS	17,270,833.73	18,860,672.40	8.43-	2,389,570,775	2,599,727,348	8.08-	711,079	711,197	0.72	0.73
		SALES FOR RESALE										
4470	XXX	OTHER ELEC UTILS	5,245.37	5,774.86	9.17-	837,240	819,600	2.15	3	3	0.63	0.70
		TOTAL SALES FOR RESALE	5,245.37	5,774.86	9.17-	837,240	819,600	2.15	3	3	0.63	0.70
					0.00						0.00	0.00
		TOTAL SALES OF ELECTRICITY	17,276,079.10	18,866,447.26	8.43-	2,390,408,015	2,600,546,948	8.08-	711,082	711,200	0.72	0.73
		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	17,276,079.10	18,866,447.26	8.43-	2,390,408,015	2,600,546,948	8.08-	711,082	711,200	0.72	0.73

Schedule D-3b
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American Electric Power
OHIO POWER COMPANY

Estimate Billings For MACSS GTD
MCSRESTB

Prepared: 02/02/2010 04:21:57 PM

January 2010

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
211	G	OH	5	368,085	25.0	8,566.00	39,888.21
211	T	OH	4	268,062	20.0	0.00	1,095.25
211	D	OH	5	368,085	25.0	0.00	15,422.54
Total : 211			5	368,085	25.0	8,566.00	56,406.00
221	G	OH	5	89,139,991	25.0	1,859,750.00	4,156,666.84
221	T	OH	5	89,139,991	25.0	0.00	304,862.60
221	D	OH	5	89,139,991	25.0	0.00	264,894.56
Total : 221			5	89,139,991	25.0	1,859,750.00	4,726,424.00
	Total G:		10	89,508,076	50.0	1,868,316.00	4,196,555.05
	Total T:		9	89,408,053	45.0	0.00	305,957.86
	Total D:		10	89,508,076	50.0	0.00	280,317.10
	Grand Total :		10	89,508,076	50.0	1,868,316.00	4,782,830.00

Ohio Power Company
Expanded Transmission Cost Recovery Rider Revenues
Feb 2010

Total Transmission Revenues	Current Month	Prior Month Reversal (4)	Net	
(1) Billed "T" Revenue	16,777,588.39	n/a	16,777,588 39	
(2) Estimated "T" Revenue	236,456.54	(305,957.85)	(69,501 31)	
(3) **Estimated** Unbilled T Revenue	7,437,417.17	(8,669,457.24)	(1,232,040.07)	**3rd W/D**
Total Amount of Transmission Revenues			**15,476,047.01**	

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

954,126,642 Est Unbilled KWH on Unbilled Kwh Calc SS for Board Est
0.007795 9-1T Cents/Kwh
7,437,417 17

American Electric Power OPERATING REVENUES, KILOWATT HOUR SALES, CUSTOMER REALIZATION(CENTS PER KWH), AVG REV AND KWH USE Prepared: 03/08/2010 10:38:56 AM
OHIO POWER COMPANY 1 MONTH BILLED - MCSR0194 - FINAL Page: 1 of 1

State : OH Line of Business: TRANSMISSION February 2010 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 2010	2009
		SALES OF ELECTRICITY										
		RESIDENTIAL										
4400	002	WITHOUT SPACE HEATING	4,150,088.70	3,837,127.90	8.16	471,407,436	478,953,221	1.58-	454,155	459,036	0.88	0.80
4400	001	WITH SPACE HEATING	3,054,052.67	2,837,648.40	7.63	346,727,532	354,053,326	2.07-	150,913	151,394	0.88	0.80
		TOTAL RESIDENTIAL	7,204,141.37	6,674,776.30	7.93	818,134,968	833,016,547	1.79-	605,068	610,430	0.88	0.80
					0.00						0.00	0.00
		COMMERCIAL										
4420	001	OTHER THAN PUBLIC AUTHORITIES	2,716,632.62	3,273,898.91	17.02-	375,367,033	382,908,462	1.97-	83,143	83,106	0.72	0.86
4420	006	PUBLIC AUTHS - SCHOOLS	315,270.99	379,602.85	16.95-	43,427,347	43,966,846	1.23-	1,676	1,715	0.73	0.88
4420	007	PUBLIC AUTHS-OTHER THAN SCHOOL	412,638.09	494,472.01	16.51-	59,423,465	61,766,931	3.79-	7,381	7,327	0.69	0.80
		TOTAL COMMERCIAL	3,444,541.70	4,147,973.17	16.95-	478,217,845	488,642,039	2.13-	92,200	92,148	0.72	0.85
					0.00						0.00	0.00
		INDUSTRIAL										
4420	002	EXCLUDING MINE POWER	5,990,612.82	6,255,294.91	4.23-	997,834,424	947,451,244	5.32	7,084	7,195	0.60	0.66
4420	004	MINE POWER	92,308.88	96,502.24	4.35-	15,216,910	15,290,417	0.48-	62	69	0.61	0.63
4420	005	ASSOCIATED COMPANIES	12,833.49	5,886.87	118.70	2,029,059	850,806	138.49	23	20	0.64	0.69
		TOTAL INDUSTRIAL	6,095,755.19	6,357,684.02	4.12-	1,015,080,393	963,592,467	5.34	7,169	7,284	0.60	0.66
		COMMERCIAL AND INDUSTRIAL	9,540,386.89	10,505,657.19	9.19-	1,493,298,238	1,452,234,506	2.83	99,369	99,432	0.64	0.72
		PUBLIC STREET & HIGHWAY LIGHT										
4440	000	PUBLIC STREET & HIGHWAY LIGHT	28,004.38	35,388.47	20.87-	6,116,383	6,880,641	11.11-	2,495	2,540	0.46	0.51
		TOTAL PUBLIC STREET & HIGHWAY LIGHT	28,004.38	35,388.47	20.87-	6,116,383	6,880,641	11.11-	2,495	2,540	0.46	0.51
					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	531.84	858.62	37.91-	67,146	83,497	19.58-	26	26	0.79	1.03
		TOTAL OTHER SALES TO PUBLIC AUTHS	531.84	858.62	37.91-	67,146	83,497	19.58-	26	26	0.79	1.03
		ULTIMATE CUSTOMERS	16,773,074.48	17,216,678.58	2.58-	2,317,616,735	2,292,215,191	1.11	706,958	712,428	0.72	0.79
		SALES FOR RESALE										
4470	XXX	OTHER ELEC UTILS	4,513.91	5,211.51	13.39-	676,140	732,120	7.65-	3	3	0.67	0.71
		TOTAL SALES FOR RESALE	4,513.91	5,211.51	13.39-	676,140	732,120	7.65-	3	3	0.67	0.71
					0.00						0.00	0.00
		TOTAL SALES OF ELECTRICITY	16,777,588.39	17,221,890.09	2.58-	2,318,292,875	2,292,947,311	1.11	706,961	712,431	0.72	0.75
		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	16,777,588.39	17,221,890.09	2.58-	2,318,292,875	2,292,947,311	1.11	706,961	712,431	0.72	0.75

Estimate Billings For MACSS GTD
MCSRESTB

Prepared: 03/03/2010 11:52:57 AM

February 2010 Page: 1

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
211	G	OH	2	156,207	10.0	3,715.00	8,665.77
211	T	OH	2	156,207	10.0	0.00	586.03
211	D	OH	2	156,207	10.0	0.00	2,591.20
Total : 211			2	156,207	10.0	3,715.00	11,843.00
213	G	OH	1	74,973	5.0	1,834.00	4,353.93
213	T	OH	1	74,973	5.0	0.00	263.96
213	D	OH	1	74,973	5.0	0.00	1,386.11
Total : 213			1	74,973	5.0	1,834.00	6,004.00
216	G	OH	1	195,711	5.0	4,488.00	9,089.89
216	T	OH	1	195,711	5.0	0.00	501.67
216	D	OH	1	195,711	5.0	0.00	2,073.44
Total : 216			1	195,711	5.0	4,488.00	11,665.00
221	G	OH	8	81,158,091	40.0	1,697,201.00	3,389,872.15
221	T	OH	8	81,158,091	40.0	0.00	233,495.71
221	D	OH	8	81,158,091	40.0	0.00	210,421.14
Total : 221			8	81,158,091	40.0	1,697,201.00	3,833,789.00
230	G	OH	1	374,097	5.0	8,373.00	21,662.99
230	T	OH	1	374,097	5.0	0.00	1,609.17
230	D	OH	1	374,097	5.0	0.00	5,521.84
Total : 230			1	374,097	5.0	8,373.00	28,794.00
	Total G:		13	81,959,079	65.0	1,715,611.00	3,433,844.73
	Total T:		13	81,959,079	65.0	0.00	236,456.54
	Total D:		13	81,959,079	65.0	0.00	221,993.73
	Grand Total :		13	81,959,079	65.0	1,715,611.00	3,892,095.00

Columbus Southern Power Company
Expanded Transmission Cost Recovery Rider Revenues
Jan 2010

Total Transmission Revenues	Current Month	Prior Month Reversal (4)	Net	
(1) Billed "T" Revenue	15,035,592.22	n/a	15,035,592 22	
(2) Estimated "T" Revenue	12,195.59	(602.29)	11,593 30	
(3) **Estimated** Unbilled I Revenue	6,101,788.41	(6,515,271.72)	(413,483.31)	**3rd W/D**
Total Amount of Transmission Revenues			**14,633,702.21**	

Source of Data:

(1) Billed Transmission revenues

(2) Estimated Billed Transmission Revenue - MACSS Report MCSRESTB

(3) **Estimated** Unbilled Transmission Revenues - Calculated from KWH

781,278,926	Est Unbilled KWH on Unbilled Kwh Calc SS for Board Est
0.00781	9-1T Cents/Kwh
6,101,788 41	

State : OH Line of Business: TRANSMISSION January 2010 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 2010	2009
		SALES OF ELECTRICITY										
		RESIDENTIAL										
4400	002	WITHOUT SPACE HEATING	5,029,081.47	5,096,879.19	1.33-	580,571,707	574,573,539	1.04	553,020	551,359	0.87	0.89
4400	001	WITH SPACE HEATING	2,454,015.65	2,503,511.00	1.98-	283,102,477	281,950,559	0.41	115,777	114,770	0.87	0.89
		TOTAL RESIDENTIAL	7,483,097.12	7,600,390.19	1.54-	863,674,184	856,524,098	0.83	668,797	666,129	0.87	0.89
					0.00						0.00	0.00
		COMMERCIAL										
4420	001	OTHER THAN PUBLIC AUTHORITIES	4,568,985.66	5,097,149.24	10.36-	657,625,171	664,491,273	1.03-	77,096	76,602	0.69	0.77
4420	006	PUBLIC AUTHS - SCHOOLS	485,180.50	498,861.49	2.74-	76,536,396	79,176,726	3.33-	734	731	0.63	0.55
4420	007	PUBLIC AUTHS-OTHER THAN SCHOOL	39,784.33	37,956.07	4.82	6,871,765	6,730,459	2.10	171	172	0.58	0.56
		TOTAL COMMERCIAL	5,093,950.49	5,633,966.80	9.59-	741,033,332	750,398,458	1.25-	78,001	77,505	0.69	0.75
					0.00						0.00	0.00
		INDUSTRIAL										
4420	002	EXCLUDING MINE POWER	2,414,197.91	2,738,634.89	11.85-	388,092,896	447,491,187	13.27-	3,327	3,348	0.62	0.61
4420	004	MINE POWER	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
4420	005	ASSOCIATED COMPANIES	24,419.09	26,144.88	6.60-	3,980,149	3,878,726	2.61	27	27	0.61	0.67
		TOTAL INDUSTRIAL	2,438,617.00	2,764,779.77	11.80-	392,073,045	451,369,913	13.14-	3,354	3,375	0.62	0.61
		COMMERCIAL AND INDUSTRIAL	7,532,567.49	8,398,746.57	10.31-	1,133,106,377	1,201,768,371	5.71-	81,355	80,880	0.66	0.70
		PUBLIC STREET & HIGHWAY LIGHT										
4440	000	PUBLIC STREET & HIGHWAY LIGHT	19,827.61	19,217.77	3.17	4,627,961	3,543,169	30.62	307	306	0.43	0.54
		TOTAL PUBLIC STREET & HIGHWAY LIGHT	19,827.61	19,217.77	3.17	4,627,961	3,543,169	30.62	307	306	0.43	0.54
					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	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
		TOTAL OTHER SALES TO PUBLIC AUTHS	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
		ULTIMATE CUSTOMERS	15,035,492.22	16,018,354.53	6.14-	2,001,408,522	2,061,835,638	2.93-	750,459	747,315	0.75	0.78
		SALES FOR RESALE										
4470	XXX	OTHER ELEC UTILS	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
		TOTAL SALES FOR RESALE	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
					0.00						0.00	0.00
		TOTAL SALES OF ELECTRICITY	15,035,492.22	16,018,354.53	6.14-	2,001,408,522	2,061,835,638	2.93-	750,459	747,315	0.75	0.78
		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	15,035,492.22	16,018,354.53	6.14-	2,001,408,522	2,061,835,638	2.93-	750,459	747,315	0.75	0.78

American Electric Power
COLUMBUS SOUTHERN POWER COMPANY

Estimate Billings For MACSS GTD
MCSRESTB

Prepared: 02/02/2010 04:26:29 PM

January 2010 Page: 1

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
211	G	OH	3	2,563,692	15.0	74,650.00	189,294.15
211	T	OH	3	2,563,692	15.0	0.00	9,905.11
211	D	OH	3	2,563,692	15.0	0.00	31,650.74
Total : 211			3	2,563,692	15.0	74,650.00	230,850.00
212	G	OH	1	93,111	5.0	3,237.00	7,671.99
212	T	OH	1	93,111	5.0	0.00	429.17
212	D	OH	1	93,111	5.0	0.00	1,531.84
Total : 212			1	93,111	5.0	3,237.00	9,633.00
216	G	OH	1	72,223	5.0	2,511.00	5,950.96
216	T	OH	1	72,223	5.0	0.00	332.88
216	D	OH	1	72,223	5.0	0.00	1,188.16
Total : 216			1	72,223	5.0	2,511.00	7,472.00
221	G	OH	1	406,963	5.0	11,618.00	29,545.16
221	T	OH	1	406,963	5.0	0.00	1,528.43
221	D	OH	1	406,963	5.0	0.00	4,782.41
Total : 221			1	406,963	5.0	11,618.00	35,856.00
	Total G:		6	3,135,989	30.0	91,916.00	232,462.26
	Total T:		6	3,135,989	30.0	0.00	12,195.59
	Total D:		6	3,135,989	30.0	0.00	39,153.15
	Grand Total :		6	3,135,989	30.0	91,916.00	283,811.00

Columbus Southern Power Company
Expanded Transmission Cost Recovery Rider Revenues
Feb 2010

Total Transmission Revenues	Current Month	Prior Month Reversal (4)	Net	
(1) Billed "T" Revenue	14,020,917.03	n/a	14,020,917 03	
(2) Estimated "T" Revenue	15,122 23	(12,195.59)	2,926.64	
(3) **Estimated** Unbilled "T" Revenue	5,458,720 64	(6,101,788.41)	(643,067.77)	3rd W/D
Total Amount of Transmission Revenues			**13,380,775.90**	

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

699,925,714 Est Unbilled KWH on Unbilled Kwh Calc SS for Board Est
0.007799 9-1T Cents/Kwh
5,458,720 64

American Electric Power — OPERATING REVENUES, KILOWATT HOUR SALES, CUSTOMER REALIZATION(CENTS PER KWH), AVG REV AND KWH USE — Prepared: 03/08/2010 12:04:46 PM
COLUMBUS SOUTHERN POWER COMPANY — 1 MONTH BILLED - MCSR0194 - FINAL — Page: 1 of 1

State : OH — Line of Business: TRANSMISSION — February 2010 — 9-1T

FERC ACCT	NO	OPERATING REVENUE ACCOUNTS	OPERATING REVENUES THIS YR	OPERATING REVENUES LAST YR	%CHNG	KILOWATT-HOUR SALES THIS YR	KILOWATT-HOUR SALES LAST YR	%CHNG	CUSTOMERS THIS YR	CUSTOMERS LAST YR	CENTS PER KWH 2010	CENTS PER KWH 2009
		SALES OF ELECTRICITY										
		RESIDENTIAL										
4400	002	WITHOUT SPACE HEATING	4,398,334.58	4,590,843.62	4.18-	507,818,382	517,601,577	1.89-	550,841	554,180	0.87	0.89
4400	001	WITH SPACE HEATING	2,341,637.44	2,432,484.84	3.74-	270,128,874	274,013,555	1.42-	115,862	115,417	0.87	0.89
		TOTAL RESIDENTIAL	6,739,872.02	7,023,328.46	4.04-	777,947,256	791,615,132	1.73-	666,703	669,597	0.87	0.89
					0.00						0.00	0.00
		COMMERCIAL										
4420	001	OTHER THAN PUBLIC AUTHORITIES	4,325,633.18	4,989,494.98	13.31-	596,988,523	624,029,582	4.33-	76,626	76,508	0.72	0.80
4420	006	PUBLIC AUTHS - SCHOOLS	467,420.08	480,544.45	2.73-	71,166,697	71,182,779	0.02-	721	730	0.66	0.59
4420	007	PUBLIC AUTHS-OTHER THAN SCHOOL	36,976.28	36,107.61	2.41	5,811,454	5,944,367	2.24-	168	170	0.64	0.60
		TOTAL COMMERCIAL	4,830,829.52	5,506,146.92	12.26-	673,966,674	701,156,728	3.88-	77,515	77,408	0.72	0.79
					0.00						0.00	0.00
		INDUSTRIAL										
4430	002	EXCLUDING MINE POWER	2,407,808.09	2,739,220.17	12.10-	387,422,576	426,353,263	9.13-	3,284	3,378	0.62	0.64
4420	004	MINE POWER	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
4420	065	ASSOCIATED COMPANIES	23,228.50	25,478.04	8.83-	3,576,563	3,763,287	4.96-	27	27	0.65	0.68
		TOTAL INDUSTRIAL	2,431,036.59	2,764,698.21	12.07-	390,998,128	430,116,550	9.09-	3,311	3,405	0.62	0.64
		COMMERCIAL AND INDUSTRIAL	7,261,866.11	8,270,845.13	12.21-	1,064,964,802	1,131,273,278	5.86-	80,826	80,813	0.68	0.73
		PUBLIC STREET & HIGHWAY LIGHT										
4440	000	PUBLIC STREET & HIGHWAY LIGHT	19,978.90	23,860.60	16.58-	4,420,191	4,550,666	2.87-	308	307	0.45	0.53
		TOTAL PUBLIC STREET & HIGHWAY LIGHT	19,978.90	23,860.60	16.58-	4,420,191	4,550,666	2.87-	308	307	0.45	0.53
					0.00						0.00	0.00
		OTHER SALES TO PUBLIC AUTHS										
4450	001	PUBLIC SCHOOLS	0.00	0.08	100.00	0	0	100.00	0	0	0.00	0.00
4450	002	OTHER THAN PUBLIC SCHOOLS	0.00	0.08	100.00	0	0	100.00	0	0	0.00	0.00
		TOTAL OTHER SALES TO PUBLIC AUTHS	0.00	0.08	100.00	0	0	100.00	0	0	0.00	0.00
		ULTIMATE CUSTOMERS	14,020,917.03	15,318,124.09	8.47-	1,847,332,249	1,927,439,096	4.16-	747,837	760,717	0.76	0.79
		SALES FOR RESALE										
4470	XXX	OTHER ELEC UTILS	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
		TOTAL SALES FOR RESALE	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
					0.00						0.00	0.00
		TOTAL SALES OF ELECTRICITY	14,020,917.03	15,318,124.09	8.47-	1,847,332,249	1,927,439,096	4.16-	747,837	750,717	0.76	0.79
		PROVISION FOR REFUND										
		PROVISION FOR REFUND										
4491		PROVISION FOR REVENUE REFUND	0.00	0.00	100.00	0	0	100.00	0	0	0.00	0.00
		TOTAL PROVISION FOR REFUND	0.00	0.00	100.00	0	0	100.00	0	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	14,020,917.03	15,318,124.09	8.47-	1,847,332,249	1,927,439,096	4.16-	747,837	750,717	0.76	0.79

American Electric Power
COLUMBUS SOUTHERN POWER COMPANY

Estimate Billings For MACSS GTD
MCSRESTB

Prepared: 03/03/2010 11:58:24 AM

February 2010 Page: 1

Revn Cl	LOB		Cust	Mtrd KWH	Demand	Fuel Clause	Revenue
211	G	OH	9	2,255,098	45.0	78,032.00	140,664.96
211	T	OH	9	2,255,098	45.0	0.00	6,030.30
211	D	OH	9	2,255,098	45.0	0.00	21,635.74
Total : 211			9	2,255,098	45.0	78,032.00	168,331.00
212	G	OH	1	140,642	5.0	4,889.00	8,729.05
212	T	OH	1	140,642	5.0	0.00	371.60
212	D	OH	1	140,642	5.0	0.00	1,326.35
Total : 212			1	140,642	5.0	4,889.00	10,427.00
213	G	OH	3	392,703	15.0	13,649.00	20,910.96
213	T	OH	2	265,957	10.0	0.00	702.74
213	D	OH	3	392,703	15.0	0.00	4,655.28
Total : 213			3	392,703	15.0	13,649.00	26,269.00
216	G	OH	3	364,857	15.0	12,683.00	22,645.07
216	T	OH	3	364,857	15.0	0.00	964.02
216	D	OH	3	364,857	15.0	0.00	3,440.91
Total : 216			3	364,857	15.0	12,683.00	27,050.00
221	G	OH	2	3,012,629	10.0	101,263.00	184,456.94
221	T	OH	2	3,012,629	10.0	0.00	7,053.57
221	D	OH	2	3,012,629	10.0	0.00	22,070.49
Total : 221			2	3,012,629	10.0	101,263.00	213,581.00
	Total G:		18	6,165,927	90.0	210,515.00	377,407.00
	Total T:		17	6,039,181	85.0	0.00	15,122.23
	Total D:		18	6,165,927	90.0	0.00	53,128.77
	Grand Total :		18	6,165,927	90.0	210,515.00	445,658.00

Schedule D-3b
Page 12 of 12

Schedule D-3c
Narrative
Reconciliation of One Month's Invoice from RTO to Financial Records of the Company
(January 2010 PJM Invoice)

Description of the Reconciliation Process

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

- AEP Generation (AEPSCG),
- City of Auburn (AEPAUB)
- Buckeye (AEPBCK)
- APCo Dedicated (AEPAPD) (Appalachian Power Company dedicated wind purchases)
- CSP Dedicated (AEPCSD) (Columbus Southern Power dedicated wind purchases)
- IM Dedicated (AEPIMD) (Indiana Michigan Power dedicated wind purchases)
- OCG (AEPOCG) (Camp Grove Wind Farm)
- OPCo Dedicated (AEPOPD) (Ohio Power Company dedicated wind purchases)
- Monongahela Power (AEPMON)

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

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

The PJM invoice is received after AEP's month-end closing process and therefore an estimate is booked for the current month. The following month, the estimate entry is reversed out of the general ledger and a new entry is made reflecting the actual invoice amount. Therefore, the detail provided in Schedule D-3c shows the February general ledger amounts booked for the January 1, 2010 through January 31, 2010 billing period, as shown on the PJM Billing Statements.

The assignment methodology for PJM costs and credits is detailed in **Schedule D-3c, Summary of January 2010 PJM Invoice Reconciliation, Pages 14-17, PJM Invoice Explanations**. As background, AEP uses the hourly MWh information from PJM to reconstruct the resources (both generation and purchased energy) used to serve the native load requirements and fulfill OSS. The reconstruction of the hourly data is completed by AEP's Energy Costing and Reporting Application (ECR)[1]. AEP is able to use the output from ECR to assign certain costs/credits, while other costs/credits are either directly assigned or assigned based on the Load Ratio Share (LRS).

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

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

Schedule D-3C, Summary of January 2010 PJM Invoice Reconciliation, Pages 5 through 7, demonstrates the settlement of the credits and charges (line items in the January 2010 PJM Invoice) for the PJM accounts listed above and the allocation of each to the AEP and CSP and OPCo general ledgers. **Schedule D-3C, Summary of January 2010 PJM Invoice Reconciliation to General Ledger (GL) Transmission Accounts,** Pages 18 through 20 shows the reconciliation for the TCRR accounts for AEP Transmission (AEPSCT). As noted earlier, the AEP Transmission accounts (AEPSCT), are settled in a separate process from the PJM accounts listed above.

Description of the PJM Invoice Reconciliation Details

Page 5, "**Summary of January 2010 PJM Invoice to General Ledger (GL) Accounts**", shows a list of the PJM charges that represents Columbus Southern Power (CSP) and Ohio Power Company (OPCo) TCRR activity for the month, and their FERC-based General Ledger account number. Three columns each (for CSP and OPCo) show the total amount allocated from the PJM invoice for each account, the corresponding General Ledger total for each account, and the variance (if any) for each. This summary illustrates that the January invoice is reconciled for CSP and OPCo, with a zero variance (within \$0.00 to \$0.03).

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

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

Pages 6 and 7, "**January 2010 PJM Reconciled Invoice Allocation**" shows the AEP allocation for each of the CSP and OPCo activities from Page 5, and that the CSP and OPCo portions of each activity, together with the remainder of the AEP East Operating Companies, reconcile with the total from the PJM bills for each activity. The Internal Allocation Column shows the breakdown of the AEP allocation for the Load Serving Entities (LSEs), which are the retail customers of the AEP East operating companies, plus allocations for OSS activities from all of the East Operating Companies. For each activity/account number, the sum of the LSE Allocation plus the OSS amount is equal to the total from all PJM bills for January 2010.

Pages 8 through 13, **PJM Invoice Detail,** lists, for each of the PJM Invoices, the detail for each Billing Line Item (BLI), consisting of a description of the individual entry, and the total invoice amount included under each account. The sum of each individual BLI entry is equal to the total amount for each account as shown on the Reconciled Invoice Allocations for each of the PJM Invoices.

Pages 14 through 17 **PJM Invoice Explanations,** is a list of each activity and the specific PJM Invoice Billing Line Item (BLI) for each activity, described in the "Notes" column. The last column lists the assignment methodology for allocation of each AEPSCG item. Referring to the CONFIDENTIAL January PJM bills attached, the assignment methodology described for each activity shows how each billing line item is assigned to determine the amounts reflected in the general ledger.

Attachments:

- Invoice Statement Summary AEP Generation (AEPSCG)
- Invoice Statement Summary City of Auburn (AEPAUB)
- Invoice Statement Summary Buckeye (AEPBCK)
- Invoice Statement Summary APCo Dedicated (AEPAPD)
- Invoice Statement Summary CSP Dedicated (AEPCSD)
- Invoice Statement Summary IM Dedicated (AEPIMD)
- Invoice Statement Summary OCG (AEPOCG)
- Invoice Statement Summary OPCo Dedicated (AEPOPD)
- Invoice Statement Summary Monongahela Power) (AEPMON)

Description of the AEP Transmission PJM Invoice Reconciliation

Page 18, "**Summary of January 2010 PJM Invoice Reconciliation to General Ledger (GL) Transmission Accounts**" shows a list of the AEP Transmission PJM charges that represents Columbus Southern Power (CSP) and Ohio Power Company (OPCo) TCRR activity for the month, and their FERC-based General Ledger account numbers. Three columns each (for CSP and OPCO) show the total amount allocated from the PJM invoice by Transmission Settlements for the Network Integration Transmission Service (NITS), Transmission Owner and Dispatch Service, PJM RTO Formation Cost Recovery, Expansion Cost Recovery, PJM Operating Reserve-LSE charge and PJM Implicit Congestion accounts, the corresponding General Ledger total for each account, and the variance (if any) for each. The PJM Implicit Congestion represents an over or under collection of load LMPs from LSEs within the AEP Zone that have not elected to use a specific nodal aggregate LMP. Note that these are received on the PJM Invoice and are booked by Transmission Settlements. This summary illustrates that the January invoice is reconciled for CSP and OPCo is reconciled to the General Ledger.

Page 19, **January 2010 PJM Transmission Reconciled Invoice Allocation,** illustrates the Internal Allocation for each of the CSP and OPCo activities from Page 18, and that the CSP and OPCo portions of each activity, together with the remainder of the AEP East Operating Companies, reconcile with the amounts from the following bills, AEP Transmission (AEPSCT), AEP Generation (AEPSCG), and AEP City of Auburn (AEPAUB). (AEP does not have transmission responsibilities for the other PJM accounts). The Internal Allocation Column shows the breakdown of the Internal Allocation for the Load Serving Entities (LSEs) and Non-Affiliate Wholesale allocation, the Non-Affiliate PJM, and the OSS activities from all of the East Operating Companies. For each activity, the sum of the LSE Allocations and Non-Affiliate Wholesale Allocation, the Non-Affiliate PJM, and OSS for each activity/account number is equal to the total from the AEPSCT, AEPSCG, and AEPAUB PJM invoices for January 2010.

Page 20, **PJM Transmission Invoice Explanations**, is a list of each activity and the specific PJM Invoice Billing Line Item (BLI) for each activity and the assignment methodology for allocation of each item. Referring to the CONFIDENTIAL January PJM invoice for AEPSCT AEPSCG, and AEPAUB attached, the assignment methodology described for each activity shows how each billing line item is translated to the total allocated amounts in the general ledger.

Attachments:

- Invoice Statement Summary AEP Transmission (AEPSCT)

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

Summary of January 2010 PJM Invoice to General Ledger (GL) Accounts

TCRR Activity Jan 2010

Charge	LSE GL Account	Allocated by Settlements CSP	GL Amount (Actual Booked in Feb 2010) CSP	Variance CSP	Allocated by Settlements OPCO	GL Amount (Actual Booked in Feb 2010) OPCO	Variance OPCO
PJM Implicit Congestion	4470093	$ 8,769,785.13	$ 8,769,785.12	$ 0.01	$ 10,211,480.23	$ 10,211,480.21	$ 0.02
PJM FTR & ARR Revenue	4470101	$ (8,748,361.37)	$ (8,748,361.37)	$ -	$ (10,186,534.55)	$ (10,186,534.56)	$ 0.01
PJM Operating Reserve (a)	4470203	$ 872,462.03	$ 872,462.02	$ 0.01	$ 1,015,689.06	$ 1,015,689.03	$ 0.03
PJM Ancillary Services (a)							
PJM Synchronous Condensing	5550041	$ 1,672.20	$ 1,672.21	$ (0.01)	$ 1,947.10	$ 1,947.11	$ (0.01)
PJM Reactive Supply	5550074	$ 512,501.63	512,501.63	$ -	$ 596,753.53	$ 596,753.53	$ -
PJM Blackstart	5550076	$ 10,664.72	$ 10,664.72	$ -	$ 12,417.92	$ 12,417.93	$ (0.01)
PJM Regulation Charges	5550078	$ 976,454.79	$ 976,454.79	$ -	$ 1,136,977.55	1136977.55	$ -
PJM Spinning Reserve Charges	5550083	$ 37,164.18	$ 37,164.19	$ (0.01)	$ 43,273.73	$ 43,273.73	$ -
PJM 30 minute Supplemental Reserve Market (DASR)	5550090	$ 24.33	$ 24.33	$ -	$ 28.33	$ 28.32	$ 0.01
PJM Administration Service Fees (b)	5614001	$319,630.75	$ 319,630.75	$ -	$372,175.94	$ 372,175.94	$ -
	5618001	$ 67,445.96	$ 67,445.97	$ (0.01)	$ 78,533.65	$ 78,533.65	$ -
	5757001	$ 334,392.81	$ 334,392.81	$ -	$ 389,364.78	$ 389,364.77	$ 0.01
PJM Administration Service Fees Sub Total		$721,469.52	$721,469.53	$ (0.01)	$840,074.37	$840,074.36	$ 0.01
Expansion Cost Recovery Charge	4561003	$ 12,969.99	$ 12,969.99	$ -	$ 36,858.42	$ 36,858.41	$ 0.01
PJM RTO Formation Cost Recovery	4561002	$ 20,294.92	$ 20,294.92	$ -	$ 57,674.58	$ 57,674.58	$ -
PJM Transmission Enhancement Charges	5650012	$ 332,509.70	$ 332,509.70	$ -	$ 387,172.11	$ 387,172.11	$ -
Real-time Economic Load Response Charge	5550036			$ -			$ -
PJM Transmission Implicit Loss Charges	4470207	$ 6,135,236.23	$ 6,135,236.22	$ 0.01	$ 7,143,828.79	$ 7,143,828.78	$ 0.01
PJM Transmission Implicit Loss Credit	4470208	$ (2,545,840.43)	$ (2,545,840.43)	$ -	$ (2,964,359.88)	$ (2,964,359.89)	$ 0.01
Net Transmission Implicit Losses		$ 3,589,395.80	$ 3,589,395.79	$ 0.01	$ 4,179,468.91	$ 4,179,468.89	$ 0.02
Pt-to-Pt Transm. Revenues	4561005	$ (217,120.41)	$ (217,120.40)	$ (0.01)	$ (252,813.58)	$ (252,813.58)	$ -

Reconciled Invoice Allocation

TCRR Activity Jan 2010

		Internal Allocation				
		LSE Allocation			OSS Total	
Charge	LSE GL Account	CSP	OPCO	APCO, KY and I&M	All Operating COs	Total
PJM Implicit Congestion	4470093	$ 8,769,785.13	$ 10,211,480.23	$ 29,642,515.58	$ 4,651,212.23	$ 53,274,993.17
PJM FTR & ARR Revenue	4470101	$ (8,748,361.37)	$ (10,186,534.55)	$ (29,570,101.71)	$ (10,177,658.93)	$(58,682,656.56)
PJM Operating Reserve (a)	4470203	$ 872,462.03	$ 1,015,889.06	$ 2,948,985.51	$ 625,276.98	$ 5,462,613.58
PJM Ancillary Services (a)						
PJM Synchronous Condensing	5550041	$ 1,672.20	$ 1,947.10	$ 5,652.18	$ 684.71	$ 9,956.19
PJM Reactive Supply	5550074	$ 512,501.63	$ 596,753.53	$ 1,732,283.00	212,821.37	$ 3,054,369.53
PJM Blackstart	5550076	$ 10,664.72	$ 12,417.92	$ 36,047.52	5,054.10	$ 64,184.26
PJM Regulation Charges	5550078	$ 976,454.79	$ 1,136,977.55	$ 3,300,488.65	$ 398,235.98	$ 5,812,156.97
PJM Spinning Reserve Charges	5550083	$ 37,164.18	$ 43,273.73	$ 125,617.86	$ 14,795.11	$ 220,850.68
PJM *30 minute Supplemental Reserve Market (DASR)*	5550090	$ 24.33	$ 28.33	$ 82.23	$ 47,094.43	$ 47,229.32
PJM Administration Service Fees (b)						
	5614001	$319,630.75	$372,175.94	$ 1,080,375.30	$ 537,799.90	
	5618001	$ 67,445.96	$ 78,533.65	$ 227,972.31		
	5757001	$ 334,392.81	$ 389,364.78	$ 1,130,272.17		
PJM Administration Service Fees Sub Total		$721,469.52	$840,074.37	$2,438,619.78	$537,799.90	$4,537,963.57
Expansion Cost Recovery Charge	4561003	$ 12,969.99	$ 36,858.42	$ 66,078.56	$7,108.61	$ 123,015.58
PJM RTO Formation Cost Recovery	4561002	$ 20,294.92	$ 57,674.58	$ 103,397.11	$9,174.45	$ 190,541.06
PJM Transmission Enhancement Charges	5650012	$ 332,509.70	$ 387,172.11	$ 1,123,907.10	$111,301.31	$ 1,954,890.22
Real-time Economic Load Response Charge	5550036					$ -
PJM Transmission Implicit Loss Charges	4470207	$ 6,135,236.23	$ 7,143,828.79	$ 20,737,547.47	$ 6,068,855.84	$ 40,085,468.33
PJM Transmission Implicit Loss Credit	4470208	$ (2,545,840.43)	$ (2,964,359.88)	$ (8,605,126.96)	$ (2,408,456.90)	$(16,523,784.17)
Net Transmission Implicit Losses		$ 3,589,395.80	$ 4,179,468.91	$ 12,132,420.51	$ 3,660,398.94	$ 23,561,684.16
Pt-to-Pt Transm. Revenues	4561005	$ (217,120.41)	$ (252,813.58)	$ (733,882.88)	$ (63,386.53)	$ (1,267,203.40)

***Participant charges and credits are allocated to the operating companies based on their respective MLR %.

PJM Invoices January 2010

AEPSCG	AEPAUB	AEPBCK	AEPAPD	AEPCSD	AEPIMD	AEPOCG	AEPOPD	AEPMON	AEPSCT	Total
$ 59,891,209.14	$ (213,910.00)	$ (6,108,449.17)	$ 417,540.30	$89,990.21	$ 289,304.07	$ 225,449.81	$89,990.21		($1,406,131.40)	$ 53,274,993.17
$ (54,287,106.02)	$ (51,651.89)	$ (3,949,771.63)						$ (394,127.02)		$ (58,682,656.56)
$ 5,017,321.60	$ 17,724.62	$ 299,651.10	$ 42,519.59	$ 19,140.98	$ 35,941.80	$ 11,026.49	$19,140.98	$146.41		$ 5,462,613.57
$ 9,251.68	$ 19.80	$ 684.71								$ 9,956.19
$2,836,136.26	$ 5,411.90	$212,821.37								$ 3,054,369.53
$59,021.55	$ 108.61	$5,054.10								$ 64,184.26
$ 5,398,365.87	$ 15,555.12	$ 398,235.98								$ 5,812,156.97
$ 205,413.97	$ 650.38	$ 14,795.11						$ (8.78)		$ 220,850.68
$ 43,856.04	$ 131.68	$ 3,241.60								$ 47,229.32
$ 4,261,289.52	$ 10,477.98	$ 260,394.38	$ 1,966.34	$ 500.94	$ 1,530.47	$ 822.13	$ 500.94	$ 480.87		$ 4,537,963.57
$115,680.67	$ 226.30	$7,108.61								$ 123,015.58
$181,012.59	$ 354.02	$9,174.45								$ 190,541.06
$1,839,989.85	$ 3,599.06	$111,301.31								$ 1,954,890.22
										$ -
$ 41,896,231.97	$ (101,412.73)	$ (2,491,374.13)	$ 298,282.58	$61,496.35	$ 205,259.17	$ 155,488.77	$61,496.35			$ 40,085,468.33
$ (15,272,697.87)	$ (51,005.21)	$ (1,205,627.16)						$ 5,546.07		$ (16,523,784.17)
										$ -
$ (1,201,459.89)	$ (2,356.98)	$ (63,386.53)								$ (1,267,203.40)
										$ 38,364,588.32

PJM Invoice Detail

PJM Invoices January 2010

PJM Invoice Line Item	BLI	AEPSCG	AEPAUB	AEPBCK	AEPAPD	AEPCSD	AEPIMD	AEPOCG
PJM Implicit Congestion		59,891,209.14	(213,910.00)	(6,108,449.17)	417,540.30	89,990.21	289,304.07	225,449.81
Day-ahead Transmission Congestion	1210	61,413,885.87	(227,699.63)	(5,956,563.71)	239,580.71		189,941.99	195,591.60
Balancing Transmission Congestion	1215	(1,530,214.55)	13,789.63	(152,649.32)	177,959.59	89,990.21	99,362.08	29,899.68
Load Reconciliation for Transmission Congestion	1410	7,537.82		763.86				
Synchronized Reserve	2360A							(41.47)
PJM FTR & ARR Revenue		(54,287,106.02)	(51,651.89)	(3,949,771.63)	0.00	0.00	0.00	0.00
Transmission Congestion	2210	(57,264,355.41)	(51,651.89)	(3,838,094.65)				
Transmission Congestion	2210A	(8,879.24)		(316.10)				
Auction Revenue Rights	2510	(16,359,691.26)		(1,078,594.47)				
Financial Transmission Rights Auction	1500	19,351,811.38		967,233.79				
Financial Transmission Rights Auction	2500	(7,891.49)						
PJM Operating Reserve (a)		5,017,321.60	17,724.82	299,651.10	42,519.59	19,140.98	35,941.80	11,026.49
Day-ahead Operating Reserve	1370	1,651,633.87	5,106.76	112,906.79				
Balancing Operating Reserve	1375	3,199,331.73	12,167.06	176,702.16	42,192.45	19,087.29	35,668.05	10,791.96
Day-ahead Operating Reserve	1370A	7,216.92	39.47	$281.11	$49.55	47.62	69.82	$99.72
Balancing Operating Reserve	1375A	6,309.41		275.30	15.43		51.78	48.93
Balancing Operating Reserve	1375A	2,927.01		105.72	26.99		9.92	14.33
Balancing Operating Reserve	1375A	1,643.62		112.76	26.34		17.98	15.65
Balancing Operating Reserve	1375A	1,025.32		59.26	169.31		12.93	12.14
Balancing Operating Reserve	1375A	3,345.14		99.54			98.49	38.81
Balancing Operating Reserve for Load Response	1376	639.03		37.65	19.52			
Load Reconciliation for Balancing Operating Reserve	1478	953.54	4.65	11.23		6.07	12.83	4.93
Reactive Services	1378	142,296.01	406.68	7,057.56				
PJM Ancillary Services (a)								
PJM Synchronous Condensing		9,251.68	19.80	684.71	0.00	0.00	0.00	0.00
Synchronous Condensing	1377	9,258.79	19.80	684.22				
Load Reconciliation for Synchronous Condensing	1480	(7.11)		0.49				
PJM Reactive Supply		2,836,136.26	5,411.90	212,821.37	0.00	0.00	0.00	0.00
Reactive Supply and Voltage Control from Generation and Other Sources Service	1330	2,836,136.26	5,411.90	212,821.37				
PJM Blackstart								
Black Start Service	1380	58,021.55	108.61	5,054.10				
PJM Regulation Charges		5,398,365.87	15,555.12	398,235.98	0.00	0.00	0.00	0.00
Regulation and Frequency Response Service	1340	5,397,434.46	15,555.12	398,125.31				
Load Reconciliation for Regulation and Frequency Response Service	1460	931.41		110.67				
PJM Spinning Reserve Charges		205,413.97	650.38	14,796.11	0.00	0.00	0.00	0.00
Synchronized Reserve	1360	175,236.70	650.56	12,805.57				
Load Reconciliation for Synchronized Reserve	1470	78.42		10.06				
Synchronized Reserve	1360A	(878.21)	(0.18)	(38.59)				
Synchronized Reserve	1360A	31,065.40		2,020.50				
Synchronized Reserve	1360A	(88.34)		(4.43)				

PJM Invoice Detail

PJM Invoice Line Item	AEPOPD	AEPMON	AEPSCT	Totals
PJM Implicit Congestion	89,990.21	0.00	(1,544,812.93)	53,136,311.64
Day-ahead Transmission Congestion				
Balancing Transmission Congestion	89,990.21		-1544812.93	
Load Reconciliation for Transmission Congestion				
Synchronized Reserve				
PJM FTR & ARR Revenue	0.00	(394,127.02)	0.00	(58,682,656.56)
Transmission Congestion		(563,987.99)		
Transmission Congestion		(61.19)		
Auction Revenue Rights				
Financial Transmission Rights Auction		169,922.16		
Financial Transmission Rights Auction				
PJM Operating Reserve (a)	19,140.98	146.41	0.00	5,462,613.57
Day-ahead Operating Reserve				
Balancing Operating Reserve	19,087.29			
Day-ahead Operating Reserve	47.62	146.41		
Balancing Operating Reserve				
Balancing Operating Reserve				
Balancing Operating Reserve				
Balancing Operating Reserve				
Balancing Operating Reserve				
Balancing Operating Reserve for Load Response				
Load Reconciliation for Balancing Operating Reserve	6.07			
Reactive Services				
PJM Ancillary Services (a)				
PJM Synchronous Condensing	0.00	0.00	0.00	9,956.19
Synchronous Condensing				
Load Reconciliation for Synchronous Condensing				
PJM Reactive Supply	0.00	0.00	0.00	3,054,369.53
Reactive Supply and Voltage Control from Generation and Other Sources Service				
PJM Blackstart				
Black Start Service				64,184.26
PJM Regulation Charges	0.00	0.00	0.00	5,812,166.97
Regulation and Frequency Response Service				
Load Reconciliation for Regulation and Frequency Response Service				
PJM Spinning Reserve Charges	0.00	(8.78)	0.00	220,850.68
Synchronized Reserve				
Load Reconciliation for Synchronized Reserve				
Synchronized Reserve		(8.78)		
Synchronized Reserve				
Synchronized Reserve				

PJM Invoice Detail

PJM Invoices January 2010

PJM Invoice Line Item	BLI	AEPSCG	AEPAUB	AEPBCK	AEPAPD	AEPCSD	AEPIMD	AEPOCG
PJM 30 minute Supplemental Reserve Market (DASR)		43,856.04	131.68	3,241.60	0.00	0.00	0.00	0.00
Day-ahead Scheduling Reserve	1365	43,852.84	131.68	3,240.41				
Load Reconciliation for Day-ahead Scheduling Reserve	1475	3.20		1.19				
PJM Administration Service Fees Sub Total		4,261,289.52	10,477.98	260,394.38	1,966.34	500.94	1,530.47	822.13
PJM Scheduling, System Control and Dispatch Service - Control Area Administration	1301	2,207,564.13	6,572.27	158,016.21				
PJM Scheduling, System Control and Dispatch Service - FTR Administration	1302	46,589.70	$ -	3,284.14				
PJM Scheduling, System Control and Dispatch Service - Market Support	1303	1,077,056.79	1,492.35	40,496.00	1,967.03	501.13	1,531.01	$ 822.45
PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration	1304	39,274.74	94.57	2,282.38				
PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.	1305	136,461.38	$ -	4,694.02				
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	1306	91,365.18	220.26	5,505.49	53.55	13.64	41.66	$ 22.39
PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration	1308	(323,385.55)	(962.75)	(23,147.76)				
PJM Scheduling, System Control and Dispatch Service Refund - FTR Administration	1309	(5,482.98)	(232.92)	(373.24)				
PJM Scheduling, System Control and Dispatch Service Refund - Market Support	1310	(169,957.43)	(16.84)	(6,380.69)	(310.60)	(79.13)	(241.73)	$ (129.88)
PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration	1311	(6,980.04)	192.06	(405.64)				
PJM Scheduling, System Control and Dispatch Service Refund - Capacity Resource/Obligation Mgmt.	1312	(18,500.80)	2,267.04	(636.43)				
Market Monitoring Unit (MMU) Funding	1314	140,272.53	19.97	5,265.33	258.36	65.30	199.51	$ 107.17
FERC Annual Recovery	1315	761,461.51	294.28	54,506.41				
Organization of PJM States, Inc. (OPSI) Funding	1316	6,711.72	537.69	480.43				
North American Electric Reliability Corporation (NERC)	1317	97,643.15		5,920.05				
Reliability First Corporation (RFC)	1318	178,409.64		10,816.87				
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service	1440	1,196.66		110.63				
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund	1441	(932.18)		(86.19)				
Load Reconciliation for Schedule 9-6 - Advanced Second Control Center	1442	83.37		7.70				
Load Reconciliation for Market Monitoring Unit (MMU) Funding	1444	28.17		2.62				
Load Reconciliation for FERC Annual Recovery	1445	302.42		27.96				
Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding	1446	3.41		0.32				
Load Reconciliation for North American Electric Reliability Corporation (NERC)	1447	36.85		3.41				
Load Reconciliation for Reliability First Corporation (RFC)	1448	47.16		4.36				
Expansion Cost Recovery Charge								
Expansion Cost Recovery	1730	116,680.67	226.30	7,108.61	0.00	0.00	0.00	0.00
PJM RTO Formation Cost Recovery								
RTO Start-up Cost Recovery	1720	181,012.59	354.02	9,174.45	0.00	0.00	0.00	0.00
PJM Transmission Enhancement Charges								
Transmission Enhancement	1108	1,839,988.85	3,599.06	111,301.31	0.00	0.00	0.00	0.00
Real-time Economic Load Response Charge								
NA		0.00	0.00	0.00	0.00	0.00	0.00	0.00
PJM Transmission Implicit Loss Charges		41,896,231.97	(101,412.73)	(2,491,374.13)	298,282.58	61,496.35	205,259.17	155,488.77
Day-ahead Transmission Losses	1220	42,241,902.94	(108,811.32)	(2,452,501.45)	211,201.14		152,139.93	154,573.60
Balancing Transmission Losses	1225	(341,831.51)	7,398.59	(38,415.51)	87,081.44	61,496.35	53,119.24	915.17
Load Reconciliation for Transmission Losses	1420	(3,839.46)		(457.17)				

PJM Invoice Detail

PJM Invoice Line Item	AEPOPD	AEPMON	AEPSCT	Totals
PJM 30 minute Supplemental Reserve Market (DASR)	0.00	0.00	0.00	47,229.32
Day-ahead Scheduling Reserve				
Load Reconciliation for Day-ahead Scheduling Reserve				
PJM Administration Service Fees Sub Total	500.94	480.87	0.00	4,537,963.57
PJM Scheduling, System Control and Dispatch Service - Control Area Administration				
PJM Scheduling, System Control and Dispatch Service - FTR Administration		532.27		
PJM Scheduling, System Control and Dispatch Service - Market Support	501.13			
PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration				
PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.				
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	13.64	9.36		
PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration				
PJM Scheduling, System Control and Dispatch Service Refund - FTR Administration		($60.76)		
PJM Scheduling, System Control and Dispatch Service Refund - Market Support	(79.13)			
PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration				
PJM Scheduling, System Control and Dispatch Service Refund - Capacity Resource/Obligation Mgmt.				
Market Monitoring Unit (MMU) Funding	65.30			
FERC Annual Recovery				
Organization of PJM States, Inc. (OPSI) Funding				
North American Electric Reliability Corporation (NERC)				
Reliability First Corporation (RFC)				
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service				
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund				
Load Reconciliation for Schedule 9-6 - Advanced Second Control Center				
Load Reconciliation for Market Monitoring Unit (MMU) Funding				
Load Reconciliation for FERC Annual Recovery				
Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding				
Load Reconciliation for North American Electric Reliability Corporation (NERC)				
Load Reconciliation for Reliability First Corporation (RFC)				
Expansion Cost Recovery Charge				
Expansion Cost Recovery	0.00	0.00	0.00	123,015.58
PJM RTO Formation Cost Recovery				
RTO Start-up Cost Recovery	0.00	0.00	0.00	190,541.06
PJM Transmission Enhancement Charges				
Transmission Enhancement	0.00	0.00	0.00	1,954,890.22
Real-time Economic Load Response Charge				
NA	0.00	0.00	0.00	0.00
PJM Transmission Implicit Loss Charges	61,496.35	0.00	0.00	40,085,468.33
Day-ahead Transmission Losses				
Balancing Transmission Losses	61,496.35	0.00	0.00	
Load Reconciliation for Transmission Losses				

PJM Invoice Detail

PJM Invoices January 2010

PJM Invoice Line Item	BLI	AEPSCG	AEPAUB	AEPBCK	AEPAPD	AEPCSD	AEPIMD	AEPOCG
PJM Transmission Implicit Loss Credit		(15,272,697.87)	(51,005.21)	(1,205,627.16)	0.00	0.00	0.00	0.00
Transmission Losses	2220	(17,059,896.11)	(51,005.14)	(1,246,414.17)				
Load Reconciliation for Transmission Losses	2420	(2,961.83)		(390.76)				
Load Reconciliation for Transmission Losses	2420A	264,086.02	(0.07)	2,549.19				
Transmission Losses	2220A	263,596.59		(2,145.66)				
Transmission Losses	2220A	256,140.95		1,245.94				
Transmission Losses	2220A	447,286.77		23,565.69				
Transmission Losses	2220A	260,026.00		12,334.04				
Transmission Losses	2220A	11,532.90		277.20				
Transmission Losses	2220A	(38.43)		(2.68)				
Transmission Losses	2220A	287,529.27		3,353.85				
Pt-to-Pt Transm. Revenues		(1,201,459.89)	(2,356.98)	(63,386.53)	0.00	0.00	0.00	0.00
Firm Point-to-Point Transmission Service	2130	(764,373.93)	(1,495.14)	(38,741.81)				
Non-Firm Point-to-Point Transmission Service	2140	(431,663.34)	(844.35)	(24,316.83)				
Non-Firm Point-to-Point Transmission Service	2140A	(244.19)	(17.49)	(13.91)				
Non-Firm Point-to-Point Transmission Service	2140A	(5,494.67)		(313.98)				
Non-Firm Point-to-Point Transmission Service	1140A	316.24						

[1] The amount of $[illegible] from this total was allocated to other LSEs in the AEP Zone (other than AEP) [illegible] was allocated to the AEP LSE to arrive at the amount invoiced by PJM

PJM Invoice Detail

PJM Invoice Line Item	AEPOPD	AEPMON	AEPSCT	Totals
PJM Transmission Implicit Loss Credit	0.00	5,546.07	0.00	(16,523,784.17)
Transmission Losses				
Load Reconciliation for Transmission Losses				
Load Reconciliation for Transmission Losses		3,388.08		
Transmission Losses		1,942.14		
Transmission Losses		40.40		
Transmission Losses		175.45		
Transmission Losses				
Transmission Losses				
Transmission Losses				
Transmission Losses				
Pt-to-Pt Transm. Revenues	0.00	0.00	0.00	(1,267,203.40)
Firm Point-to-Point Transmission Service				
Non-Firm Point-to-Point Transmission Service				
Non-Firm Point-to-Point Transmission Service				
Non-Firm Point-to-Point Transmission Service				
Non-Firm Point-to-Point Transmission Service				

[1] The amount of [illegible] from this total was allocated to other LSEs in the AEP Zone (other than AEP) [illegible] was allocated to the AEP LSE to arrive at the amount invoiced by PJM

PJM Invoice Explanations

Charge	PJM Invoice BLI #	Notes
PJM Implicit Congestion	1210, 1215 and 1410	The sum of these line items plus any prior period adjustments on the invoices (All 10 in question) result in the total invoiced congestion by PJM. To match the AEP allocated amount to the invoiced congestion, one will need to include explicit congestion charges (booked separately from implicit by AEP)
PJM FTR & ARR Revenue	2210, 2510, 1500 & 2500	Add these line items together plus any prior period adjustments on the invoices (All 10 in question) to get the PJM Total.
PJM Operating Reserve (a)	1378, 1370, 1478,1375 and 1376	Add these line items together plus any prior period adjustments on the invoices (All 10 in question) to get the PJM Total.
PJM Synchronous Condensing	1377, 1480	This line item, plus any prior period adjustments on the invoices (All 10 in question) produces the PJM Total.
PJM Reactive Supply	1330	This line item, plus any prior period adjustments on the invoices (All 10 in question) produces the PJM Total.
PJM Blackstart	1380	This line item, plus any prior period adjustments on the invoices (All 10 in question) produces the PJM Total.
PJM Regulation Charges	1340 and 1460	These line items, plus any prior period adjustments on the invoices (All 10 in question) produces the PJM Total.
PJM Spinning Reserve Charges	1360, 1470	These line items, plus any prior period adjustments on the invoices (All 10 in question) produces the PJM Total.
PJM 30 minute Supplemental Reserve Market (DASR)	1365 and 1475	Add these line items together, plus any prior period adjustments on the invoices (All 10 in question), to obtain the PJM Total.
PJM Administration Service Fees (b)	1301, 1302, 1303, 1304, 1305,1306,1308, 1309, 1310, 1311, 1312, 1314, 1315, 1316, 1317, 1318, 1440, 1441, 1442, 1444, 1445, 1446, 1447, 1448	Add these line items together plus any prior period adjustments on the invoices (All 10 in question) to obtain the PJM Total.
Net Expansion Cost Recovery Charge	1730	This line item, plus any prior period adjustments on the invoices (All 10 in question) produces the PJM Total.
PJM RTO Formation Cost Recovery	1720	This line item, plus any prior period adjustments on the invoices (All 10 in question) produces the PJM Total.
PJM Transmission Enhancement Charges	1108	This line item, plus any prior period adjustments on the invoices (All 10 in question) produces the PJM Total.
NITS Charges	1100	This line item, plus any prior period adjustments on the invoices (All 10 in question) produces the PJM Total.
TO Charges	1320	This line item, plus any prior period adjustments on the invoices (All 10 in question) produces the PJM Total.

Charge	PJM Invoice BLI #	Notes
PJM Transmission Implicit Loss Charges	1220, 1225 &1420	Add these line items together, plus any prior period adjustments on the invoices (All 10 in question), to obtain the total invoiced congestion by PJM. To match the AEP allocated amount to that you will have to include explicit loss charges (booked separately from implicit by AEP).
PJM Transmission Implicit Loss Credit	2220 & 2420	Add these line items together plus any prior period adjustments on the invoices (All 10 in question) to obtain the PJM Total.
Pt-to-Pt Transm. Revenues	2130 & 2140	Add these line items together plus any prior period adjustments on the invoices (All 10 in question) to obtain the PJM Total.

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

Footnotes

[1] For market participant AEPOCG a small synchronized reserve adjustment (line item 2360A in the amount of 41.47) was booked to the wrong account in January. It was later corrected, but needs to be included in AEPOCG's congestion total to get back to what was booked.

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

PJM Invoice Explanations

Charge	PJM Invoice BLI #	Assignment Methodology (AEPSCO)
PJM Implicit Congestion	1210, 1215 and 1410	[2] ECR Dispatch.
PJM FTR & ARR Revenue	2210, 2510, 1500 & 2500	FTR Target credits are assigned hourly between LSE and OSS. The FTR credits are first used to offset LSE congestion charges, if excess credits remain they are then used to offset OSS congestion charges, if still more excess credits exist they are shared between the LSE and OSS. ARR revenue is assigned directly to the LSE.
PJM Operating Reserve (a)	1378, 1370, 1478,1375 and 1376	A Load Ratio Share (LRS) is used when there is not adequate market data from PJM to attribute the cause of a charge to an one specific activity or when the use of a more granular approach would not yield a more appropriate allocation. The Load Ratio Share is the LSE's load as a percentage of the entire PJM load.
PJM Synchronous Condensing	1377, 1480	Directly to the LSE. The cost to the PJM pool for synchronous condensing is allocated to participants based upon load. AEP's internal assignment of costs matches that approach by assigning it to LSE.
PJM Reactive Supply	1330	Ancillary Service charges and credits are aggregated and recorded based on the netted result. Since ancillary services are used by loads, PJM charges the load for the service while the generators receive credits for providing the service. If the net amount is a charge, this reflects that the native load customers of AEP purchased all or a portion of the service from PJM (AEP net, did not receive awards to supply its load requirement). If the net amount is a credit, the effect is AEP supplied all its requirements for its load for that service and was able to sell additional to PJM, thus making a sale to the market. As a result, net charges are recorded to LSE accounts while net credits would be recorded to OSS accounts.
PJM Blackstart	1380	Same as above.
PJM Regulation Charges	1340 and 1460	Same as above.
PJM Spinning Reserve Charges	1360, 1470	Same as above.
PJM 30 minute Supplemental Reserve Market (DASR)	1365 and 1475	Same as above.
PJM Administration Service Fees (b)	1301, 1302, 1303, 1304, 1305,1306,1308, 1309, 1310, 1311, 1312, 1314, 1315, 1316, 1317, 1318, 1440, 1441, 1442, 1444, 1445, 1446, 1447, 1448	A LRS is used when there is not adequate market data from PJM to attribute the cause of a charge to any one specific activity or when the use of a more granular approach would not yield a more appropriate allocation.
Net Expansion Cost Recovery Charge	1730	PJM allocates these costs to participants based upon load. AEP's internal assignment of costs matches that approach by assigning it to LSE.
PJM RTO Formation Cost Recovery	1720	PJM allocates these costs to participants based upon load. AEP's internal assignment of costs matches that approach by assigning it to LSE.
PJM Transmission Enhancement Charges	1108	PJM allocates these costs to participants based upon load. AEP's internal assignment of costs matches that approach by assigning it to LSE.
NITS Charges	1100	Assigned by Transmission Settlements. Refer to Schedule D3c PJM Transmission Invoice Explanations.
TO Charges	1320	Assigned by Transmission Settlements. Refer to Schedule D3c PJM Transmission Invoice Explanations.

Charge	PJM Invoice BLI #	Assignment Methodology (AEPSCG)
PJM Transmission Implicit Loss Charges	1220, 1225 &1420	[2] ECR Dispatch.
PJM Transmission Implicit Loss Credit	2220 & 2420	The allocation of this credit is based on the monthly percentage of Implicit Loss Charges allocated to LSE versus OSS. The percentage is applied to the Transmission Loss Credit for all subaccounts for assignment to LSE and OSS.
Pt-to-Pt Transm. Revenues	2130 & 2140	Revenues collected by PJM are distributed to a large degree based upon load. Therefore, the internal allocation of the credi is directly assigned to internal load.

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

Footnotes

[1] For market participant AEPOCG a small synchronized reserve adjustment (line item 2360A in the amount of 41.47) was booked to the wrong account in January. It was later corrected, but needs to be included in AEPOCG's congestion total to get back to what was booked.

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

Summary of January 2010 PJM Invoice to General Ledger (GL) Transmission Accounts

TCRR Activity Jan 2010

Transmission Account Activity

Charge/Credits	LSE GL Account	Allocated by Settlements CSP	GL Amount (Actual Booked in Feb 2010) CSP	Variance CSP	Allocated by Settlements OPCO	GL Amount (Actual Booked in Feb 2010) OPCO	Variance OPCO
PJM NITS Charges	4561035	$ 8,567,581.93	$ 8,567,581.94	$ 0.01	$ 9,976,036.16	$ 9,976,036.17	$ 0.01
Transmission Owner Scheduling, System Control & Dispatch	4561036	$ 155,050.57	$ 155,050.58	$ 0.01	$ 180,539.87	$ 180,539.87	$ -
PJM RTO Formation Cost Recovery	4561002	$ (22,450.00)	$ (22,449.99)	$ 0.01	$ (63,798.92)	$ (63,798.92)	$ 0.00
Expansion Cost Recovery	4561003	$ (23,586.09)	$ (23,586.09)	$ 0.00	$ (67,027.50)	$ (67,027.50)	$ (0.00)
PJM Operating Reserve-LSE-Charge	4470203	$ 72,504.18	$ 72,504.17	$ (0.01)	$ 84,423.39	$ 84,423.39	$ 0.00
PJM Implicit Congestion	4470093	$ (253,609.86)	$ (253,609.86)	$ -	$ (295,301.66)	$ (295,301.66)	$ -

January 2010 PJM Transmission Reconciled Invoice Allocation

TCRR Activity Jan 2010

Transmission Account Activity

Charge/Credit	LSE GL Account	Internal Allocation: LSE & Non-Affiliate Wholesale Allocation: CSP	OPCO	APCO, KY and I&M	Non-Affiliate PJM: CSP	OPCO	APCO, KY and I&M	OSS Total: All Operating COs	Total	PJM Invoices January 2010: AEPSCT	AEPSCG	AEPAUB	Total
Transmission Account Activity													
PJM RTO Formation Cost Recovery	4561002				$ (22,450.00)	$ (63,798.92)	$ (114,376.62)		$ (200,625.54)	$ (200,625.54)			$ (200,625.54)
Expansion Cost Recovery	4561003				$ (23,586.09)	$ (67,027.50)	$ (120,164.70)		$ (210,778.29)	$ (210,778.29)			$ (210,778.29)
PJM Operating Reserve-LSE-Charge	4470203				$ 72,504.18	$ 84,423.39	$ 245,069.43		$ 401,996.99	$ 401,996.99			$ 401,996.99
PJM Implicit Congestion (a)	4470093				$ (253,609.86)	$ (295,301.66)	$ (857,219.88)		$ (1,406,131.40)	$ (1,511,587.24)			$ (1,511,587.24)
Generation Account Activity													
PJM NITS Charges	4561035	$ 8,567,581.93	$ 9,976,036.16	$ 28,959,053.96					$ 47,502,672.05		$ 47,420,261.20	$ 92,755.41	$ 47,513,016.61
Network Integration Transmission Service Charge	4470107							$ 22,347.02	$ 22,347.02				
Power Factor Charges	6650030							$ 2,107.98	$ 2,107.98		$ 12,795.64	$ 1,314.78	$ 14,110.42
Transmission Owner Scheduling, System Control & Dispatch	4561036	$ 155,050.57	$ 180,539.87	$ 524,082.29					$ 859,672.73		$ 872,224.09	$ 2,583.13	$ 874,807.22
PJM Transmission Owner Administrative Services Charges	4470110							$ 15,134.49	$ 15,134.49				
		$ 8,722,632.50	$ 10,156,576.03	$ 29,483,136.25	$ (227,141.77)	$ (341,704.69)	$ (846,691.78)	$ 39,589.49	$ 46,986,396.03	$ (1,520,994.08)	$ 48,305,280.93	$ 96,653.32	$ 46,880,940.17

Difference between Total Internal Allocation and PJM Invoices $ 105,455.86
Adjustments in Footnote (a) $ 105,455.84
Difference $ 0.02

Footnote

(a) AEP did not record current and prior period adjustments of $105,455.84 from the PJM invoice for Other Supporting facilities charges.

PJM Transmission Invoice Explanations

Charge/Credit	PJM Invoice BLI #	Notes	Assignment Methodology
PJM NITS Charges	1100	Take this line item plus any prior period adjustments of the invoices (AEPSCG, AEPAUB) to get the PJM Total.	Allocated to the operating companies based on each companies MLR.
Transmission Owner Scheduling, System Control & Dispatch	1320	Take this line item plus any prior period adjustments of the invoices (AEPSCG, AEPAUB) to get the PJM Total.	Allocated to the operating companies based on each companies MLR.
PJM Operating Reserve-LSE-Charge	1375, 1375 A	This line item is directly from the PJM invoice.	Allocated to the operating companies based on each companies MLR.
PJM Implicit Congestion	1215, 1225, 1360, 1410, 1420, 1470, 1360A, 2120A	Take these line items from the PJM invoice and are adjusted for Power Factor Credits, Distribution Facility Charges and current and prior period adjustments also included in those line items.	Allocated to the operating companies based on each companies MLR.
Power Factor Charges	1120 A	This line item for Other Supporting Facilities includes Power Factor Credits.	Allocated to the operating companies based on each companies MLR.
PJM RTO Formation Cost Recovery	2720	This line item is directly from the PJM invoice.	Allocated to the operating companies based on each companies share of Transmission Pole Miles as of 12/31/2004.
Expansion Cost Recovery	2730	This line item is directly from the PJM invoice.	Allocated to the operating companies based on each companies share of Transmission Pole Miles as of 12/31/2004.

Footnotes

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

BLI, Billing Line Item

"A" on the PJM Bill in the ADJ column represents an adjustment.

Charges on the PJM Bill are represented with a Billing Line Item that starts with a "1", and credits start with a "2".

pjm

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

INVOICE NUMBER: 2010013112406

CUSTOMER ACCOUNT: Appalachian Power Company (APCO Dedicated)

CUSTOMER IDENTIFIERS: AEPAPD (12406)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

Monthly Billing Total:	($1,831,050.66)
Previous Weekly Billing Total:	($1,725,043.57)

Monthly Billing Statement Summary	Total
Total Net Credit to You. Please Do Not Pay	$106,007.09

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 02/12/2010

WIRE TRANSFER FUNDS TO: PJM INTERCONNECTION, L.L.C
PNC BANK N.A.
NEW JERSEY
ABA NUMBER 031207607

ACCOUNT NUMBER - 8013589834

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

ADDITIONAL BILLING STATEMENT INFORMATION:

David Budney
Manager, PJM Market Settlement Operations

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (APCO Dedicated)

CUSTOMER IDENTIFIERS: AEPAPD (12406)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$0.00
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		$(1,907,030.68)
1205		Balancing Spot Market Energy		$(684,134.34)
1210		Day-ahead Transmission Congestion		$239,580.71
1215		Balancing Transmission Congestion		$177,959.59
1220		Day-ahead Transmission Losses		$211,201.14
1225		Balancing Transmission Losses		$87,081.44
1250		Meter Error Correction		$(160.98)
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$0.00
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$0.00
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		$1,967.03
1304		PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$0.00
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		$53.55
1310		PJM Scheduling, System Control and Dispatch Service Refund - Market Support		$(310.60)
1314		Market Monitoring Unit (MMU) Funding		$256.36
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
1340		Regulation and Frequency Response Service		$0.00
1360		Synchronized Reserve		$0.00
1365		Day-ahead Scheduling Reserve		$0.00
1370		Day-ahead Operating Reserve		$0.00
1375		Balancing Operating Reserve		$42,192.45
1376		Balancing Operating Reserve for Load Response		$19.62
1380		Black Start Service		$0.00
1375	A	Balancing Operating Reserve	08/01/2009	$49.55
1375	A	Balancing Operating Reserve	09/01/2009	$15.43
1375	A	Balancing Operating Reserve	10/01/2009	$26.99
1375	A	Balancing Operating Reserve	11/01/2009	$26.34
1375	A	Balancing Operating Reserve	12/01/2009	$189.31
		Total Charges		**($1,831,017.19)**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (APCO Dedicated)

CUSTOMER IDENTIFIERS: AEPAPD (12406)

FINAL BILLING STATEMENT ISSUED: 02/06/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$0.00
2130		Firm Point-to-Point Transmission Service		$0.00
2140		Non-Firm Point-to-Point Transmission Service		$0.00
2210		Transmission Congestion		$0.00
2220		Transmission Losses		$0.00
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
2340		Regulation and Frequency Response Service		$0.00
2360		Synchronized Reserve		$0.00
2365		Day-ahead Scheduling Reserve		$0.00
2370		Day-ahead Operating Reserve		$0.00
2375		Balancing Operating Reserve		$0.00
2380		Black Start Service		$0.00
2360	A	Synchronized Reserve	10/01/2009	$33.47
		Total Credits		**$33.47**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

INVOICE NUMBER:	2010013116617
CUSTOMER ACCOUNT:	Appalachian Power Company (City of Auburn)
CUSTOMER IDENTIFIERS:	AEPAUB (16617)
FINAL BILLING STATEMENT ISSUED:	02/05/2010 10:03:43
BILLING PERIOD:	01/01/2010 to 01/31/2010

Monthly Billing Total:	$1,714,723.41
Previous Weekly Billing Total:	$1,453,161.16

Monthly Billing Statement Summary	Total
Total Net Charge. Please Pay This Amount.	$261,562.25

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 02/12/2010

WIRE TRANSFER FUNDS TO: PJM INTERCONNECTION, L.L.C
PNC BANK N.A.
NEW JERSEY
ABA NUMBER 031207607

ACCOUNT NUMBER - 8013589834

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

ADDITIONAL BILLING STATEMENT INFORMATION:

David Budney
Manager, PJM Market Settlement Operations

pjm

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (City of Auburn)

CUSTOMER IDENTIFIERS: AEPAUB (16617)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$92,755.41
1108		Transmission Enhancement		$3,599.06
1120		Other Supporting Facilities		$738.00
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		$2,142,152.26
1205		Balancing Spot Market Energy		$(157,033.80)
1210		Day-ahead Transmission Congestion		$(227,699.63)
1215		Balancing Transmission Congestion		$13,789.63
1220		Day-ahead Transmission Losses		$(108,811.32)
1225		Balancing Transmission Losses		$7,398.59
1230		Inadvertent Interchange		$(731.76)
1250		Meter Error Correction		$0.82
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$6,572.27
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$0.00
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		$1,492.35
1304		PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$94.57
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		$220.26
1308		PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration		$(962.75)
1310		PJM Scheduling, System Control and Dispatch Service Refund - Market Support		$(232.92)
1311		PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration		$(18.84)
1314		Market Monitoring Unit (MMU) Funding		$192.06
1315		FERC Annual Recovery		$2,267.04
1316		Organization of PJM States, Inc. (OPSI) Funding		$19.97
1317		North American Electric Reliability Corporation (NERC)		$294.28
1318		Reliability First Corporation (RFC)		$537.69
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$2,583.13
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$5,411.90
1340		Regulation and Frequency Response Service		$15,555.12
1360		Synchronized Reserve		$650.56
1365		Day-ahead Scheduling Reserve		$161.68
1370		Day-ahead Operating Reserve		$5,106.76
1375		Balancing Operating Reserve		$12,167.06
1376		Balancing Operating Reserve for Load Response		$4.65

pjm

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (City of Auburn)

CUSTOMER IDENTIFIERS: AEPAUB (16617)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

1377		Synchronous Condensing		$19.80
1378		Reactive Services		$406.68
1380		Black Start Service		$108.61
1720		RTO Start-up Cost Recovery		$354.02
1730		Expansion Cost Recovery		$226.30
1120	A	Other Supporting Facilities	12/01/2009	$336.62
1230	A	Inadvertent Interchange	12/01/2009	$1.07
1360	A	Synchronized Reserve	12/01/2009	$(0.18)
1375	A	Balancing Operating Reserve	12/01/2009	$39.47
		Total Charges		**$1,819,737.49**

pjm

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (City of Auburn)

CUSTOMER IDENTIFIERS: AEPAUB (16617)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$0.00
2130		Firm Point-to-Point Transmission Service		$1,495.14
2140		Non-Firm Point-to-Point Transmission Service		$844.35
2210		Transmission Congestion		$0.00
2220		Transmission Losses		$51,005.14
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
2340		Regulation and Frequency Response Service		$0.00
2360		Synchronized Reserve		$0.00
2365		Day-ahead Scheduling Reserve		$0.00
2370		Day-ahead Operating Reserve		$0.00
2375		Balancing Operating Reserve		$0.00
2380		Black Start Service		$0.00
2510		Auction Revenue Rights		$51,651.89
2140	A	Non-Firm Point-to-Point Transmission Service	12/01/2009	$17.49
2220	A	Transmission Losses	12/01/2009	$0.07
		Total Credits		**$105,014.08**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

INVOICE NUMBER:	2010013111485
CUSTOMER ACCOUNT:	Appalachian Power Company (Buckeye)
CUSTOMER IDENTIFIERS:	AEPBCK (11485)
FINAL BILLING STATEMENT ISSUED:	02/05/2010 10:03:43
BILLING PERIOD:	01/01/2010 to 01/31/2010

Monthly Billing Total:	**$42,751,512.47**
Previous Weekly Billing Total:	**$36,292,840.01**

Monthly Billing Statement Summary	Total
Total Net Charge. Please Pay This Amount.	**$6,458,672.46**

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 02/12/2010

WIRE TRANSFER FUNDS TO: PJM INTERCONNECTION, L.L.C
PNC BANK N.A.
NEW JERSEY
ABA NUMBER 031207607

ACCOUNT NUMBER - 8013589834

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

ADDITIONAL BILLING STATEMENT INFORMATION:

David Budney
Manager, PJM Market Settlement Operations

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (Buckeye)

CUSTOMER IDENTIFIERS: AEPBCK (11485)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$2,671,318.98
1108		Transmission Enhancement		$111,301.31
1120		Other Supporting Facilities		$111,732.16
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		$45,321,350.70
1205		Balancing Spot Market Energy		$1,737,973.27
1210		Day-ahead Transmission Congestion		$(5,956,563.71)
1215		Balancing Transmission Congestion		$(152,649.32)
1220		Day-ahead Transmission Losses		$(2,452,501.45)
1225		Balancing Transmission Losses		$(38,415.51)
1230		Inadvertent Interchange		$(13,892.02)
1250		Meter Error Correction		$16.52
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$158,016.21
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$3,284.14
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		$40,496.00
1304		PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$2,282.38
1305		PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.		$4,694.02
1306		PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center		$5,505.49
1308		PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration		$(23,147.76)
1309		PJM Scheduling, System Control and Dispatch Service Refund - FTR Administration		$(373.24)
1310		PJM Scheduling, System Control and Dispatch Service Refund - Market Support		$(6,380.69)
1311		PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration		$(405.64)
1312		PJM Scheduling, System Control and Dispatch Service Refund - Capacity Resource/Obligation Mgmt		$(658.43)
1314		Market Monitoring Unit (MMU) Funding		$5,265.33
1315		FERC Annual Recovery		$54,506.41
1316		Organization of PJM States, Inc. (OPSI) Funding		$480.43
1317		North American Electric Reliability Corporation (NERC)		$5,920.05
1318		Reliability First Corporation (RFC)		$10,816.87
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$67,622.43
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$212,821.37
1340		Regulation and Frequency Response Service		$398,125.31

pjm

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (Buckeye)

CUSTOMER IDENTIFIERS: AEPBCK (11485)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

1360		Synchronized Reserve		$12,805.57
1365		Day-ahead Scheduling Reserve		$3,240.41
1370		Day-ahead Operating Reserve		$112,908.79
1375		Balancing Operating Reserve		$178,702.18
1376		Balancing Operating Reserve for Load Response		$37.65
1377		Synchronous Condensing		$684.22
1378		Reactive Services		$7,057.56
1380		Black Start Service		$5,054.10
1400		Load Reconciliation for Spot Market Energy		$15,748.50
1410		Load Reconciliation for Transmission Congestion		$763.86
1420		Load Reconciliation for Transmission Losses		$(457.17)
1430		Load Reconciliation for Inadvertent Interchange		$(3.01)
1440		Load Reconciliation for PJM Scheduling, System Control and Dispatch Service		$110.63
1441		Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund		$(88.19)
1442		Load Reconciliation for Schedule 9-6 - Advanced Second Control Center		$7.70
1444		Load Reconciliation for Market Monitoring Unit (MMU) Funding		$2.62
1445		Load Reconciliation for FERC Annual Recovery		$27.96
1446		Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding		$0.32
1447		Load Reconciliation for North American Electric Reliability Corporation (NERC)		$3.41
1448		Load Reconciliation for Reliability First Corporation (RFC)		$4.36
1450		Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service		$38.61
1460		Load Reconciliation for Regulation and Frequency Response Service		$110.67
1470		Load Reconciliation for Synchronized Reserve		$10.06
1475		Load Reconciliation for Day-ahead Scheduling Reserve		$1.19
1478		Load Reconciliation for Balancing Operating Reserve		$11.23
1480		Load Reconciliation for Synchronous Condensing		$0.49
1500		Financial Transmission Rights Auction		$967,233.79
1610		Locational Reliability		$5,836,221.89
1720		RTO Start-up Cost Recovery		$9,174.45
1730		Expansion Cost Recovery		$7,108.61
1120	A	Other Supporting Facilities	10/01/2009	$14.09
1120	A	Other Supporting Facilities	12/01/2009	$3,124.63
1230	A	Inadvertent Interchange	12/01/2009	$32.85
1330	A	Reactive Supply and Voltage Control from Generation and Other Sources Service	12/01/2009	$(0.02)
1360	A	Synchronized Reserve	08/01/2009	$(36.59)
1360	A	Synchronized Reserve	10/01/2009	$2,020.50
1360	A	Synchronized Reserve	12/01/2009	$(4.43)

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (Buckeye)

CUSTOMER IDENTIFIERS: AEPBCK (11485)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

1375	A	Balancing Operating Reserve	12/01/2008	$281.11
1375	A	Balancing Operating Reserve	08/01/2009	$275.30
1375	A	Balancing Operating Reserve	09/01/2009	$105.72
1375	A	Balancing Operating Reserve	10/01/2009	$112.76
1375	A	Balancing Operating Reserve	11/01/2009	$59.26
1375	A	Balancing Operating Reserve	12/01/2009	$99.54
		Total Charges		**$48,941,170.99**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (Buckeye)

CUSTOMER IDENTIFIERS: AEPBCK (11485)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$0.00
2130		Firm Point-to-Point Transmission Service		$38,741.81
2140		Non-Firm Point-to-Point Transmission Service		$24,316.83
2210		Transmission Congestion		$3,838,094.85
2220		Transmission Losses		$1,246,414.17
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
2340		Regulation and Frequency Response Service		$0.00
2360		Synchronized Reserve		$0.00
2365		Day-ahead Scheduling Reserve		$0.00
2370		Day-ahead Operating Reserve		$0.00
2375		Balancing Operating Reserve		$0.00
2380		Black Start Service		$0.00
2420		Load Reconciliation for Transmission Losses		$390.78
2510		Auction Revenue Rights		$1,078,594.47
2661		Capacity Resource Deficiency		$76.85
2666		Load Management Test Failure		$3,451.23
2140	A	Non-Firm Point-to-Point Transmission Service	11/01/2009	$13.91
2140	A	Non-Firm Point-to-Point Transmission Service	12/01/2009	$313.98
2210	A	Transmission Congestion	12/01/2009	$316.10
2220	A	Transmission Losses	12/01/2007	$(2,549.19)
2220	A	Transmission Losses	01/01/2008	$2,146.66
2220	A	Transmission Losses	02/01/2008	$(1,246.94)
2220	A	Transmission Losses	01/01/2009	$(23,565.89)
2220	A	Transmission Losses	02/01/2009	$(12,394.04)
2220	A	Transmission Losses	03/01/2009	$(277.20)
2220	A	Transmission Losses	12/01/2009	$2.68
2220	A	Transmission Losses	01/01/2010	$(3,353.85)
2666	A	Load Management Test Failure	12/01/2009	$111.33
		Total Credits		**$6,189,658.52**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

INVOICE NUMBER:	2010013116500
CUSTOMER ACCOUNT:	Appalachian Power Company (Columbus SP Dedicated)
CUSTOMER IDENTIFIERS:	AEPCSD (16500)
FINAL BILLING STATEMENT ISSUED:	02/05/2010 10:03:43
BILLING PERIOD:	01/01/2010 to 01/31/2010

Monthly Billing Total:	($465,199.81)
Previous Weekly Billing Total:	($450,124.54)

Monthly Billing Statement Summary	Total
Total Net Credit to You, Please Do Not Pay	**$15,075.27**

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 02/12/2010

WIRE TRANSFER FUNDS TO: PJM INTERCONNECTION, L.L.C
PNC BANK N.A.
NEW JERSEY
ABA NUMBER 031207607

ACCOUNT NUMBER - 8013589834

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

ADDITIONAL BILLING STATEMENT INFORMATION:

David Budney
Manager, PJM Market Settlement Operations

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (Columbus SP Dedicated)

CUSTOMER IDENTIFIERS: AEPCSD (16500)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$0.00
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		$0.00
1205		Balancing Spot Market Energy		$(636,951.31)
1210		Day-ahead Transmission Congestion		$0.00
1215		Balancing Transmission Congestion		$89,990.21
1220		Day-ahead Transmission Losses		$0.00
1225		Balancing Transmission Losses		$81,496.35
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$0.00
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$0.00
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		$501.13
1304		PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$0.00
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		$13.64
1310		PJM Scheduling, System Control and Dispatch Service Refund - Market Support		$(79.13)
1314		Market Monitoring Unit (MMU) Funding		$65.30
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
1340		Regulation and Frequency Response Service		$0.00
1360		Synchronized Reserve		$0.00
1365		Day-ahead Scheduling Reserve		$0.00
1370		Day-ahead Operating Reserve		$0.00
1375		Balancing Operating Reserve		$19,087.29
1376		Balancing Operating Reserve for Load Response		$6.07
1380		Black Start Service		$0.00
1250	A	Meter Error Correction	12/01/2009	$623.02
1375	A	Balancing Operating Reserve	12/01/2009	$47.62
		Total Charges		**($465,199.81)**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (Columbus SP Dedicated)

CUSTOMER IDENTIFIERS: AEPCSD (16500)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$0.00
2130		Firm Point-to-Point Transmission Service		$0.00
2140		Non-Firm Point-to-Point Transmission Service		$0.00
2210		Transmission Congestion		$0.00
2220		Transmission Losses		$0.00
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
2340		Regulation and Frequency Response Service		$0.00
2360		Synchronized Reserve		$0.00
2365		Day-ahead Scheduling Reserve		$0.00
2370		Day-ahead Operating Reserve		$0.00
2375		Balancing Operating Reserve		$0.00
2380		Black Start Service		$0.00
		Total Credits		**$0.00**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

INVOICE NUMBER:	2010013112405
CUSTOMER ACCOUNT:	Appalachian Power Company (IM Dedicated)
CUSTOMER IDENTIFIERS:	AEPIMD (12405)
FINAL BILLING STATEMENT ISSUED:	02/05/2010 10:03:43
BILLING PERIOD:	01/01/2010 to 01/31/2010

Monthly Billing Total:	($1,471,024.58)
Previous Weekly Billing Total:	($1,392,796.45)

Monthly Billing Statement Summary	Total
Total Net Credit to You. Please Do Not Pay	**$78,228.13**

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 02/12/2010

WIRE TRANSFER FUNDS TO: PJM INTERCONNECTION, L.L.C
PNC BANK N.A.
NEW JERSEY
ABA NUMBER 031207607

ACCOUNT NUMBER - 8013589834

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

ADDITIONAL BILLING STATEMENT INFORMATION:

David Budney
Manager, PJM Market Settlement Operations

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (IM Dedicated)

CUSTOMER IDENTIFIERS: AEPIMD (12405)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$0.00
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		$(1,463,240.68)
1205		Balancing Spot Market Energy		$(540,184.67)
1210		Day-ahead Transmission Congestion		$189,941.99
1215		Balancing Transmission Congestion		$99,362.08
1220		Day-ahead Transmission Losses		$152,139.93
1225		Balancing Transmission Losses		$53,119.24
1250		Meter Error Correction		$(237.99)
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$0.00
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$0.00
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		$1,531.01
1304		PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$0.00
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		$41.68
1310		PJM Scheduling, System Control and Dispatch Service Refund - Market Support		$(241.73)
1314		Market Monitoring Unit (MMU) Funding		$199.51
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
1340		Regulation and Frequency Response Service		$0.00
1360		Synchronized Reserve		$0.00
1365		Day-ahead Scheduling Reserve		$0.00
1370		Day-ahead Operating Reserve		$0.00
1375		Balancing Operating Reserve		$35,668.05
1376		Balancing Operating Reserve for Load Response		$12.83
1380		Black Start Service		$0.00
1250	A	Meter Error Correction	12/01/2009	$623.05
1375	A	Balancing Operating Reserve	12/01/2008	$69.82
1375	A	Balancing Operating Reserve	08/01/2009	$51.78
1375	A	Balancing Operating Reserve	09/01/2009	$9.92
1375	A	Balancing Operating Reserve	10/01/2009	$17.98
1375	A	Balancing Operating Reserve	11/01/2009	$12.93
1375	A	Balancing Operating Reserve	12/01/2009	$98.49
		Total Charges		**($1,471,004.78)**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (IM Dedicated)

CUSTOMER IDENTIFIERS: AEPIMD (12405)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$0.00
2130		Firm Point-to-Point Transmission Service		$0.00
2140		Non-Firm Point-to-Point Transmission Service		$0.00
2210		Transmission Congestion		$0.00
2220		Transmission Losses		$0.00
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
2340		Regulation and Frequency Response Service		$0.00
2360		Synchronized Reserve		$0.00
2365		Day-ahead Scheduling Reserve		$0.00
2370		Day-ahead Operating Reserve		$0.00
2375		Balancing Operating Reserve		$0.00
2380		Black Start Service		$0.00
2360	A	Synchronized Reserve	10/01/2009	$19.80
		Total Credits		**$19.80**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

INVOICE NUMBER:	2010013111675
CUSTOMER ACCOUNT:	Appalachian Power Company (MONPWR)
CUSTOMER IDENTIFIERS:	AEPMON (11675)
FINAL BILLING STATEMENT ISSUED:	02/05/2010 10:03:43
BILLING PERIOD:	01/01/2010 to 01/31/2010

Monthly Billing Total:	($387,962.45)
Previous Weekly Billing Total:	($315,350.75)

Monthly Billing Statement Summary	Total
Total Net Credit to You. Please Do Not Pay	$72,611.70

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 02/12/2010

WIRE TRANSFER FUNDS TO: PJM INTERCONNECTION, L.L.C
PNC BANK N.A.
NEW JERSEY
ABA NUMBER 031207607

ACCOUNT NUMBER - 8013589834

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

ADDITIONAL BILLING STATEMENT INFORMATION:

David Budney
Manager, PJM Market Settlement Operations

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (MONPWR)

CUSTOMER IDENTIFIERS: AEPMON (11675)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$0.00
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		$0.00
1205		Balancing Spot Market Energy		$0.00
1210		Day-ahead Transmission Congestion		$0.00
1215		Balancing Transmission Congestion		$0.00
1220		Day-ahead Transmission Losses		$0.00
1225		Balancing Transmission Losses		$0.00
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$0.00
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$532.27
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		$0.00
1304		PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$0.00
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		$9.36
1309		PJM Scheduling, System Control and Dispatch Service Refund - FTR Administration		$(60.75)
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
1340		Regulation and Frequency Response Service		$0.00
1360		Synchronized Reserve		$0.00
1365		Day-ahead Scheduling Reserve		$0.00
1370		Day-ahead Operating Reserve		$0.00
1375		Balancing Operating Reserve		$0.00
1380		Black Start Service		$0.00
1500		Financial Transmission Rights Auction		$169,922.16
1360	A	Synchronized Reserve	08/01/2009	$(8.79)
1375	A	Balancing Operating Reserve	08/01/2009	$146.41
		Total Charges		**$170,540.66**

pjm

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (MONPWR)

CUSTOMER IDENTIFIERS: AEPMON (11675)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$0.00
2130		Firm Point-to-Point Transmission Service		$0.00
2140		Non-Firm Point-to-Point Transmission Service		$0.00
2210		Transmission Congestion		$563,987.99
2220		Transmission Losses		$0.00
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
2340		Regulation and Frequency Response Service		$0.00
2360		Synchronized Reserve		$0.00
2365		Day-ahead Scheduling Reserve		$0.00
2370		Day-ahead Operating Reserve		$0.00
2375		Balancing Operating Reserve		$0.00
2380		Black Start Service		$0.00
2210	A	Transmission Congestion	12/01/2009	$61.19
2220	A	Transmission Losses	01/01/2009	$(3,388.08)
2220	A	Transmission Losses	02/01/2009	$(1,942.14)
2220	A	Transmission Losses	03/01/2009	$(40.40)
2220	A	Transmission Losses	01/01/2010	$(175.45)
		Total Credits		**$558,503.11**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

INVOICE NUMBER:	2010013112219
CUSTOMER ACCOUNT:	Appalachian Power Company (OCG B)
CUSTOMER IDENTIFIERS:	AEPOCG (12219)
FINAL BILLING STATEMENT ISSUED:	02/05/2010 10:03:43
BILLING PERIOD:	01/01/2010 to 01/31/2010

Monthly Billing Total:	**($736,825.52)**
Previous Weekly Billing Total:	**($691,153.28)**

Monthly Billing Statement Summary	Total
Total Net Credit to You. Please Do Not Pay	**$45,672.24**

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 02/12/2010

WIRE TRANSFER FUNDS TO: PJM INTERCONNECTION, L.L.C
PNC BANK N.A.
NEW JERSEY
ABA NUMBER 031207607

ACCOUNT NUMBER - 8013589834

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

ADDITIONAL BILLING STATEMENT INFORMATION:

David Budney
Manager, PJM Market Settlement Operations

pjm

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (OCG B)

CUSTOMER IDENTIFIERS: AEPOCG (12219)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$0.00
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		$(1,147,379.42)
1205		Balancing Spot Market Energy		$17,766.70
1210		Day-ahead Transmission Congestion		$195,591.60
1215		Balancing Transmission Congestion		$29,899.68
1220		Day-ahead Transmission Losses		$154,573.60
1225		Balancing Transmission Losses		$915.17
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$0.00
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$0.00
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		$822.45
1304		PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$0.00
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		$22.39
1310		PJM Scheduling, System Control and Dispatch Service Refund - Market Support		$(129.88)
1314		Market Monitoring Unit (MMU) Funding		$107.17
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
1340		Regulation and Frequency Response Service		$0.00
1360		Synchronized Reserve		$0.00
1365		Day-ahead Scheduling Reserve		$0.00
1370		Day-ahead Operating Reserve		$0.00
1375		Balancing Operating Reserve		$10,791.98
1376		Balancing Operating Reserve for Load Response		$4.93
1380		Black Start Service		$0.00
1375	A	Balancing Operating Reserve	12/01/2008	$99.72
1375	A	Balancing Operating Reserve	08/01/2009	$48.93
1375	A	Balancing Operating Reserve	09/01/2009	$14.33
1375	A	Balancing Operating Reserve	10/01/2009	$15.65
1375	A	Balancing Operating Reserve	11/01/2009	$12.14
1375	A	Balancing Operating Reserve	12/01/2009	$38.81
		Total Charges		**($736,784.05)**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (OCG B)
CUSTOMER IDENTIFIERS: AEPOCG (12219)
FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43
BILLING PERIOD: 01/01/2010 to 01/31/2010

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$0.00
2130		Firm Point-to-Point Transmission Service		$0.00
2140		Non-Firm Point-to-Point Transmission Service		$0.00
2210		Transmission Congestion		$0.00
2220		Transmission Losses		$0.00
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
2340		Regulation and Frequency Response Service		$0.00
2360		Synchronized Reserve		$0.00
2365		Day-ahead Scheduling Reserve		$0.00
2370		Day-ahead Operating Reserve		$0.00
2375		Balancing Operating Reserve		$0.00
2380		Black Start Service		$0.00
2360	A	Synchronized Reserve	10/01/2009	$41.47
		Total Credits		**$41.47**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

INVOICE NUMBER: 2010013116501

CUSTOMER ACCOUNT: Appalachian Power Company (Ohio Dedicated)

CUSTOMER IDENTIFIERS: AEPOPD (16501)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

Monthly Billing Total:	($465,199.81)
Previous Weekly Billing Total:	($450,124.54)

Monthly Billing Statement Summary	Total
Total Net Credit to You. Please Do Not Pay	**$15,075.27**

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 02/12/2010

WIRE TRANSFER FUNDS TO: PJM INTERCONNECTION, L.L.C
PNC BANK N.A.
NEW JERSEY
ABA NUMBER 031207607

ACCOUNT NUMBER - 8013589834

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

ADDITIONAL BILLING STATEMENT INFORMATION:

David Budney
Manager, PJM Market Settlement Operations

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (Ohio Dedicated)

CUSTOMER IDENTIFIERS: AEPOPD (16501)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$0.00
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		$0.00
1205		Balancing Spot Market Energy		$(636,951.31)
1210		Day-ahead Transmission Congestion		$0.00
1215		Balancing Transmission Congestion		$89,990.21
1220		Day-ahead Transmission Losses		$0.00
1225		Balancing Transmission Losses		$61,496.35
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$0.00
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$0.00
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		$501.13
1304		PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$0.00
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		$13.64
1310		PJM Scheduling, System Control and Dispatch Service Refund - Market Support		$(79.13)
1314		Market Monitoring Unit (MMU) Funding		$65.30
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
1340		Regulation and Frequency Response Service		$0.00
1360		Synchronized Reserve		$0.00
1365		Day-ahead Scheduling Reserve		$0.00
1370		Day-ahead Operating Reserve		$0.00
1375		Balancing Operating Reserve		$19,087.29
1376		Balancing Operating Reserve for Load Response		$6.07
1380		Black Start Service		$0.00
1250	A	Meter Error Correction	12/01/2009	$623.02
1375	A	Balancing Operating Reserve	12/01/2009	$47.62
		Total Charges		**($465,199.81)**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (Ohio Dedicated)

CUSTOMER IDENTIFIERS: AEPOPD (16501)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$0.00
2130		Firm Point-to-Point Transmission Service		$0.00
2140		Non-Firm Point-to-Point Transmission Service		$0.00
2210		Transmission Congestion		$0.00
2220		Transmission Losses		$0.00
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
2340		Regulation and Frequency Response Service		$0.00
2360		Synchronized Reserve		$0.00
2365		Day-ahead Scheduling Reserve		$0.00
2370		Day-ahead Operating Reserve		$0.00
2375		Balancing Operating Reserve		$0.00
2380		Black Start Service		$0.00
		Total Credits		**$0.00**

pjm

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

INVOICE NUMBER:	2010013100063
CUSTOMER ACCOUNT:	Appalachian Power Company (AEP Generation)
CUSTOMER IDENTIFIERS:	AEPSCG (63)
FINAL BILLING STATEMENT ISSUED:	02/05/2010 10:03:43
BILLING PERIOD:	01/01/2010 to 01/31/2010

Monthly Billing Total:	**$1,548,699.91**
Previous Weekly Billing Total:	**($2,923,245.42)**

Monthly Billing Statement Summary	Total
Total Net Charge. Please Pay This Amount.	**$4,471,945.33**

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 02/12/2010

WIRE TRANSFER FUNDS TO: PJM INTERCONNECTION, L.L.C
PNC BANK N.A.
NEW JERSEY
ABA NUMBER 031207607

ACCOUNT NUMBER - 8013589834

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

ADDITIONAL BILLING STATEMENT INFORMATION:

David Budney
Manager, PJM Market Settlement Operations

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (AEP Generation)

CUSTOMER IDENTIFIERS: AEPSCG (63)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$47,420,261.20
1108		Transmission Enhancement		$1,839,989.85
1120		Other Supporting Facilities		$51,375.00
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$6,129.70
1200		Day-ahead Spot Market Energy		$(106,330,689.72)
1205		Balancing Spot Market Energy		$18,765,640.39
1210		Day-ahead Transmission Congestion		$61,413,885.87
1215		Balancing Transmission Congestion		$(1,530,214.55)
1220		Day-ahead Transmission Losses		$42,241,902.94
1225		Balancing Transmission Losses		$(341,831.51)
1230		Inadvertent Interchange		$(237,235.33)
1250		Meter Error Correction		$(1,885.71)
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$2,207,564.13
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$48,589.70
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		$1,077,056.79
1304		PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$39,274.74
1305		PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.		$136,461.38
1306		PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center		$91,365.18
1308		PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration		$(323,385.55)
1309		PJM Scheduling, System Control and Dispatch Service Refund - FTR Administration		$(5,482.98)
1310		PJM Scheduling, System Control and Dispatch Service Refund - Market Support		$(169,957.43)
1311		PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration		$(6,980.04)
1312		PJM Scheduling, System Control and Dispatch Service Refund - Capacity Resource/Obligation Mgmt.		$(18,500.80)
1314		Market Monitoring Unit (MMU) Funding		$140,272.53
1315		FERC Annual Recovery		$761,481.51
1316		Organization of PJM States, Inc. (OPSI) Funding		$6,711.72
1317		North American Electric Reliability Corporation (NERC)		$97,643.15
1318		Reliability First Corporation (RFC)		$178,409.64
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$872,224.09
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$2,836,136.26
1340		Regulation and Frequency Response Service		$5,397,434.46

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (AEP Generation)

CUSTOMER IDENTIFIERS: AEPSCG (63)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

1360		Synchronized Reserve		$175,236.70
1365		Day-ahead Scheduling Reserve		$43,852.84
1370		Day-ahead Operating Reserve		$1,651,633.87
1375		Balancing Operating Reserve		$3,199,331.73
1376		Balancing Operating Reserve for Load Response		$639.03
1377		Synchronous Condensing		$9,268.79
1378		Reactive Services		$142,296.01
1380		Black Start Service		$59,021.55
1400		Load Reconciliation for Spot Market Energy		$112,786.09
1410		Load Reconciliation for Transmission Congestion		$7,537.82
1420		Load Reconciliation for Transmission Losses		$(3,839.46)
1430		Load Reconciliation for Inadvertent Interchange		$(71.13)
1440		Load Reconciliation for PJM Scheduling, System Control and Dispatch Service		$1,196.68
1441		Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund		$(932.18)
1442		Load Reconciliation for Schedule 9-6 - Advanced Second Control Center		$83.37
1444		Load Reconciliation for Market Monitoring Unit (MMU) Funding		$28.17
1445		Load Reconciliation for FERC Annual Recovery		$302.42
1446		Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding		$3.41
1447		Load Reconciliation for North American Electric Reliability Corporation (NERC)		$36.85
1448		Load Reconciliation for Reliability First Corporation (RFC)		$47.15
1450		Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service		$365.34
1460		Load Reconciliation for Regulation and Frequency Response Service		$931.41
1470		Load Reconciliation for Synchronized Reserve		$78.42
1475		Load Reconciliation for Day-ahead Scheduling Reserve		$3.20
1478		Load Reconciliation for Balancing Operating Reserve		$953.54
1480		Load Reconciliation for Synchronous Condensing		$(7.11)
1500		Financial Transmission Rights Auction		$19,351,811.38
1600		RPM Auction		$44,020.00
1610		Locational Reliability		$980,826.98
1720		RTO Start-up Cost Recovery		$181,012.59
1730		Expansion Cost Recovery		$115,680.67
1980		Miscellaneous Bilateral		$4,503.88
1120	A	Other Supporting Facilities	10/01/2009	$12.26
1120	A	Other Supporting Facilities	12/01/2009	$(1,677.33)
1140	A	Non-Firm Point-to-Point Transmission Service	12/01/2009	$316.24
1230	A	Inadvertent Interchange	12/01/2009	$552.15
1330	A	Reactive Supply and Voltage Control from Generation and Other Sources Service	12/01/2009	$(0.23)

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (AEP Generation)

CUSTOMER IDENTIFIERS: AEPSCG (63)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

1360	A	Synchronized Reserve	08/01/2009	$(878.21)
1360	A	Synchronized Reserve	10/01/2009	$31,065.40
1360	A	Synchronized Reserve	12/01/2009	$(88.34)
1375	A	Balancing Operating Reserve	12/01/2008	$7,216.92
1375	A	Balancing Operating Reserve	08/01/2009	$6,309.41
1375	A	Balancing Operating Reserve	09/01/2009	$2,927.01
1375	A	Balancing Operating Reserve	10/01/2009	$1,643.62
1375	A	Balancing Operating Reserve	11/01/2009	$1,025.32
1375	A	Balancing Operating Reserve	12/01/2009	$3,345.14
		Total Charges		**$102,794,071.96**

PJM Interconnection, L.L.C.
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CUSTOMER ACCOUNT: Appalachian Power Company (AEP Generation)

CUSTOMER IDENTIFIERS: AEPSCG (63)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$0.00
2130		Firm Point-to-Point Transmission Service		$784,373.93
2140		Non-Firm Point-to-Point Transmission Service		$431,663.34
2210		Transmission Congestion		$57,264,355.41
2220		Transmission Losses		$17,059,896.11
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$2,846,353.48
2340		Regulation and Frequency Response Service		$1,652,966.20
2360		Synchronized Reserve		$4,660.00
2365		Day-ahead Scheduling Reserve		$57,230.06
2370		Day-ahead Operating Reserve		$268,105.96
2375		Balancing Operating Reserve		$2,081,994.25
2380		Black Start Service		$27,747.18
2420		Load Reconciliation for Transmission Losses		$2,961.83
2500		Financial Transmission Rights Auction		$7,991.49
2510		Auction Revenue Rights		$16,359,691.26
2600		RPM Auction		$4,025,539.41
2650		Non-Unit Specific Capacity Transaction		$126,529.60
2661		Capacity Resource Deficiency		$14.08
2666		Load Management Test Failure		$634.26
2140	A	Non-Firm Point-to-Point Transmission Service	11/01/2009	$244.19
2140	A	Non-Firm Point-to-Point Transmission Service	12/01/2009	$5,494.67
2210	A	Transmission Congestion	12/01/2009	$6,879.24
2220	A	Transmission Losses	12/01/2007	$(264,086.02)
2220	A	Transmission Losses	01/01/2008	$(263,596.59)
2220	A	Transmission Losses	02/01/2008	$(256,140.95)
2220	A	Transmission Losses	01/01/2009	$(447,286.77)
2220	A	Transmission Losses	02/01/2009	$(260,026.00)
2220	A	Transmission Losses	03/01/2009	$(11,532.90)
2220	A	Transmission Losses	12/01/2009	$38.43
2220	A	Transmission Losses	01/01/2010	$(287,529.27)
2360	A	Synchronized Reserve	10/01/2009	$40,185.71
2666	A	Load Management Test Failure	12/01/2009	$20.46
		Total Credits		**$101,246,372.05**

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

INVOICE NUMBER:	2010013110842
CUSTOMER ACCOUNT:	Appalachian Power Company (AEP Transmission)
CUSTOMER IDENTIFIERS:	AEPSCT (10842)
FINAL BILLING STATEMENT ISSUED:	02/05/2010 10:03:43
BILLING PERIOD:	01/01/2010 to 01/31/2010

Monthly Billing Total:	($55,901,780.28)
Previous Weekly Billing Total:	($47,125,339.09)

Monthly Billing Statement Summary	Total
Total Net Credit to You. Please Do Not Pay	$8,776,441.19

TERMS: PAYABLE IN FULL BY 12:00 PM EPT ON 02/12/2010

WIRE TRANSFER FUNDS TO: PJM INTERCONNECTION, L.L.C
PNC BANK N.A.
NEW JERSEY
ABA NUMBER 031207607

ACCOUNT NUMBER - 8013589834

FOR INQUIRIES CONTACT:

PJM MEMBER RELATIONS (Banking / Payment):	custsvc@pjm.com	(866) 400-8980
PJM MARKET SETTLEMENTS (Billing Line Items):	mrkt_settlement_ops@pjm.com	(866) 400-8980

ADDITIONAL BILLING STATEMENT INFORMATION:

David Budney
Manager, PJM Market Settlement Operations

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (AEP Transmission)

CUSTOMER IDENTIFIERS: AEPSCT (10842)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CHARGES	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
1100		Network Integration Transmission Service		$0.00
1130		Firm Point-to-Point Transmission Service		$0.00
1140		Non-Firm Point-to-Point Transmission Service		$0.00
1200		Day-ahead Spot Market Energy		$0.00
1205		Balancing Spot Market Energy		$0.09
1210		Day-ahead Transmission Congestion		$0.00
1215		Balancing Transmission Congestion		$(1,544,812.93)
1220		Day-ahead Transmission Losses		$0.00
1225		Balancing Transmission Losses		$(14,376.04)
1250		Meter Error Correction		$16,698.68
1301		PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$0.00
1302		PJM Scheduling, System Control and Dispatch Service - FTR Administration		$0.00
1303		PJM Scheduling, System Control and Dispatch Service - Market Support		$0.00
1304		PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$0.00
1305		PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.		$0.00
1320		Transmission Owner Scheduling, System Control and Dispatch Service		$0.00
1330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
1340		Regulation and Frequency Response Service		$0.00
1360		Synchronized Reserve		$(21,027.73)
1365		Day-ahead Scheduling Reserve		$0.00
1370		Day-ahead Operating Reserve		$0.00
1375		Balancing Operating Reserve		$3,393,826.42
1380		Black Start Service		$0.00
1410		Load Reconciliation for Transmission Congestion		$136.69
1420		Load Reconciliation for Transmission Losses		$(18.98)
1470		Load Reconciliation for Synchronized Reserve		$(3.03)
1980		Miscellaneous Bilateral		$(124,991.75)
1250	A	Meter Error Correction	12/01/2009	$(1,869.09)
1360	A	Synchronized Reserve	10/01/2009	$294.56
1360	A	Synchronized Reserve	12/01/2009	$4.57
1375	A	Balancing Operating Reserve	10/01/2009	$0.00
1375	A	Balancing Operating Reserve	01/01/2010	$(2,991,829.43)

Total Charges **($1,287,967.97)**

PJM Interconnection, L.L.C.
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Norristown, PA 19403-2497

CUSTOMER ACCOUNT: Appalachian Power Company (AEP Transmission)

CUSTOMER IDENTIFIERS: AEPSCT (10842)

FINAL BILLING STATEMENT ISSUED: 02/05/2010 10:03:43

BILLING PERIOD: 01/01/2010 to 01/31/2010

CREDITS	ADJ	BILLING LINE ITEM NAME	SOURCE BILLING PERIOD START	AMOUNT
2100		Network Integration Transmission Service		$52,558,387.66
2108		Transmission Enhancement		$262,226.16
2120		Other Supporting Facilities		$217,850.61
2130		Firm Point-to-Point Transmission Service		$0.00
2140		Non-Firm Point-to-Point Transmission Service		$0.00
2210		Transmission Congestion		$0.00
2220		Transmission Losses		$0.00
2320		Transmission Owner Scheduling, System Control and Dispatch Service		$1,094,649.63
2330		Reactive Supply and Voltage Control from Generation and Other Sources Service		$0.00
2340		Regulation and Frequency Response Service		$0.00
2360		Synchronized Reserve		$0.00
2365		Day-ahead Scheduling Reserve		$0.00
2370		Day-ahead Operating Reserve		$0.00
2375		Balancing Operating Reserve		$0.00
2380		Black Start Service		$0.00
2720		RTO Start-up Cost Recovery		$200,625.54
2730		Expansion Cost Recovery		$210,778.29
2120	A	Other Supporting Facilities	10/01/2009	$35.20
2120	A	Other Supporting Facilities	12/01/2009	$68,185.02
2120	A	Other Supporting Facilities	01/01/2010	$1,074.36
2320	A	Transmission Owner Scheduling, System Control and Dispatch Service	12/01/2009	$(0.16)
		Total Credits		**$54,613,812.31**

Appendix A
Columbus Southern Power and Ohio Power
Costs to be Reviewed in Biennial Audit

		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 when there is a need for PJM to dispatch units out of merit in order to manage congestion on transmission lines.	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 1% of 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 3% 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) in place of FTRs. The number of ARRs and the method for obtaining them are similar to the FTR allocation process. ARRs additionally allow the holder to monetize the value of the FTR through selling the rights of the associated FTR to another entity during the annual a	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 at a rate of LMP+$50.
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 has begun to examine 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
Columbus Southern Power and Ohio Power
Costs to be Reviewed in Biennial Audit

		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 was a credit in 2009 vs a charge in 2008 due to depressed LMPs and demand in the PJM footprint. FTR revenue is expected to offset congestion charges in 2010.	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). The most economic source is from the units "on the margin", and during the summer months, marginal units are typically gas units. Total regulation in 2009 was lower than 2008 due to depressed LMPs and demand in the PJM footprint. In 2009 the marginal unit was less expensive due to the decreased LMPs	There was a decrease in Spinning Reserve charges in 2009 due to a combination of Synchronized Reserve Market Clearing Price (SRMCP) decreases and depressed market conditions
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.
N	**Provide any additional information that would enhance Staff's investigation.**	N/A	N/A	Starting in June 2008, PJM implemented a "30-minute" Supplemental Day-Ahead Scheduling Reserve market, an offer-based market designed to encourage PJM market participants to provide day-ahead scheduling reserves. Prior to implementing the market for these reserves (capable of being on line within 30 minutes), they were scheduled by PJM in both the day-ahead market and during the Reliability Analysis (post day-ahead market awards) and were compensated with Operation Reserve credits. At this time it appears this impact will be minimal.

Appendix A
Columbus Southern Power and Ohio Power
Costs to be Reviewed in Biennial Audit

		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 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.	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, and the Advanced Second Control Center. 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. If a market participant has no variance from their day-ahead load and generation bids, the participant will not be assessed any Balancing Operating Reserve charges.	PJM Administrative Fees are established by the FERC and participants do not have the option to avoid paying these fees. As noted previously, PJM recently came to an agreement with the stakeholders to stabilize rates through 2010. This will put more responsibility on PJM to control costs than they had previously with the formula rate structure. 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.**	The Companies attempt to minimize Operating Reserve cost risk by evaluating Day ahead and Real time LMPs to determine an appropriate bidding strategy for generating units and load. The make whole payments that generators are paid for additional generation are based upon the LMP at that generator. Constant attention to unit dispatch and PJM basepoint signals, accurate communication with PJM regarding unit status, and prudent management of unplanned operational events minimizes real time deviations and real-time operating reserve charges 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. Our operations personnel update bidding strategies to make sure they are consistent with the operational performance of the AEP fleet. 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.	As described above, AEP, as a member of PJM, does not have the option to avoid PJM Administrative Costs. However, PJM recently came to an agreement with the stakeholders to stabilize rates through 2010. Additionally, AEP actively participated in the RTO accounting Notice of Proposed Rulemaking (NOPR) proceeding that resulted in the FERC supplementing accounting practices to provide better transparency into RTO costs, which has been a matter of national concern with the continuing escalation of RTO costs.

Appendix A
Columbus Southern Power and Ohio Power
Costs to be Reviewed in Biennial Audit

		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.**	No significant change. Operating Reserve costs were mostly level from 2008 to 2009. There may be an increase in 2010 if market LMPs recover from 2009 levels and the marginal units brought on for Operating Reserves get more expensive.	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.
N	**Provide any additional information that would enhance Staff's investigation.**	On September 24, 2008, PJM filed revisions to Schedule 1 of the PJM Operating agreement to *implement changes in the* Operating Reserve methodology intended to encourage generation dispatch performance and to allocate costs in a manner that reflects balancing Operating Reserve charges due to both real-time deviations and those called on to meet reliability objectives. These changes went into effect beginning in December 2008. In 2009 Operating Reserve costs were less than 2008 but it was mainly due to the depressed LMPs in the PJM footprint. Since the LMPs were much lower in 2009 vs 2008, the marginal unit PJM would call on for Operating Reserves would cost much less than it did the previous year. If LMPs recover and the cost of the marginal units goes up, the rule changes from December 2008 could result in more costs being allocated based on AEP's Load Ratio Share within PJM, this increases the likelihood that Operating Reserve costs could increase.	N/A

American Electric Power Service Corporation
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: Market Operations, Commercial and Financial Analysis, and Energy Trading and Marketing.

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 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 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.

Financial Performance 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. As a result of the morning meetings and ongoing daily analyses, there is consistent research and development of new business processes which minimize the overall costs associated with operating within PJM.

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.