LARGE FILING SEPARATOR SHEET

CASE NUMBER
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APPLICATION & SCHEDULES

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CLASS COST-OF-SERVICE STUDY

OHIO POWER COMPANY

Case No. 11-351-EL-AIR

Test Year: Twelve Months Ended May 31, 2011

Date Certain: August 31, 2010

OHIO POWER COMPANY
CLASS COST-OF-SERVICE STUDY - CUSTOMER CHARGE
TWELVE MONTHS ENDING MAY 31, 2011

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: >Original__Updated__Revised
Work Paper Reference No(s): WP A-1e-p and all Schedule E3.2 Work Papers

Witness Responsible:
Daniel E. High

Label	Allocation Factor	Function	Total Retail	RS	GS-1	SEC	PRI	SUB/TRAN	OL	SL
Rate Base										
Plant in Service										
Distribution										
360 Land and Land Rights	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
361 Structures and Improvements	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
362 Station Equipment	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
363 Storage Battery Equipment	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
364 Poles, Towers & Fixtures	DIST_POLES	TOTAL	-	-	-	-	-	-	-	-
365 Overhead Lines	DIST_OHLINES	TOTAL	-	-	-	-	-	-	-	-
366 Underground Conduit	DIST_UGLINES	TOTAL	-	-	-	-	-	-	-	-
367 Underground Lines	DIST_UGLINES	TOTAL	-	-	-	-	-	-	-	-
368 Transformers	DIST_TRANSF	TOTAL	-	-	-	-	-	-	-	-
369 Services	DIST_SERV	TOTAL	135,157,954	106,525,465	11,519,258	6,102,533	-	-	10,834,152	176,546
370 Meters	DIST_METERS	TOTAL	70,138,185	39,848,665	6,371,020	16,971,615	2,493,786	4,453,099	-	-
371 Install on Cust. Premises	DIST_OL	TOTAL	22,791,009	-	-	-	-	-	22,791,009	-
372 Leased Prop. On Cust. Premises	DIST_OL	TOTAL	1,104	-	-	-	-	-	1,104	-
373 Street Lighting	DIST_SL	TOTAL	21,232,932	-	-	-	-	-	-	21,232,932
Total		TOTAL	249,321,184	146,374,130	17,890,278	23,074,148	2,493,786	4,453,099	33,626,265	21,409,478
Total Plant in Service		TOTAL	249,321,184	146,374,130	17,890,278	23,074,148	2,493,786	4,453,099	33,626,265	21,409,478
General Plant	LABOR_M	TOTAL	32,629,866	24,016,177	2,272,437	2,128,672	167,732	839,436	2,296,881	908,531
Intangible Plant	LABOR_M	TOTAL	7,482,064	5,506,936	521,072	488,107	38,461	192,484	526,677	208,327
Total General & Intangible Plant		TOTAL	40,111,930	29,523,113	2,793,509	2,616,779	206,194	1,031,919	2,823,558	1,116,858
Total Electric Plant in Service		TOTAL	289,433,114	175,897,243	20,683,787	25,690,928	2,699,979	5,485,018	36,449,823	22,526,336
Electric Plant Acquisition Adj. - Account 302	LABOR_M	TOTAL	192,123	141,406	13,380	12,534	988	4,943	13,524	5,349
Electric Utility Plant		TOTAL	289,625,237	176,038,649	20,697,167	25,703,461	2,700,967	5,489,961	36,463,347	22,531,685
Accum. Depreciation and Amortiz.										
Distribution	RB_GUP_EPIS_D	TOTAL	(81,621,472)	(47,919,201)	(5,856,826)	(7,553,895)	(816,403)	(1,457,832)	(11,008,392)	(7,008,924)
General & Intangible	RB_GUP_EPIS_G	TOTAL	(21,399,689)	(15,750,562)	(1,490,335)	(1,396,050)	(110,004)	(550,528)	(1,506,366)	(595,843)
Total		TOTAL	(103,021,161)	(63,669,763)	(7,347,161)	(8,949,945)	(926,407)	(2,008,361)	(12,514,758)	(7,604,766)
Amortiz. Of Plant Acquisition Adj. - Acct 302	LABOR_M	TOTAL	(160,836)	(118,379)	(11,201)	(10,492)	(827)	(4,138)	(11,322)	(4,478)
Net Electric Plant In Service		TOTAL	186,443,240	112,250,508	13,338,804	16,743,024	1,773,734	3,477,462	23,937,267	14,922,441
Working Capital										
Uncollectibles	RSALE	TOTAL	-	-	-	-	-	-	-	-
Materials & Supplies - Dist	RB_GUP_EPIS_D	TOTAL	1,040,534	610,888	74,665	96,299	10,408	18,585	140,338	89,352
Prepayments - Other (Insurance, etc.)	RB_GUP	TOTAL	293,729	178,533	20,990	26,068	2,739	5,568	36,980	22,851
Other Current Assets	LABOR_M	TOTAL	-	-	-	-	-	-	-	-
Total Working Capital		TOTAL	1,334,263	789,421	95,655	122,367	13,147	24,153	177,318	112,203
Rate Base Offsets										

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Customer Deposits	CUST_DEP	TOTAL	(26,468,865)	(16,034,032)	(807,800)	(4,982,051)	(919,359)	(3,694,937)	(30,687)	-
Customer Advances	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-	-	-	-
Prepayments - Pension	LABOR_M	TOTAL	20,670,064	15,213,545	1,439,522	1,348,452	106,254	531,758	1,455,007	575,527
Deferred Taxes (190.1)	RB_GUP_EPIS_D	TOTAL	6,883,525	4,041,253	493,934	637,056	68,851	122,946	928,390	591,096
Deferred Taxes (281.1)	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-	-	-	-
Deferred Taxes (282.1)	RB_GUP_EPIS_D	TOTAL	(23,622,075)	(13,868,299)	(1,695,024)	(2,186,173)	(236,275)	(421,911)	(3,185,939)	(2,028,453)
Deferred Taxes (283.1)	RB_GUP_EPIS_D	TOTAL	(10,057,800)	(5,904,840)	(721,707)	(930,828)	(100,601)	(179,641)	(1,356,508)	(863,674)
Deferred Taxes - State (283.1)	RB_GUP_EPIS_D	TOTAL	(173,313)	(101,750)	(12,436)	(16,040)	(1,734)	(3,096)	(23,375)	(14,883)
Deferred Investment Tax Credits (255)	RB_GUP_EPIS_D	TOTAL	(77,000)	(45,206)	(5,525)	(7,126)	(770)	(1,375)	(10,385)	(6,612)
Total		TOTAL	(32,845,463)	(16,699,329)	(1,309,037)	(6,136,710)	(1,083,634)	(3,646,256)	(2,223,498)	(1,746,999)
Total Rate Base		TOTAL	154,932,039	96,340,599	12,125,422	10,728,681	703,246	(144,641)	21,891,088	13,287,645
Operating Revenues										
Firm Sales of Electricity	RSALE	TOTAL	95,291,817	54,775,152	5,614,276	5,057,830	460,138	21,095,729	4,767,475	3,521,221
Other Operating Revenues										
Forfeited Discounts	FORF_DISC	TOTAL	207,781	11,692	145,969	54,849	2,403	(7,165)	31	1
Miscellaneous Service Revenue	MISC_SERV_REV	TOTAL	437,206	396,945	28,675	4,214	15	20	5,926	1,412
Rent Assoc Co	RB_GUP_EPIS_D	TOTAL	603,247	354,161	43,287	55,829	6,034	10,775	81,361	51,801
Rent Non-Assoc Co	RB_GUP_EPIS_D	TOTAL	1,110,985	652,249	79,720	102,819	11,112	19,843	149,840	95,402
Rent ABD	RB_GUP_EPIS_D	TOTAL	10,347	6,075	742	958	103	185	1,396	889
Other Electric Revenue-NonAff	RB_GUP_EPIS_D	TOTAL	363,012	213,121	26,048	33,596	3,631	6,484	48,960	31,172
Other Electric Revenue - ABD	RB_GUP_EPIS_D	TOTAL	239,347	140,518	17,175	22,151	2,394	4,275	32,281	20,553
Other Electric Rev. - PJM Trans Dist/Meter	RB_GUP_EPIS_D	TOTAL	128,162	75,254	9,198	11,863	1,282	2,289	17,288	11,007
Total - Other Operating Revenues		TOTAL	3,100,108	1,850,015	350,814	286,279	26,974	36,706	337,082	212,237
Total Operating Revenues		TOTAL	98,391,925	56,625,167	5,965,090	5,344,109	487,112	21,132,435	5,104,557	3,733,458
Operating Expense										
O&M Expense										
Distribution Operation										
580 Supervision & Engineering	TOTOXEXP	TOTAL	696,102	397,903	52,314	88,949	11,244	20,056	66,634	59,002
581 Load Dispatching	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
582 Station Equipment	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
583 Overhead Lines	DIST_OHLINES	TOTAL	-	-	-	-	-	-	-	-
584 Undergroung Lines	DIST_UGLINES	TOTAL	-	-	-	-	-	-	-	-
585 Street Lighting	DIST_SL	TOTAL	130,576	-	-	-	-	-	-	130,576
586 Meters	DIST_METERS	TOTAL	1,355,619	770,188	123,138	328,025	48,199	86,069	-	-
587 Customer Installations	DIST_PCUST	TOTAL	104,068	81,949	8,862	4,695	92	-	8,335	136
588 Miscellaneous Distribution	RB_GUP_EPIS_D	TOTAL	3,198,173	1,877,617	229,488	295,984	31,989	57,122	431,342	274,631
589 Rents	RB_GUP_EPIS_D	TOTAL	477,601	280,395	34,271	44,201	4,777	8,530	64,415	41,012
Total		TOTAL	5,962,139	3,408,053	448,073	761,854	96,301	171,777	570,725	505,357
Distribution Maintenance										
590 Supervision & Engineering	TOTMXEXP	TOTAL	32,066	3,503	560	1,492	219	391	21,879	4,021
591 Structures	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
592 Station Equipment	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
593 Overhead Lines	TOTOHLINES	TOTAL	-	-	-	-	-	-	-	-
594 Underground Lines	TOTUGLINES	TOTAL	-	-	-	-	-	-	-	-

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595 Line Transformers	DIST_TRANSF	TOTAL	-	-	-	-	-	-	-	-
596 Street Lighting	DIST_SL	TOTAL	291,693	-	-	-	-	-	-	291,693
597 Meters	DIST_METERS	TOTAL	447,298	254,130	40,630	108,234	15,904	28,399	-	-
598 Miscellaneous Distribution	DIST_OL	TOTAL	1,587,332	-	-	-	-	-	1,587,332	-
Total		TOTAL	2,358,389	257,633	41,190	109,726	16,123	28,791	1,609,211	295,714
Customer Accounts										
901 Supervision & Engineering	TOTOX234	TOTAL	1,236,517	1,080,747	94,360	58,685	1,242	309	43	1,131
902 Meter Reading	CUST_902	TOTAL	4,971,654	4,119,497	445,467	394,262	9,820	2,609	-	-
903 Customer Records & Collection Exp.	CUST_903	TOTAL	19,708,498	17,453,402	1,437,934	776,771	14,911	3,442	-	22,038
904 Uncollectible Accounts	UNCOLFAC	TOTAL	6,342	3,723	455	587	63	113	855	545
Factoring Expense	RSALE	TOTAL	3,007,437	1,728,719	177,188	159,627	14,522	665,787	150,463	111,131
431-Interest on Customer Deposits	CUST_DEP	TOTAL	793,231	480,515	24,209	149,304	27,552	110,732	920	-
905 Miscellaneous Customer Accounts	TOTOX234	TOTAL	73,207	63,985	5,587	3,474	74	18	3	67
Total		TOTAL	29,796,885	24,930,589	2,185,199	1,542,710	68,184	783,010	152,263	134,911
Customer Service & Inf & Sales Exp										
907 Supervision	EXP_OM_CUSTACCT	TOTAL	1,074,267	898,822	78,783	55,619	2,458	28,230	5,490	4,864
908 Customer Assistance	EXP_OM_CUSTACCT	TOTAL	1,287,487	1,077,221	94,420	66,659	2,946	33,833	6,580	5,829
909 Information & Instruction	EXP_OM_CUSTACCT	TOTAL	295,991	247,651	21,707	15,325	677	7,778	1,513	1,340
910 Miscellaneous Customer Service	EXP_OM_CUSTACCT	TOTAL	1,776	1,486	130	92	4	47	9	8
911-916 Misc Selling Expense	EXP_OM_CUSTACCT	TOTAL	9,607	8,038	705	497	22	252	49	43
Total		TOTAL	2,669,128	2,233,218	195,744	138,192	6,108	70,140	13,841	12,085
Administrative & General Expense										
920-Salaries	LABOR_M	TOTAL	2,459,015	1,809,880	171,253	160,419	12,640	63,261	173,095	68,468
921-Office Supplies	LABOR_M	TOTAL	246,061	181,098	17,136	16,052	1,265	6,330	17,320	6,851
922-Admin Exp Transferred	LABOR_M	TOTAL	(973,026)	(716,165)	(67,764)	(63,477)	(5,002)	(25,032)	(68,493)	(27,092)
923.0001 Outside Svcs Empl - Non-Assoc.	LABOR_M	TOTAL	375,253	276,193	26,134	24,480	1,929	9,654	26,415	10,448
923.0003 AEPSC Billed to Client Co.	LABOR_M	TOTAL	2,480,673	1,825,820	172,761	161,831	12,752	63,818	174,619	69,071
924-Property Insurance	RB_GUP_EPIS_D	TOTAL	40,027	23,600	2,872	3,704	400	715	5,399	3,437
925-Injuries & Damages	LABOR_M	TOTAL	592,185	435,859	41,241	38,632	3,044	15,235	41,685	16,489
926.0000 OPEB - Employee Benefits	LABOR_M	TOTAL	2,114,752	1,556,498	147,277	137,960	10,871	54,404	148,862	58,882
926.0003 Pension Plan	LABOR_M	TOTAL	648,112	477,022	45,138	42,281	3,332	16,673	45,622	18,046
927-Franchise Requirements	RSALE	TOTAL	-	-	-	-	-	-	-	-
9280000 Reg. Commission Exp.	RSALE	TOTAL	28,347	16,294	1,670	1,505	137	6,275	1,418	1,047
929 Duplicate Charges	LABOR_M	TOTAL	-	-	-	-	-	-	-	-
930.1 Gen. Advertising Exp.	LABOR_M	TOTAL	278,555	205,021	19,399	18,172	1,432	7,166	19,608	7,756
930.2000 Misc. General Expenses	LABOR_M	TOTAL	629,754	463,511	43,858	41,083	3,237	16,201	44,330	17,535
930.2007 ABD Exp.	RB_GUP_EPIS_D	TOTAL	71,052	41,714	5,098	6,576	711	1,269	9,583	6,101
931 Rent	LABOR_M	TOTAL	337,341	248,289	23,493	22,007	1,734	8,678	23,746	9,393
935 A&G - Maintenance	LABOR_M	TOTAL	1,258,111	925,992	87,618	82,075	6,467	32,366	88,561	35,030
Total		TOTAL	10,586,202	7,770,525	737,184	693,300	54,949	277,013	751,769	301,461
Total O&M Expense		TOTAL	51,372,743	38,600,018	3,607,390	3,245,782	241,665	1,330,730	3,097,630	1,249,528
Depreciation & Amortization Expense										
Distribution	RB_GUP_EPIS_D	TOTAL	9,294,156	5,456,512	666,911	860,154	92,963	166,002	1,253,515	798,099
General & Intangible	RB_GUP_EPIS_G	TOTAL	1,890,244	1,391,254	131,642	123,314	9,717	48,628	133,058	52,631
Total Depreciation & Amort Expense		TOTAL	11,184,400	6,847,766	798,553	983,468	102,680	214,630	1,386,573	850,730

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Taxes Other Than Income										
Payroll Taxes	LABOR_M	TOTAL	732,811	539,382	51,035	47,806	3,767	18,852	51,584	20,404
Commercial Activity Taxes	RSALE	TOTAL	1,314,864	755,803	77,467	69,789	6,349	291,085	65,783	48,587
Property Taxes	NP	TOTAL	8,960,269	5,394,655	641,051	804,654	85,244	167,124	1,150,403	717,159
Regulatory Fees	RSALE	TOTAL	816,882	469,556	48,128	43,358	3,944	180,841	40,869	30,185
Franchise Tax	RSALE	TOTAL	38,330	22,033	2,258	2,034	185	8,486	1,918	1,416
Miscellaneous Taxes	NP	TOTAL	(1,183)	(712)	(85)	(106)	(11)	(22)	(152)	(95)
Total Taxes Other Than Income		TOTAL	11,861,992	7,180,696	819,855	967,536	99,478	668,366	1,310,404	817,657
Total Operating Expense Before Income Tax		TOTAL	74,419,136	52,628,481	5,225,797	5,196,787	443,823	2,211,726	5,794,607	2,917,914
Gross Operating Income		TOTAL	23,972,790	3,996,686	739,293	147,322	43,289	18,920,709	(690,050)	815,544
Interest Expense Factor										
Interest Expense Synchronized		TOTAL	3,752,764	2,333,562	293,702	259,870	17,034	(3,504)	530,246	321,853
Net Operating Income Before Income Tax		TOTAL	20,220,026	1,663,124	445,591	(112,548)	26,255	18,924,212	(1,220,296)	493,690
Schedule M Income Adjustments										
Labor Related	LABOR_M	TOTAL	(3,357,600)	(2,471,255)	(233,833)	(219,040)	(17,260)	(86,378)	(236,348)	(93,487)
Rate Base Related	RATEBASE	TOTAL	(50,806)	(31,592)	(3,976)	(3,518)	(231)	47	(7,179)	(4,357)
Distribution Plant Related	RB_GUP_EPIS_D	TOTAL	(5,584,448)	(3,278,577)	(400,717)	(516,829)	(55,857)	(99,743)	(753,182)	(479,543)
General Plant Related	RB_GUP_EPIS_D	TOTAL	35,706	20,963	2,562	3,305	357	638	4,816	3,066
Total Schedule M Income Adjustments		TOTAL	(8,957,148)	(5,760,462)	(635,964)	(736,082)	(72,990)	(185,436)	(991,893)	(574,321)
State Tax Adjustments										
Illinois - Plant Related	RB_GUP_EPIS_D	TOTAL	1,932,755	1,134,702	138,687	178,872	19,332	34,521	260,673	165,968
Michigan - Plant Related	RB_GUP_EPIS_D	TOTAL	2,339,352	1,373,411	167,862	216,502	23,399	41,783	315,511	200,883
Ohio - Plant Related	RB_GUP_EPIS_D	TOTAL	678,014	398,056	48,652	62,749	6,782	12,110	91,446	58,222
West Virginia - Plant Related	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-	-	-	-
Illinois Taxable Income		TOTAL	13,195,633	(2,962,635)	(51,687)	(669,757)	(27,403)	18,773,297	(1,951,515)	85,337
Tax Factor (Tax Rate x Apportionment)										
Illinois Tax		TOTAL	7,694	(1,727)	(30)	(391)	(16)	10,946	(1,138)	50
Michigan Taxable Income		TOTAL	13,602,229	(2,723,926)	(22,511)	(632,128)	(23,337)	18,780,559	(1,896,677)	120,252
Tax Factor (Tax Rate x Apportionment)										
Michigan Tax		TOTAL	4,167	(834)	(7)	(194)	(7)	5,753	(581)	37
Ohio Municipal Taxable Income		TOTAL	11,940,692	(3,699,262)	(141,722)	(785,881)	(39,954)	18,750,887	(2,120,744)	(22,409)
Tax Factor (Tax Rate x Apportionment)										
Ohio Tax		TOTAL	42,049	(13,027)	(499)	(2,767)	(141)	66,030	(7,468)	(79)
West Virginia Taxable Income		TOTAL	11,262,878	(4,097,338)	(190,373)	(848,630)	(46,735)	18,738,777	(2,212,188)	(80,631)
Tax Factor (Tax Rate x Apportionment)										
West Virginia Tax		TOTAL	148,546	(54,040)	(2,511)	(11,193)	(616)	247,146	(29,177)	(1,063)

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Deferred State Income Tax (410.1 & 411.1)	RB_GUP_EPIS_D	TOTAL	19,054	11,187	1,367	1,763	191	340	2,570	1,636
Total State Income Tax		TOTAL	221,510	(58,442)	(1,680)	(12,781)	(590)	330,215	(35,794)	580
Federal Taxable Income		TOTAL	11,060,422	(4,027,709)	(187,326)	(834,086)	(45,955)	18,408,902	(2,173,825)	(79,575)
Tax Factor (Tax Rate x Apportionment)										
Gross Current FIT		TOTAL	3,871,148	(1,409,698)	(65,564)	(291,930)	(16,084)	6,443,116	(760,839)	(27,851)
Deferred FIT										
DFIT (410.1 & 411.1)	RB_GUP_EPIS_D	TOTAL	2,491,005	1,462,446	178,744	230,537	24,916	44,492	335,965	213,905
Deferred ITC										
Investment Tax Credit (411.4 & 411.5)	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-	-	-	-
Total Federal Income Tax		TOTAL	6,362,153	52,748	113,180	(61,393)	8,831	6,487,607	(424,874)	186,054
Total Income Tax		TOTAL	6,583,663	(5,694)	111,501	(74,173)	8,242	6,817,822	(460,667)	186,634
Total Expenses		TOTAL	81,002,798	52,622,787	5,337,298	5,122,613	452,065	9,029,549	5,333,940	3,104,549
Net Operating Income		TOTAL	17,389,127	4,002,380	627,792	221,496	35,047	12,102,888	(229,383)	628,909
Current Rate of Return			4.72%	4.15%	5.18%	2.16%	4.14%	-8367.52%	-1.05%	4.73%
<u>O&M Labor</u>										
Distribution	EXP_OM_DIST	TOTAL	3,867,413	1,703,825	227,411	405,114	52,256	93,225	1,013,243	372,341
Customer Accounts	EXP_OM_CUSTACCT	TOTAL	9,191,787	7,690,625	674,093	475,897	21,034	241,544	46,977	41,618
Customer Service	EXP_OM_CUSTSERV	TOTAL	2,159,217	1,806,583	158,349	111,792	4,941	56,740	11,036	9,776
Total		TOTAL	15,218,417	11,201,033	1,059,854	992,803	78,230	391,509	1,071,254	423,734
<u>Calculation of Proposed Revenues</u>										
Proposed Operating Income (NOI + Inc. Defic.)	RATEBASE	TOTAL	13,063,936	8,123,481	1,022,421	904,647	59,298	(12,196)	1,845,866	1,120,420
Proposed Rate of Return			8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%
Income Increase		TOTAL	(4,325,191)	4,121,100	394,628	683,151	24,251	(12,115,083)	2,075,248	491,511
Gross Revenue Conversion Factor										
Total Revenue Increase		TOTAL	(6,818,594)	6,496,848	622,125	1,076,977	38,231	(19,099,233)	3,271,596	774,859
Less: Miscellaneous Service Charge Increases	MISC_SERV_REV	TOTAL	68,531	62,220	4,495	660	2	3	929	221
Less: Pole Attachment Increases	RB_GUP_EPIS_D	TOTAL	196,630	115,440	14,109	18,198	1,967	3,512	26,520	16,886
Proposed Sales Revenue Increase		TOTAL	(7,083,755)	6,319,189	603,521	1,058,119	36,262	(19,102,748)	3,244,147	757,752
Total Proposed Sales Revenue		TOTAL	88,208,063	61,094,341	6,217,798	6,115,948	496,400	1,992,981	8,011,622	4,278,974

OHIO POWER COMPANY
CLASS COST-OF-SERVICE STUDY - CUSTOMER CHARGE
TWELVE MONTHS ENDING MAY 31, 2011

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: >Original__Updated__Revised
Work Paper Reference No(s): WP A-1e-p and all Schedule E3.2 Work Papers

Witness Responsible:
Daniel E. High

Label	Allocation Factor	Function	Total Retail	RS	GS-1	SEC	PRI	SUB/TRAN	OL	SL
Customer Bills				7,212,183	786,893	423,494	8,142	1,916		
Full Cost Customer Charge				8.47	7.90	14.44	60.97	1,040.18		

Source: WP A-1e-p and all Schedule E-3.2 Work Papers

Date Prepared: 2/28/2011

	Constant	Allocation Factor	Function	Total Retail	RS	GS-1	Demand Metered SEC	Demand Metered PRI
	21,424,375	DIST_CPD	TOTAL	21,424,375	10,892,143	461,029	6,817,024	3,218,677
ts	8,994,067	DIST_CPD	TOTAL	8,994,067	4,572,580	193,542	2,861,823	1,351,218
	243,177,626	DIST_CPD	TOTAL	243,177,626	123,631,405	5,232,913	77,376,711	36,533,627
	5,062,199	DIST_CPD	TOTAL	5,062,199	2,573,620	108,933	1,610,742	760,516
	325,702,514	DIST_POLES	TOTAL	325,702,514	186,642,287	7,769,243	99,697,980	30,225,110
	281,574,210	DIST_OHLINES	TOTAL	281,574,210	149,413,360	6,285,309	88,423,290	36,739,384
	52,235,350	DIST_UGLINES	TOTAL	52,235,350	28,904,196	1,208,845	16,181,739	5,761,666
	92,715,092	DIST_UGLINES	TOTAL	92,715,092	51,303,479	2,145,638	28,721,764	10,226,664
	319,156,554	DIST_TRANSF	TOTAL	319,156,554	204,764,522	8,403,131	93,603,933	10,184,213
	135,157,954	DIST_SERV	TOTAL	135,157,954	106,525,465	11,519,258	6,102,533	-
	70,138,185	DIST_METERS	TOTAL	70,138,185	39,848,665	6,371,020	16,971,615	2,493,786
	22,791,009	DIST_OL	TOTAL	22,791,009	-	-	-	-
nises	1,104	DIST_OL	TOTAL	1,104	-	-	-	-
	21,232,932	DIST_SL	TOTAL	21,232,932	-	-	-	-
	1,599,363,171		TOTAL	1,599,363,171	909,071,722	49,698,861	438,369,154	137,494,859
				- -	-	-	-	-
	1,599,363,171		TOTAL	1,599,363,171	909,071,722	49,698,861	438,369,154	137,494,859
				-	-	-	-	-
	108,008,426	LABOR_M	TOTAL	108,008,426	65,987,200	4,032,767	25,299,811	8,382,405
				-	-	-	-	-
	24,766,452	LABOR_M	TOTAL	24,766,452	15,130,938	924,718	5,801,275	1,922,095
				-	-	-	-	-
	132,774,878		TOTAL	132,774,878	81,118,138	4,957,485	31,101,086	10,304,499
				-	-	-	-	-
	1,732,138,049		TOTAL	1,732,138,049	990,189,860	54,656,345	469,470,240	147,799,358
				-	-	-	-	-
ccount 302	635,949	LABOR_M	TOTAL	635,949	388,530	23,745	148,964	49,355
	1,732,773,998		TOTAL	1,732,773,998	990,578,390	54,680,090	469,619,204	147,848,713
				-	-	-	-	-
				-	-	-	-	-
				-	-	-	-	-
	(523,591,196)	RB_GUP_EPIS_D	TOTAL	(523,591,196)	(297,607,172)	(16,270,155)	(143,511,014)	(45,012,352)
	(70,835,311)	RB_GUP_EPIS_G	TOTAL	(70,835,311)	(43,276,474)	(2,644,815)	(16,592,409)	(5,497,444)
	(594,426,507)		TOTAL	(594,426,507)	(340,883,646)	(18,914,969)	(160,103,422)	(50,509,795)
				-	-	-	-	-
i. - Acct 302	(532,386)	LABOR_M	TOTAL	(532,386)	(325,259)	(19,878)	(124,706)	(41,318)
	1,137,815,105		TOTAL	1,137,815,105	649,369,486	35,745,243	309,391,076	97,297,600
				-	-	-	-	-
				-	-	-	-	-
		RSALE	TOTAL					

	Constant	Allocation Factor	Function	Total Retail	RS	GS-1	Demand Metered SEC	Demand Metered PRI
	(26,468,865)	CUST_DEP	TOTAL	(26,468,865)	(16,034,032)	(807,800)	(4,982,051)	(919,359)
	-	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-
	68,420,174	LABOR_M	TOTAL	68,420,174	41,800,958	2,554,640	16,026,689	5,310,008
	44,156,926	RB_GUP_EPIS_D	TOTAL	44,156,926	25,098,623	1,372,139	12,102,964	3,796,105
	-	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-
	(151,532,561)	RB_GUP_EPIS_D	TOTAL	(151,532,561)	(86,130,510)	(4,708,746)	(41,533,531)	(13,027,028)
	(64,519,490)	RB_GUP_EPIS_D	TOTAL	(64,519,490)	(36,672,624)	(2,004,889)	(17,684,135)	(5,546,644)
	(1,111,778)	RB_GUP_EPIS_D	TOTAL	(1,111,778)	(631,930)	(34,548)	(304,727)	(95,578)
; (255)	(493,942)	RB_GUP_EPIS_D	TOTAL	(493,942)	(280,755)	(15,349)	(135,384)	(42,463)
	(131,549,536)		TOTAL	(131,549,536)	(72,850,270)	(3,644,553)	(36,510,176)	(10,524,959)
				-	-	-	-	-
	1,014,697,784		TOTAL	1,014,697,784	581,317,810	32,363,561	275,186,692	87,496,415
				-	-	-	-	-
				-	-	-	-	-
	324,382,905	RSALE	TOTAL	324,382,905	187,678,411	11,389,179	69,786,358	25,391,005
				-	-	-	-	-
				-	-	-	-	-
	1,162,931	FORF_DISC	TOTAL	1,162,931	40,060	296,114	722,999	110,888
	2,622,214	MISC_SERV_REV	TOTAL	2,622,214	2,465,267	79,660	68,768	507
	3,869,753	RB_GUP_EPIS_D	TOTAL	3,869,753	2,199,552	120,249	1,060,660	332,677
	7,126,827	RB_GUP_EPIS_D	TOTAL	7,126,827	4,050,860	221,460	1,953,391	612,683
	66,376	RB_GUP_EPIS_D	TOTAL	66,376	37,728	2,063	18,193	5,706
	2,328,677	RB_GUP_EPIS_D	TOTAL	2,328,677	1,323,611	72,362	638,267	200,193
	1,535,381	RB_GUP_EPIS_D	TOTAL	1,535,381	872,705	47,711	420,832	131,994
Dist/Meter	822,270	RB_GUP_EPIS_D	TOTAL	822,270	467,375	25,551	225,376	70,689
ɜs	19,534,429		TOTAL	19,534,429	11,457,158	865,170	5,108,485	1,465,337
				-	-	-	-	-
	343,917,334		TOTAL	343,917,334	199,135,569	12,254,349	74,894,843	26,856,342
				-	-	-	-	-
				-	-	-	-	-
				-	-	-	-	-
				-	-	-	-	-
	3,784,077	TOTOXEXP	TOTAL	3,784,077	2,123,813	124,398	1,042,343	336,578
	(28,918)	DIST_CPD	TOTAL	(28,918)	(14,702)	(622)	(9,201)	(4,344)
	1,723,487	DIST_CPD	TOTAL	1,723,487	876,220	37,088	548,396	258,927
	1,083,879	DIST_OHLINES	TOTAL	1,083,879	575,145	24,194	340,373	141,423
	678,346	DIST_UGLINES	TOTAL	678,346	375,360	15,698	210,142	74,823
	130,576	DIST_SL	TOTAL	130,576	-	-	-	-
	1,355,619	DIST_METERS	TOTAL	1,355,619	770,188	123,138	328,025	48,199
	104,068	DIST_PCUST	TOTAL	104,068	81,949	8,862	4,695	92
	20,515,866	RB_GUP_EPIS_D	TOTAL	20,515,866	11,661,137	637,513	5,623,190	1,763,718
	3,063,751	RB_GUP_EPIS_D	TOTAL	3,063,751	1,741,424	95,203	839,743	263,386
	32,410,751		TOTAL	32,410,751	18,190,535	1,065,472	8,927,704	2,882,802

	Constant	Allocation Factor	Function	Total Retail	RS	GS-1	Demand Metered SEC	Demand Metered PRI
	1,119,162	DIST_TRANSF	TOTAL	1,119,162	718,032	29,467	328,234	35,712
	291,693	DIST_SL	TOTAL	291,693	-	-	-	-
	447,298	DIST_METERS	TOTAL	447,298	254,130	40,630	108,234	15,904
	1,587,332	DIST_OL	TOTAL	1,587,332	-	-	-	-
	45,591,067		TOTAL	45,591,067	24,135,429	1,040,074	13,510,951	4,824,589
				-	-	-	-	-
				-	-	-	-	-
	1,238,237	TOTOX234	TOTAL	1,238,237	1,081,719	94,401	59,214	1,414
	4,971,654	CUST_902	TOTAL	4,971,654	4,119,497	445,467	394,262	9,820
tion Exp.	19,708,498	CUST_903	TOTAL	19,708,498	17,453,402	1,437,934	776,771	14,911
	40,680	UNCOLFAC	TOTAL	40,680	23,122	1,264	11,150	3,497
	10,237,616	RSALE	TOTAL	10,237,616	5,923,184	359,446	2,202,477	801,347
its	793,231	CUST_DEP	TOTAL	793,231	480,515	24,209	149,304	27,552
counts	73,309	TOTOX234	TOTAL	73,309	64,042	5,589	3,506	84
	37,063,225		TOTAL	37,063,225	29,145,482	2,368,308	3,596,684	858,625
				-	-	-	-	-
)				-	-	-	-	-
	1,336,240	EXP_OM_CUSTACCT	TOTAL	1,336,240	1,050,782	85,385	129,671	30,956
	1,601,457	EXP_OM_CUSTACCT	TOTAL	1,601,457	1,259,341	102,332	155,408	37,100
	368,172	EXP_OM_CUSTACCT	TOTAL	368,172	289,520	23,526	35,728	8,529
rvice	2,209	EXP_OM_CUSTACCT	TOTAL	2,209	1,737	141	214	51
	11,950	EXP_OM_CUSTACCT	TOTAL	11,950	9,397	764	1,160	277
	3,320,028		TOTAL	3,320,028	2,610,777	212,147	322,182	76,913
				-	-	-	-	-
				-	-	-	-	-
	8,139,609	LABOR_M	TOTAL	8,139,609	4,972,853	303,913	1,906,616	631,705
	814,457	LABOR_M	TOTAL	814,457	497,588	30,410	190,778	63,209
	(3,220,822)	LABOR_M	TOTAL	(3,220,822)	(1,967,745)	(120,258)	(754,443)	(249,964)
lon-Assoc.	1,242,127	LABOR_M	TOTAL	1,242,127	758,871	46,378	290,955	96,400
t Co.	8,211,298	LABOR_M	TOTAL	8,211,298	5,016,651	306,589	1,923,408	637,269
	256,771	RB_GUP_EPIS_D	TOTAL	256,771	145,948	7,979	70,378	22,074
	1,960,197	LABOR_M	TOTAL	1,960,197	1,197,572	73,189	459,155	152,129
nefits	7,000,062	LABOR_M	TOTAL	7,000,062	4,276,652	261,365	1,639,689	543,266
	2,145,321	LABOR_M	TOTAL	2,145,321	1,310,673	80,101	502,518	166,496
	-	RSALE	TOTAL	-	-	-	-	-
	96,496	RSALE	TOTAL	96,496	55,830	3,388	20,760	7,553
	-	LABOR_M	TOTAL	-	-	-	-	-
	922,046	LABOR_M	TOTAL	922,046	563,319	34,427	215,979	71,559
es	2,084,556	LABOR_M	TOTAL	2,084,556	1,273,549	77,832	488,285	161,780
	455,789	RB_GUP_EPIS_D	TOTAL	455,789	259,069	14,163	124,927	39,183
	1,116,635	LABOR_M	TOTAL	1,116,635	682,202	41,692	261,560	86,661
	4,164,484	LABOR_M	TOTAL	4,164,484	2,544,270	155,492	975,486	323,201
	35,389,026		TOTAL	35,389,026	21,587,303	1,316,660	8,316,051	2,752,521

	Constant	Allocation Factor	Function	Total Retail	RS	GS-1	Demand Metered SEC	Demand Metered PRI
				-	-	-	-	-
				-	-	-	-	-
	2,425,683	LABOR_M	TOTAL	2,425,683	1,481,959	90,569	568,190	188,254
	4,475,929	RSALE	TOTAL	4,475,929	2,589,641	157,151	962,932	350,352
	54,682,337	NP	TOTAL	54,682,337	31,208,094	1,717,883	14,869,048	4,676,032
	2,780,747	RSALE	TOTAL	2,780,747	1,608,858	97,633	598,238	217,662
	130,480	RSALE	TOTAL	130,480	75,492	4,581	28,071	10,213
	(7,222)	NP	TOTAL	(7,222)	(4,122)	(227)	(1,964)	(618)
	64,487,954		TOTAL	64,487,954	36,959,923	2,067,590	17,024,515	5,441,897
				-	-	-	-	-
me Tax	284,139,776		TOTAL	284,139,776	170,340,313	10,156,537	69,505,159	22,448,452
				-	-	-	-	-
	59,777,558		TOTAL	59,777,558	28,795,256	2,097,812	5,389,685	4,407,890
				-	-	-	-	-
	2.422200000%			-	-	-	-	-
	24,578,010		TOTAL	24,578,010	14,080,680	783,910	6,665,572	2,119,338
				-	-	-	-	-
e Tax	35,199,548		TOTAL	35,199,548	14,714,576	1,313,902	(1,275,887)	2,288,552
				-	-	-	-	-
				-	-	-	-	-
	(11,114,024)	LABOR_M	TOTAL	(11,114,024)	(6,790,057)	(414,970)	(2,603,340)	(862,546)
	(332,743)	RATEBASE	TOTAL	(332,743)	(190,628)	(10,613)	(90,240)	(28,692)
	(35,823,515)	RB_GUP_EPIS_D	TOTAL	(35,823,515)	(20,361,945)	(1,113,185)	(9,818,861)	(3,079,694)
	229,051	RB_GUP_EPIS_D	TOTAL	229,051	130,192	7,118	62,781	19,691
ts	(47,041,231)		TOTAL	(47,041,231)	(27,212,437)	(1,531,651)	(12,449,661)	(3,951,241)
				-	-	-	-	-
				-	-	-	-	-
	12,398,373	RB_GUP_EPIS_D	TOTAL	12,398,373	7,047,186	385,269	3,398,268	1,065,870
	15,006,639	RB_GUP_EPIS_D	TOTAL	15,006,639	8,529,714	466,319	4,113,167	1,290,098
	4,349,375	RB_GUP_EPIS_D	TOTAL	4,349,375	2,472,168	135,153	1,192,119	373,909
	-	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-
				-	-	-	-	-
				-	-	-	-	-
	556,690		TOTAL	556,690	(5,450,675)	167,520	(10,327,280)	(596,819)
nt)	0.0583051%			-	-	-	-	-
	325		TOTAL	325	(3,178)	98	(6,021)	(348)
				-	-	-	-	-
				-	-	-	-	-
	3,164,956		TOTAL	3,164,956	(3,968,147)	248,570	(9,612,381)	(372,591)
nt)	0.0306333%			-	-	-	-	-
	970		TOTAL	970	(1,216)	76	(2,945)	(114)
				-	-			
	(7,492,308)		TOTAL	(7,492,308)	(10,025,694)	(82,596)	(12,533,429)	(1,288,780)
nt)	0.3521415%							

	Constant	Allocation Factor	Function	Total Retail	RS	GS-1	Demand Metered SEC	Demand Metered PRI
411.1)	122,230	RB_GUP_EPIS_D	TOTAL	122,230	69,475	3,798	33,502	10,508
				-	-	-	-	-
	(59,040)		TOTAL	(59,040)	(135,058)	809	(200,626)	(16,422)
				-	-	-	-	-
	(11,660,413)		TOTAL	(11,660,413)	(12,293,328)	(214,760)	(13,491,420)	(1,635,759)
nt)	35.00%			-	-	-	-	-
	(4,081,145)		TOTAL	(4,081,145)	(4,302,665)	(75,166)	(4,721,997)	(572,516)
				-	-	-	-	-
				-	-	-	-	-
	15,979,477	RB_GUP_EPIS_D	TOTAL	15,979,477	9,082,672	496,549	4,379,812	1,373,732
				-	-	-	-	-
				-	-	-	-	-
411.5)	-	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-
				-	-	-	-	-
	11,898,332		TOTAL	11,898,332	4,780,007	421,383	(342,185)	801,216
				-	-	-	-	-
	11,839,293		TOTAL	11,839,293	4,644,949	422,192	(542,811)	784,794
				-	-	-	-	-
	295,979,069		TOTAL	295,979,069	174,985,262	10,578,729	68,962,348	23,233,246
				-	-	-	-	-
	47,938,265		TOTAL	47,938,265	24,150,307	1,675,620	5,932,496	3,623,096
				-	-	-	-	-
				4.72%	4.15%	5.18%	2.16%	4.14%
				-	-	-	-	-
				-	-	-	-	-
				-	-	-	-	-
	36,255,538	EXP_OM_DIST	TOTAL	36,255,538	19,673,267	978,666	10,429,571	3,582,425
	11,433,318	EXP_OM_CUSTACCT	TOTAL	11,433,318	8,990,841	730,579	1,109,510	264,870
	2,685,769	EXP_OM_CUSTSERV	TOTAL	2,685,769	2,112,013	171,618	260,632	62,220
	50,374,625		TOTAL	50,374,625	30,776,122	1,880,864	11,799,714	3,909,514
				-	-	-	-	-
				-	-	-	-	-
nc. Defic.)	85,559,752	RATEBASE	TOTAL	85,559,752	49,016,967	2,728,909	23,203,860	7,377,735
				-	-	-	-	-
				8.43%	8.43%	8.43%	8.43%	8.43%
				-	-	-	-	-
	37,621,487		TOTAL	37,621,487	24,866,660	1,053,289	17,271,364	3,754,639
				-	-	-	-	-
	1.576484			-	-	-	-	-
				-	-	-	-	-
	59,309,669		TOTAL	59,309,669	39,201,890	1,660,494	27,228,028	5,919,128
				-	-	-	-	-
Increases	411,024	MISC_SERV_REV	TOTAL	411,024	386,423	12,486	10,779	79
	1,261,355	RB_GUP_EPIS_D	TOTAL	1,261,355	716,040	30,106	245,725	109,437

Constant	Allocation Factor	Function	Total Retail	RS	GS-1	Demand Metered SEC	Demand Metered PRI
		DISTPRI	202,418,648	102,765,024	4,288,077	64,322,561	30,705,217
		DISTSEC	91,393,484	61,917,563	2,492,116	26,219,373	-
		ENERGY	-	-	-	-	-
		CUSTOMER	88,208,063	61,094,341	6,217,798	6,115,948	496,400
382,020,195		TOTAL	382,020,195	225,776,928	12,997,991	96,657,882	31,201,617
			-	-	-	-	-
17.77%			17.77%	20.30%	14.13%	38.51%	22.88%
			-	-	-	-	-
			-	-	-	-	-

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Class and Schedule Revenue Summary
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Schedule E-4
Page 1 of 2
Witness Responsible: T. Zelina / A. Moore

			Proposed Annualized						
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total Exclusive of Fuel Costs (G)	Annualized Gas or Fuel Cost Revenue (H)	Proposed Revenue Total (I)
1	RS	Residential Service	7,207,281	7,741,217,506	$0.04367	$338,085,966	54.10%	-	$338,085,966
2	RS-TOD	Residential Time Of Day Service	4,902	9,354,030	$0.04010	$375,069	0.06%	-	$375,069
3	GS-1	General Service - Non-Demand Metered	778,125	378,423,775	$0.05029	$19,032,469	3.05%	-	$19,032,469
4	GS-1 TOD	GS-1 On-Peak Service	263	860,395	$0.03280	$28,218	0.00%	-	$28,218
5	GS-1 Unmetered	GS-1 Unmeterd Service	8,193	2,426,567	$0.05749	$139,440	0.02%	-	$139,440
6	GS-2	General Service - Low Load Factor - Secondary	339,818	2,724,183,486	$0.03508	$95,554,384	15.29%	-	$95,554,384
7	GS-2	General Service - Low Load Factor - Primary	4,069	405,842,942	$0.02984	$12,110,987	1.94%	-	$12,110,987
8	GS-2	General Service - Low Load Factor - Subtransmission	401	213,059,422	$0.01127	$2,402,072	0.38%	-	$2,402,072
9	GS-2	General Service - Low Load Factor - Transmission	58	76,223,333	$0.01061	$808,699	0.13%	-	$808,699
10	GS-2 ONPK	General Service - Energy Storage Provision	216	2,318,777	$0.02696	$62,514	0.01%	-	$62,514
11	GS-2 AF	General Service - Athletic Fields	4,468	8,028,112	$0.03454	$277,257	0.04%	-	$277,257
12	GS-TOD	General Service - Time-of-Day	8,926	107,572,995	$0.02727	$2,933,152	0.47%	-	$2,933,152
13	GS-3	General Service - Medium/High Load Factor - Secondary	61,852	2,785,279,656	$0.02259	$62,910,379	10.07%	-	$62,910,379
14	GS-3	General Service - Medium/High Load Factor - Primary	4,005	2,622,741,376	$0.01827	$47,921,899	7.67%	-	$47,921,899
15	GS-3	General Service - Medium/High Load Factor - Subtransmission	913	868,569,023	$0.01023	$8,887,728	1.42%	-	$8,887,728
16	GS-3	General Service - Medium/High Load Factor - Transmission	53	44,947,739	$0.00848	$381,242	0.06%	-	$381,242
17	GS-4	General Service - Large - Primary Voltage	48	259,140,848	$0.00888	$2,300,796	0.37%	-	$2,300,796
18	GS-4	General Service - Large - Subtransmission Voltage	337	2,293,255,639	$0.00129	$2,946,927	0.47%	-	$2,946,927
19	GS-4	General Service - Large - Transmission Voltage	71	2,792,860,624	$0.00076	$2,133,575	0.34%	-	$2,133,575
20	IRP-D	Interruptible Power - Discretionary - Subtransmission	12	21,696,725	$0.00583	$126,528	0.02%	-	$126,528
21	IRP-D	Interruptible Power - Discretionary - Transmission	59	3,018,199,162	$0.00075	$2,255,890	0.36%	-	$2,255,890
22	SBS	Standby Service - Transmission Voltage	12	101,700	$0.11558	$11,754	0.00%	-	$11,754
23	OL	Outdoor Lighting	1,020,315	59,258,630	$0.16007	$9,485,559	1.52%	-	$9,485,559
24	SL	Street Lighting	11,979	66,771,476	$0.08543	$5,704,464	0.91%	-	$5,704,454
25	EHG	Electric Heating General	5,989	23,402,333	$0.04273	$1,000,030	0.16%	-	$1,000,030
26	EHS	Electric Heating Schools	12	423,167	$0.03658	$15,480	0.00%	-	$15,480
27	SS	School Service	2,216	44,933,370	$0.03342	$1,501,453	0.24%	-	$1,501,453
28	FL PUMP-Q	Flood Pumps	312	515,359	$0.03567	$18,381	0.00%	-	$18,381
29		Proposed Distribution Retail Revenue	9,464,923	26,571,606,167	$0.02331	$619,412,502	99.11%	-	$619,412,502
30	PA	Pole Attachment Revenues				$2,325,956	0.37%		$2,325,956
31		Misc. Service Revenues				$3,213,632	0.51%		$3,213,632
32		Total Distribution Revenue				$624,952,090	100.00%	-	$624,952,090

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Class and Schedule Revenue Summary
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Schedule E-4
Page 2 of 2
Witness Responsible: T. Zelina / A. Moore

			Current Annualized							
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Chapter Fuel Costs (M=F-K)	Increase in Revenue Less Fuel Cost Revenue (N=F-K/K)	Total Revenue % Increase (O)
1	RS	Residential Service	7,207,281	7,741,217,506	$0.03680	$284,865,526	53.58%	$53,230,440	18.69%	18.69%
2	RS-TOD	Residential Time Of Day Service	4,902	9,354,030	$0.02971	$277,864	0.05%	$97,205	34.98%	34.98%
3	GS-1	General Service - Non-Demand Metered	778,125	378,423,775	$0.04302	$16,279,406	3.06%	$2,753,064	16.91%	16.91%
4	GS-1 TOD	GS-1 On-Peak Service	263	860,395	$0.01571	$13,513	0.00%	$14,705	108.82%	108.82%
5	GS-1 Unmetered	GS-1 Unmeterd Service	8,193	2,425,567	$0.04057	$98,415	0.02%	$41,026	41.69%	41.69%
6	GS-2	General Service - Low Load Factor - Secondary	339,818	2,724,183,486	$0.02493	$67,909,822	12.77%	$27,644,561	40.71%	40.71%
7	GS-2	General Service - Low Load Factor - Primary	4,089	405,842,942	$0.02097	$8,512,389	1.60%	$3,598,598	42.27%	42.27%
8	GS-2	General Service - Low Load Factor - Subtransmission	401	213,059,422	$0.01689	$3,598,367	0.68%	-$1,196,295	-33.25%	-33.25%
9	GS-2	General Service - Low Load Factor - Transmission	58	76,223,333	$0.01729	$1,317,967	0.25%	-$509,069	-38.63%	-38.63%
10	GS-2 ONPK	General Service - Energy Storage Provision	216	2,318,777	$0.01449	$33,589	0.01%	$28,925	86.12%	86.12%
11	GS-2 AF	General Service - Athletic Fields	4,465	8,028,112	$0.03384	$271,645	0.05%	$5,611	2.07%	2.07%
12	GS-TOD	General Service - Time-of-Day	8,926	107,572,995	$0.02154	$2,317,424	0.44%	$615,728	26.57%	26.57%
13	GS-3	General Service - Medium/High Load Factor - Secondary	61,852	2,785,279,656	$0.01918	$53,408,150	10.05%	$9,502,229	17.79%	17.79%
14	GS-3	General Service - Medium/High Load Factor - Primary	4,006	2,622,741,376	$0.01569	$41,154,827	7.74%	$6,767,072	16.44%	16.44%
15	GS-3	General Service - Medium/High Load Factor - Subtransmission	913	868,669,023	$0.01515	$13,161,839	2.48%	-$4,274,111	-32.47%	-32.47%
16	GS-3	General Service - Medium/High Load Factor - Transmission	53	44,947,739	$0.01256	$564,449	0.11%	-$183,208	-32.46%	-32.46%
17	GS-4	General Service - Large - Primary Voltage	48	259,140,848	$0.00686	$1,776,454	0.33%	$524,342	29.52%	29.52%
18	GS-4	General Service - Large - Subtransmission Voltage	337	2,293,255,639	$0.00381	$8,725,845	1.64%	-$5,776,918	-66.23%	-66.23%
19	GS-4	General Service - Large - Transmission Voltage	71	2,792,860,624	$0.00173	$4,826,213	0.91%	-$2,692,639	-55.79%	-55.79%
20	IRP-D	Interruptible Power - Discretionary - Subtransmission	12	21,695,725	$0.00769	$166,841	0.03%	-$40,313	-24.16%	-24.16%
21	IRP-D	Interruptible Power - Discretionary - Transmission	59	3,018,199,182	$0.00186	$5,612,840	1.06%	-$3,356,950	-59.81%	-59.81%
22	SBS	Standby Service - Transmission Voltage	12	101,700	$0.45415	$46,187	0.01%	-$34,432	-74.55%	-74.55%
23	OL	Outdoor Lighting	1,020,315	59,258,630	$0.10400	$6,163,132	1.16%	$3,322,427	53.91%	53.91%
24	SL	Street Lighting	11,979	66,771,476	$0.07308	$4,879,697	0.92%	$824,757	16.90%	16.90%
25	EHG	Electric Heating General	5,969	23,402,333	$0.03075	$719,665	0.14%	$280,365	38.96%	38.96%
26	EHS	Electric Heating Schools	12	423,167	$0.01056	$4,467	0.00%	$11,012	246.50%	246.50%
27	SS	School Service	2,216	44,933,370	$0.02414	$1,084,558	0.20%	$416,894	38.44%	38.44%
28	FL PUMP-Q	Flood Pumps	312	515,359	$0.02916	$15,028	0.00%	$3,353	22.31%	22.31%
29		Distribution Retail Revenue	9,464,923	26,571,606,167	$0.01986	$527,796,120	99.27%	$91,616,382	17.36%	17.36%
30		Pole Attachment Revenues				$1,064,601	0.20%	$1,261,355	118.48%	
31		Misc. Service Revenues				$2,802,608	0.53%	$411,024	14.67%	
32		Total Distribution Revenue				$531,663,329	100.00%	$93,288,761	17.55%	

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1a - WP E-4.1c

Schedule E-4.1
Page 1 of 60
Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Test Year Proposed: Proposed Rate (E)	Test Year Proposed: Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	Test Year Proposed: % of Revenue to Total (G)	Annualized Gas or Fuel Cost Revenue (H)	Proposed Revenue Total (I)
1	RS	Residential Service							
2		Tariffs: 011 to 015, 017, 022 and 038							
3									
4		Distribution Charges							
5		Customer Charge:							
6		Bills	7,207,281		$8.40	$60,541,160	17.91%		
7		Energy Charge:							
8		First 800 kWh		4,620,925,075	$0.0214000	$98,887,797			
9		All Excess kWh		2,980,891,915	$0.0214000	$63,791,087			
10		Total Energy Charge				$162,678,884	48.12%		
11									
12		Storage Water Heater Energy Charge		139,400,516	$0.0214000	$2,983,171	0.88%		
13									
14		Load Management Water Heater Provision		0	$0.0214000	$0	0.00%		
15									
16		Universal Service Fund Rider							
17		First 833,000 kWh		7,741,217,506	$0.0024312	$18,820,448			
18		All Excess kWh		0	$0.0001731	$0			
19		Total Charge				$18,820,448	5.57%		
20									
21		Advanced Energy Fund Rider	7,207,281		$0.0000	$0	0.00%		
22									
23		KWH Tax Rider							
24		First 2,000 kWh		6,995,452,623	$0.00465	$32,528,855			
25		Next 13,000 kWh		743,278,873	$0.00419	$3,114,338			
26		Excess kWh		2,486,010	$0.00363	$9,024			
27		Total Charge				$35,652,217	10.55%		
28									
29		Energy Efficiency and Peak Demand Rider		7,741,217,506	$0.0028902	$22,373,667	6.62%		
30									
31		Economic Development Cost Recovery Rider			9.63500%	$21,794,680	6.45%		
32									
33		Enhanced Service Reliability Rider			4.58062%	$10,361,510	3.06%		
34									
35		gridSMART® Rider	7,207,281		$0.27	$1,945,966	0.58%		
36									
37		Monongahela Power Rider		7,601,816,990	$0.0001229	$934,263	0.28%		
38									
39		Total RS	7,207,281	7,741,217,506		$338,085,966	100.00%	$0	$338,085,966

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►*Original*__Updated__Revised
Work Paper Reference No(s): WP E-4.1a - WP E-4.1c

Schedule E-4.1
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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	RS	Residential Service								
2		Tariffs: 011 to 015, 017, 022 and 038								
3										
4		Distribution Charges								
5		Customer Charge:								
6		Bills	7,207,281		$3.82	$27,531,813	9.67%	$33,009,347	119.90%	119.90%
7		Energy Charge:								
8		First 800 kWh		4,620,925,075	$0.0235642	$108,888,403				
9		All Excess kWh		2,980,891,915	$0.0171224	$51,040,024				
10		Total Energy Charge				$159,928,426	56.14%	$2,750,457	1.72%	1.72%
11										
12		Storage Water Heater Energy Charge		139,400,516	$0.0003512	$48,957	0.02%	$2,934,214	5993.39%	5993.39%
13										
14		Load Management Water Heater Provision		0	$0.0003512	$0	0.00%	$0	0.00%	0.00%
15										
16		Universal Service Fund Rider								
17		First 833,000 kWh		7,741,217,506	$0.0015873	$12,287,635				
18		All Excess kWh		0	$0.0001681	$0				
19		Total Charge				$12,287,635	4.31%	$6,532,813	53.17%	53.17%
20										
21		Advanced Energy Fund Rider	7,207,281		$0.0895	$645,052	0.23%	-$645,052	-100.00%	-100.00%
22										
23		KWH Tax Rider								
24		First 2,000 kWh		6,995,452,623	$0.00465	$32,528,855				
25		Next 13,000 kWh		743,278,873	$0.00419	$3,114,338				
26		Excess kWh		2,486,010	$0.00363	$9,024				
27		Total Charge				$35,652,217	12.52%	$0	0.00%	0.00%
28										
29		Energy Efficiency and Peak Demand Rider		7,741,217,506	$0.0029405	$22,763,050	7.99%	-$389,383	-1.71%	-1.71%
30										
31		Economic Development Cost Recovery Rider			8.36693%	$15,688,763	5.51%	$6,105,916	38.92%	38.92%
32										
33		Enhanced Service Reliability Rider			5.49819%	$10,309,612	3.62%	$51,898	0.50%	0.50%
34										
35		gridSMART® Rider				$0	0.00%	$1,946,986	100.00%	100.00%
36										
37		Monongahela Power Rider				$0	0.00%	$934,263	100.00%	100.00%
38										
39		Total RS	7,207,281	7,741,217,506		$284,855,526	100.00%	$53,230,440	18.69%	18.69%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
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Work Paper Reference No(s): WP E-4.1d - WP E-4.1e

Schedule E-4.1
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Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Annualized Gas or Fuel Cost Revenue (H)	Proposed Revenue Total (I)
1	RS-TOD	Residential - Time of Day Service							
2	Tariffs: 030, 032, 034								
3									
4	Distribution Charges								
5	Customer Charge:								
6	Bills		4,902		$9.25	$45,344	12.09%		
7	Energy Charge:								
8	On-Peak			2,696,466	$0.0214000	$57,704			
9	Off-Peak			6,657,564	$0.0214000	$142,472			
10	Total					$200,176	53.37%		
11									
12	Universal Service Fund Rider								
13	First 833,000 kWh			9,354,030	$0.0024312	$22,742			
14	All Excess kWh			0	$0.0001731	$0			
15	Total Charge					$22,742	6.06%		
16									
17	Advanced Energy Fund Rider		4,902		$0.0000	$0	0.00%		
18									
19	KWH Tax Rider								
20	First 2,000 kWh			6,991,977	$0.00465	$32,513			
21	Next 13,000 kWh			2,339,937	$0.00419	$9,804			
22	Excess kWh			22,116	$0.00363	$80			
23	Total Charge					$42,397	11.30%		
24									
25	Energy Efficiency and Peak Demand Rider			9,354,030	$0.0028902	$27,035	7.21%		
26									
27	Economic Development Cost Recovery Rider				9.63500%	$23,656	6.31%		
28									
29	Enhanced Service Reliability Rider				4.58062%	$11,246	3.00%		
30									
31	gridSMART® Rider		4,902		$0.27	$1,324	0.35%		
32									
33	Monongahela Power Rider			9,354,030	$0.0001229	$1,150	0.31%		
34									
35	Total RS-ES		4,902	9,354,030		$375,069	100.00%	$0	$375,069

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
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Schedule E-4.1
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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M÷K)	Total Revenue % Increase (O)
1	RS-TOD	Residential - Time of Day Service								
2	Tariffs: 030, 032, 034									
3										
4	Distribution Charges									
5	Customer Charge:									
6	Bills		4,902		$7.64	$37,451	13.48%	$7,892	21.07%	21.07%
7	Energy Charge:									
8	On-Peak			2,696,466	$0.0479974	$129,423				
9	Off-Peak			6,657,564	$0.0003512	$2,338				
10	Total					$131,761	47.42%	$68,415	51.92%	51.92%
11										
12	Universal Service Fund Rider									
13	First 833,000 kWh			9,354,030	$0.0015873	$14,848				
14	All Excess kWh			0	$0.0001681	$0				
15	Total Charge					$14,848	5.34%	$7,894	53.17%	53.17%
16										
17	Advanced Energy Fund Rider		4,902		$0.0895	$439	0.16%	-$439	-100.00%	-100.00%
18										
19	KWH Tax Rider									
20	First 2,000 kWh			6,991,977	$0.00465	$32,513				
21	Next 13,000 kWh			2,339,937	$0.00419	$9,804				
22	Excess kWh			22,116	$0.00363	$80				
23	Total Charge					$42,397	15.26%	$0	0.00%	0.00%
24										
25	Energy Efficiency and Peak Demand Rider			9,354,030	$0.0029405	$27,506	9.90%	-$471	-1.71%	-1.71%
26										
27	Economic Development Cost Recovery Rider				8.36693%	$14,158	5.10%	$9,498	67.09%	67.09%
28										
29	Enhanced Service Reliability Rider				5.49819%	$9,304	3.35%	$1,943	20.88%	20.88%
30										
31	gridSMART® Rider					$0	0.00%	$1,324	100.00%	100.00%
32										
33	Monongahela Power Rider					$0	0.00%	$1,150	100.00%	100.00%
34										
35	Total RS-ES		4,902	9,354,030		$277,864	100.00%	$97,205	34.98%	34.98%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▸Original__Updated__Revised
Work Paper Reference No(s): WP-4.1f

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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Test Year Proposed: Proposed Rate (E)	Test Year Proposed: Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-1	General Service - Non-Demand Metered							
2		Tariffs: 211 and 830							
3									
4	Customer Charge:		778,125		$7.85	$6,108,281	32.09%		
5	Energy Charge			378,423,775	$0.0174700	$6,611,063	34.74%		
6									
7	Universal Service Fund Rider								
8	First 833,000 kWh			378,423,775	$0.0024312	$920,024			
9	All Excess kWh			0	$0.0001731	$0			
10	Total Charge					$920,024	4.83%		
11									
12	Advanced Energy Fund Rider		778,125		$0.0000	$0	0.00%		
13									
14	KWH Tax Rider								
15	First 2,000 kWh			351,460,014	$0.00465	$1,634,289			
16	Next 13,000 kWh			26,807,844	$0.00419	$112,325			
17	Excess kWh			155,917	$0.00363	$566			
18	Total Charge					$1,747,180	9.18%		
19									
20	Energy Efficiency and Peak Demand Rider			378,423,775	$0.0026773	$1,013,154	5.32%		
21									
22	Economic Development Cost Recovery Rider				9.63500%	$1,225,509	6.44%		
23									
24	Enhanced Service Reliability Rider				4.58062%	$582,625	3.06%		
25									
26	gridSMART® Rider		778,125		$1.00	$778,125	4.09%		
27									
28	Monongahela Power Rider			378,423,775	$0.0001229	$46,508	0.24%		
29									
30	Total GS-1		778,125	378,423,775		$19,032,469	100.00%	$0	$19,032,469

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
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Most Current Rates
(Electric and Gas Utilities)

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Work Paper Reference No(s): WP-4.11

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Witness Responsible: T. Zelina / A. Moore

					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-1	General Service - Non-Demand Metered								
2		Tariffs: 211 and 830								
3										
4		Customer Charge:	778,125		$13.17	$10,247,906	62.95%	-$4,139,625	-40.39%	-40.39%
5		Energy Charge		378,423,775	$0.0027999	$1,059,549	6.51%	$5,551,515	523.95%	523.95%
6										
7		Universal Service Fund Rider								
8		First 833,000 kWh		378,423,775	$0.0015873	$600,672				
9		All Excess kWh		0	$0.0001681	$0				
10		Total Charge				$600,672	3.69%	$319,352	53.17%	53.17%
11										
12		Advanced Energy Fund Rider	778,125		$0.0895	$69,642	0.43%	-$69,642	-100.00%	-100.00%
13										
14		KWH Tax Rider								
15		First 2,000 kWh		351,460,014	$0.00465	$1,634,289				
16		Next 13,000 kWh		26,807,844	$0.00419	$112,325				
17		Excess kWh		155,917	$0.00363	$566				
18		Total Charge				$1,747,180	10.73%	$0	0.00%	0.00%
19										
20		Energy Efficiency and Peak Demand Rider		378,423,775	$0.0026073	$986,664	6.06%	$26,490	2.68%	2.68%
21										
22		Economic Development Cost Recovery Rider			8.36693%	$946,087	5.81%	$279,422	29.53%	29.53%
23										
24		Enhanced Service Reliability Rider			5.49819%	$621,705	3.82%	-$39,081	-6.29%	-6.29%
25										
26		gridSMART® Rider				$0	0.00%	$778,125	100.00%	100.00%
27										
28		Monongahela Power Rider				$0	0.00%	$46,508	100.00%	100.00%
29										
30		Total GS-1	778,125	378,423,775		$16,279,406	100.00%	$2,753,064	16.91%	16.91%

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OHIO POWER COMPANY
Case No. 11-352-EL-AIR
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Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ➤Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1g

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-1	GS-1 On-Peak							
2	Tariff: 225								
3									
4	Distribution Charges								
5	Customer Charge:								
6	Bills		263		$8.70	$2,288	8.11%		
7	Energy Charge:								
8	On-Peak			240,886	$0.0174700	$4,208			
9	Off-Peak			619,509	$0.0174700	$10,823			
10	Total					$15,031	53.27%		
11									
12	Universal Service Fund Rider								
13	First 833,000 kWh			860,395	$0.0024312	$2,092			
14	All Excess kWh			0	$0.0001731	$0			
15	Total Charge					$2,092	7.41%		
16									
17	Advanced Energy Fund Rider		263		$0.0000	$0	0.00%		
18									
19	KWH Tax Rider								
20	First 2,000 kWh			279,158	$0.00465	$1,298			
21	Next 13,000 kWh			473,023	$0.00419	$1,982			
22	Excess kWh			108,214	$0.00363	$393			
23	Total Charge					$3,673	13.02%		
24									
25	Energy Efficiency and Peak Demand Rider			860,395	$0.0026773	$2,304	8.16%		
26									
27	Economic Development Cost Recovery Rider				9.63500%	$1,669	5.91%		
28									
29	Enhanced Service Reliability Rider				4.58062%	$793	2.81%		
30									
31	gridSMART® Rider		263		$1.00	$263	0.93%		
32									
33	Monongahela Power Rider			860,395	$0.0001229	$106	0.37%		
34									
35	Total GS-1 On-Peak Service		263	860,395		$28,218	100.00%	$0	$28,218

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OHIO POWER COMPANY
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Most Current Rates
(Electric and Gas Utilities)

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Work Paper Reference No(s): WP E-4.1g

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-1	GS-1 On-Peak								
2	Tariff: 225									
3										
4	Distribution Charges									
5	Customer Charge:									
6	Bills		263		$15.08	$3,966	29.35%	-$1,678	-42.31%	-42.31%
7	Energy Charge:									
8	On-Peak			240,886	$0.0052646	$1,268				
9	Off-Peak			619,509	$0.0003512	$218				
10	Total					$1,486	10.99%	$13,545	911.69%	911.69%
11										
12	Universal Service Fund Rider									
13	First 833,000 kWh			860,395	$0.0015873	$1,366				
14	All Excess kWh			0	$0.0001681	$0				
15	Total Charge					$1,366	10.11%	$726	53.17%	53.17%
16										
17	Advanced Energy Fund Rider		263		$0.0895	$24	0.17%	-$24	-100.00%	-100.00%
18										
19	KWH Tax Rider									
20	First 2,000 kWh			279,158	$0.00465	$1,298				
21	Next 13,000 kWh			473,023	$0.00419	$1,982				
22	Excess kWh			108,214	$0.00363	$393				
23	Total Charge					$3,673	27.18%	$0	0.00%	0.00%
24										
25	Energy Efficiency and Peak Demand Rider			860,395	$0.0026073	$2,243	16.60%	$60	2.68%	2.68%
26										
27	Economic Development Cost Recovery Rider				8.36693%	$456	3.38%	$1,213	266.83%	266.83%
28										
29	Enhanced Service Reliability Rider				5.49819%	$300	2.22%	$494	164.66%	164.66%
30										
31	gridSMART® Rider					$0	0.00%	$263	100.00%	100.00%
32										
33	Monongahela Power Rider					$0	0.00%	$106	100.00%	100.00%
34										
35	Total GS-1 On-Peak Service		263	860,395		$13,513	100.00%	$14,705	108.82%	108.82%

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OHIO POWER COMPANY
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Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1h

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-1	General Service - Non-Demand Unmetered							
2		Tariff: 213							
3									
4	Customer Charge:		8,193		$6.30	$51,616	37.02%		
5	Energy Charge			2,425,567	$0.0174700	$42,375	30.39%		
6									
7	Universal Service Fund Rider								
8	First 833,000 kWh			2,425,567	$0.0024312	$5,897			
9	All Excess kWh			0	$0.0001731	$0			
10	Total Charge					$5,897	4.23%		
11									
12	Advanced Energy Fund Rider		8,193		$0.0000	$0	0.00%		
13									
14	KWH Tax Rider								
15	First 2,000 kWh			2,268,056	$0.00465	$10,546			
16	Next 13,000 kWh			157,511	$0.00419	$660			
17	Excess kWh			0	$0.00363	$0			
18	Total Charge					$11,206	8.04%		
19									
20	Energy Efficiency and Peak Demand Rider			2,425,567	$0.0026773	$6,494	4.66%		
21									
22	Economic Development Cost Recovery Rider				9.63500%	$9,056	6.49%		
23									
24	Enhanced Service Reliability Rider				4.58062%	$4,305	3.09%		
25									
26	gridSMART® Rider		8,193		$1.00	$8,193	5.88%		
27									
28	Monongahela Power Rider			2,425,567	$0.0001229	$298	0.21%		
29									
30	Total GS-1 Unmetered		8,193	2,425,567		$139,440	100.00%	$0	$139,440

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OHIO POWER COMPANY
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Most Current Rates
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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-1	General Service - Non-Demand Unmetered								
2		Tariff: 213								
3										
4		Customer Charge:	8,193		$7.35	$60,219	61.19%	-$8,603	-14.29%	-14.29%
5		Energy Charge		2,425,567	$0.0027999	$6,791	6.90%	$35,583	523.95%	523.95%
6										
7		Universal Service Fund Rider								
8		First 833,000 kWh		2,425,567	$0.0015873	$3,850				
9		All Excess kWh		0	$0.0001681	$0				
10		Total Charge				$3,850	3.91%	$2,047	53.17%	53.17%
11										
12		Advanced Energy Fund Rider	8,193		$0.0895	$733	0.75%	-$733	-100.00%	-100.00%
13										
14		KWH Tax Rider								
15		First 2,000 kWh		2,268,056	$0.00465	$10,546				
16		Next 13,000 kWh		157,511	$0.00419	$660				
17		Excess kWh		0	$0.00363	$0				
18		Total Charge				$11,206	11.39%	$0	0.00%	0.00%
19										
20		Energy Efficiency and Peak Demand Rider		2,425,567	$0.0026073	$6,324	6.43%	$170	2.68%	2.68%
21										
22		Economic Development Cost Recovery Rider			8.36693%	$5,607	5.70%	$3,449	61.52%	61.52%
23										
24		Enhanced Service Reliability Rider			5.49819%	$3,684	3.74%	$621	16.86%	16.86%
25										
26		gridSMART® Rider				$0	0.00%	$8,193	100.00%	100.00%
27										
28		Monongahela Power Rider				$0	0.00%	$298	100.00%	100.00%
29										
30		Total GS-1 Unmetered	8,193	2,425,567		$98,415	100.00%	$41,026	41.69%	41.69%

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OHIO POWER COMPANY
Case No. 11-352-EL-AIR
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Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1i - WP E-4.1j

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-2	General Service - Low Load Factor (Proposed GS-2)							
2	Secondary Voltage								
3	Tariffs: 215, 218, 231, 840								
4									
5	Customer Charge		328,961		$12.85	$4,227,149	4.42%		
6	Demand Charge ($ per kW)			10,771,564	$4.90	$52,780,864	55.24%		
7	Excess Demand Charge ($ per KVA)			243,780	$2.04	$497,311	0.52%		
8	Energy Charge ($ per kWh)			2,721,618,861	$0.0000000	$0	0.00%		
9									
10	Minimum Energy Charge Calculation								
11	Customer Charge		8,480		$12.85	$108,968			
12	Demand Charge ($ per kW)			107,837	$4.90	$528,401			
13	Excess Demand Charge ($ per KVA)			33,032	$2.04	$67,385			
14	Energy ($ per kWh)			599,693	$0.0000000				
15	Total					$704,755	0.74%		
16									
17	Maximum Energy Charge Calculation								
18	Customer Charge		2,377		$12.85	$30,544			
19	Demand Charge ($ per kW)			61,408	$4.90	$300,899			
20	Excess Demand Charge ($ per KVA)			58,442	$2.04	$119,222			
21	Energy Charge			1,964,932	$0.0000000	$0			
22	Total					$450,665	0.47%		
23									
24	Alternate Feed Service Charges		1,950		$3.81	$7,430	0.01%		
25									
26	Universal Service Fund Rider								
27	First 833,000 kWh			2,724,508,516	$0.0024312	$6,623,825			
28	All Excess kWh			100,579	$0.0001731	$17			
29	Total Charge					$6,623,843	6.93%		
30									
31	Advanced Energy Fund Rider		339,818		$0.0000	$0	0.00%		
32									
33	KWH Tax Rider								
34	First 2,000 kWh			585,041,175	$0.00465	$2,720,441			
35	Next 13,000 kWh			1,150,065,387	$0.00419	$4,818,774			
36	Excess kWh			980,380,568	$0.00363	$3,558,781			
37	Total Charge					$11,097,997	11.61%		
38									
39	Energy Efficiency and Peak Demand Rider			2,724,609,095	$0.0026773	$7,294,596	7.63%		
40									
41	Economic Development Cost Recovery Rider				9.36500%	$5,494,256	5.75%		
42									
43	Enhanced Service Reliability Rider				4.58062%	$2,687,357	2.81%		
44									
45	gridSMART® Rider		339,818		$1.00	$339,818	0.36%		
46									
47	Monongahela Power Rider			2,724,609,095	$0.0012290	$3,348,545	3.50%		
48									
49	Total GS-2 Secondary		339,818	2,724,183,486		$95,554,384	100.00%	$0	$95,554,384

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Most Current Rates
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Witness Responsible: T. Zelina / A. Moore

					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-2	General Service - Low Load Factor								
2	Secondary Voltage									
3	Tariffs: 215, 218, 231, 840									
4										
5	Customer Charge		328,961		$22.91	$7,536,497	11.10%	-$3,309,348	-43.91%	-43.91%
6	Demand Charge ($ per kW)			10,771,132	$2.75	$29,620,613	43.62%	$23,160,051	78.19%	78.19%
7	Excess Demand Charge ($ per KVA)			243,780	$3.82	$931,240	1.37%	-$433,928	-46.60%	-46.60%
8	Energy Charge ($ per kWh)			2,721,618,861	$0.0003512	$955,833	1.41%	-$955,833	-100.00%	-100.00%
9										
10	Minimum Energy Charge Calculation									
11	Customer Charge		8,480		$22.91	$194,277				
12	Demand Charge ($ per kW)			107,837	$2.75	$296,552				
13	Excess Demand Charge ($ per KVA)			33,032	$3.82	$126,182				
14	Energy Charge ($ per kWh)			599,693	$0.0000000	$0				
15	Total					$617,011	0.91%	$87,744	14.22%	14.22%
16										
17	Maximum Energy Charge Calculation									
18	Customer Charge		2,377		$22.91	$54,457				
19	Energy Charge ($ per kWh)			1,964,932	$0.0553420	$108,743				
20	Total					$163,200	0.24%	$287,465	176.14%	176.14%
21										
22	Alternate Feed Service Charges		1,950		$3.07	$5,987	0.01%	$1,443	24.10%	24.10%
23										
24	Universal Service Fund Rider									
25	First 833,000 kWh			2,724,508,516	$0.0015873	$4,324,612				
26	All Excess kWh			100,579	$0.0001681	$17				
27	Total Charge					$4,324,629	6.37%	$2,299,213	53.17%	53.17%
28										
29	Advanced Energy Fund Rider		339,818		$0.0895	$30,414	0.04%	-$30,414	-100.00%	-100.00%
30										
31	KWH Tax Rider									
32	First 2,000 kWh			585,041,175	$0.00465	$2,720,441				
33	Next 13,000 kWh			1,150,065,387	$0.00419	$4,818,774				
34	Excess kWh			980,380,568	$0.00363	$3,558,781				
35	Total Charge					$11,097,997	16.34%	$0	0.00%	0.00%
36										
37	Energy Efficiency and Peak Demand Rider			2,724,609,095	$0.0026073	$7,103,873	10.46%	$190,723	2.68%	2.68%
38										
39	Economic Development Cost Recovery Rider				8.36693%	$3,332,580	4.91%	$2,161,676	64.86%	64.86%
40										
41	Enhanced Service Reliability Rider				5.49819%	$2,189,950	3.22%	$497,407	22.71%	22.71%
42										
43	gridSMART® Rider					$0	0.00%	$339,818	100.00%	100.00%
44										
45	Monongahela Power Rider					$0	0.00%	$3,348,545	100.00%	100.00%
46										
47	Total GS-2 Secondary		339,818	2,724,183,486		$67,909,822	100.00%	$27,644,561	40.71%	40.71%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1k - WP E-4.1l

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-2	General Service - Low Load Factor (Proposed GS-2)							
2	Primary Voltage								
3									
4	Customer Charge		3,861		$52.60	$203,074	1.68%		
5	Demand Charge ($ per kW)			1,720,198	$3.81	$6,553,954	54.12%		
6	Excess Demand Charge ($ per KVA)			86,439	$2.04	$176,336	1.46%		
7	Energy Charge ($ per kWh)			404,739,699	$0.0000000	$0	0.00%		
8									
9	Minimum Energy Charge ($ per kWh)								
10	Customer Charge		152		$52.60	$8,006			
11	Demand Charge ($ per kW)			33,288	$3.81	$126,827			
12	Excess Demand Charge ($ per KVA)			87,971	$2.04	$179,461			
13	Energy Charge ($ per kWh)			227,331	$0.0000000	$0			
14	Total					$314,294	2.60%		
15									
16	Maximum Energy Charge Calculation								
17	Customer Charge		76		$52.80	$4,017			
18	Demand Charge ($ per kW)			24,227	$3.81	$92,305			
19	Excess Demand Charge ($ per KVA)			65,686	$2.04	$133,999			
20	Energy Charge ($ per kWh)			875,912	$0.0000000	$0			
21	Total					$230,321	1.90%		
22									
23	Universal Service Fund Rider								
24	First 833,000 kWh			378,110,057	$0.0024312	$919,261			
25	All Excess kWh			27,741,423	$0.0001731	$4,802			
26	Total Charge					$924,063	7.63%		
27									
28	Advanced Energy Fund Rider		4,089		$0.0000	$0	0.00%		
29									
30	KWH Tax Rider								
31	First 2,000 kWh			8,164,462	$0.00465	$37,965			
32	Next 13,000 kWh			43,097,505	$0.00419	$180,579			
33	Excess kWh			354,492,110	$0.00363	$1,286,806			
34	Total Charge					$1,505,350	12.43%		
35									
36	Energy Efficiency and Peak Demand Rider			405,851,480	$0.0026773	$1,086,586	8.97%		
37									
38	Economic Development Cost Recovery Rider				9.63500%	$720,503	5.95%		
39									
40	Enhanced Service Reliability Rider				4.58062%	$342,538	2.83%		
41									
42	gridSMART® Rider		4,089		$1.00	$4,089	0.03%		
43									
44	Monongahela Power Rider			405,851,480	$0.0001229	$49,879	0.41%		
45									
46	Total GS-2 Primary		4,089	405,842,942		$12,110,987	100.00%	$0	$12,110,987

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
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Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1k - WP E-4.1

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-2	General Service - Low Load Factor								
2	Primary Voltage									
3										
4	Customer Charge		3,861		$95.47	$368,583	4.33%	-$165,509	-44.90%	-44.90%
5	Demand Charge ($ per kW)			1,713,822	$1.98	$3,393,368	39.86%	$3,160,587	93.14%	93.14%
6	Excess Demand Charge ($ per KVA)			86,439	$3.82	$330,197	3.88%	-$153,861	-46.60%	-46.60%
7	Energy Charge ($ per kWh)			404,739,699	$0.0003512	$142,145	1.67%	-$142,145	-100.00%	-100.00%
8										
9	Minimum Energy Charge ($ per kWh)									
10	Customer Charge		152		$95.47	$14,531				
11	Demand Charge ($ per kW)			33,288	$1.98	$65,910				
12	Excess Demand Charge ($ per KVA)			87,971	$3.82	$336,049				
13	Energy Charge ($ per kWh)			227,331	$0.0000000	$0				
14	Total					$416,491	4.89%	-$102,196	-24.54%	-24.54%
15										
16	Maximum Energy Charge Calculation									
17	Customer Charge		76		$95.47	$7,263				
18	Energy Charge ($ per kWh)			875,912	$0.0398758	$34,928				
19	Total					$42,190	0.50%	$188,131	445.91%	445.91%
20										
21	Universal Service Fund Rider									
22	First 833,000 kWh			378,110,057	$0.0015873	$600,174				
23	All Excess kWh			27,741,423	$0.0001681	$4,663				
24	Total Charge					$604,837	7.11%	$319,226	52.78%	52.78%
25										
26	Advanced Energy Fund Rider		4,089		$0.0895	$366	0.00%	-$366	-100.00%	-100.00%
27										
28	KWH Tax Rider									
29	First 2,000 kWh			8,164,462	$0.00465	$37,965				
30	Next 13,000 kWh			43,097,505	$0.00419	$180,579				
31	Excess kWh			354,492,110	$0.00363	$1,286,806				
32	Total Charge					$1,505,350	17.68%	$0	0.00%	0.00%
33										
34	Energy Efficiency and Peak Demand Rider			405,851,480	$0.0026073	$1,058,177	12.43%	$28,410	2.68%	2.68%
35										
36	Economic Development Cost Recovery Rider				8.36693%	$392,658	4.61%	$327,846	83.49%	83.49%
37										
38	Enhanced Service Reliability Rider				5.49819%	$258,029	3.03%	$84,509	32.75%	32.75%
39										
40	gridSMART® Rider					$0	0.00%	$4,089	100.00%	100.00%
41										
42	Monongahela Power Rider					$0	0.00%	$49,879	100.00%	100.00%
43										
44	Total GS-2 Primary		4,089	405,842,942		$8,512,389	100.00%	$3,598,598	42.27%	42.27%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1m - WP E-4.1n

Schedule E-4.1
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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Test Year Proposed: Proposed Rate (E)	Test Year Proposed: Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	Test Year Proposed: % of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I=F+H)
1	GS-2	General Service - Low Load Factor (Proposed GS-2)							
2	Subtransmission Voltage								
3									
4	Customer Charge		378		$806.10	$304,706	12.69%		
5	Demand Charge ($ per kW)			788,857	$0.00	$0	0.00%		
6	Excess Demand Charge ($ per KVA)			83,495	$2.04	$170,330	7.09%		
7	*Energy Charge ($ per kWh)*			213,035,416	$0.0000000	$0	0.00%		
8									
9	Minimum Energy Charge Calculation								
10	Customer Charge		23		$806.10	$18,540			
11	Demand Charge ($ per kW)			3,180	$0.00	$0			
12	Excess Demand Charge ($ per KVA)			308	$2.04	$628			
13	Energy Charge ($ per kWh)			24,006	$0.0000000	$0			
14	Total					$19,169	0.80%		
15									
16	Maximum Energy Charge Calculation								
17	Customer Charge		0		$806.10	$0			
18	Demand Charge ($ per kW)			0	$0.00	$0			
19	Excess Demand Charge ($ per KVA)			0	$2.04	$0			
20	Energy Charge ($ per kWh)			0	$0.0000000	$0			
21	Total					$0	0.00%		
22									
23	Universal Service Fund Rider								
24	First 833,000 kWh			162,324,636	$0.0024312	$394,644			
25	All Excess kWh			49,829,820	$0.0017310	$86,255			
26	Total Charge					$480,899	20.02%		
27									
28	Advanced Energy Fund Rider		401		$0.0000	$0	0.00%		
29									
30	KWH Tax Rider								
31	First 2,000 kWh			812,126	$0.00465	$3,776			
32	Next 13,000 kWh			4,898,791	$0.00419	$20,526			
33	Excess kWh			203,288,227	$0.00363	$737,936			
34	Total Charge					$762,239	31.73%		
35									
36	Energy Efficiency and Peak Demand Rider			212,154,456	$0.0026773	$568,001	23.65%		
37									
38	Economic Development Cost Recovery Rider				9.63500%	$47,617	1.98%		
39									
40	Enhanced Service Reliability Rider				4.58062%	$22,638	0.94%		
41									
42	gridSMART® Rider		401		$1.00	$401	0.02%		
43									
44	Monongahela Power Rider			212,154,456	$0.0001229	$26,074	1.09%		
45									
46	Total GS-2 Subtransmission		401	213,059,422		$2,402,072	100.00%	$0	$2,402,072

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1m - WP E-4.1r

Schedule E-4.1
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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-2	General Service - Low Load Factor								
2	Subtransmission Voltage									
3										
4	Customer Charge		378		$272.09	$102,850	2.86%	$201,856	196.26%	196.26%
5	Demand Charge ($ per kW)			788,857	$1.60	$1,262,171	35.08%	-$1,262,171	-100.00%	-100.00%
6	Excess Demand Charge ($ per KVA)			83,495	$3.82	$318,951	8.86%	-$148,621	-46.60%	-46.60%
7	Energy Charge ($ per kWh)			213,035,416	$0.0003512	$74,818	2.08%	-$74,818	-100.00%	-100.00%
8										
9	Minimum Energy Charge Calculation									
10	Customer Charge		23		$272.09	$6,258				
11	Demand Charge ($ per kW)			3,180	$1.60	$5,088				
12	Excess Demand Charge ($ per KVA)			308	$3.82	$1,177				
13	Energy Charge ($ per kWh)			24,006	$0.0000000	$0				
14	Total					$12,523	0.35%	$6,646	53.07%	53.07%
15										
16	Maximum Energy Charge Calculation									
17	Customer Charge		0		$272.09	$0				
18	Energy Charge ($ per kWh)			0	$0.0324291	$0				
19	Total					$0	0.00%	$0	0.00%	0.00%
20										
21	Universal Service Fund Rider									
22	First 833,000 kWh			162,324,636	$0.0015873	$257,658				
23	All Excess kWh			49,829,820	$0.0001681	$8,376				
24	Total Charge					$266,034	7.39%	$214,865	80.77%	80.77%
25										
26	Advanced Energy Fund Rider		401		$0.0895	$36	0.00%	-$36	-100.00%	-100.00%
27										
28	KWH Tax Rider									
29	First 2,000 kWh			812,126	$0.00465	$3,776				
30	Next 13,000 kWh			4,898,791	$0.00419	$20,526				
31	Excess kWh			203,288,227	$0.00363	$737,936				
32	Total Charge					$762,239	21.18%	$0	0.00%	0.00%
33										
34	Energy Efficiency and Peak Demand Rider			212,154,456	$0.0026073	$553,150	15.37%	$14,851	2.68%	2.68%
35										
36	Economic Development Cost Recovery Rider				8.36693%	$148,205	4.12%	-$100,588	-67.87%	-67.87%
37										
38	Enhanced Service Reliability Rider				5.49819%	$97,390	2.71%	-$74,753	-76.76%	-76.76%
39										
40	gridSMART® Rider					$0	0.00%	$401	100.00%	
41										
42	Monongahela Power Rider					$0	0.00%	$26,074	100.00%	
43										
44	Total GS-2 Subtransmission		401	213,059,422		$3,598,367	100.00%	-$1,196,295	-33.25%	

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1o - WP E-4.1q

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-2	General Service - Low Load Factor (Proposed GS-2)							
2	Transmission Voltage								
3									
4	Customer Charge		58		$806.10	$46,754	5.78%		
5	Demand Charge ($ per kW)			276,467	$0.00	$0	0.00%		
6	Excess Demand Charge ($ per KVA)			96,827	$2.04	$197,527	24.42%		
7	Energy Charge ($ per kWh)			76,223,333	$0.0000000	$0	0.00%		
8									
9	*Universal Service Fund Rider*								
10	First 833,000 kWh			43,349,135	$0.0024312	$105,390			
11	All Excess kWh			32,618,545	$0.0001731	$5,646			
12	Total Charge					$111,037	13.73%		
13									
14	Advanced Energy Fund Rider		58		$0.0000	$0	0.00%		
15									
16	KWH Tax Rider								
17	First 2,000 kWh			90,346	$0.00465	$420			
18	Next 13,000 kWh			587,253	$0.00419	$2,461			
19	Excess kWh			55,975,876	$0.00363	$203,192			
20	Total Charge					$206,072	25.48%		
21									
22	Energy Efficiency and Peak Demand Rider			75,967,680	$0.0026773	$203,388	25.14%		
23									
24	Economic Development Cost Recovery Rider				9.63500%	$23,536	2.91%		
25									
26	Enhanced Service Reliability Rider				4.58062%	$11,190	1.38%		
27									
28	gridSMART® Rider		58		$1.00	$58	0.01%		
29									
30	Monongahela Power Rider			75,967,680	$0.0001229	$9,336	1.15%		
31									
32	Total GS-2 Transmission		58	76,223,333		$808,899	100.00%	$0	$808,899

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original__Updated__Revised
Work Paper Reference No(s): WP E-4.1c - WP E-4.1c

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-2	General Service - Low Load Factor								
2	Transmission Voltage									
3										
4	Customer Charge		58		$534.63	$31,009	2.35%	$15,745	50.78%	50.78%
5	Demand Charge ($ per kW)			276,467	$1.12	$309,643	23.49%	-$309,643	-100.00%	-100.00%
6	Excess Demand Charge ($ per KVA)			96,827	$3.82	$369,879	28.06%	-$172,352	-46.60%	-46.60%
7	Energy Charge ($ per kWh)			76,223,333	$0.0003512	$26,770	2.03%	-$26,770	-100.00%	-100.00%
8										
9	Universal Service Fund Rider									
10	First 833,000 kWh			43,349,135	$0.0015873	$68,808				
11	All Excess kWh			32,618,545	$0.0001681	$5,483				
12	Total Charge					$74,291	5.64%	$36,745	49.46%	49.46%
13										
14	Advanced Energy Fund Rider		58		$0.0895	$5	0.00%	-$5	-100.00%	-100.00%
15										
16	KWH Tax Rider									
17	First 2,000 kWh			90,346	$0.00465	$420				
18	Next 13,000 kWh			587,253	$0.00419	$2,461				
19	Excess kWh			55,975,676	$0.00363	$203,192				
20	Total Charge					$206,072	15.64%	$0	0.00%	0.00%
21										
22	Energy Efficiency and Peak Demand Rider			75,967,680	$0.0026073	$198,071	15.03%	$5,318	2.68%	2.68%
23										
24	Economic Development Cost Recovery Rider				8.36693%	$61,689	4.68%	-$38,153	-61.85%	-61.85%
25										
26	Enhanced Service Reliability Rider				5.49819%	$40,538	3.08%	-$29,349	-72.40%	-72.40%
27										
28	gridSMART® Rider						0.00%	$58	100.00%	100.00%
29										
30	Monongahela Power Rider						0.00%	$9,336	100.00%	100.00%
31										
32	Total GS-2 Transmission		58	76,223,333		$1,317,967	100.00%	-$509,069	-38.63%	-38.63%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1r

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Test Year Proposed: Proposed Rate (E)	Test Year Proposed: Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	Test Year Proposed: % of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-2	GS-2 Energy Storage Provision							
2	Tariff 223								
3									
4	Distribution Charges								
5	Customer Charge:								
6	Bills		216		$7.95	$1,717	2.75%		
7	Energy Charge:								
8	On-Peak			504,725	$0.0146800	$7,409			
9	Off-Peak			1,814,052	$0.0146800	$26,630			
10	Total					$34,040	54.45%		
11									
12	Universal Service Fund Rider								
13	First 833,000 kWh			2,318,777	$0.0024312	$5,637			
14	All Excess kWh			0	$0.0001731	$0			
15	Total Charge					$5,637	9.02%		
16									
17	Advanced Energy Fund Rider		216		$0.0000	$0	0.00%		
18									
19	KWH Tax Rider								
20	First 2,000 kWh			328,109	$0.00465	$1,526			
21	Next 13,000 kWh			1,028,321	$0.00419	$4,309			
22	Excess kWh			962,347	$0.00363	$3,493			
23	Total Charge					$9,328	14.92%		
24									
25	Energy Efficiency and Peak Demand Rider			2,318,777	$0.0026773	$6,208	9.93%		
26									
27	Economic Development Cost Recovery Rider				9.63500%	$3,445	5.51%		
28									
29	Enhanced Service Reliability Rider				4.58062%	$1,638	2.62%		
30									
31	gridSMART® Rider		216		$1.00	$216	0.35%		
32									
33	Monongahela Power Rider			2,318,777	$0.0001229	$285	0.46%		
34									
35	Total GS-2 Energy Storage		216	2,318,777		$62,514	100.00%	$0	$62,514

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original__Updated__Revised
Work Paper Reference No(s): WP E-4.1

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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-2	GS-2 Energy Storage Provision								
2	Tariff 223									
3										
4	Distribution Charges									
5	Customer Charge:									
6	Bills		216		$2.96	$639	1.90%	$1,078	168.58%	168.58%
7	Energy Charge:									
8	On-Peak			504,725	$0.0227282	$11,471				
9	Off-Peak			1,814,052	$0.0003512	$637				
10	Total					$12,109	36.05%	$21,931	181.12%	181.12%
11										
12	Universal Service Fund Rider									
13	First 833,000 kWh			2,318,777	$0.0015873	$3,681				
14	All Excess kWh			0	$0.0001681	$0				
15	Total Charge					$3,681	10.96%	$1,957	53.17%	53.17%
16										
17	Advanced Energy Fund Rider		216		$0.0895	$19	0.06%	-$19	-100.00%	-100.00%
18										
19	KWH Tax Rider									
20	First 2,000 kWh			328,109	$0.00465	$1,526				
21	Next 13,000 kWh			1,028,321	$0.00419	$4,309				
22	Excess kWh			962,347	$0.00363	$3,493				
23	Total Charge					$9,328	27.77%	$0	0.00%	0.00%
24										
25	Energy Efficiency and Peak Demand Rider			2,318,777	$0.0026073	$6,046	18.00%	$162	2.68%	2.68%
26										
27	Economic Development Cost Recovery Rider				8.36693%	$1,067	3.18%	$2,379	223.00%	223.00%
28										
29	Enhanced Service Reliability Rider				5.49819%	$701	2.09%	$937	133.68%	133.68%
30										
31	gridSMART® Rider					$0	0.00%	$216	100.00%	100.00%
32										
33	Monongahela Power Rider					$0	0.00%	$285	100.00%	100.00%
34										
35	Total GS-2 Energy Storage		216	2,318,777		$33,589	100.00%	$28,925	86.12%	86.12%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1s

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-2	General Service - Low Load Factor - Athletic Fields							
2	Tariff: 214								
3									
4	Customer Charge:		4,465		$12.00	$53,580	19.33%		
5	Energy Charge			8,028,112	$0.0146800	$117,853	42.51%		
6									
7	Universal Service Fund Rider								
8	First 833,000 kWh			8,028,112	$0.0024312	$19,518			
9	All Excess kWh			0	$0.0001731	$0			
10	Total Charge					$19,518	7.04%		
11									
12	Advanced Energy Fund Rider		4,465		$0.0000	$0	0.00%		
13									
14	KWH Tax Rider								
15	First 2,000 kWh			3,661,107	$0.00465	$17,024			
16	Next 13,000 kWh			3,775,161	$0.00419	$15,818			
17	Excess kWh			591,844	$0.00363	$2,148			
18	Total Charge					$34,990	12.62%		
19									
20	Energy Efficiency and Peak Demand Rider			8,028,112	$0.0026773	$21,494	7.75%		
21									
22	Economic Development Cost Recovery Rider				9.63500%	$16,518	5.96%		
23									
24	Enhanced Service Reliability Rider				4.58062%	$7,853	2.83%		
25									
26	gridSMART® Rider		4,465		$1.00	$4,465	1.61%		
27									
28	Monongahela Power Rider			8,028,112	$0.0001229	$987	0.36%		
29									
30	Total GS-2 Athletic Fields		4,465	8,028,112		$277,257	100.00%	$0	$277,257

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-2	General Service - Low Load Factor - Athletic Fields								
2	Tariff: 214									
3										
4	Customer Charge:		4,465		$17.23	$76,932	28.32%	-$23,352	-30.35%	-30.35%
5	Energy Charge			8,028,112	$0.0125784	$100,981	37.17%	$16,872	16.71%	16.71%
6										
7	Universal Service Fund Rider									
8	First 833,000 kWh			8,028,112	$0.0015873	$12,743				
9	All Excess kWh			0	$0.0001681	$0				
10	Total Charge					$12,743	4.69%	$6,775	53.17%	53.17%
11										
12	Advanced Energy Fund Rider		4,465		$0.0895	$400	0.15%	-$400	-100.00%	-100.00%
13										
14	KWH Tax Rider									
15	First 2,000 kWh			3,661,107	$0.00465	$17,024				
16	Next 13,000 kWh			3,775,161	$0.00419	$15,818				
17	Excess kWh			591,844	$0.00363	$2,148				
18	Total Charge					$34,990	12.88%	$0	0.00%	0.00%
19										
20	Energy Efficiency and Peak Demand Rider			8,028,112	$0.0026073	$20,932	7.71%	$562	2.68%	2.68%
21										
22	Economic Development Cost Recovery Rider				8.36693%	$14,886	5.48%	$1,632	10.96%	10.96%
23										
24	Enhanced Service Reliability Rider				5.49819%	$9,782	3.60%	-$1,929	-19.72%	-19.72%
25										
26	gridSMART® Rider					$0	0.00%	$4,465	100.00%	100.00%
27										
28	Monongahela Power Rider					$0	0.00%	$987	100.00%	100.00%
29										
30	Total GS-2 Athletic Fields		4,465	8,028,112		$271,645	100.00%	$5,611	2.07%	2.07%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1t

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-TOD	General Service - Time-of-Day							
2									
3	Distribution Charges								
4	Customer Charge:								
5	Bills		8,926		$12.85	$114,699	3.91%		
6	Energy Charge:								
7	On-Peak			45,538,024	$0.0146800	$668,498			
8	Off-Peak			62,034,971	$0.0146800	$910,673			
9	Total					$1,579,172	53.84%		
10									
11	Universal Service Fund Rider								
12	First 833,000 kWh			107,572,995	$0.0024312	$261,531			
13	All Excess kWh			0	$0.0001731	$0			
14	Total Charge					$261,531	8.92%		
15									
16	Advanced Energy Fund Rider		8,926		$0.0000	$0	0.00%		
17									
18	KWH Tax Rider								
19	First 2,000 kWh			14,225,928	$0.00465	$66,151			
20	Next 13,000 kWh			38,934,639	$0.00419	$163,136			
21	Excess kWh			54,412,428	$0.00363	$197,517			
22	Total Charge					$426,804	14.55%		
23									
24	Energy Efficiency and Peak Demand Rider			107,572,995	$0.0026773	$288,005	9.82%		
25									
26	Economic Development Cost Recovery Rider				9.63500%	$163,204	5.56%		
27									
28	Enhanced Service Reliability Rider				4.58062%	$77,590	2.65%		
29									
30	gridSMART® Rider		8,926		$1.00	$8,926	0.30%		
31									
32	Monongahela Power Rider			107,572,995	$0.0001229	$13,221	0.45%		
33									
34	Total GS-TOD		8,926	107,572,995		$2,933,152	100.00%	$0	$2,933,152

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

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Work Paper Reference No(s): WP E-4.11

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-TOD	General Service - Time-of-Day								
2										
3	Distribution Charges									
4	Customer Charge:									
5	Bills		8,926		$23.15	$206,637	8.92%	-$91,938	-44.49%	-44.49%
6	Energy Charge:									
7	On-Peak			45,538,024	$0.0227282	$1,034,997				
8	Off-Peak			62,034,971	$0.0003512	$21,787				
9	Total					$1,056,784	45.60%	$522,388	49.43%	49.43%
10										
11	Universal Service Fund Rider									
12	First 833,000 kWh			107,572,995	$0.0015873	$170,751				
13	All Excess kWh			0	$0.0001681	$0				
14	Total Charge					$170,751	7.37%	$90,781	53.17%	53.17%
15										
16	Advanced Energy Fund Rider		8,926		$0.0895	$799	0.03%	-$799	-100.00%	-100.00%
17										
18	KWH Tax Rider									
19	First 2,000 kWh			14,225,928	$0.00465	$66,151				
20	Next 13,000 kWh			38,934,639	$0.00419	$163,136				
21	Excess kWh			54,412,428	$0.00363	$197,517				
22	Total Charge					$426,804	18.42%	$0	0.00%	0.00%
23										
24	Energy Efficiency and Peak Demand Rider			107,572,995	$0.0026073	$280,475	12.10%	$7,530	2.68%	2.68%
25										
26	Economic Development Cost Recovery Rider				8.36693%	$105,710	4.56%	$57,495	54.39%	54.39%
27										
28	Enhanced Service Reliability Rider				5.49819%	$69,465	3.00%	$8,124	11.70%	11.70%
29										
30	gridSMART® Rider					$0	0.00%	$8,926	100.00%	100.00%
31										
32	Monongahela Power Rider					$0	0.00%	$13,221	100.00%	100.00%
33										
30	Total GS-TOD		8,926	107,572,995		$2,317,424	100.00%	$615,728	26.57%	26.57%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1u - WP E-4.1v

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-3	General Service - Medium/High Load Factor (Proposed GS-2)							
2	Secondary Voltage								
3									
4	Distribution Charges								
5	Customer Charge		61,453		$12.85	$789,671	1.26%		
6	Demand Charge ($ per kW)			5,943,911	$4.90	$29,125,164	46.30%		
7	Excess Demand Charge (per KVA)			101,067	$2.04	$206,177	0.33%		
8	Energy Charge ($ per kWh)			2,784,572,118	$0.0000000	$0	0.00%		
9									
10	Minimum Energy Charge Calculation								
11	Customer Charge		386		$12.85	$4,960			
12	Demand Charge ($ per kW)			14,635	$4.90	$71,712			
13	Excess Demand Charge ($ per KVA)			8,369	$2.04	$17,073			
14	Energy Charge ($ per kWh)			666,026	$0.0000000	$0			
15	Total					$93,744	0.15%		
16									
17	Maximum Energy Charge Calculation								
18	Customer Charge		13		$12.85	$167			
19	Demand Charge ($ per kW)			417	$4.90	$2,043			
20	Excess Demand Charge ($ per KVA)			1,118	$2.04	$2,281			
21	Energy Charge ($ per kWh)			41,512	$0.0000000	$0			
22	Total					$4,491	0.01%		
23									
24	Alternate Feed Service Charges		6,000		$3.81	$22,860	0.04%		
25									
26	Universal Service Fund Rider								
27	First 833,000 kWh			2,761,584,389	$0.0024312	$6,713,964			
28	All Excess kWh			24,010,325	$0.0001731	$4,156			
29	Total Charge					$6,718,120	10.68%		
30									
31	Advanced Energy Fund Rider		61,852		$0.0000	$0	0.00%		
32									
33	KWH Tax Rider								
34	First 2,000 kWh			123,519,331	$0.00465	$574,365			
35	Next 13,000 kWh			625,128,172	$0.00419	$2,619,287			
36	Excess kWh			2,023,789,584	$0.00363	$7,346,356			
37	Total Charge					$10,540,008	16.75%		
38									
39	Energy Efficiency and Peak Demand Rider			2,784,613,630	$0.0038450	$10,706,839	17.02%		
40									
41	Economic Development Cost Recovery Rider				9.63500%	$2,913,827	4.63%		
42									
43	Enhanced Service Reliability Rider				4.58062%	$1,385,276	2.20%		
44									
45	gridSMART® Rider		61,852		$1.00	$61,852	0.10%		
46									
47	Monongahela Power Rider			2,785,594,714	$0.0001229	$342,350	0.54%		
48									
49	Total GS-3 Secondary		61,852	2,785,279,656		$62,910,379	100.00%	$0	$62,910,379

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
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Most Current Rates
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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	Current Annualized: % of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M÷K)	Total Revenue % Increase (O)
1	GS-3	General Service - Medium/High Load Factor								
2	Secondary Voltage									
3										
4	Distribution Charges									
5	Customer Charge		61,453		$22.91	$1,407,888	2.64%	-$618,217	-43.91%	-43.91%
6	Demand Charge ($ per kW)			5,937,098	$4.13	$24,520,215	45.91%	$4,604,949	18.78%	18.78%
7	Excess Demand Charge (per KVA)			101,067	$3.82	$386,076	0.72%	-$179,899	-46.60%	-46.60%
8	Energy Charge ($ per kWh)			2,784,572,118	$0.0003512	$977,942	1.83%	-$977,942	-100.00%	-100.00%
9										
10	Minimum Energy Charge Calculation									
11	Customer Charge		386		$22.91	$8,843				
12	Demand Charge ($ per kW)			14,635	$4.13	$60,443				
13	Excess Demand Charge ($ per KVA)			8,369	$3.82	$31,970				
14	Energy Charge ($ per kWh)			666,026	$0.0000000	$0				
15	Total					$101,255	0.19%	-$7,511	-7.42%	-7.42%
16										
17	Maximum Energy Charge Calculation									
18	Customer Charge		13		$22.91	$298				
19	Energy Charge ($ per kWh)			41,512	$0.0416897	$1,731				
20	Total					$2,028	0.00%	$2,463	121.40%	121.40%
21										
22	Alternate Feed Service Charges		6,000		$3.07	$18,420	0.03%	$4,440	24.10%	24.10%
23										
24	Universal Service Fund Rider									
25	First 833,000 kWh			2,761,584,389	$0.0015873	$4,383,463				
26	All Excess kWh			24,010,325	$0.0001681	$4,036				
27	Total Charge					$4,387,499	8.22%	$2,330,621	53.12%	53.12%
28										
29	Advanced Energy Fund Rider		61,852		$0.0895	$5,536	0.01%	-$5,536	-100.00%	-100.00%
30										
31	KWH Tax Rider									
32	First 2,000 kWh			123,519,331	$0.00465	$574,365				
33	Next 13,000 kWh			625,128,172	$0.00419	$2,619,287				
34	Excess kWh			2,023,789,584	$0.00363	$7,346,356				
35	Total Charge					$10,540,008	19.73%	$0	0.00%	0.00%
36										
37	Energy Efficiency and Peak Demand Rider			2,784,613,630	$0.0026073	$7,260,323	13.59%	$3,446,516	47.47%	47.47%
38										
39	Economic Development Cost Recovery Rider				8.36693%	$2,293,696	4.29%	$620,132	27.04%	27.04%
40										
41	Enhanced Service Reliability Rider				5.49819%	$1,507,264	2.82%	-$121,988	-8.09%	-8.09%
42										
43	gridSMART® Rider					$0	0.00%	$61,852	100.00%	100.00%
44										
45	Monongahela Power Rider					$0	0.00%	$342,350	100.00%	100.00%
46										
47	Total GS-3 Secondary		61,852	2,785,279,656		$53,408,150	100.00%	$9,502,229	17.79%	17.79%

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OHIO POWER COMPANY
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Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I=F+H)
1	GS-3	General Service - Medium/High Load Factor (Proposed GS-2)							
2	Primary Voltage								
3									
4	Distribution Charges								
5	Customer Charge		3,943		$52.60	$207,402	0.43%		
6	Demand Charge ($ per kW)			5,227,063	$3.81	$19,915,110	41.56%		
7	Excess Demand Charge (per KVA)			112,111	$2.04	$228,706	0.48%		
8	Energy Charge ($ per kWh)			2,620,948,363	$0.0000000	$0	0.00%		
9									
10	Minimum Energy Charge Calculation								
11	Customer Charge		60		$52.60	$3,156			
12	Demand Charge ($ per kW)			33,263	$3.81	$126,732			
13	Excess Demand Charge ($ per KVA)			2,288	$2.04	$4,668			
14	Energy Charge ($ per kWh)			1,757,287	$0.0000000	$0			
15	Total					$134,556	0.28%		
16									
17	Maximum Energy Charge Calculation								
18	Customer Charge		2		$52.60	$105			
19	Demand Charge ($ per kW)			332	$3.81	$1,265			
20	Excess Demand Charge ($ per KVA)			463	$2.04	$945			
21	Energy Charge ($ per kWh)			35,726	$0.0000000	$0			
22	Total					$2,315	0.00%		
23									
24	Alternate Feed Service Charges		62,700		$3.81	$245,523	0.51%		
25									
26	Universal Service Fund Rider								
27	First 833,000 kWh			1,777,896,569	$0.0024312	$4,322,422			
28	All Excess kWh			844,284,872	$0.0001731	$146,146			
29	*Total Charge*					$4,468,568	9.32%		
30									
31	Advanced Energy Fund Rider		4,005		$0.0000	$0	0.00%		
32									
33	KWH Tax Rider								
34	First 2,000 kWh			8,357,792	$0.00465	$38,864			
35	Next 13,000 kWh			53,040,762	$0.00419	$222,241			
36	Excess kWh			2,507,615,742	$0.00363	$9,102,645			
37	Total Charge					$9,363,750	19.54%		
38									
39	Energy Efficiency and Peak Demand Rider			2,622,181,441	$0.0038450	$10,082,288	21.04%		
40									
41	Economic Development Cost Recovery Rider				9.63500%	$1,997,683	4.17%		
42									
43	Enhanced Service Reliability Rider				4.58062%	$949,728	1.98%		
44									
45	gridSMART® Rider		4,005		$1.00	$4,005	0.01%		
46									
47	Monongahela Power Rider			2,622,181,441	$0.0001229	$322,266	0.67%		
48									
49	Total GS-3 Primary		4,005	2,622,741,376		$47,921,899	100.00%	$0	$47,921,899

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1w - WP E-4.1x

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-3	General Service - Medium/High Load Factor								
2	Primary Voltage									
3										
4	Distribution Charges									
5	Customer Charge		3,943		$95.47	$376,438	0.91%	-$169,036	-44.90%	-44.90%
6	Demand Charge ($ per kW)			5,215,105	$3.31	$17,261,998	41.94%	$2,653,112	15.37%	15.37%
7	Excess Demand Charge (per KVA)			112,111	$3.82	$428,264	1.04%	-$199,558	-46.60%	-46.60%
8	Energy Charge ($ per kWh)			2,620,948,363	$0.0003512	$920,477	2.24%	-$920,477	-100.00%	-100.00%
9										
10	Minimum Energy Charge Calculation									
11	Customer Charge		60		$95.47	$5,728				
12	Demand Charge ($ per kW)			33,263	$3.31	$110,101				
13	Excess Demand Charge ($ per KVA)			2,288	$3.82	$8,740				
14	Energy Charge ($ per kWh)			1,757,287	$0.0000000	$0				
15	Total					$124,569	0.30%	$9,987	8.02%	8.02%
16										
17	Maximum Energy Charge Calculation									
18	Customer Charge		2		$95.47	$191				
19	Energy Charge ($ per kWh)			35,726	$0.0334793	$1,196				
20	Total					$1,387	0.00%	$928	66.88%	66.88%
21										
22	Alternate Feed Service Charges		62,700		$3.07	$199,125	0.48%	$46,398	23.30%	23.30%
23										
24	Universal Service Fund Rider									
25	First 833,000 kWh			1,777,896,569	$0.0015873	$2,822,055				
26	All Excess kWh			844,284,872	$0.0001681	$141,924				
27	Total Charge					$2,963,980	7.20%	$1,504,688	50.76%	50.76%
28										
29	Advanced Energy Fund Rider		4,005		$0.0895	$358	0.00%	-$358	-100.00%	-100.00%
30										
31	KWH Tax Rider									
32	First 2,000 kWh			8,357,792	$0.00465	$38,864				
33	Next 13,000 kWh			53,040,762	$0.00419	$222,241				
34	Excess kWh			2,507,615,742	$0.00363	$9,102,645				
35	Total Charge					$9,363,750	22.75%	$0	0.00%	0.00%
36										
37	Energy Efficiency and Peak Demand Rider			2,622,181,441	$0.0026073	$6,836,814	16.61%	$3,245,474	47.47%	47.47%
38										
39	Economic Development Cost Recovery Rider				8.36693%	$1,615,843	3.93%	$381,840	23.63%	23.63%
40										
41	Enhanced Service Reliability Rider				5.49819%	$1,061,825	2.58%	-$112,097	-10.56%	-10.56%
42										
43	gridSMART® Rider					$0	0.00%	$4,005	100.00%	100.00%
44										
45	Monongahela Power Rider					$0	0.00%	$322,266	100.00%	100.00%
46										
47	Total GS-3 Primary		4,005	2,622,741,376		$41,154,827	100.00%	$6,767,072	16.44%	16.44%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶ Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1y - WP E-4.1z

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Test Year Proposed: Proposed Rate (E)	Test Year Proposed: Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	Test Year Proposed: % of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-3	General Service - Medium/High Load Factor (Proposed GS-2)							
2	Subtransmission Voltage								
3									
4	Distribution Charges								
5	Customer Charge		892		$806.10	$719,041	8.09%		
6	Demand Charge ($ per kW)			1,961,867	$0.00	$0	0.00%		
7	Excess Demand Charge (per KVA)			66,639	$2.04	$135,944	1.53%		
8	Energy Charge ($ per kWh)			868,133,352	$0.0000000	$0	0.00%		
9									
10	Minimum Energy Charge Calculation								
11	Customer Charge		21		$806.10	$16,928			
12	Demand Charge ($ per kW)			10,957	$0.00	$0			
13	Excess Demand Charge ($ per KVA)			3,256	$2.04	$6,642			
14	Energy Charge ($ per kWh)			435,671	$0.0000000	$0			
15	Total					$23,570	0.27%		
16									
17	Maximum Energy Charge Calculation								
18	Customer Charge		0		$806.10	$0			
19	Demand Charge ($ per kW)			0	$0.00	$0			
20	Excess Demand Charge ($ per KVA)			0	$2.04	$0			
21	Energy Charge ($ per kWh)			0	$0.0000000	$0			
22	Total					$0	0.00%		
23									
24	Universal Service Fund Rider								
25	First 833,000 kWh			505,663,652	$0.0024312	$1,229,369			
26	All Excess kWh			360,718,088	$0.0001731	$62,440			
27	Total Charge					$1,291,810	14.53%		
28									
29	Advanced Energy Fund Rider		913		$0.0000	$0	0.00%		
30									
31	KWH Tax Rider								
32	First 2,000 kWh			1,926,598	$0.00465	$8,959			
33	Next 13,000 kWh			12,342,136	$0.00419	$51,714			
34	Excess kWh			852,113,006	$0.00363	$3,093,170			
35	Total Charge					$3,153,842	35.49%		
36									
37	Energy Efficiency and Peak Demand Rider			866,381,740	$0.0038450	$3,331,238	37.48%		
38									
39	Economic Development Cost Recovery Rider				9.63500%	$84,649	0.95%		
40									
41	Enhanced Service Reliability Rider				4.58062%	$40,243	0.45%		
42									
43	gridSMART® Rider		913		$1.00	$913	0.01%		
44									
45	Monongahela Power Rider			866,381,740	$0.0001229	$106,478	1.20%		
46									
47	Total GS-3 Subtransmission		913	868,569,023		$8,887,728	100.00%	$0	$8,887,728

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1y - WP E-4.1z

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-3	General Service - Medium/High Load Factor								
2	Subtransmission Voltage									
3										
4	Distribution Charges									
5	Customer Charge		892		$272.09	$242,704	1.84%	$476,337	196.26%	196.26%
6	Demand Charge ($ per kW)			1,772,987	$2.93	$5,194,852	39.47%	-$5,194,852	-100.00%	-100.00%
7	Excess Demand Charge (per KVA)			66,639	$3.82	$254,561	1.93%	-$118,617	-46.60%	-46.60%
8	Energy Charge ($ per kWh)			868,133,352	$0.0003512	$304,888	2.32%	-$304,888	-100.00%	-100.00%
9										
10	Minimum Energy Charge Calculation									
11	Customer Charge		21		$272.09	$5,714				
12	Demand Charge ($ per kW)			10,957	$2.93	$32,104				
13	Excess Demand Charge ($ per KVA)			3,256	$3.82	$12,438				
14	Energy Charge ($ per kWh)			435,671	$0.0000000	$0				
15	Total					$50,256	0.38%	-$26,685	-53.10%	-53.10%
16										
17	Maximum Energy Charge Calculation									
18	Customer Charge		0		$272.09	$0				
19	Energy Charge ($ per kWh)			0	$0.0296605	$0				
20	Total					$0	0.00%	$0	0.00%	0.00%
21										
22	Universal Service Fund Rider									
23	First 833,000 kWh			505,663,652	$0.0015873	$802,640				
24	All Excess kWh			360,718,088	$0.0001681	$60,637				
25	Total Charge					$863,277	6.56%	$428,533	49.64%	49.64%
26										
27	Advanced Energy Fund Rider		913		$0.0895	$82	0.00%	-$82	-100.00%	-100.00%
28										
29	KWH Tax Rider									
30	First 2,000 kWh			1,926,598	$0.00465	$8,959				
31	Next 13,000 kWh			12,342,136	$0.00419	$51,714				
32	Excess kWh			852,113,006	$0.00363	$3,093,170				
33	Total Charge					$3,153,842	23.96%	$0	0.00%	0.00%
34										
35	Energy Efficiency and Peak Demand Rider			866,381,740	$0.0026073	$2,258,917	17.16%	$1,072,321	47.47%	47.47%
36										
37	Economic Development Cost Recovery Rider				8.36693%	$505,970	3.84%	-$421,321	-83.27%	-83.27%
38										
39	Enhanced Service Reliability Rider				5.49819%	$332,490	2.53%	-$292,247	-87.90%	-87.90%
40										
41	gridSMART® Rider					$0	0.00%	$913	100.00%	100.00%
42										
43	Monongahela Power Rider					$0	0.00%	$106,478	100.00%	100.00%
44										
45	Total GS-3 Subtransmission		913	866,569,023		$13,161,839	100.00%	-$4,274,111	-32.47%	-32.47%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1aa - WP E4.1ac

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-3	General Service - Medium/High Load Factor (Proposed GS-2)							
2	Transmission Voltage								
3									
4	Distribution Charges								
5	Customer Charge		52		$806.10	$41,917	10.99%		
6	Demand Charge ($ per kW)			87,426	$0.00	$0	0.00%		
7	Excess Demand Charge (per KVA)			10,886	$2.04	$22,207	5.83%		
8	Energy Charge ($ per kWh)			44,840,951	$0.0000000	$0	0.00%		
9									
10	Minimum Energy Charge Calculation								
11	Customer Charge		1		$806.10	$806			
12	Demand Charge ($ per kW)			2,136	$0.00	$0			
13	Excess Demand Charge ($ per KVA)			0	$2.04	$0			
14	Energy Charge ($ per kWh)			106,786	$0.0000000	$0			
15	Total					$806	0.21%		
16									
17	Maximum Energy Charge Calculation								
18	Customer Charge		0		$806.10	$0			
19	Demand Charge ($ per kW)			0	$0.00	$0			
20	Excess Demand Charge ($ per KVA)			0	$2.04	$0			
21	Energy Charge ($ per kWh)			0	$0.0000000	$0			
22	Total					$0	0.00%		
23									
24	Universal Service Fund Rider								
25	First 833,000 kWh			21,103,883	$0.0024312	$51,308			
26	All Excess kWh			23,843,856	$0.0001731	$4,127			
27	Total Charge					$55,435	14.54%		
28									
29	Advanced Energy Fund Rider		53		$0.0000	$0	0.00%		
30									
31	KWH Tax Rider								
32	First 2,000 kWh			76,507	$0.00465	$356			
33	Next 13,000 kWh			497,300	$0.00419	$2,084			
34	Excess kWh			19,505,541	$0.00363	$70,805			
35	Total Charge					$73,245	19.21%		
36									
37	Energy Efficiency and Peak Demand Rider			44,947,739	$0.0038450	$172,824	45.33%		
38									
39	Economic Development Cost Recovery Rider				9.63500%	$6,256	1.64%		
40									
41	Enhanced Service Reliability Rider				4.58062%	$2,974	0.78%		
42									
43	gridSMART® Rider		53		$1.00	$53	0.01%		
44									
45	Monongahela Power Rider			44,947,739	$0.0001229	$5,524	1.45%		
46									
47	Total GS-3 Transmission		53	44,947,739		$381,242	100.00%	$0	$381,242

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original__Updated__Revised
Work Paper Reference No(s): WP E-4.1aa - WP E4.1ac

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-3	General Service - Medium/High Load Factor								
2	Transmission Voltage									
3										
4	Distribution Charges									
5	Customer Charge		52		$534.63	$27,801	4.93%	$14,116	50.78%	50.78%
6	Demand Charge ($ per kW)			85,305	$2.40	$204,732	36.27%	-$204,732	-100.00%	-100.00%
7	Excess Demand Charge (per KVA)			10,886	$3.82	$41,586	7.37%	-$19,377	-46.60%	-46.60%
8	Energy Charge ($ per kWh)			44,840,951	$0.0003512	$15,748	2.79%	-$15,748	-100.00%	-100.00%
9										
10	Minimum Energy Charge Calculation									
11	Customer Charge		1		$534.63	$535				
12	Demand Charge ($ per kW)			2,136	$2.40	$5,126				
13	Excess Demand Charge ($ per KVA)			0	$3.82	$0				
14	Energy Charge ($ per kWh)			106,788	$0.0000000	$0				
15	Total					$5,661	1.00%	-$4,855	-85.76%	-85.76%
16										
17	Maximum Energy Charge Calculation									
18	Customer Charge		0		$534.63	$0				
19	Energy Charge ($ per kWh)			0	$0.0243142	$0				
20	Total					$0	0.00%	$0	0.00%	0.00%
21										
22	Universal Service Fund Rider									
23	First 833,000 kWh			21,103,883	$0.0015873	$33,498				
24	All Excess kWh			23,843,856	$0.0001681	$4,008				
25	Total Charge					$37,506	6.64%	$17,929	47.80%	47.80%
26										
27	Advanced Energy Fund Rider		53		$0.0895	$5	0.00%	-$5	-100.00%	-100.00%
28										
29	KWH Tax Rider									
30	First 2,000 kWh			76,507	$0.00465	$356				
31	Next 13,000 kWh			497,300	$0.00419	$2,084				
32	Excess kWh			19,505,541	$0.00363	$70,805				
33	Total Charge					$73,245	12.98%	$0	0.00%	0.00%
34										
35	Energy Efficiency and Peak Demand Rider			44,947,739	$0.0026073	$117,192	20.76%	$55,632	47.47%	47.47%
36										
37	Economic Development Cost Recovery Rider				8.36693%	$24,726	4.38%	-$18,470	-74.70%	-74.70%
38										
39	Enhanced Service Reliability Rider				5.49819%	$16,249	2.88%	-$13,274	-81.70%	-81.70%
40										
41	gridSMART® Rider					$0	0.00%	$53	100.00%	100.00%
42										
43	Monongahela Power Rider					$0	0.00%	$5,524	100.00%	100.00%
44										
45	Total GS-3 Transmission		53	44,947,739		$564,449	100.00%	-$183,208	-32.46%	-32.46%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1ad

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-4	General Service - Large (Proposed GS-2)							
2	Primary Voltage								
3									
4	Distribution Charges								
5	Customer Charge		48		$52.60	$2,525	0.11%		
6	Demand Charge ($ per kW)			457,344	$3.81	$1,742,481	75.73%		
7	Reactive Demand Charge ($ per KVAR)			45,348	$0.69	$31,290	1.36%		
8	Energy Charge ($ per kWh)			259,140,848	$0.0000000	$0	0.00%		
9									
10	Universal Service Fund Rider								
11	First 833,000 kWh			42,334,660	$0.0024312	$102,924			
12	All Excess kWh			216,806,188	$0.0001731	$37,529			
13	Total Charge					$140,453	6.10%		
14									
15	Advanced Energy Fund Rider		48		$0.0000	$0	0.00%		
16									
17	KWH Tax Rider								
18	First 2,000 kWh			0	$0.00465	$0			
19	Next 13,000 kWh			0	$0.00419	$0			
20	Excess kWh			0	$0.00363	$0			
21	Total Charge					$0	0.00%		
22									
23	Energy Efficiency and Peak Demand Rider			259,140,848	$0.0003845	$99,640	4.33%		
24									
25	Economic Development Cost Recovery Rider				9.63500%	$171,146	7.44%		
26									
27	Enhanced Service Reliability Rider				4.58062%	$81,365	3.54%		
28									
29	gridSMART® Rider		48		$1.00	$48	0.00%		
30									
31	Monongahela Power Rider			259,140,848	$0.0001229	$31,848	1.38%		
32									
33	Total GS-4 Primary		48	259,140,848		$2,300,796	100.00%	$0	$2,300,796

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1ad

Schedule E-4.1
Page 34 of 60
Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
					Current Annualized					
1	GS-4	General Service - Large								
2	Primary Voltage									
3										
4	Distribution Charges									
5	Customer Charge		48		$162.30	$7,790	0.44%	-$5,266	-67.59%	-67.59%
6	Demand Charge ($ per kW)			456,752	$2.77	$1,265,203	71.22%	$477,278	37.72%	37.72%
7	Reactive Demand Charge ($ per KVAR)			45,348	$0.48	$21,767	1.23%	$9,523	43.75%	43.75%
8	Energy Charge ($ per kWh)			259,140,848	$0.0003512	$91,010	5.12%	-$91,010	-100.00%	-100.00%
9										
10	Universal Service Fund Rider									
11	First 833,000 kWh			42,334,660	$0.0015873	$67,198				
12	All Excess kWh			216,806,188	$0.0001681	$36,445				
13	Total Charge					$103,643	5.83%	$36,810	35.52%	35.52%
14										
15	Advanced Energy Fund Rider		48		$0.0895	$4	0.00%	-$4	-100.00%	-100.00%
16										
17	KWH Tax Rider									
18	First 2,000 kWh			0	$0.00465	$0				
19	Next 13,000 kWh			0	$0.00419	$0				
20	Excess kWh			0	$0.00363	$0				
21	Total Charge					$0	0.00%	$0	0.00%	0.00%
22										
23	Energy Efficiency and Peak Demand Rider			259,140,848	$0.0003662	$94,897	5.34%	$4,742	5.00%	5.00%
24										
25	Economic Development Cost Recovery Rider				8.36693%	$115,946	6.53%	$55,200	47.61%	47.61%
26										
27	Enhanced Service Reliability Rider				5.49819%	$76,192	4.29%	$5,173	6.79%	6.79%
28										
29	gridSMART® Rider					$0	0.00%	$48	100.00%	100.00%
30										
31	Monongahela Power Rider					$0	0.00%	$31,848	100.00%	100.00%
32										
33	Total GS-4 Primary		48	259,140,848		$1,776,454	100.00%	$524,342	29.52%	29.52%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original__Updated__Revised
Work Paper Reference No(s): WP E-4.1ae - WP E-4.1af

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-4	General Service - Large (Proposed GS-2)							
2	Subtransmission Voltage								
3									
4	*Distribution Charges*								
5	Customer Charge		337		$806.10	$271,656	9.22%		
6	Demand Charge ($ per kW)			4,231,890	$0.00	$0	0.00%		
7	Energy Charge ($ per kWh)			2,293,121,263	$0.0000000	$0	0.00%		
8									
9	Reactive Demand Charge ($ per KVAR)			13,240	$0.69	$9,136	0.31%		
10									
11	Standby Service Backup Reservation Charge			159,000	$0.00	$0	0.00%		
12	Standby Service Backup Energy			134,376	$0.0000000	$0	0.00%		
13									
14	Universal Service Fund Rider								
15	First 833,000 kWh			293,384,250	$0.0024312	$713,276			
16	All Excess kWh			1,999,613,141	$0.0001731	$346,133			
17	Total Charge					$1,059,409	35.95%		
18									
19	Advanced Energy Fund Rider		337		$0.0000	$0	0.00%		
20									
21	KWH Tax Rider								
22	First 2,000 kWh			24,231	$0.00465	$113			
23	Next 13,000 kWh			157,514	$0.00419	$660			
24	Excess kWh			110,808,171	$0.00363	$402,234			
25	Total Charge					$403,006	13.68%		
26									
27	Energy Efficiency and Peak Demand Rider			2,292,997,391	$0.0003845	$881,657	29.92%		
28									
29	Economic Development Cost Recovery Rider				9.83500%	$27,054	0.92%		
30									
31	Enhanced Service Reliability Rider				4.58062%	$12,862	0.44%		
32									
33	gridSMART® Rider		337		$1.00	$337	0.01%		
34									
35	Monongahela Power Rider			2,292,997,391	$0.0001229	$281,809	9.56%		
36									
37	Total GS-4 Subtransmission		337	2,293,255,639		$2,946,927	100.00%	$0	$2,946,927

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1ae - WP E-4.1ai

Schedule E-4.1
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Witness Responsible: T. Zelina / A. Moore

					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-4	General Service - Large								
2	Subtransmission Voltage									
3										
4	Distribution Charges									
5	Customer Charge		337		$429.62	$144,782	1.66%	$126,874	87.63%	87.63%
6	Demand Charge ($ per kW)			4,231,890	$1.15	$4,866,674	55.77%	-$4,866,674	-100.00%	-100.00%
7	Energy Charge ($ per kWh)			2,293,121,263	$0.0003512	$805,344	9.23%	-$805,344	-100.00%	-100.00%
8										
9	Reactive Demand Charge ($ per KVAR)			13,240	$0.48	$6,355	0.07%	$2,780	43.75%	43.75%
10										
11	Standby Service Backup Reservation Charge			159,000	$0.28	$44,520	0.51%	-$44,520	-100.00%	-100.00%
12	Standby Service Backup Energy			134,376	$0.0003512	$47	0.00%	-$47	-100.00%	-100.00%
13										
14	Universal Service Fund Rider									
15	First 833,000 kWh			293,384,250	$0.0015873	$465,689				
16	All Excess kWh			1,999,613,141	$0.0001681	$336,135				
17	Total Charge					$801,824	9.19%	$257,585	32.12%	32.12%
18										
19	Advanced Energy Fund Rider		337		$0.0895	$30	0.00%	-$30	-100.00%	-100.00%
20										
21	KWH Tax Rider									
22	First 2,000 kWh			24,231	$0.00465	$113				
23	Next 13,000 kWh			157,514	$0.00419	$660				
24	Excess kWh			110,808,171	$0.00363	$402,234				
25	Total Charge					$403,006	4.62%	$0	0.00%	0.00%
26										
27	Energy Efficiency and Peak Demand Rider			2,292,997,391	$0.0003662	$839,696	9.62%	$41,962	5.00%	5.00%
28										
29	Economic Development Cost Recovery Rider				8.36693%	$490,948	5.63%	-$463,894	-94.49%	-94.49%
30										
31	Enhanced Service Reliability Rider				5.49819%	$322,619	3.70%	-$309,757	-96.01%	-96.01%
32										
33	gridSMART® Rider					$0	0.00%	$337	100.00%	100.00%
34										
35	Monongahela Power Rider					$0	0.00%	$281,809	100.00%	100.00%
36										
37	Total GS-4 Subtransmission		337	2,293,255,639		$8,725,845	100.00%	-$5,778,918	-66.23%	-66.23%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1ag

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	GS-4	General Service - Large (Proposed GS-2)							
2	Transmission Voltage								
3									
4	Distribution Charges								
5	Customer Charge		59		$806.10	$47,560	4.23%		
6	Demand Charge ($ per kW)			2,234,290	$0.00	$0	0.00%		
7	Reactive Demand Charge ($ per KVAR)			34,042	$0.69	$23,489	2.09%		
8	Energy Charge ($ per kWh)			1,359,231,693	$0.0000000	$0	0.00%		
9									
10	Universal Service Fund Rider								
11	First 833,000 kWh			52,341,747	$0.0024312	$127,253			
12	All Excess kWh			1,306,889,946	$0.0001731	$226,223			
13	Total Charge					$353,476	31.44%		
14									
15	Advanced Energy Fund Rider		59		$0.0000	$0	0.00%		
16									
17	KWH Tax Rider								
18	First 2,000 kWh			0	$0.00465	$0			
19	Next 13,000 kWh			0	$0.00419	$0			
20	Excess kWh			0	$0.00363	$0			
21	Total Charge					$0	0.00%		
22									
23	Energy Efficiency and Peak Demand Rider			1,359,231,693	$0.0003845	$522,625	46.48%		
24									
25	Economic Development Cost Recovery Rider				9.63500%	$6,846	0.61%		
26									
27	Enhanced Service Reliability Rider				4.58062%	$3,254	0.29%		
28									
29	gridSMART® Rider		59		$1.00	$59	0.01%		
30									
31	Monongahela Power Rider			1,359,231,693	$0.0001229	$167,050	14.86%		
32									
33	Total GS-4 Transmission		59	1,359,231,693		$1,124,358	100.00%	$0	$1,124,358

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original__Updated__Revised
Work Paper Reference No(s): WP E-4.1ag

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	GS-4	General Service - Large								
2	Transmission Voltage									
3										
4	Distribution Charges									
5	Customer Charge		59		$534.63	$31,543	1.27%	$16,017	50.78%	50.78%
6	Demand Charge ($ per kW)			2,234,290	$0.43	$960,745	38.54%	-$960,745	-100.00%	-100.00%
7	Reactive Demand Charge ($ per KVAR)			34,042	$0.48	$16,340	0.66%	$7,149	43.75%	43.75%
8	*Energy Charge ($ per kWh)*			1,359,231,693	$0.0003512	$477,362	19.15%	-$477,362	-100.00%	-100.00%
9										
10	Universal Service Fund Rider									
11	First 833,000 kWh			52,341,747	$0.0015873	$83,082				
12	All Excess kWh			1,306,889,946	$0.0001681	$219,688				
13	Total Charge					$302,770	12.15%	$50,706	16.75%	16.75%
14										
15	Advanced Energy Fund Rider		59		$0.0895	$5	0.00%	-$5	-100.00%	-100.00%
16										
17	KWH Tax Rider									
18	First 2,000 kWh			0	$0.00465	$0				
19	Next 13,000 kWh			0	$0.00419	$0				
20	Excess kWh			0	$0.00363	$0				
21	Total Charge					$0	0.00%	$0	0.00%	0.00%
22										
23	Energy Efficiency and Peak Demand Rider			1,359,231,693	$0.0003662	$497,751	19.97%	$24,874	5.00%	5.00%
24										
25	Economic Development Cost Recovery Rider				8.36693%	$124,332	4.99%	-$117,486	-94.49%	-94.49%
26										
27	*Enhanced Service Reliability Rider*				5.49819%	$81,703	3.28%	-$78,448	-96.02%	-96.02%
28										
29	gridSMART® Rider					$0	0.00%	$59	100.00%	100.00%
30										
31	Monongahela Power Rider					$0	0.00%	$167,050	100.00%	100.00%
32										
33	Total GS-4 Transmission		59	1,359,231,693		$2,492,551	100.00%	-$1,368,193	-54.89%	-54.89%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1ah

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	IRP-D	Interruptible Power - Discretionary (Proposed GS-2)							
2	Subtransmission Voltage								
3									
4	Distribution Charges								
5	Customer Charge		12		$806.10	$9,673	7.65%		
6	Demand Charge ($ per kW)			36,741	$0.00	$0	0.00%		
7	Energy Charge ($ per kWh)			21,695,725	$0.0000000	$0	0.00%		
8									
9	Universal Service Fund Rider								
10	First 833,000 kWh			9,670,465	$0.0024312	$23,511			
11	All Excess kWh			12,025,260	$0.0001731	$2,082			
12	Total Charge					$25,592	20.23%		
13									
14	Advanced Energy Fund Rider		12		$0.0000	$0	0.00%		
15									
16	KWH Tax Rider								
17	First 2,000 kWh			24,000	$0.00465	$112			
18	Next 13,000 kWh			156,000	$0.00419	$654			
19	Excess kWh			21,515,725	$0.00363	$78,102			
20	Total Charge					$78,867	62.33%		
21									
22	Energy Efficiency and Peak Demand Rider			21,695,725	$0.0003845	$8,342	6.59%		
23									
24	Economic Development Cost Recovery Rider				9.63600%	$932	0.74%		
25									
26	Enhanced Service Reliability Rider				4.58062%	$443	0.35%		
27									
28	gridSMART® Rider		12		$1.00	$12	0.01%		
29									
30	Monongahela Power Rider			21,695,725	$0.0001229	$2,666	2.11%		
31									
32	Total IRP-D Subtransmission		12	21,695,725		$126,528	100.00%	$0	$126,528

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
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Most Current Rates
(Electric and Gas Utilities)

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Work Paper Reference No(s): WP E-4.1ah

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	IRP-D	Interruptible Power - Discretionary								
2	Subtransmission Voltage									
3										
4	Distribution Charges									
5	Customer Charge		12		$429.62	$5,155	3.09%	$4,516	87.63%	87.63%
6	Demand Charge ($ per kW)			36,741	$1.15	$42,252	25.32%	-$42,252	-100.00%	-100.00%
7	Energy Charge ($ per kWh)			21,695,725	$0.0003512	$7,620	4.57%	-$7,620	-100.00%	-100.00%
8										
9	Universal Service Fund Rider									
10	First 833,000 kWh			9,670,465	$0.0015873	$15,350				
11	All Excess kWh			12,025,260	$0.0001681	$2,021				
12	Total Charge					$17,371	10.41%	$8,221	47.33%	47.33%
13										
14	Advanced Energy Fund Rider		12		$0.0895	$1	0.00%	-$1	-100.00%	-100.00%
15										
16	KWH Tax Rider									
17	First 2,000 kWh			24,000	$0.00465	$112				
18	Next 13,000 kWh			156,000	$0.00419	$654				
19	Excess kWh			21,515,725	$0.00363	$78,102				
20	Total Charge					$78,867	47.27%	$0	0.00%	0.00%
21										
22	Energy Efficiency and Peak Demand Rider			21,695,725	$0.0003662	$7,945	4.76%	$397	5.00%	5.00%
23										
24	Economic Development Cost Recovery Rider				8.36693%	$4,604	2.76%	-$3,672	-79.76%	-79.76%
25										
26	Enhanced Service Reliability Rider				5.49819%	$3,025	1.81%	-$2,582	-85.35%	-85.35%
27										
28	gridSMART® Rider					$0	0.00%	$12	100.00%	100.00%
29										
30	Monongahela Power Rider					$0	0.00%	$2,666	100.00%	100.00%
31										
32	Total IRP-D Subtransmission		12	21,695,725		$166,841	100.00%	-$40,313	-24.16%	-24.16%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1al - WP E-4.1al

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I=F+H)
1	IRP-D	Interruptible Power - Discretionary (Proposed GS-2)							
2	Transmission Voltage								
3									
4	Distribution Charges								
5	Customer Charge		59		$806.10	$47,560	2.11%		
6	Demand Charge ($ per kW)			5,431,410	$0.00	$0	0.00%		
7	Energy Charge ($ per kWh)			3,018,199,162	$0.0000000	$0	0.00%		
8									
9	Alternate Feed Service Charge					$3,594	0.16%		
10									
11	Universal Service Fund Rider								
12	First 833,000 kWh			53,064,016	$0.0024312	$129,009			
13	All Excess kWh			2,999,957,185	$0.0001731	$519,293			
14	Total Charge					$648,302	28.74%		
15									
16	Advanced Energy Fund Rider		59		$0.0000	$0	0.00%		
17									
18	KWH Tax Rider								
19	First 2,000 kWh			0	$0.00465	$0			
20	Next 13,000 kWh			0	$0.00419	$0			
21	Excess kWh			0	$0.00363	$0			
22	Total Charge					$0	0.00%		
23									
24	Energy Efficiency and Peak Demand Rider			3,053,021,201	$0.0003845	$1,173,887	52.04%		
25									
26	Economic Development Cost Recovery Rider				9.63500%	$4,929	0.22%		
27									
28	Enhanced Service Reliability Rider				4.58062%	$2,343	0.10%		
29									
30	gridSMART® Rider		59		$1.00	$59	0.00%		
31									
32	Monongahela Power Rider			3,053,021,201	$0.0001229	$375,216	16.63%		
33									
34	Total IRP-D Transmission		59	3,018,199,162		$2,255,890	100.00%	$0	$2,255,890

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶ Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1ai - WP E-4.1a

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	Current Annualized: % of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	IRP-D	Interruptible Power - Discretionary								
2	Transmission Voltage									
3										
4	Distribution Charges									
5	Customer Charge		59		$534.63	$31,543	0.56%	$16,017	50.78%	50.78%
6	Demand Charge ($ per kW)			5,431,410	$0.43	$2,335,506	41.61%	-$2,335,506	-100.00%	-100.00%
7	Energy Charge ($ per kWh)			3,018,199,162	$0.0003512	$1,059,992	18.89%	-$1,059,992	-100.00%	-100.00%
8										
9	Alternate Feed Service Charge					$3,594	0.06%	$0	0.00%	0.00%
10										
11	Universal Service Fund Rider									
12	First 833,000 kWh			53,064,016	$0.0015873	$84,229				
13	All Excess kWh			2,999,957,185	$0.0001681	$504,293				
14	Total Charge					$588,521	10.49%	$59,781	10.16%	10.16%
15										
16	Advanced Energy Fund Rider		59		$0.0895	$5	0.00%	-$5	-100.00%	-100.00%
17										
18	KWH Tax Rider									
19	First 2,000 kWh			0	$0.00465	$0				
20	Next 13,000 kWh			0	$0.00419	$0				
21	Excess kWh			0	$0.00363	$0				
22	Total Charge					$0	0.00%	$0	0.00%	0.00%
23										
24	Energy Efficiency and Peak Demand Rider			3,053,021,201	$0.0003662	$1,118,016	19.92%	$55,870	5.00%	5.00%
25										
26	Economic Development Cost Recovery Rider				8.36693%	$287,039	5.11%	-$282,110	-98.28%	-98.28%
27										
28	Enhanced Service Reliability Rider				5.49819%	$188,623	3.36%	-$186,280	-98.76%	-98.76%
29										
30	gridSMART® Rider					$0	0.00%	$59	100.00%	100.00%
31										
32	Monongahela Power Rider					$0	0.00%	$375,216	100.00%	100.00%
33										
34	Total IRP-D Transmission		59	3,018,199,162		$5,612,840	100.00%	-$3,356,950	-59.81%	-59.81%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original__Updated__Revised
Work Paper Reference No(s): WP E-4.1am

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Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	SBS	Standby Service (Proposed GS-2)							
2	Transmission Voltage								
3									
4	Distribution Charges								
5	Customer Charge		12		$806.10	$9,673	82.29%		
6	Backup Reservation Charge ($ per kW)			240,000	$0.00	$0	0.00%		
7	Backup Energy Charge ($ per kWh)			101,700	$0.0000000	$0	0.00%		
8									
9	Universal Service Fund Rider								
10	First 833,000 kWh			101,700	$0.0024312	$247			
11	*All Excess kWh*			*0*	*$0.0001731*	*$0*			
12	Total Charge					$247	2.10%		
13									
14	Advanced Energy Fund Rider		12		$0.0000	$0	0.00%		
15									
16	KWH Tax Rider								
17	First 2,000 kWh			18,000	$0.00465	$84			
18	Next 13,000 kWh			83,700	$0.00419	$351			
19	Excess kWh			0	$0.00363	$0			
20	Total Charge					$434	3.70%		
21									
22	Energy Efficiency and Peak Demand Rider			101,700	$0.0000000	$0	0.00%		
23									
24	Economic Development Cost Recovery Rider				9.63500%	$932	7.93%		
25									
26	Enhanced Service Reliability Rider				4.58062%	$443	3.77%		
27									
28	gridSMART® Rider		12		$1.00	$12	0.10%		
29									
30	Monongahela Power Rider			101,700	$0.0001229	$12	0.11%		
31									
32	Total SBS Transmission		12	101,700		$11,754	100.00%	$0	$11,754

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OHIO POWER COMPANY
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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	Current Annualized: % of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	SBS	Standby Service								
2	Transmission Voltage									
3										
4	Distribution Charges									
5	Customer Charge		12		$534.63	$6,416	13.89%	$3,258	50.78%	50.78%
6	Backup Reservation Charge ($ per kW)			240,000	$0.14	$33,600	72.75%	-$33,600	-100.00%	-100.00%
7	Backup Energy Charge ($ per kWh)			101,700	$0.0003512	$36	0.08%	-$36	-100.00%	-100.00%
8										
9	Universal Service Fund Rider									
10	First 833,000 kWh			101,700	$0.0015873	$161				
11	All Excess kWh			0	$0.0001681	$0				
12	Total Charge					$161	0.35%	$86	53.17%	53.17%
13										
14	Advanced Energy Fund Rider		12		$0.0895	$1	0.00%	-$1	-100.00%	-100.00%
15										
16	KWH Tax Rider									
17	First 2,000 kWh			18,000	$0.00465	$84				
18	Next 13,000 kWh			83,700	$0.00419	$351				
19	Excess kWh			0	$0.00363	$0				
20	Total Charge					$434	0.94%	$0	0.00%	0.00%
21										
22	Energy Efficiency and Peak Demand Rider			101,700	$0.0000000	$0	0.00%	$0	0.00%	0.00%
23										
24	Economic Development Cost Recovery Rider				8.33091%	$3,337	7.22%	-$2,405	-72.07%	-72.07%
25										
26	Enhanced Service Reliability Rider				5.49819%	$2,202	4.77%	-$1,759	-79.88%	-79.88%
27										
28	gridSMART® Rider					$0	0.00%	$12	100.00%	100.00%
29										
30	Monongahela Power Rider					$0	0.00%	$12	100.00%	100.00%
31										
32	Total SBS Transmission		12	101,700		$46,187	100.00%	-$34,432	-74.55%	-74.55%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1an - WP E-4.1ao

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	OL	Outdoor Lighting							
2									
3	Distribution Charges:								
4	9,000 lumen high pressure sodium		380,556		$7.25	$2,759,031	29.09%		
5	22,000 lumen high pressure sodium		69,117		$9.14	$631,729	6.66%		
6	22,000 lumen high pressure sodium floodlight		40,015		$9.11	$364,637	3.84%		
7	50,000 lumen high pressure sodium floodlight		108,680		$10.12	$1,099,842	11.59%		
8	17,000 lumen metal halide floodlight		7,065		$10.58	$74,748	0.79%		
9	29,000 lumen high metal halide floodlight		69,617		$10.62	$739,333	7.79%		
10									
11	2,500 lumen incandescent		1,149		$9.75	$11,203	0.12%		
12	4,000 lumen incandescent		122		$10.51	$1,282	0.01%		
13	7,000 lumen mercury		28,021		$7.66	$214,641	2.26%		
14	20,000 lumen mercury		2,242		$9.81	$21,994	0.23%		
15	20,000 lumen mercury floodlight		1,466		$12.38	$18,149	0.19%		
16	50,000 lumen mercury floodlight		1,165		$14.18	$16,520	0.17%		
17									
18	7,000 lumen mercury lam on 12 ft. post		5,162		$13.27	$68,500	0.72%		
19	9,000 lumen high pressure sodium lamp on 12 ft. pos		24,095		$13.77	$331,788	3.50%		
20									
21	400 W High Pressure Sodium (special)		614		$10.79	$6,625	0.07%		
22	1,000 W Metal Halide Floodlight (special)		1,003		$17.11	$17,161	0.18%		
23									
24	Facilities Charges:								
25	Poles and/or spans of secondary overhead circuit		239,395		$6.34	$1,517,765	16.00%		
26	Underground circuits in excess of 30 feet		40,831		$0.89	$36,340	0.38%		
27									
28	Universal Service Fund Rider								
29	First 833,000 kWh			59,258,630	$0.0024312	$144,070			
30	All Excess kWh			0	$0.0001731	$0			
31	Total Charge					$144,070	1.52%		
32									
33	Advanced Energy Fund Rider		0		$0.0000	$0	0.00%		
34									
35	KWH Tax Rider								
36	First 2,000 kWh			59,258,630	$0.00465	$275,553			
37	Next 13,000 kWh			0	$0.00419	$0			
38	Excess kWh			0	$0.00363	$0			
39	Total Charge					$275,553	2.90%		
40									
41	Energy Efficiency and Peak Demand Rider			59,258,630	$0.0000000	$0	0.00%		
42									
43	Economic Development Cost Recovery Rider				9.63500%	$764,170	8.06%		
44									
45	Enhanced Service Reliability Rider				4.58062%	$363,298	3.83%		
46									
47	gridSMART® Rider				$0.00	$0	0.00%		
48									
49	Monongahela Power Rider			59,258,630	$0.0001229	$7,283	0.08%		
50									
51	Total OL		1,020,315	59,258,630		$9,485,569	100.00%	$0	$9,485,559

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original__Updated__Revised
Work Paper Reference No(s): WP E-4.1an - WP E-4.1ao

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M÷K)	Total Revenue % Increase (O)
1	OL	Outdoor Lighting								
2										
3		Distribution Charges:								
4		9,000 lumen high pressure sodium	380,556		$4.76	$1,811,447	29.39%	$947,584	52.31%	52.31%
5		22,000 lumen high pressure sodium	69,117		$5.66	$391,202	6.35%	$240,527	61.48%	61.48%
6		22,000 lumen high pressure sodium floodlight	40,015		$5.64	$225,685	3.66%	$138,852	61.52%	61.52%
7		50,000 lumen high pressure sodium floodlight	108,680		$6.26	$680,337	11.04%	$419,505	61.66%	61.66%
8		17,000 lumen metal halide floodlight	7,065		$7.14	$50,444	0.82%	$24,304	48.18%	48.18%
9		29,000 lumen high metal halide floodlight	69,617		$6.57	$457,384	7.42%	$281,949	61.64%	61.64%
10										
11		2,500 lumen incandescent	1,149		$6.91	$7,940	0.13%	$3,263	41.10%	41.10%
12		4,000 lumen incandescent	122		$7.45	$909	0.01%	$373	41.07%	41.07%
13		7,000 lumen mercury	28,021		$5.43	$152,154	2.47%	$62,487	41.07%	41.07%
14		20,000 lumen mercury	2,242		$6.95	$15,582	0.25%	$6,412	41.15%	41.15%
15		20,000 lumen mercury floodlight	1,466		$8.77	$12,857	0.21%	$5,292	41.16%	41.16%
16		50,000 lumen mercury floodlight	1,165		$10.05	$11,708	0.19%	$4,811	41.09%	41.09%
17										
18		7,000 lumen mercury lam on 12 ft. post	5,162		$9.40	$48,523	0.79%	$19,977	41.17%	41.17%
19		9,000 lumen high pressure sodium lamp on 12 ft. pos	24,095		$8.93	$215,168	3.49%	$116,620	54.20%	54.20%
20										
21		400 W High Pressure Sodium (special)	614		$6.67	$4,095	0.07%	$2,530	61.77%	61.77%
22		1,000 W Metal Halide Floodlight (special)	1,003		$10.58	$10,612	0.17%	$6,550	61.72%	61.72%
23										
24		Facilities Charges:								
25		Poles and/or spans of secondary overhead circuit	239,395		$4.05	$969,550	15.73%	$548,215	56.54%	56.54%
26		Underground circuits in excess of 30 feet	40,831		$0.55	$22,457	0.36%	$13,883	61.82%	61.82%
27										
28		Universal Service Fund Rider								
29		First 833,000 kWh		59,258,630	$0.0016873	$94,061				
30		All Excess kWh		0	$0.0001681	$0				
31		Total Charge				$94,061	1.53%	$50,008	53.17%	53.17%
32										
33		Advanced Energy Fund Rider	0		$0.0896	$0	0.00%	$0	0.00%	0.00%
34										
35		KWH Tax Rider								
36		First 2,000 kWh		59,258,630	$0.00465	$275,553				
37		Next 13,000 kWh		0	$0.00419	$0				
38		Excess kWh		0	$0.00363	$0				
39		Total Charge				$275,553	4.47%	$0	0.00%	0.00%
40										
41		Energy Efficiency and Peak Demand Rider		69,258,630	$0.0000000	$0	0.00%	$0	0.00%	0.00%
42										
43		Economic Development Cost Recovery Rider			8.36693%	$425,714	6.91%	$338,456	79.50%	79.50%
44										
45		Enhanced Service Reliability Rider			5.49819%	$279,751	4.54%	$83,647	29.86%	29.86%
46										
47		gridSMART® Rider				$0	0.00%	$0	0.00%	0.00%
48										
49		Monongahela Power Rider				$0	0.00%	$7,283	100.00%	100.00%
50										
51		Total OL	1,020,315	59,258,630		$6,163,132	100.00%	$3,322,427	53.91%	53.91%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1ap

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	SL	Street Lighting							
2									
3	Distribution Charges:								
4	On Wood Pole								
5		7,000 lumen mercury vapor	93,493		$4.20	$392,671	6.88%		
6		11,000 lumen mercury vapor	9,048		$4.86	$43,973	0.77%		
7		20,000 lumen mercury vapor	11,602		$5.20	$60,332	1.06%		
8		50,000 lumen mercury vapor	12		$9.43	$113	0.00%		
9		9,000 lumen high pressure sodium	637,051		$3.82	$2,433,535	42.66%		
10		16,000 lumen high pressure sodium	51,660		$3.89	$200,957	3.52%		
11		22,000 lumen high pressure sodium	75,075		$4.46	$334,835	5.87%		
12		50,000 lumen high pressure sodium	6,660		$4.83	$32,168	0.56%		
13		9,000 lumen high pressure sodium (post 1988)	23,528		$10.55	$248,220	4.35%		
14		16,000 lumen high pressure sodium (post 1988)	1,706		$10.62	$18,118	0.32%		
15		22,000 lumen high pressure sodium (post 1988)	6,886		$11.20	$77,123	1.35%		
16		50,000 lumen high pressure sodium (post 1988)	968		$11.58	$11,209	0.20%		
17									
18	On Metal Pole:								
19		7,000 lumen mercury vapor	2,868		$8.14	$23,346	0.41%		
20		11,000 lumen mercury vapor	0		$9.56	$0	0.00%		
21		20,000 lumen mercury vapor	4,440		$10.26	$45,554	0.80%		
22		50,000 lumen mercury vapor	708		$14.98	$10,606	0.19%		
23		9,000 lumen high pressure sodium	3,994		$9.50	$37,943	0.67%		
24		16,000 lumen high pressure sodium	2,110		$9.55	$20,151	0.35%		
25		22,000 lumen high pressure sodium	16,813		$10.15	$170,652	2.99%		
26		50,000 lumen high pressure sodium	8,602		$10.51	$90,407	1.58%		
27		9,000 lumen high pressure sodium (post 1998)	60		$23.22	$1,393	0.02%		
28		22,000 lumen high pressure sodium (post 1998)	588		$23.77	$13,977	0.25%		
29		50,000 lumen high pressure sodium (post 1998)	396		$26.00	$10,296	0.18%		
30									
31	Multiple Lamps on Metal Pole:								
32		20,000 lumen mercury vapor	12		$7.97	$96	0.00%		
33		9,000 lumen high pressure sodium	3,550		$6.65	$23,608	0.41%		
34		16,000 lumen high pressure sodium	0		$6.71	$0	0.00%		
35		22,000 lumen high pressure sodium	934		$7.31	$6,828	0.12%		
36		50,000 lumen high pressure sodium	156		$7.67	$1,197	0.02%		
37									
38	Post Top Unit:								
39		7,000 lumen mercury vapor	0		$8.06	$0	0.00%		
40		9,000 lumen high pressure sodium	10,380		$6.77	$70,273	1.23%		
41		9,000 lumen high pressure sodium (post 1988)	19,140		$9.76	$186,806	3.27%		
42									
43	Special Lighting:								
44		9,000 lumen high pressure sodium	2,808		$11.07	$31,085	0.54%		
45		50,000 lumen high pressure sodium	36		$9.90	$356	0.01%		
46		16,000 lumen high pressure sodium (Tiffin)	180		$22.63	$4,073	0.07%		
47	Facilities Charges:								
48	Receptacle Charge		3,288		$2.11	$6,938	0.12%		

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Work Paper Reference No(s): WP E-4.1ap

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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Test Year Proposed: Proposed Rate (E)	Test Year Proposed: Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	SL	Street Lighting							
2									
3	Universal Service Fund Rider								
4	First 833,000 kWh			66,771,476	$0.0024312	$162,335			
5	All Excess kWh			0	$0.0001731	$0			
6	Total Charge					$162,335	2.85%		
7									
8	Advanced Energy Fund Rider		11,979		$0.0000	$0	0.00%		
9									
10	KWH Tax Rider								
11	First 2,000 kWh			15,023,582	$0.00465	$69,860			
12	Next 13,000 kWh			22,348,413	$0.00419	$93,640			
13	Excess kWh			29,399,481	$0.00363	$106,720			
14	Total Charge					$270,220	4.74%		
15									
16	Energy Efficiency and Peak Demand Rider			66,771,476	$0.0000000	$0	0.00%		
17									
18	Economic Development Cost Recovery Rider				9.63500%	$444,061	7.78%		
19									
20	Enhanced Service Reliability Rider				4.58062%	$210,796	3.70%		
21									
22	gridSMART® Rider				$0.00	$0	0.00%		
23									
24	Monongahela Power Rider			66,771,476	$0.0001229	$8,206	0.14%		
25									
26	Total SL		11,979	66,771,476		$5,704,454	100.00%	$0	$5,704,454

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Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	Current Annualized: % of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	SL	Street Lighting								
2										
3	Distribution Charges:									
4	On Wood Pole									
5		7,000 lumen mercury vapor	93,493		$3.67	$343,119	7.03%	$49,551	14.44%	14.44%
6		11,000 lumen mercury vapor	9,048		$4.24	$38,364	0.79%	$5,610	14.62%	14.62%
7		20,000 lumen mercury vapor	11,602		$4.54	$52,674	1.08%	$7,658	14.54%	14.54%
8		50,000 lumen mercury vapor	12		$8.23	$99	0.00%	$14	14.58%	14.58%
9		9,000 lumen high pressure sodium	637,051		$3.25	$2,070,416	42.43%	$363,119	17.54%	17.54%
10		16,000 lumen high pressure sodium	51,660		$3.31	$170,995	3.50%	$29,963	17.52%	17.52%
11		22,000 lumen high pressure sodium	75,075		$3.80	$285,285	5.85%	$49,550	17.37%	17.37%
12		50,000 lumen high pressure sodium	6,660		$4.11	$27,373	0.56%	$4,795	17.52%	17.52%
13		9,000 lumen high pressure sodium (post 1988)	23,528		$8.98	$211,281	4.33%	$36,939	17.48%	17.48%
14		16,000 lumen high pressure sodium (post 1988)	1,706		$9.04	$15,422	0.32%	$2,695	17.48%	17.48%
15		22,000 lumen high pressure sodium (post 1988)	6,886		$9.54	$65,692	1.35%	$11,431	17.40%	17.40%
16		50,000 lumen high pressure sodium (post 1988)	968		$9.86	$9,544	0.20%	$1,665	17.44%	17.44%
17										
18	On Metal Pole:									
19		7,000 lumen mercury vapor	2,868		$7.11	$20,391	0.42%	$2,954	14.49%	14.49%
20		11,000 lumen mercury vapor	0		$8.35	$0	0.00%	$0	0.00%	0.00%
21		20,000 lumen mercury vapor	4,440		$8.96	$39,782	0.82%	$5,772	14.51%	14.51%
22		50,000 lumen mercury vapor	708		$13.08	$9,261	0.19%	$1,345	14.53%	14.53%
23		9,000 lumen high pressure sodium	3,994		$8.09	$32,311	0.66%	$5,632	17.43%	17.43%
24		16,000 lumen high pressure sodium	2,110		$8.13	$17,154	0.35%	$2,996	17.47%	17.47%
25		22,000 lumen high pressure sodium	16,813		$8.64	$145,264	2.98%	$25,388	17.48%	17.48%
26		50,000 lumen high pressure sodium	8,602		$8.95	$76,988	1.58%	$13,419	17.43%	17.43%
27		9,000 lumen high pressure sodium (post 1998)	60		$23.22	$1,393	0.03%	$0	0.00%	0.00%
28		22,000 lumen high pressure sodium (post 1998)	588		$23.77	$13,977	0.29%	$0	0.00%	0.00%
29		50,000 lumen high pressure sodium (post 1998)	396		$24.09	$9,540	0.20%	$756	7.93%	7.93%
30										
31	Multiple Lamps on Metal Pole:									
32		20,000 lumen mercury vapor	12		$6.96	$84	0.00%	$12	14.51%	14.51%
33		9,000 lumen high pressure sodium	3,550		$5.66	$20,093	0.41%	$3,515	17.49%	17.49%
34		16,000 lumen high pressure sodium	0		$5.71	$0	0.00%	$0	0.00%	0.00%
35		22,000 lumen high pressure sodium	934		$6.22	$5,809	0.12%	$1,018	17.52%	17.52%
36		50,000 lumen high pressure sodium	156		$6.53	$1,019	0.02%	$178	17.46%	17.46%
37										
38	Post Top Unit:									
39		7,000 lumen mercury vapor	0		$7.04	$0	0.00%	$0	0.00%	0.00%
40		9,000 lumen high pressure sodium	10,380		$6.77	$70,273	1.44%	$0	0.00%	0.00%
41		9,000 lumen high pressure sodium (post 1988)	19,140		$8.31	$159,053	3.26%	$27,753	17.45%	17.45%
42										
43	Special Lighting:									
44		9,000 lumen high pressure sodium	2,808		$11.07	$31,085	0.64%	$0	0.00%	0.00%
45		50,000 lumen high pressure sodium	36		$8.43	$303	0.01%	$53	17.44%	17.44%
46		16,000 lumen high pressure sodium (Tiffin)	180		$22.63	$4,073	0.08%	$0	0.00%	0.00%
47										
48	Facilities Charges:									
49	Receptacle Charge		3,288		$1.84	$6,050	0.12%	$888	14.67%	14.67%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
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					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	SL	Street Lighting								
2										
3	Universal Service Fund Rider									
4	First 833,000 kWh			66,771,476	$0.0015873	$105,986				
5	All Excess kWh			0	$0.0001681	$0				
6	Total Charge					$105,986	2.17%	$56,348	53.17%	53.17%
7										
8	Advanced Energy Fund Rider		11,979		$0.0895	$1,072	0.02%	-$1,072	-100.00%	-100.00%
9										
10	KWH Tax Rider									
11	First 2,000 kWh			15,023,582	$0.00465	$69,860				
12	Next 13,000 kWh			22,348,413	$0.00419	$93,640				
13	Excess kWh			29,399,481	$0.00363	$106,720				
14	Total Charge					$270,220	5.54%	$0	0.00%	0.00%
15										
16	Energy Efficiency and Peak Demand Rider			66,771,476	$0.0000000	$0	0.00%	$0	0.00%	0.00%
17										
18	Economic Development Cost Recovery Rider				8.36693%	$330,843	6.78%	$113,219	34.22%	34.22%
19										
20	Enhanced Service Reliability Rider				5.49819%	$217,408	4.46%	-$6,612	-3.04%	-3.04%
21										
22	gridSMART® Rider					$0	0.00%	$0	0.00%	0.00%
23										
24	Monongahela Power Rider					$0	0.00%	$8,206	100.00%	100.00%
25										
26	Total SL		11,979	66,771,476		$4,879,697	100.00%	$824,757	16.90%	16.90%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
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Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▸Original__Updated__Revised
Work Paper Reference No(s): WP E-4.1aq - WP E-4.1ar

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	EHG	Electric Heating General (Proposed GS-2)							
2									
3	Distribution Charges:								
4	Customer Charge		5,989		$12.85	$76,959	7.70%		
5	Energy Charge ($ per kwh)			23,402,333	$0.0000000	$0	0.00%		
6	Demand Charge in excess of 30 KW ($ per kW)			121,877	$4.90	$597,197	59.72%		
7									
8	Universal Service Fund Rider								
9	First 833,000 kWh			23,402,333	$0.0024312	$56,896			
10	All Excess kWh			0	$0.0001731	$0			
11	Total Charge					$56,896	5.69%		
12									
13	Advanced Energy Fund Rider		5,989		$0.0000	$0	0.00%		
14									
15	KWH Tax Rider								
16	First 2,000 kWh			9,185,472	$0.00465	$42,712			
17	Next 13,000 kWh			13,041,079	$0.00419	$54,642			
18	Excess kWh			1,175,782	$0.00363	$4,268			
19	Total Charge					$101,623	10.16%		
20									
21	Energy Efficiency and Peak Demand Rider			23,402,333	$0.0026773	$62,655	6.27%		
22									
23	Economic Development Cost Recovery Rider				9.63500%	$64,955	6.50%		
24									
25	Enhanced Service Reliability Rider				4.58062%	$30,881	3.09%		
26									
27	gridSMART® Rider		5,989		$1.00	$5,989	0.60%		
28									
29	Monongahela Power Rider			23,402,333	$0.0001229	$2,876	0.29%		
30									
31	Total EHG		5,989	23,402,333		$1,000,030	100.00%	$0	$1,000,030

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					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase In Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	EHG	Electric Heating General								
2										
3	Distribution Charges:									
4	Customer Charge		5,989		$21.96	$131,518	18.27%	-$54,560	-41.48%	-41.48%
5	Energy Charge ($ per kwh)			23,402,333	$0.0132863	$310,930	43.20%	-$310,930	-100.00%	-100.00%
6	Demand Charge in excess of 30 KW ($ per kW)			11,572	$1.18	$13,665	1.90%	$583,542	4273.48%	4273.48%
7										
8	Universal Service Fund Rider									
9	First 833,000 kWh			23,402,333	$0.0015873	$37,147				
10	All Excess kWh			0	$0.0001681	$0				
11	Total Charge					$37,147	5.16%	$19,749	53.17%	53.17%
12										
13	Advanced Energy Fund Rider		5,989		$0.0895	$536	0.07%	-$536	-100.00%	-100.00%
14										
15	KWH Tax Rider									
16	First 2,000 kWh			9,185,472	$0.00465	$42,712				
17	Next 13,000 kWh			13,041,079	$0.00419	$54,642				
18	Excess kWh			1,175,782	$0.00363	$4,268				
19	Total Charge					$101,623	14.12%	$0	0.00%	0.00%
20										
21	Energy Efficiency and Peak Demand Rider			23,402,333	$0.0026073	$61,017	8.48%	$1,636	2.68%	2.68%
22										
23	Economic Development Cost Recovery Rider				6.36693%	$38,162	5.30%	$26,793	70.21%	70.21%
24										
25	Enhanced Service Reliability Rider				5.49819%	$25,077	3.48%	$5,803	23.14%	23.14%
26										
27	gridSMART® Rider						0.00%	$5,989	100.00%	100.00%
28										
29	Monongahela Power Rider						0.00%	$2,876	100.00%	100.00%
30										
31	Total EHG		5,989	23,402,333		$719,665	100.00%	$280,366	38.96%	38.96%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
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Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
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Work Paper Reference No(s): WP E-4.1as

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I=F+H)
1	EHS	Electric Heating Schools (Proposed GS-2)							
2									
3	Distribution Charges:								
4	Customer Charge		12		$12.85	$155	1.00%		
5	Energy Charge ($ per kWh)			423,167	$0.0000000	$0	0.00%		
6	Demand Charge ($ per kW)			2,043	$4.90	$10,011	64.67%		
7									
8	Universal Service Fund Rider								
9	First 833,000 kWh			423,167	$0.0024312	$1,029			
10	All Excess kWh			0	$0.0001731	$0			
11	Total Charge					$1,029	6.65%		
12									
13	Advanced Energy Fund Rider		12		$0.0000	$0	0.00%		
14									
15	KWH Tax Rider								
16	First 2,000 kWh			24,000	$0.00465	$112			
17	Next 13,000 kWh			148,219	$0.00419	$621			
18	Excess kWh			250,948	$0.00363	$911			
19	Total Charge					$1,644	10.62%		
20									
21	Energy Efficiency and Peak Demand Rider			423,167	$0.0026773	$1,133	7.32%		
22									
23	Economic Development Cost Recovery Rider				9.63500%	$979	6.33%		
24									
25	Enhanced Service Reliability Rider				4.58062%	$466	3.01%		
26									
27	gridSMART® Rider		12		$1.00	$12	0.08%		
28									
29	Monongahela Power Rider			423,167	$0.0001229	$52	0.34%		
30									
31	Total EHS		12	423,167		$15,480	100.00%	$0	$15,480

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OHIO POWER COMPANY
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Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized Most Current Rate (J)	Current Annualized Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	EHS	Electric Heating Schools								
2										
3	Customer Charge		12			$0	0.00%	$155	100.00%	100.00%
4	Energy Charge ($ per kWh)			423,167	0.0021744	$920	20.60%	-$920	-100.00%	-100.00%
5	Demand Charge ($ per kW)					$0	0.00%	$10,011	100.00%	100.00%
6										
7										
8	Universal Service Fund Rider									
9	First 833,000 kWh			423,167	$0.0015873	$672				
10	All Excess kWh			0	$0.0001681	$0				
11	Total Charge					$672	15.04%	$357	53.17%	53.17%
12										
13	Advanced Energy Fund Rider		12		$0.0895	$1	0.02%	-$1	-100.00%	-100.00%
14										
15	KWH Tax Rider									
16	First 2,000 kWh			24,000	$0.00465	$112				
17	Next 13,000 kWh			148,219	$0.00419	$621				
18	Excess kWh			250,948	$0.00363	$911				
19	Total Charge					$1,644	36.79%	$0	0.00%	0.00%
20										
21	Energy Efficiency and Peak Demand Rider			423,167	$0.0026073	$1,103	24.70%	$30	2.68%	2.68%
22										
23	Economic Development Cost Recovery Rider				8.36693%	$77	1.72%	$902	1172.19%	1172.19%
24										
25	Enhanced Service Reliability Rider				5.49619%	$51	1.13%	$415	820.39%	820.39%
26										
27	gridSMART® Rider					$0	0.00%	$12	100.00%	100.00%
28										
29	Monongahela Power Rider					$0	0.00%	$52	100.00%	100.00%
30										
31	Total EHS		12	423,167		$4,467	100.00%	$11,012	246.50%	246.50%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
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Witness Responsible: T. Zelina / A. Moore

					Test Year Proposed				
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Proposed Rate (E)	Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	SS	School Service (Proposed GS-2)							
2									
3	Distribution Charges:								
4	Customer Charge		2,216		$12.85	$28,476	1.90%		
5	Demand Charge ($ per kW)			188,385	$4.90	$923,087	61.48%		
6	*Energy Charge - 1st 300 KWH/sq ft ($ per KWH)*			20,846,715	$0.0000000	$0	0.00%		
7	Energy Charge - additional KWH ($ per KWH)			24,086,655	$0.0000000	$0	0.00%		
8									
9	Universal Service Fund Rider								
10	First 833,000 kWh			44,933,370	$0.0024312	$109,242			
11	All Excess kWh			0	$0.0001731	$0			
12	Total Charge					$109,242	7.28%		
13									
14	Advanced Energy Fund Rider		2,216		$0.0000	$0	0.00%		
15									
16	KWH Tax Rider								
17	First 2,000 kWh			4,064,859	$0.00465	$18,902			
18	Next 13,000 kWh			18,009,549	$0.00419	$75,460			
19	Excess kWh			22,858,962	$0.00363	$82,978			
20	Total Charge					$177,340	11.81%		
21									
22	Energy Efficiency and Peak Demand Rider			44,933,370	$0.0026773	$120,300	8.01%		
23									
24	Economic Development Cost Recovery Rider				9.63500%	$91,683	6.11%		
25									
26	Enhanced Service Reliability Rider				4.58062%	$43,587	2.90%		
27									
28	*gridSMART® Rider*		2,216		$1.00	$2,216	0.15%		
29									
30	Monongahela Power Rider			44,933,370	$0.0001229	$5,522	0.37%		
31									
32	Total SS		2,216	44,933,370		$1,501,453	100.00%	$0	$1,501,453

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Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Current Annualized: Most Current Rate (J)	Current Annualized: Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase In Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	SS	School Service								
2										
3	Distribution Charges:									
4	Customer Charge		2,216		$31.84	$70,657	6.51%	-$42,082	-59.64%	-59.64%
5	Demand Charge ($ per kW)						0.00%	$923,087	100.00%	100.00%
6	Energy Charge - 1st 300 KWH/sq ft ($ per KWH)			20,846,715	$0.0124738	$260,038	23.98%	-$260,038	-100.00%	-100.00%
7	Energy Charge - additional KWH ($ per KWH)			24,086,655	$0.0124738	$300,452	27.70%	-$300,452	-100.00%	-100.00%
8										
9	Universal Service Fund Rider									
10	First 833,000 kWh			44,933,370	$0.0015873	$71,323				
11	All Excess kWh			0	$0.0001681	$0				
12	Total Charge					$71,323	6.58%	$37,919	53.17%	53.17%
13										
14	Advanced Energy Fund Rider		2,216		$0.0895	$198	0.02%	-$198	-100.00%	-100.00%
15										
16	KWH Tax Rider									
17	First 2,000 kWh			4,064,859	$0.00465	$18,902				
18	Next 13,000 kWh			18,009,549	$0.00419	$75,460				
19	Excess kWh			22,858,962	$0.00363	$82,978				
20	Total Charge					$177,340	16.35%	$0	0.00%	0.00%
21										
22	Energy Efficiency and Peak Demand Rider			44,933,370	$0.0026073	$117,155	10.80%	$3,145	2.68%	2.68%
23										
24	Economic Development Cost Recovery Rider				8.36893%	$52,799	4.87%	$38,884	73.64%	73.64%
25										
26	Enhanced Service Reliability Rider				5.49819%	$34,696	3.20%	$8,891	25.63%	25.63%
27										
28	gridSMART® Rider					$0	0.00%	$2,216	100.00%	100.00%
29										
30	Monongahela Power Rider					$0	0.00%	$5,522	100.00%	100.00%
31										
32	Total SS		2,216	44,933,370		$1,084,558	100.00%	$416,894	38.44%	38.44%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
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Work Paper Reference No(s): WP E-4.1au

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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Test Year Proposed: Proposed Rate (E)	Test Year Proposed: Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	% of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	FL PUMP-Q	Flood Pumps							
2									
3	Distribution Charges:								
4	Customer Charge		312		$7.85	$2,449	13.32%		
5	Energy Charge - 1st 1,500 KWH			243,982	$0.01747	$4,262	23.19%		
6	Energy Charge - additional KWH			271,377	$0.01747	$4,741	25.79%		
7									
8	Prompt Payment Discount			515,359	$0.00000	$0	0.00%		
9									
10	Universal Service Fund Rider								
11	First 833,000 kWh			515,359	$0.0024312	$1,253			
12	All Excess kWh			0	$0.0001731	$0			
13	Total Charge					$1,253	6.82%		
14									
15	Advanced Energy Fund Rider		312		$0.0000	$0	0.00%		
16									
17	KWH Tax Rider								
18	First 2,000 kWh			294,609	$0.00465	$1,370			
19	Next 13,000 kWh			215,880	$0.00419	$905			
20	Excess kWh			4,870	$0.00363	$18			
21	Total Charge					$2,292	12.47%		
22									
23	Energy Efficiency and Peak Demand Rider			515,359	$0.0026773	$1,380	7.51%		
24									
25	Economic Development Cost Recovery Rider				9.63500%	$1,103	6.00%		
26									
27	Enhanced Service Reliability Rider				4.58062%	$525	2.85%		
28									
29	gridSMART® Rider		312		$1.00	$312	1.70%		
30									
31	Monongahela Power Rider			515,359	$0.0001229	$63	0.34%		
32									
33	Total FL PUMP-Q		312	515,359		$18,381	100.00%	$0	$18,381

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1au

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	FL PUMP-Q	Flood Pumps								
2										
3	Distribution Charges:									
4	Customer Charge		312		$4.30	$1,342	8.93%	$1,108	82.56%	82.56%
5	Energy Charge - 1st 1,500 KWH			243,982	$0.01637	$3,994	26.58%	$269	6.73%	6.73%
6	Energy Charge - additional KWH			271,377	$0.01637	$4,442	29.56%	$299	6.73%	6.73%
7										
8	Prompt Payment Discount			515,359	($0.00100)	-$515	-3.43%	$515	-100.00%	-100.00%
9										
10	Universal Service Fund Rider									
11	First 833,000 kWh			515,359	$0.0015873	$818				
12	All Excess kWh			0	$0.0001681	$0				
13	Total Charge					$818	5.44%	$435	53.17%	53.17%
14										
15	Advanced Energy Fund Rider		312		$0.0895	$28	0.19%	-$28	-100.00%	-100.00%
16										
17	KWH Tax Rider									
18	First 2,000 kWh			294,609	$0.00465	$1,370				
19	Next 13,000 kWh			215,880	$0.00419	$905				
20	Excess kWh			4,870	$0.00363	$18				
21	Total Charge					$2,292	15.25%	$0	0.00%	0.00%
22										
23	Energy Efficiency and Peak Demand Rider			515,359	$0.0026073	$1,344	8.94%	$36	2.68%	2.68%
24										
25	Economic Development Cost Recovery Rider				8.36693%	$775	5.16%	$328	42.39%	42.39%
26										
27	Enhanced Service Reliability Rider				5.49819%	$509	3.39%	$15	3.01%	3.01%
28										
29	gridSMART® Rider					$0	0.00%	$312	100.00%	100.00%
30										
31	Monongahela Power Rider					$0	0.00%	$63	100.00%	100.00%
32										
33	Total FL PUMP-Q		312	515,359		$15,028	100.00%	$3,353	22.31%	22.31%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original__Updated__Revised
Work Paper Reference No(s): WP E-4.1av

Schedule E-4.1

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Test Year Proposed: Proposed Rate (E)	Test Year Proposed: Proposed Annualized Revenue Less Gas or Fuel Cost Revenue (F)	Test Year Proposed: % of Revenue to Total (G)	Increase Less Gas or Fuel Costs (H)	Proposed Total Revenue (I =F+H)
1	JOINT SVC	Joint Service Territory							
2	Transmission Voltage								
3									
4	Distribution Charges								
5	Customer Charge		12		$806.10	$9,673	0.96%		
6	Demand Charge ($ per kW)			1,988,019	$0.00	$0	0.00%		
7	Energy Charge ($ per kWh)			1,433,628,931	$0.0000000	$0	0.00%		
8									
9	Universal Service Fund Rider								
10	First 833,000 kWh			9,996,000	$0.0024312	$24,302			
11	All Excess kWh			1,423,632,931	$0.0001731	$246,431			
12	Total Charge					$270,733	26.83%		
13									
14	Advanced Energy Fund Rider		12		$0.0000	$0	0.00%		
15									
16	KWH Tax Rider								
17	First 2,000 kWh			0	$0.00465	$0			
18	Next 13,000 kWh			0	$0.00419	$0			
19	Excess kWh			0	$0.00363	$0			
20	Total Charge					$0	0.00%		
21									
22	Energy Efficiency and Peak Demand Rider			1,433,628,931	$0.0003845	$551,230	54.62%		
23									
24	Economic Development Cost Recovery Rider				9.63500%	$932	0.09%		
25									
26	Enhanced Service Reliability Rider				4.58062%	$443	0.04%		
27									
28	gridSMART® Rider		12		$1.00	$12	0.00%		
29									
30	Monongahela Power Rider			1,433,628,931	$0.0001229	$176,193	17.46%		
31									
32	Total ORMET		12	1,433,628,931		$1,009,217	100.00%	$0	$1,009,217

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Annualized Test Year Revenues at Proposed Rates vs.
Most Current Rates
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s): WP E-4.1av

Schedule E-4.1
Page 60 of 60
Witness Responsible: T. Zelina / A. Moore

					Current Annualized					
Line No.	Rate Code (A)	Class/ Descript. (B)	Customer Bills (C)	Sales KW / KWH (D)	Most Current Rate (J)	Current Annualized Revenue Less Gas or Fuel Cost Revenue (K)	% of Revenue to Total (L)	Increase Less Gas or Fuel Costs (M=F-K)	% Increase in Revenue Less Fuel Cost Revenue (N=M+K)	Total Revenue % Increase (O)
1	JOINT SVC	Joint Service Territory								
2	Transmission Voltage									
3										
4	Distribution Charges									
5	Customer Charge		12		$534.63	$6,416	0.27%	$3,258	50.78%	50.78%
6	Demand Charge ($ per kW)			1,988,019	$0.43	$854,848	36.63%	-$854,848	-100.00%	-100.00%
7	Energy Charge ($ per kWh)			1,433,628,931	$0.0003512	$503,490	21.58%	-$503,490	-100.00%	-100.00%
8										
9	Universal Service Fund Rider									
10	First 833,000 kWh			9,996,000	$0.0015873	$15,867				
11	All Excess kWh			1,423,632,931	$0.0001681	$239,313				
12	Total Charge					$255,179	10.93%	$15,554	6.10%	6.10%
13										
14	Advanced Energy Fund Rider		12		$0.0895	$1	0.00%	-$1	-100.00%	-100.00%
15										
16	KWH Tax Rider									
17	First 2,000 kWh			0	$0.00465	$0				
18	Next 13,000 kWh			0	$0.00419	$0				
19	Excess kWh			0	$0.00363	$0				
20	Total Charge					$0	0.00%	$0	0.00%	0.00%
21										
22	Energy Efficiency and Peak Demand Rider			1,433,628,931	$0.0003662	$524,995	22.50%	$26,235	5.00%	5.00%
23										
24	Economic Development Cost Recovery Rider				8.33091%	$113,696	4.87%	-$112,764	-99.18%	-99.18%
25										
26	Enhanced Service Reliability Rider				5.49819%	$75,037	3.22%	-$74,594	-99.41%	-99.41%
27										
28	gridSMART® Rider					$0	0.00%	$12	100.00%	100.00%
29										
30	Monongahela Power Rider					$0	0.00%	$176,193	100.00%	100.00%
31										
32	Total ORMET		12	1,433,628,931		$2,333,663	100.00%	-$1,324,446	-56.75%	-56.75%

Date Prepared: Feb. 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E+H)
1											
2	RS		0	4.37	9.86	5.49	125.74%	-	4.37	9.86	125.74%
3			30	6.61	12.02	5.42	82.00%	0.95	7.56	12.98	71.65%
4			70	9.59	14.90	5.31	55.42%	2.23	11.81	17.13	44.98%
5			120	13.32	18.50	5.18	38.93%	3.82	17.13	22.32	30.26%
6			200	19.28	24.26	4.98	25.82%	6.36	25.64	30.62	19.41%
7			300	26.74	31.46	4.72	17.65%	9.54	36.28	41.00	13.01%
8			500	41.65	45.85	4.20	10.09%	15.90	57.55	61.75	7.30%
9			800	64.01	67.44	3.43	5.35%	25.44	89.46	92.88	3.83%
10			1,000	76.52	80.90	4.38	5.73%	31.80	108.32	112.70	4.05%
11			1,200	89.02	94.36	5.34	6.00%	38.16	127.18	132.52	4.20%
12			1,500	107.77	114.55	6.78	6.29%	47.70	155.47	162.25	4.36%
13			2,000	139.02	148.19	9.17	6.60%	63.60	202.63	211.80	4.53%
14			4,000	263.12	281.86	18.74	7.12%	127.20	390.32	409.06	4.80%
15			5,000	325.17	348.69	23.53	7.23%	159.01	484.17	507.70	4.86%
16			8,000	511.31	549.19	37.88	7.41%	254.41	765.72	803.60	4.95%
17			10,000	635.40	682.85	47.45	7.47%	318.01	953.42	1,000.87	4.98%
18			12,000	759.50	816.52	57.02	7.51%	381.61	1,141.11	1,198.13	5.00%
19			15,000	945.64	1,017.02	71.38	7.55%	477.02	1,422.66	1,494.03	5.02%
20											
21	RS										
22	SWH	80 gal.	500	31.16	42.00	10.84	34.79%	15.90	47.06	57.91	23.03%
23		80 gal.	800	53.53	63.60	10.07	18.80%	25.44	78.97	89.04	12.75%
24		80 gal.	1,000	68.44	77.99	9.55	13.95%	31.80	100.24	109.79	9.53%
25		80 gal.	1,500	100.30	111.87	11.57	11.54%	47.70	148.00	159.57	7.82%
26		80 gal.	2,000	131.55	145.52	13.97	10.62%	63.60	195.15	209.12	7.16%
27		80 gal.	4,000	255.65	279.18	23.54	9.21%	127.20	382.85	406.39	6.15%
28		80 gal.	6,000	379.74	412.85	33.11	8.72%	190.81	570.55	603.65	5.80%
29		80 gal.	8,000	503.84	546.51	42.68	8.47%	254.41	758.25	800.92	5.63%

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	RS										
2	SWH	100 gal.	500	27.88	40.05	12.17	43.65%	15.90	43.78	55.95	27.80%
3		100 gal.	800	49.34	62.06	12.72	25.78%	25.44	74.78	87.50	17.01%
4		100 gal.	1,000	64.25	76.45	12.20	19.00%	31.80	96.05	108.25	12.71%
5		100 gal.	1,500	97.31	110.80	13.49	13.86%	47.70	145.01	158.50	9.30%
6		100 gal.	2,000	128.56	144.45	15.88	12.36%	63.60	192.17	208.05	8.27%
7		100 gal.	4,000	252.66	278.11	25.45	10.07%	127.20	379.86	405.32	6.70%
8		100 gal.	6,000	376.75	411.78	35.02	9.30%	190.81	567.56	602.58	6.17%
9		100 gal.	8,000	500.85	545.44	44.59	8.90%	254.41	755.26	799.85	5.90%
10											
11		120 gal.	500	27.88	40.05	12.17	43.65%	15.90	43.78	55.95	27.80%
12		120 gal.	800	45.14	60.52	15.38	34.06%	25.44	70.58	85.96	21.78%
13		120 gal.	1,000	60.05	74.91	14.86	24.74%	31.80	91.86	106.72	16.18%
14		120 gal.	1,500	94.32	109.73	15.41	16.34%	47.70	142.02	157.43	10.85%
15		120 gal.	2,000	125.57	143.38	17.80	14.18%	63.60	189.18	206.98	9.41%
16		120 gal.	4,000	249.67	277.04	27.37	10.96%	127.20	376.87	404.25	7.26%
17		120 gal.	6,000	373.76	410.71	36.94	9.88%	190.81	564.57	601.51	6.54%
18		120 gal.	8,000	497.86	544.37	46.51	9.34%	254.41	752.27	798.78	6.18%
19		120 gal.	10,000	621.95	678.04	56.08	9.02%	318.01	939.97	996.05	5.97%
20											
21											
22	RS-TOD										
23	On - Peak 25%		1,000	62.80	75.24	12.44	19.81%	31.80	94.61	107.05	13.15%
24	Off-Peak 75%		2,000	116.87	139.65	22.78	19.49%	63.60	180.47	203.26	12.62%
25			3,000	170.48	203.60	33.13	19.43%	95.40	265.88	299.01	12.46%
26			4,000	224.08	267.55	43.47	19.40%	127.20	351.29	394.76	12.37%
27			5,000	277.69	331.50	53.82	19.38%	159.01	436.69	490.51	12.32%
28			6,000	331.29	395.45	64.16	19.37%	190.81	522.10	586.26	12.29%
29			7,000	384.90	459.40	74.50	19.36%	222.61	607.51	682.01	12.26%
30			8,000	438.50	523.35	84.85	19.35%	254.41	692.91	777.76	12.24%

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original__Updated__Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code		Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	RS-TOD											
2	On - Peak	30%		1,000	67.09	76.81	9.71	14.48%	31.80	98.89	108.61	9.82%
3	Off-Peak	70%		2,000	125.45	142.78	17.33	13.82%	63.60	189.05	206.38	9.17%
4				3,000	183.34	208.29	24.95	13.61%	95.40	278.75	303.70	8.95%
5				4,000	241.24	273.81	32.57	13.50%	127.20	368.44	401.01	8.84%
6				5,000	299.13	339.32	40.19	13.44%	159.01	458.14	498.33	8.77%
7				6,000	357.03	404.83	47.81	13.39%	190.81	547.83	595.64	8.73%
8				7,000	414.92	470.35	55.43	13.36%	222.61	637.53	692.96	8.69%
9				8,000	472.81	535.86	63.05	13.33%	254.41	727.22	790.27	8.67%
10												
11	On - Peak	35%		1,000	71.38	78.37	6.99	9.79%	31.80	103.18	110.17	6.77%
12	Off-Peak	65%		2,000	134.03	145.91	11.88	8.87%	63.60	197.63	209.51	6.01%
13				3,000	196.21	212.99	16.78	8.55%	95.40	291.61	308.39	5.75%
14				4,000	258.39	280.06	21.67	8.39%	127.20	385.60	407.27	5.62%
15				5,000	320.58	347.14	26.56	8.29%	159.01	479.58	506.15	5.54%
16				6,000	382.76	414.22	31.46	8.22%	190.81	573.57	605.02	5.48%
17				7,000	444.94	481.29	36.35	8.17%	222.61	667.56	703.90	5.45%
18				8,000	507.12	548.37	41.25	8.13%	254.41	761.53	802.78	5.42%
19												
20	RS-ES											
21	On - Peak	15%		1,000	54.23	72.12	17.89	32.99%	31.80	86.03	103.92	20.80%
22	Off-Peak	85%		2,000	99.71	133.40	33.68	33.78%	63.60	163.32	197.00	20.62%
23				3,000	144.74	194.22	49.48	34.18%	95.40	240.15	289.62	20.60%
24				4,000	189.77	255.04	65.27	34.40%	127.20	316.98	382.25	20.59%
25				5,000	234.80	315.86	81.07	34.53%	159.01	393.80	474.87	20.59%
26				6,000	279.83	376.69	96.86	34.61%	190.81	470.63	567.49	20.58%
27				7,000	324.85	437.51	112.66	34.68%	222.61	547.46	660.12	20.58%
28				8,000	369.88	498.33	128.45	34.73%	254.41	624.29	752.74	20.58%

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E+C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E+H)
1	RS-ES										
2	On - Peak	20%	1,000	58.52	73.68	15.16	25.92%	31.80	90.32	105.48	16.79%
3	Off-Peak	80%	2,000	108.29	136.53	28.23	26.07%	63.60	171.89	200.13	16.42%
4			3,000	157.61	198.91	41.30	26.21%	95.40	253.01	294.32	16.32%
5			4,000	206.93	261.30	54.37	26.28%	127.20	334.13	388.50	16.27%
6			5,000	256.24	323.68	67.44	26.32%	159.01	415.25	482.69	16.24%
7			6,000	305.56	386.07	80.51	26.35%	190.81	496.37	576.88	16.22%
8			7,000	354.88	448.45	93.58	26.37%	222.61	577.48	671.06	16.20%
9			8,000	404.19	510.84	106.65	26.39%	254.41	658.60	765.25	16.19%
10											
11	On - Peak	25%	1,000	62.80	75.24	12.44	19.81%	31.80	94.61	107.05	13.16%
12	Off-Peak	75%	2,000	116.87	139.65	22.78	19.49%	63.60	180.47	203.26	12.62%
13			3,000	170.48	203.60	33.13	19.43%	95.40	265.88	299.01	12.46%
14			4,000	224.08	267.55	43.47	19.40%	127.20	351.29	394.76	12.37%
15			5,000	277.69	331.50	53.82	19.38%	159.01	436.69	490.51	12.32%
16			6,000	331.29	395.45	64.16	19.37%	190.81	522.10	586.26	12.29%
17			7,000	384.90	459.40	74.50	19.36%	222.61	607.51	682.01	12.26%
18			8,000	438.50	523.35	84.85	19.35%	254.41	692.91	777.76	12.24%
19											
20	GS-1										
21	Unmetered		50	11.30	11.93	0.63	5.56%	1.65	12.94	13.57	4.85%
22			100	14.19	15.66	1.47	10.35%	3.29	17.48	18.95	8.40%
23			150	17.08	19.39	2.31	13.51%	4.94	22.02	24.33	10.48%
24			200	19.97	23.12	3.15	15.76%	6.58	26.56	29.70	11.85%
25			400	31.54	38.05	6.51	20.64%	13.17	44.70	51.21	14.56%
26			700	48.89	60.43	11.55	23.62%	23.04	71.93	83.47	16.06%
27			1,000	66.24	82.82	16.59	25.04%	32.91	99.15	115.74	16.73%
28			1,500	95.15	120.14	24.99	26.26%	49.37	144.52	169.51	17.29%
29			2,000	124.06	157.45	33.39	26.91%	65.83	189.89	223.28	17.58%
30			4,000	238.80	305.79	66.99	28.05%	131.65	370.45	437.44	18.08%
31			8,000	468.27	602.46	134.19	28.66%	263.30	731.57	865.76	18.34%
32			10,000	583.01	750.79	167.79	28.78%	329.13	912.14	1,079.92	18.39%
33			15,000	869.84	1,121.63	251.79	28.95%	493.70	1,363.54	1,615.33	18.47%
34			25,000	1,437.92	1,857.71	419.78	29.19%	822.83	2,260.75	2,680.53	18.57%

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zeline / A. Moore

Line No.	Rate Code		Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-1-ES											
2	On-Peak	10%		500	35.83	39.04	3.21	8.95%	16.46	52.29	55.50	6.13%
3	Off-Peak	90%		1,000	54.42	67.15	12.73	23.38%	32.91	87.33	100.06	14.57%
4				2,000	91.59	123.36	31.76	34.68%	65.83	157.42	189.18	20.18%
5				4,000	165.01	234.85	69.84	42.33%	131.65	296.66	366.51	23.54%
6				6,000	238.43	346.35	107.92	45.26%	197.48	435.91	543.83	24.76%
7				8,000	311.85	457.85	146.00	46.82%	263.30	575.16	721.16	25.38%
8												
9	On-Peak	15%		500	37.11	40.18	3.07	8.26%	16.46	53.57	56.64	5.72%
10	Off-Peak	85%		1,000	56.98	69.43	12.44	21.84%	32.91	89.89	102.34	13.84%
11				2,000	96.71	127.91	31.20	32.26%	65.83	162.54	193.74	19.20%
12				4,000	175.25	243.97	68.72	39.21%	131.65	306.90	375.62	22.39%
13				6,000	253.79	360.03	106.23	41.86%	197.48	451.27	557.51	23.54%
14				8,000	332.33	476.08	143.75	43.25%	263.30	595.64	739.39	24.13%
15												
16	On-Peak	20%		500	38.39	41.32	2.93	7.62%	16.46	54.85	57.78	5.33%
17	Off-Peak	80%		1,000	59.54	71.70	12.16	20.43%	32.91	92.45	104.62	13.16%
18				2,000	101.83	132.47	30.64	30.09%	65.83	167.66	198.30	18.28%
19				4,000	185.49	253.09	67.59	36.44%	131.65	317.14	384.74	21.31%
20				6,000	269.15	373.70	104.55	38.84%	197.48	466.63	571.18	22.40%
21				8,000	352.81	494.31	141.50	40.11%	263.30	616.12	757.62	22.97%
22												

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Schedule E-5

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-1										
2			600	49.76	54.74	4.98	10.01%	19.75	69.51	74.49	7.17%
3			700	55.54	62.21	6.66	11.99%	23.04	78.58	85.24	8.48%
4			800	61.33	69.67	8.34	13.60%	26.33	87.66	96.00	9.52%
5			900	67.11	77.13	10.02	14.93%	29.62	96.73	106.75	10.36%
6			1,200	84.46	99.52	15.06	17.83%	39.50	123.95	139.01	12.15%
7			1,400	96.02	114.44	18.42	19.18%	46.08	142.10	160.52	12.96%
8			1,600	107.59	129.37	21.78	20.24%	52.66	160.25	182.03	13.59%
9			1,800	119.15	144.30	25.14	21.10%	59.24	178.40	203.54	14.09%
10			2,100	136.46	166.64	30.18	22.12%	69.12	205.57	235.76	14.68%
11			2,400	153.67	188.89	35.22	22.92%	78.99	232.66	267.88	15.14%
12			2,700	170.88	211.14	40.26	23.56%	88.87	259.74	300.00	15.50%
13			2,800	176.61	218.56	41.94	23.75%	92.16	268.77	310.71	15.60%
14			3,000	188.09	233.39	45.30	24.08%	98.74	286.83	332.13	15.79%
15			3,200	199.56	248.22	48.66	24.38%	105.32	304.88	353.54	15.96%
16			3,500	216.77	270.47	53.70	24.77%	115.20	331.97	385.67	16.18%
17			3,600	222.51	277.89	55.38	24.89%	118.49	341.00	396.38	16.24%
18			4,000	245.46	307.56	62.10	25.30%	131.65	377.11	439.21	16.47%
19			4,500	274.14	344.64	70.50	25.72%	148.11	422.25	492.75	16.70%
20											
21	GS-2-										
22	Rec. Lighting		50	22.87	17.99	(4.88)	-21.34%	1.50	24.37	19.49	-20.03%
23			100	26.03	21.27	(4.76)	-18.28%	3.00	29.03	24.27	-16.40%
24			150	29.20	24.56	(4.64)	-15.89%	4.50	33.70	29.06	-13.77%
25			200	32.36	27.84	(4.52)	-13.96%	6.00	38.36	33.84	-11.78%
26			400	45.01	40.98	(4.03)	-8.96%	12.00	57.01	52.98	-7.07%
27			700	63.99	60.68	(3.30)	-5.16%	21.00	84.99	81.69	-3.89%
28			1,000	82.96	80.39	(2.58)	-3.10%	30.00	112.97	110.39	-2.28%
29			1,500	114.69	113.23	(1.36)	-1.19%	45.01	159.60	158.23	-0.85%
30			2,000	146.22	146.07	(0.15)	-0.10%	60.01	206.22	206.08	-0.07%
31			4,000	271.80	276.51	4.71	1.73%	120.02	391.82	396.53	1.20%
32			8,000	522.98	537.40	14.42	2.76%	240.04	763.01	777.43	1.89%
33			10,000	648.56	667.84	19.28	2.97%	300.05	948.61	967.88	2.03%
34			15,000	962.63	993.94	31.41	3.26%	450.07	1,412.60	1,444.01	2.22%
35			25,000	1,584.86	1,640.56	55.69	3.51%	750.12	2,334.98	2,390.67	2.39%

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zeline / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-2										
2	Secondary	10	1,000	113.22	126.85	13.63	12.04%	30.00	143.23	156.85	9.51%
3		10	2,000	160.48	173.76	13.27	8.27%	60.01	220.49	233.76	6.02%
4		10	3,000	207.28	220.20	12.92	6.23%	90.01	297.29	310.21	4.35%
5		25	2,500	243.51	293.38	49.86	20.48%	75.01	318.52	368.39	15.65%
6		25	5,000	360.51	409.49	48.98	13.59%	150.02	510.53	559.51	9.59%
7		25	7,500	477.50	525.60	48.10	10.07%	225.03	702.54	750.64	6.85%
8		50	5,000	459.90	570.15	110.25	23.97%	150.02	609.92	720.18	18.08%
9		50	10,000	693.89	802.38	108.49	15.63%	300.05	993.94	1,102.43	10.92%
10		50	15,000	927.88	1,034.61	106.73	11.50%	450.07	1,377.95	1,484.68	7.75%
11		75	7,500	676.29	846.93	170.64	25.23%	225.03	901.32	1,071.97	18.93%
12		75	15,000	1,027.27	1,195.27	168.00	16.35%	450.07	1,477.34	1,645.34	11.37%
13		75	22,500	1,374.06	1,539.42	165.35	12.03%	675.10	2,049.17	2,214.52	8.07%
14		100	10,000	892.67	1,123.71	231.04	25.88%	300.05	1,192.72	1,423.76	19.37%
15		100	20,000	1,357.86	1,585.37	227.51	16.76%	600.09	1,957.95	2,185.46	11.62%
16		100	30,000	1,820.24	2,044.22	223.98	12.31%	900.14	2,720.38	2,944.36	8.23%
17		200	20,000	1,755.42	2,228.02	472.60	26.92%	600.09	2,355.51	2,828.12	20.06%
18		200	40,000	2,680.19	3,145.74	465.55	17.37%	1,200.18	3,880.37	4,345.92	12.00%
19		200	60,000	3,604.95	4,063.45	458.50	12.72%	1,800.28	5,405.23	5,863.73	8.48%
20		500	50,000	4,335.27	5,532.56	1,197.30	27.62%	1,500.23	5,835.50	7,032.79	20.52%
21		500	100,000	6,647.18	7,826.85	1,179.66	17.75%	3,000.46	9,647.64	10,827.31	12.23%
22		500	150,000	8,959.10	10,121.13	1,162.03	12.97%	4,500.69	13,459.79	14,621.82	8.63%
23		1,000	100,000	8,635.01	11,040.13	2,405.12	27.85%	3,000.46	11,635.47	14,040.59	20.67%
24		1,000	200,000	13,258.84	15,628.70	2,369.86	17.87%	6,000.92	19,259.76	21,629.62	12.30%
25		1,000	300,000	17,882.67	20,217.27	2,334.60	13.06%	9,001.38	26,884.05	29,218.66	8.68%
26		3,000	300,000	25,833.97	33,070.40	7,236.42	28.01%	9,001.38	34,835.35	42,071.78	20.77%
27		3,000	600,000	39,705.46	46,836.10	7,130.64	17.96%	18,002.76	57,708.22	64,838.86	12.36%
28		3,000	900,000	53,415.69	60,450.51	7,034.82	13.17%	27,004.14	80,419.83	87,454.65	8.75%
29		7,000	700,000	60,231.90	77,130.93	16,899.03	28.06%	21,003.22	81,235.12	98,134.15	20.80%
30		7,000	1,400,000	91,234.00	107,970.56	16,736.56	18.34%	42,006.44	133,240.44	149,977.00	12.56%
31		7,000	2,100,000	121,915.99	138,509.87	16,593.88	13.61%	63,009.66	184,925.65	201,519.53	8.97%
32											

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-2										
2	Primary	10	1,000	186.60	158.99	(27.61)	-14.80%	27.23	213.84	186.22	-12.91%
3		10	2,000	233.35	205.39	(27.97)	-11.98%	54.47	287.82	259.85	-9.72%
4		10	3,000	279.64	251.32	(28.32)	-10.13%	81.70	361.34	333.02	-7.84%
5		25	2,500	302.47	305.63	3.16	1.04%	68.08	370.55	373.71	0.85%
6		25	5,000	418.19	420.47	2.28	0.54%	136.17	554.36	556.64	0.41%
7		25	7,500	533.91	535.31	1.40	0.26%	204.25	738.17	739.56	0.19%
8		50	5,000	494.81	549.26	54.45	11.00%	136.17	630.98	685.43	8.63%
9		50	10,000	726.26	778.94	52.68	7.25%	272.34	998.59	1,051.28	5.28%
10		50	15,000	957.70	1,008.62	50.92	5.32%	408.51	1,366.21	1,417.13	3.73%
11		75	7,500	687.16	792.89	105.73	15.39%	204.25	891.41	997.14	11.86%
12		75	15,000	1,034.32	1,137.41	103.09	9.97%	408.51	1,442.83	1,545.92	7.14%
13		75	22,500	1,377.29	1,477.73	100.44	7.29%	612.76	1,990.05	2,090.49	5.05%
14		100	10,000	879.50	1,036.62	157.02	17.86%	272.34	1,151.84	1,308.86	13.63%
15		100	20,000	1,339.59	1,493.08	153.49	11.46%	544.68	1,884.26	2,037.76	8.15%
16		100	30,000	1,796.87	1,946.84	149.97	8.35%	817.02	2,613.89	2,763.86	5.74%
17		200	20,000	1,646.07	2,008.24	362.17	22.00%	544.68	2,190.75	2,552.92	16.53%
18		200	40,000	2,560.65	2,915.76	355.12	13.87%	1,089.36	3,650.00	4,005.12	9.73%
19		200	60,000	3,475.22	3,823.28	348.06	10.02%	1,634.03	5,109.25	5,457.32	6.81%
20		500	50,000	3,937.39	4,915.01	977.61	24.83%	1,361.70	5,299.09	6,276.70	18.45%
21		500	100,000	6,223.82	7,183.81	959.98	15.42%	2,723.39	8,947.21	9,907.20	10.73%
22		500	150,000	8,510.26	9,452.61	942.35	11.07%	4,085.09	12,595.34	13,537.69	7.48%
23		1,000	100,000	7,756.26	9,759.61	2,003.35	25.83%	2,723.39	10,479.65	12,483.00	19.12%
24		1,000	200,000	12,329.12	14,297.22	1,968.09	15.96%	5,446.78	17,775.90	19,744.00	11.07%
25		1,000	300,000	16,901.99	18,834.82	1,932.83	11.44%	8,170.17	25,072.16	27,004.99	7.71%
26		3,000	300,000	23,031.73	29,138.05	6,106.32	26.51%	8,170.17	31,201.90	37,308.22	19.57%
27		3,000	600,000	36,750.32	42,750.85	6,000.53	16.33%	16,340.34	53,090.66	59,091.19	11.30%
28		3,000	900,000	50,307.65	56,212.36	5,904.71	11.74%	24,510.51	74,818.16	80,722.87	7.89%
29		7,000	700,000	53,582.66	67,894.91	14,312.25	26.71%	19,063.73	72,646.39	86,958.64	19.70%
30		7,000	1,400,000	84,228.00	98,377.78	14,149.78	16.80%	38,127.46	122,355.46	136,505.24	11.56%
31		7,000	2,100,000	114,553.22	128,560.32	14,007.10	12.23%	57,191.19	171,744.41	185,751.51	8.16%
32											

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-2										
2	Subtransmission	10	1,000	383.76	975.56	591.80	154.21%	28.23	411.99	1,003.79	143.64%
3		10	2,000	430.17	1,021.62	591.45	137.49%	56.47	486.64	1,078.09	121.54%
4		10	3,000	476.13	1,067.23	591.10	124.15%	84.70	560.83	1,151.93	105.40%
5		25	2,500	492.31	1,056.12	563.82	114.53%	70.59	562.89	1,126.71	100.16%
6		25	5,000	607.20	1,170.14	562.94	92.71%	141.17	748.37	1,311.31	75.22%
7		25	7,500	722.09	1,284.15	562.06	77.84%	211.76	933.85	1,495.91	60.19%
8		50	5,000	672.45	1,189.64	517.18	76.91%	141.17	813.63	1,330.81	63.57%
9		50	10,000	902.24	1,417.66	515.42	57.13%	282.35	1,184.59	1,700.01	43.51%
10		50	15,000	1,132.03	1,645.69	513.66	45.37%	423.52	1,555.55	2,069.20	33.02%
11		75	7,500	852.60	1,323.15	470.55	55.19%	211.76	1,064.36	1,534.91	44.21%
12		75	15,000	1,197.28	1,665.19	467.90	39.08%	423.52	1,620.80	2,088.70	28.87%
13		75	22,500	1,537.77	2,003.02	465.26	30.26%	635.28	2,173.04	2,638.30	21.41%
14		100	10,000	1,032.75	1,456.66	423.91	41.05%	282.35	1,315.10	1,739.01	32.23%
15		100	20,000	1,489.53	1,909.91	420.38	28.22%	564.69	2,054.22	2,474.60	20.46%
16		100	30,000	1,943.50	2,360.36	416.86	21.45%	847.04	2,790.54	3,207.39	14.94%
17		200	20,000	1,750.55	1,987.91	237.36	13.56%	564.69	2,315.24	2,552.60	10.25%
18		200	40,000	2,658.50	2,888.81	230.31	8.66%	1,129.38	3,787.88	4,018.19	6.08%
19		200	60,000	3,566.45	3,789.71	223.26	6.26%	1,694.07	5,260.52	5,483.78	4.24%
20		500	50,000	3,895.53	3,573.26	(322.27)	-8.27%	1,411.73	5,307.26	4,984.98	-6.07%
21		500	100,000	6,165.41	5,825.50	(339.91)	-5.51%	2,823.45	8,988.86	8,648.95	-3.78%
22		500	150,000	8,435.29	8,077.75	(357.54)	-4.24%	4,235.18	12,670.46	12,312.92	-2.82%
23		1,000	100,000	7,470.51	6,215.50	(1,255.00)	-16.80%	2,823.45	10,293.96	9,038.95	-12.19%
24		1,000	200,000	12,010.26	10,719.99	(1,290.27)	-10.74%	5,646.90	17,657.16	16,366.89	-7.31%
25		1,000	300,000	16,550.01	15,224.48	(1,325.53)	-8.01%	8,470.35	25,020.36	23,694.83	-5.30%
26		3,000	300,000	21,770.41	16,784.48	(4,985.92)	-22.90%	8,470.35	30,240.76	25,254.83	-16.49%
27		3,000	600,000	35,389.67	30,297.96	(5,091.71)	-14.39%	16,940.70	52,330.37	47,238.66	-9.73%
28		3,000	900,000	48,847.67	43,660.14	(5,187.53)	-10.62%	25,411.05	74,258.72	69,071.19	-6.99%
29		7,000	700,000	50,370.21	37,922.45	(12,447.77)	-24.71%	19,764.15	70,134.36	57,686.60	-17.75%
30		7,000	1,400,000	80,783.78	68,173.54	(12,610.24)	-15.61%	39,528.30	120,312.08	107,701.84	-10.48%
31		7,000	2,100,000	110,877.22	98,124.31	(12,752.92)	-11.50%	59,292.45	170,169.67	157,416.76	-7.49%
32											

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-3										
2	Secondary	10	3,500	241.13	238.09	(3.04)	-1.26%	98.86	339.99	336.95	-0.89%
3		10	4,500	256.14	252.75	(3.39)	-1.32%	127.11	383.25	379.85	-0.89%
4		10	5,500	271.15	267.40	(3.75)	-1.38%	155.35	426.50	422.75	-0.88%
5		25	8,750	562.15	570.34	8.19	1.46%	247.15	809.30	817.49	1.01%
6		25	11,250	599.66	606.97	7.31	1.22%	317.77	917.43	924.74	0.80%
7		25	13,750	637.17	643.61	6.43	1.01%	388.38	1,025.56	1,031.99	0.63%
8		50	17,500	1,095.77	1,122.68	26.92	2.46%	494.30	1,590.07	1,616.99	1.69%
9		50	22,500	1,167.99	1,193.15	25.15	2.15%	635.53	1,803.53	1,828.68	1.39%
10		50	27,500	1,240.22	1,263.61	23.39	1.89%	776.76	2,016.98	2,040.38	1.16%
11		75	26,250	1,625.89	1,671.53	45.64	2.81%	741.45	2,367.34	2,412.98	1.93%
12		75	33,750	1,734.23	1,777.23	43.00	2.48%	953.30	2,687.53	2,730.52	1.60%
13		75	41,250	1,842.57	1,882.92	40.35	2.19%	1,165.14	3,007.71	3,048.07	1.34%
14		100	35,000	2,156.01	2,220.37	64.37	2.99%	988.61	3,144.61	3,208.98	2.05%
15		100	45,000	2,300.46	2,361.30	60.84	2.64%	1,271.07	3,571.53	3,632.37	1.70%
16		100	55,000	2,444.92	2,502.23	57.31	2.34%	1,553.52	3,998.44	4,055.76	1.43%
17		200	70,000	4,276.49	4,415.75	139.26	3.26%	1,977.21	6,253.70	6,392.96	2.23%
18		200	90,000	4,565.40	4,697.61	132.21	2.90%	2,542.13	7,107.53	7,239.74	1.86%
19		200	110,000	4,854.31	4,979.47	125.16	2.58%	3,107.05	7,961.36	8,086.51	1.57%
20		500	175,000	10,637.93	11,001.87	363.94	3.42%	4,943.03	15,580.96	15,944.91	2.34%
21		500	225,000	11,360.21	11,706.52	346.31	3.05%	6,355.33	17,715.54	18,061.85	1.95%
22		500	275,000	12,082.49	12,411.17	328.68	2.72%	7,767.62	19,850.11	20,178.79	1.66%
23		1,000	350,000	21,240.33	21,978.75	738.42	3.48%	9,886.07	31,126.40	31,864.82	2.37%
24		1,000	450,000	22,684.89	23,388.05	703.16	3.10%	12,710.66	35,395.54	36,098.70	1.99%
25		1,000	550,000	24,129.44	24,797.34	667.89	2.77%	15,535.25	39,664.69	40,332.58	1.68%
26		3,000	1,050,000	63,127.65	65,396.26	2,268.61	3.59%	29,658.20	92,785.84	95,054.45	2.44%
27		3,000	1,350,000	66,739.25	68,946.70	2,207.46	3.31%	38,131.97	104,871.21	107,078.67	2.10%
28		3,000	1,650,000	70,350.85	72,497.15	2,146.31	3.05%	46,605.74	116,956.58	119,102.89	1.84%
29		7,000	2,450,000	144,577.22	150,049.94	5,472.72	3.79%	69,202.46	213,779.67	219,252.39	2.56%
30		7,000	3,150,000	153,004.28	158,334.32	5,330.04	3.48%	88,974.59	241,978.86	247,308.90	2.20%
31		7,000	3,850,000	161,431.34	166,618.70	5,187.36	3.21%	108,746.72	270,178.06	275,365.42	1.92%
32											

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-3										
2	Primary	10	3,500	312.86	269.15	(43.71)	-13.97%	95.32	408.18	364.47	-10.71%
3		10	4,500	328.42	284.36	(44.06)	-13.42%	122.55	450.98	406.92	-9.77%
4		10	5,500	343.99	299.67	(44.41)	-12.91%	149.79	493.77	449.36	-8.99%
5		25	8,750	616.97	579.89	(37.08)	-6.01%	238.30	855.27	818.19	-4.34%
6		25	11,250	655.87	617.91	(37.96)	-5.79%	306.38	962.26	924.29	-3.94%
7		25	13,750	694.78	655.94	(38.84)	-5.59%	374.47	1,069.25	1,030.40	-3.63%
8		50	17,500	1,122.41	1,096.38	(26.03)	-2.32%	476.59	1,599.01	1,572.98	-1.63%
9		50	22,500	1,197.42	1,169.63	(27.79)	-2.32%	612.76	1,810.19	1,782.39	-1.54%
10		50	27,500	1,272.43	1,242.88	(29.56)	-2.32%	748.93	2,021.36	1,991.81	-1.46%
11		75	26,250	1,624.36	1,609.38	(14.98)	-0.92%	714.89	2,339.25	2,324.27	-0.64%
12		75	33,750	1,736.87	1,719.25	(17.62)	-1.01%	919.14	2,656.01	2,638.39	-0.66%
13		75	41,250	1,849.39	1,829.12	(20.27)	-1.10%	1,123.40	2,972.78	2,952.51	-0.68%
14		100	35,000	2,126.30	2,122.37	(3.93)	-0.18%	953.19	3,079.49	3,075.55	-0.13%
15		100	45,000	2,276.32	2,268.86	(7.46)	-0.33%	1,225.53	3,501.84	3,494.39	-0.21%
16		100	55,000	2,426.34	2,415.36	(10.98)	-0.45%	1,497.86	3,924.20	3,913.22	-0.28%
17		200	70,000	4,134.07	4,174.34	40.27	0.97%	1,906.37	6,040.45	6,080.71	0.67%
18		200	90,000	4,434.11	4,467.33	33.21	0.75%	2,451.05	6,885.16	6,918.38	0.48%
19		200	110,000	4,734.15	4,760.31	26.16	0.55%	2,995.73	7,729.88	7,756.04	0.34%
20		500	175,000	10,157.39	10,330.25	172.86	1.70%	4,765.93	14,923.32	15,096.18	1.16%
21		500	225,000	10,907.49	11,062.72	155.23	1.42%	6,127.63	17,035.12	17,190.35	0.91%
22		500	275,000	11,657.59	11,795.19	137.60	1.18%	7,489.32	19,146.92	19,284.51	0.72%
23		1,000	350,000	20,196.26	20,590.11	393.85	1.95%	9,531.87	29,728.12	30,121.97	1.32%
24		1,000	450,000	21,696.46	22,055.04	358.58	1.65%	12,255.26	33,951.71	34,310.30	1.06%
25		1,000	550,000	23,196.66	23,519.98	323.32	1.39%	14,978.65	38,175.31	38,498.63	0.85%
26		3,000	1,050,000	59,829.43	61,139.51	1,310.09	2.19%	28,595.60	88,425.02	89,736.11	1.48%
27		3,000	1,350,000	63,607.96	64,856.90	1,248.94	1.96%	36,765.77	100,373.73	101,622.66	1.24%
28		3,000	1,650,000	67,386.49	68,574.28	1,187.79	1.76%	44,935.94	112,322.43	113,510.21	1.06%
29		7,000	2,450,000	136,770.70	140,057.01	3,286.30	2.40%	66,723.06	203,493.76	206,780.06	1.61%
30		7,000	3,150,000	145,587.28	148,730.90	3,143.62	2.16%	85,786.79	231,374.06	234,517.69	1.36%
31		7,000	3,850,000	154,403.85	157,404.79	3,000.94	1.94%	104,850.52	259,254.36	262,255.31	1.16%
32											

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▸Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-3							0.00			
2	Subtransmission	10	3,500	508.64	1,084.34	575.71	113.19%	9.30	517.94	1,093.64	111.15%
3		10	4,500	524.51	1,099.87	575.35	109.69%	11.96	536.47	1,111.83	107.25%
4		10	5,500	540.39	1,115.39	575.00	106.40%	14.62	555.01	1,130.01	103.60%
5		25	8,750	803.36	1,326.94	523.58	65.17%	23.26	826.61	1,350.19	63.34%
6		25	11,250	843.05	1,365.75	522.70	62.00%	29.90	872.96	1,395.65	59.88%
7		25	13,750	882.74	1,404.56	521.82	59.11%	36.55	919.28	1,441.10	56.76%
8		50	17,500	1,293.15	1,729.86	436.71	33.77%	46.51	1,339.67	1,776.38	32.60%
9		50	22,500	1,369.74	1,804.68	434.94	31.75%	59.80	1,429.54	1,864.48	30.43%
10		50	27,500	1,446.32	1,879.50	433.18	29.95%	73.09	1,519.41	1,952.59	28.51%
11		75	26,250	1,779.45	2,129.29	349.83	19.66%	69.77	1,849.22	2,199.06	18.92%
12		75	33,750	1,894.33	2,241.51	347.19	18.33%	89.71	1,984.03	2,331.22	17.50%
13		75	41,250	2,009.20	2,353.74	344.54	17.15%	109.64	2,118.84	2,463.38	16.26%
14		100	35,000	2,265.75	2,528.71	262.96	11.61%	93.03	2,358.78	2,621.74	11.15%
15		100	45,000	2,418.92	2,678.35	259.43	10.73%	119.61	2,538.52	2,797.96	10.22%
16		100	55,000	2,572.08	2,827.99	255.91	9.95%	146.19	2,718.27	2,974.17	9.41%
17		200	70,000	4,210.95	4,126.41	(84.54)	-2.01%	186.06	4,397.00	4,312.47	-1.92%
18		200	90,000	4,517.28	4,425.69	(91.59)	-2.03%	239.22	4,756.49	4,664.90	-1.93%
19		200	110,000	4,823.61	4,724.96	(98.64)	-2.05%	292.37	5,115.98	5,017.34	-1.93%
20		500	175,000	10,046.53	8,919.50	(1,127.03)	-11.22%	465.14	10,511.67	9,384.64	-10.72%
21		500	225,000	10,812.36	9,667.70	(1,144.66)	-10.59%	598.04	11,410.39	10,265.73	-10.03%
22		500	275,000	11,578.18	10,415.89	(1,162.29)	-10.04%	730.94	12,309.11	11,146.82	-9.44%
23		1,000	350,000	19,772.51	16,907.99	(2,864.51)	-14.49%	930.28	20,702.79	17,838.28	-13.84%
24		1,000	450,000	21,304.15	18,404.38	(2,899.78)	-13.61%	1,196.08	22,500.23	19,600.46	-12.89%
25		1,000	550,000	22,835.80	19,900.76	(2,935.04)	-12.85%	1,461.87	24,297.67	21,362.63	-12.08%
26		3,000	1,050,000	58,154.11	48,371.95	(9,782.16)	-16.82%	2,790.85	60,944.96	51,162.80	-16.05%
27		3,000	1,350,000	62,026.98	52,183.67	(9,843.31)	-15.87%	3,588.23	65,615.21	55,771.90	-15.00%
28		3,000	1,650,000	65,899.85	55,995.39	(9,904.46)	-15.03%	4,385.62	70,285.47	60,381.01	-14.09%
29		7,000	2,450,000	132,592.26	109,118.54	(23,473.72)	-17.70%	6,511.98	139,104.24	115,630.52	-16.87%
30		7,000	3,150,000	141,628.95	118,012.56	(23,616.40)	-16.67%	8,372.54	150,001.49	126,385.10	-15.74%
31		7,000	3,850,000	150,665.64	126,906.57	(23,759.08)	-15.77%	10,233.11	160,898.75	137,139.68	-14.77%
32											

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-4										
2	Primary	3,000	1,200,000	58,064.81	61,058.91	2,994.10	5.16%	29,216.64	87,281.45	90,275.55	3.43%
3		3,000	1,500,000	60,491.22	63,408.66	2,917.44	4.82%	36,520.80	97,012.02	99,929.46	3.01%
4		3,000	1,800,000	62,917.62	65,758.40	2,840.78	4.52%	43,824.96	106,742.58	109,583.36	2.66%
5		5,000	2,000,000	95,308.08	100,463.93	5,155.85	5.41%	48,694.40	144,002.48	149,158.33	3.58%
6		5,000	2,500,000	99,352.08	104,380.17	5,028.09	5.06%	60,868.00	160,220.08	165,248.17	3.14%
7		5,000	3,000,000	103,396.08	108,296.41	4,900.32	4.74%	73,041.60	176,437.68	181,338.01	2.78%
8		8,000	3,200,000	151,172.97	159,571.44	8,398.47	5.56%	77,911.04	229,084.01	237,482.48	3.67%
9		8,000	4,000,000	157,643.38	165,837.43	8,194.05	5.20%	97,388.80	255,032.18	263,226.23	3.21%
10		8,000	4,800,000	164,113.78	172,103.41	7,989.63	4.87%	116,866.56	280,980.34	288,969.97	2.84%
11		20,000	8,000,000	374,632.55	396,001.52	21,368.97	5.70%	194,777.60	569,410.15	590,779.12	3.75%
12		20,000	10,000,000	390,808.56	411,666.48	20,857.91	5.34%	243,472.00	634,280.56	655,138.48	3.29%
13		20,000	12,000,000	406,984.58	427,331.44	20,346.86	5.00%	292,166.40	699,150.98	719,497.84	2.91%
14		50,000	20,000,000	933,281.49	987,076.71	53,795.21	5.76%	486,944.00	1,420,225.49	1,474,020.71	3.79%
15		50,000	25,000,000	973,721.53	1,026,239.11	52,517.57	5.39%	608,680.00	1,582,401.53	1,634,919.11	3.32%
16		50,000	30,000,000	1,014,161.57	1,065,401.50	51,239.93	5.05%	730,416.00	1,744,577.57	1,795,817.50	2.94%
17		125,000	50,000,000	2,329,903.85	2,464,764.68	134,860.82	5.79%	1,217,360.00	3,547,263.85	3,682,124.68	3.80%
18		125,000	62,500,000	2,431,003.95	2,562,670.67	131,666.72	5.42%	1,521,700.00	3,952,703.95	4,084,370.67	3.33%
19		125,000	75,000,000	2,532,104.05	2,660,576.67	128,472.61	5.07%	1,826,040.00	4,358,144.05	4,486,616.67	2.95%
20											
21	GS-4										
22	Subtransmission	3,000	1,200,000	52,356.98	48,410.30	(3,946.69)	-7.54%	28,514.64	80,871.62	76,924.94	-4.88%
23		3,000	1,500,000	54,903.17	50,879.82	(4,023.34)	-7.33%	35,643.30	90,546.47	86,523.12	-4.44%
24		3,000	1,800,000	57,449.35	53,349.35	(4,100.00)	-7.14%	42,771.96	100,221.31	96,121.31	-4.09%
25		5,000	2,000,000	85,591.17	78,809.19	(6,782.02)	-7.92%	47,524.40	133,115.57	126,333.56	-5.09%
26		5,000	2,500,000	89,834.81	82,925.03	(6,909.78)	-7.69%	59,405.50	149,240.31	142,330.53	-4.63%
27		5,000	3,000,000	94,078.45	87,040.91	(7,037.55)	-7.48%	71,286.60	165,365.05	158,327.51	-4.26%
28		8,000	3,200,000	135,442.46	124,407.44	(11,035.01)	-8.15%	76,039.04	211,481.50	200,446.48	-5.22%
29		8,000	4,000,000	142,232.28	130,992.85	(11,239.44)	-7.90%	95,048.80	237,281.08	226,041.65	-4.74%
30		8,000	4,800,000	149,022.11	137,578.25	(11,443.86)	-7.68%	114,058.56	263,080.67	251,636.81	-4.35%
31		20,000	8,000,000	334,847.60	306,800.60	(28,047.00)	-8.38%	190,097.60	524,945.20	496,898.20	-5.34%
32		20,000	10,000,000	351,822.16	323,264.10	(28,558.06)	-8.12%	237,622.00	589,444.16	560,886.10	-4.84%
33		20,000	12,000,000	368,796.72	339,727.60	(29,069.11)	-7.88%	285,146.40	653,943.12	624,874.00	-4.45%
34		50,000	20,000,000	833,360.44	762,783.47	(70,576.97)	-8.47%	475,244.00	1,308,604.44	1,238,027.47	-5.39%

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▸Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-4	50,000	25,000,000	875,796.85	803,942.24	(71,854.61)	-8.20%	594,055.00	1,469,851.85	1,397,997.24	-4.89%
2	Subtransmission	50,000	30,000,000	918,233.25	845,101.00	(73,132.25)	-7.96%	712,866.00	1,631,099.25	1,557,967.00	-4.48%
3		125,000	50,000,000	2,079,642.56	1,902,740.67	(176,901.89)	-8.51%	1,188,110.00	3,267,752.56	3,090,850.67	-5.41%
4		125,000	62,500,000	2,185,733.57	2,005,637.57	(180,095.99)	-8.24%	1,485,137.50	3,670,871.07	3,490,775.07	-4.91%
5		125,000	75,000,000	2,291,824.58	2,108,534.48	(183,290.10)	-8.00%	1,782,165.00	4,073,989.58	3,890,699.48	-4.50%
6											
7	GS-4										
8	Transmission	3,000	1,200,000	49,421.90	47,825.86	(1,596.04)	-3.23%	28,514.64	77,936.54	76,340.50	-2.05%
9		3,000	1,500,000	51,955.17	50,282.47	(1,672.70)	-3.22%	35,643.30	87,598.47	85,925.77	-1.91%
10		3,000	1,800,000	54,488.44	52,739.09	(1,749.35)	-3.21%	42,771.96	97,260.40	95,511.05	-1.80%
11		5,000	2,000,000	80,619.28	77,835.09	(2,784.19)	-3.45%	47,524.40	128,143.68	125,359.49	-2.17%
12		5,000	2,500,000	84,841.40	81,929.45	(2,911.96)	-3.43%	59,405.50	144,246.90	141,334.95	-2.02%
13		5,000	3,000,000	89,063.52	86,023.80	(3,039.72)	-3.41%	71,286.60	160,350.12	157,310.40	-1.90%
14		8,000	3,200,000	127,415.36	122,848.94	(4,566.42)	-3.58%	76,039.04	203,454.40	198,887.98	-2.24%
15		8,000	4,000,000	134,170.76	129,399.91	(4,770.84)	-3.56%	95,048.80	229,219.56	224,448.71	-2.08%
16		8,000	4,800,000	140,926.15	135,950.88	(4,975.27)	-3.53%	114,058.56	254,984.71	250,009.44	-1.95%
17		20,000	8,000,000	314,599.69	302,904.34	(11,695.34)	-3.72%	190,097.60	504,697.29	493,001.94	-2.32%
18		20,000	10,000,000	331,488.17	319,281.77	(12,206.40)	-3.68%	237,622.00	569,110.17	556,903.77	-2.14%
19		20,000	12,000,000	348,376.65	335,659.19	(12,717.46)	-3.65%	285,146.40	633,523.05	620,805.59	-2.01%
20		50,000	20,000,000	782,560.49	753,042.84	(29,517.65)	-3.77%	475,244.00	1,257,804.49	1,228,286.84	-2.35%
21		50,000	25,000,000	824,781.69	793,986.40	(30,795.29)	-3.73%	594,055.00	1,418,836.69	1,388,041.40	-2.17%
22		50,000	30,000,000	867,002.89	834,929.96	(32,072.93)	-3.70%	712,866.00	1,579,868.89	1,547,795.96	-2.03%
23		125,000	50,000,000	1,952,462.51	1,878,389.10	(74,073.41)	-3.79%	1,188,110.00	3,140,572.51	3,066,499.10	-2.36%
24		125,000	62,500,000	2,058,015.50	1,980,747.99	(77,267.52)	-3.75%	1,485,137.50	3,543,153.00	3,465,885.49	-2.18%
25		125,000	75,000,000	2,163,568.50	2,083,106.88	(80,461.62)	-3.72%	1,782,165.00	3,945,733.50	3,865,271.88	-2.04%
26											

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Schedule E-5

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	EHG										
2		30	100	30.43	187.37	156.94	515.77%	3.02	33.45	190.39	469.18%
3		30	500	51.66	202.54	150.88	292.04%	15.11	66.77	217.65	225.97%
4		30	1,000	78.21	221.51	143.31	183.24%	30.21	108.42	251.73	132.18%
5		30	3,000	183.92	296.93	113.01	61.44%	90.64	274.56	387.57	41.16%
6		30	4,500	262.87	353.15	90.28	34.35%	135.96	398.82	489.11	22.64%
7		30	6,000	341.81	409.37	67.56	19.77%	181.28	523.09	590.65	12.92%
8		30	9,000	499.70	521.81	22.12	4.43%	271.91	771.61	793.73	2.87%
9		30	12,000	657.58	634.25	(23.33)	-3.55%	362.55	1,020.13	996.80	-2.29%
10		30	15,000	815.47	746.69	(68.78)	-8.43%	453.19	1,268.66	1,199.88	-5.42%
11		30	20,000	1,075.81	931.29	(144.52)	-13.43%	604.25	1,680.06	1,535.54	-8.60%
12		50	5,000	356.50	524.15	167.65	47.03%	151.06	507.57	675.21	33.03%
13		50	7,500	488.07	617.85	129.77	26.59%	226.60	714.67	844.44	18.16%
14		50	10,000	619.64	711.55	91.90	14.83%	302.13	921.77	1,013.67	9.97%
15		50	15,000	882.79	898.95	16.16	1.83%	453.19	1,335.98	1,352.14	1.21%
16		50	20,000	1,143.13	1,083.54	(59.58)	-5.21%	604.25	1,747.38	1,687.80	-3.41%
17		50	25,000	1,403.47	1,268.14	(135.33)	-9.64%	755.32	2,158.79	2,023.46	-6.27%
18		100	10,000	787.94	1,092.19	304.24	38.61%	302.13	1,090.07	1,394.31	27.91%
19		100	15,000	1,051.09	1,279.59	228.50	21.74%	453.19	1,504.28	1,732.78	15.19%
20		100	20,000	1,311.43	1,464.18	152.75	11.65%	604.25	1,915.68	2,068.44	7.97%
21		100	30,000	1,832.11	1,833.38	1.27	0.07%	906.38	2,738.50	2,739.76	0.05%
22		100	40,000	2,352.80	2,202.58	(150.22)	-6.38%	1,208.51	3,561.31	3,411.09	-4.22%
23		200	20,000	1,648.03	2,225.47	577.43	35.04%	604.25	2,252.28	2,829.72	25.64%
24		200	30,000	2,168.72	2,594.66	425.95	19.64%	906.38	3,075.10	3,501.04	13.85%
25		200	40,000	2,689.40	2,963.86	274.46	10.21%	1,208.51	3,897.91	4,172.37	7.04%
26		200	60,000	3,730.77	3,702.25	(28.52)	-0.76%	1,812.76	5,543.53	5,515.02	-0.51%
27											
28											
29	EHS	55	15,000	325.26	612.18	286.92	88.21%	390.96	716.22	1,003.14	40.06%
30		150	30,000	641.21	1,423.22	782.02	121.96%	781.92	1,423.13	2,205.15	54.95%
31		225	65,000	1,378.40	2,494.83	1,116.42	80.99%	1,694.17	3,072.57	4,189.00	36.34%
32											

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original__Updated__Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	SS										
2	1,000 sq ft	10	1,500	124.27	138.16	13.89	11.18%	43.66	167.93	181.82	8.27%
3		10	3,000	211.34	203.90	(7.44)	-3.52%	87.31	298.66	291.22	-2.49%
4		10	4,500	298.18	269.41	(28.77)	-9.65%	130.97	429.15	400.39	-6.70%
5											
6	5,000 sq ft	20	2,000	154.74	217.49	62.75	40.55%	58.21	212.95	275.70	29.47%
7		20	4,000	270.53	304.83	34.31	12.68%	116.42	386.94	421.25	8.87%
8		20	6,000	386.31	392.18	5.87	1.52%	174.63	560.94	566.81	1.05%
9											
10	10,000 sq ft	20	2,000	155.28	218.03	62.75	40.41%	58.21	213.49	276.24	29.39%
11		20	4,000	272.14	306.45	34.31	12.61%	116.42	388.56	422.87	8.83%
12		20	6,000	387.92	393.80	5.87	1.51%	174.63	562.55	568.42	1.04%
13		40	5,000	330.03	462.05	132.02	40.00%	145.52	475.56	607.58	27.76%
14		40	7,500	474.76	571.24	96.47	20.32%	218.29	693.05	789.52	13.92%
15		40	10,000	619.49	680.42	60.92	9.83%	291.05	910.54	971.47	6.69%
16											
17	20,000 sq ft	50	10,000	622.72	739.61	116.89	18.77%	291.05	913.77	1,030.66	12.79%
18		50	15,000	912.19	957.98	45.79	5.02%	436.57	1,348.76	1,394.55	3.40%
19		50	20,000	1,198.85	1,173.55	(25.30)	-2.11%	582.10	1,780.94	1,755.64	-1.42%
20											
21	30,000 sq ft	50	10,000	625.95	742.84	116.89	18.67%	291.05	917.00	1,033.89	12.75%
22		50	15,000	915.42	961.21	45.79	5.00%	436.57	1,351.99	1,397.78	3.39%
23		50	20,000	1,202.08	1,176.77	(25.30)	-2.10%	582.10	1,784.17	1,758.87	-1.42%
24		100	20,000	1,202.08	1,456.60	254.53	21.17%	582.10	1,784.17	2,038.70	14.27%
25		100	25,000	1,488.74	1,672.17	183.43	12.32%	727.62	2,216.36	2,399.79	8.28%
26		100	30,000	1,775.40	1,887.73	112.33	6.33%	873.14	2,648.56	2,760.88	4.24%
27											
28	50,000 sq ft	100	15,000	921.87	1,247.50	325.62	35.32%	436.57	1,358.45	1,684.07	23.97%
29		100	30,000	1,781.86	1,894.19	112.33	6.30%	873.14	2,655.00	2,767.34	4.23%
30		200	40,000	2,355.18	2,884.98	529.79	22.49%	1,164.19	3,519.38	4,049.17	15.05%
31		200	60,000	3,501.83	3,747.24	245.41	7.01%	1,746.29	5,248.12	5,493.53	4.68%
32		300	60,000	3,501.83	4,306.90	805.06	22.99%	1,746.29	5,248.12	6,053.19	15.34%
33		300	80,000	4,648.48	5,169.16	520.68	11.20%	2,328.38	6,976.87	7,497.54	7.46%

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E+C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E+H)
1	SS										
2	100,000 sq ft	250	60,000	3,517.98	4,043.22	525.24	14.93%	1,746.29	5,264.27	5,789.50	9.98%
3		250	80,000	4,664.63	4,905.48	240.85	5.16%	2,328.38	6,993.01	7,233.86	3.44%
4		400	80,000	4,664.63	5,744.96	1,080.33	23.16%	2,328.38	6,993.01	8,073.35	15.45%
5		400	120,000	6,957.93	7,469.49	511.56	7.35%	3,492.58	10,450.50	10,962.06	4.90%
6											
7	OL										
8		Lamp Size									
9		Mercury Vapor									
10		7,000 Lumen	72	11.10	13.64	2.54	22.85%	3.20	14.30	16.84	17.73%
11		20,000 Lumen	158	16.56	19.81	3.25	19.64%	7.03	23.58	26.83	13.79%
12											
13		High Pressure Sodium									
14		9,000 Lumen	40	9.04	11.88	2.83	31.35%	1.78	10.82	13.66	26.20%
15		22,000 Lumen	84	12.03	15.99	3.96	32.94%	3.73	15.77	19.73	25.14%
16											
17		Incandescent									
18		2,500 Lumen	63	8.55	11.78	3.23	37.77%	2.80	11.36	14.59	28.45%
19		4,000 Lumen	98	9.53	13.01	3.48	36.51%	4.36	13.89	17.37	25.05%
20											
21		MV Floodlight									
22		20,000 Lumen	158	19.51	23.61	4.10	21.04%	7.03	26.53	30.64	15.47%
23		50,000 Lumen	378	28.78	33.47	4.69	16.30%	16.81	45.58	50.28	10.29%
24											
25		HPS Floodlight									
26		22,000 Lumen	84	13.88	17.83	3.95	28.47%	3.73	17.61	21.57	22.44%
27		50,000 Lumen	167	15.68	20.08	4.39	28.02%	7.43	23.11	27.50	19.02%
28											
29		MH Floodlight									
30		17,000 Lumen	100	12.44	16.35	3.91	31.48%	4.45	16.88	20.80	23.19%
31		29,000 Lumen	158	13.05	17.66	4.61	35.33%	7.03	20.08	24.69	22.97%
32											
33		Post Top-MV									
34		7,000 Lumen	72	12.58	16.98	4.40	34.99%	3.20	15.78	20.19	27.89%

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	OL										
2		Post Top-HPS									
3		9,000 Lumen	40	15.90	21.41	5.51	34.66%	1.78	17.68	23.19	31.17%
4											
5		Facilities Charges:									
6		Underground circuit per 25 feet over 30 feet	0	0.63	1.02	0.39	61.58%	-	0.63	1.02	61.58%
7											
8	SL										
9		On Wood Pole									
10		7,000 lumen mercury vapor	72	6.06	6.39	0.33	5.48%	2.75	8.81	9.14	3.77%
11		11,000 lumen mercury vapor	100	7.53	7.88	0.35	4.60%	3.82	11.34	11.69	3.05%
12		20,000 lumen mercury vapor	158	8.81	9.00	0.19	2.11%	6.03	14.84	15.02	1.25%
13		50,000 lumen mercury vapor	378	15.31	15.33	0.02	0.10%	14.42	29.74	29.75	0.05%
14		9,000 lumen high pressure sodium	40	6.87	7.38	0.50	7.33%	1.53	8.40	8.90	6.00%
15		16,000 lumen high pressure sodium	59	7.84	8.29	0.45	5.71%	2.25	10.09	10.54	4.43%
16		22,000 lumen high pressure sodium	84	9.36	9.81	0.45	4.80%	3.20	12.57	13.02	3.57%
17		50,000 lumen high pressure sodium	167	12.50	12.72	0.22	1.78%	6.37	18.87	19.09	1.18%
18		9,000 lumen high pressure sodium (post 1988)	40	12.12	13.76	1.64	13.50%	1.53	13.65	15.28	11.99%
19		16,000 lumen high pressure sodium (post 198ξ	59	14.90	16.48	1.58	10.60%	2.25	17.15	18.73	9.21%
20		22,000 lumen high pressure sodium (post 198ξ	84	16.33	17.91	1.58	9.69%	3.20	19.53	21.11	8.10%
21		50,000 lumen high pressure sodium (post 198ξ	167	22.08	23.44	1.36	6.14%	6.37	28.45	29.81	4.76%
22											
23		On Metal Pole:									
24		7,000 lumen mercury vapor	72	9.13	10.04	0.91	9.95%	2.75	11.88	12.79	7.65%
25		11,000 lumen mercury vapor	100	10.94	11.95	1.01	9.26%	3.82	14.75	15.76	6.87%
26		20,000 lumen mercury vapor	158	12.44	13.34	0.91	7.31%	6.03	18.46	19.37	4.92%
27		50,000 lumen mercury vapor	378	20.19	21.00	0.81	3.99%	14.42	34.62	35.42	2.33%
28		9,000 lumen high pressure sodium	40	15.22	16.67	1.45	9.56%	1.53	16.75	18.20	8.69%
29		16,000 lumen high pressure sodium	59	16.14	17.54	1.40	8.66%	2.25	18.40	19.79	7.60%
30		22,000 lumen high pressure sodium	84	17.69	19.10	1.41	7.98%	3.20	20.89	22.31	6.76%
31		50,000 lumen high pressure sodium	167	20.80	21.98	1.17	5.64%	6.37	27.17	28.35	4.32%
32		9,000 lumen high pressure sodium (post 1998)	40	42.42	42.24	(0.18)	-0.43%	1.53	43.95	43.76	-0.41%
33		16,000 lumen high pressure sodium (post 199€	59	43.52	43.27	(0.25)	-0.57%	2.25	45.77	45.53	-0.54%
34		22,000 lumen high pressure sodium (post 199€	84	45.07	44.73	(0.34)	-0.75%	3.20	48.27	47.93	-0.70%
35		50,000 lumen high pressure sodium (post 199ξ	167	48.27	47.64	(0.63)	-1.31%	6.37	54.65	54.01	-1.16%

Date Prepared: February 28, 2011

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original__Updated__Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	SL										
2		Multiple Lamps on Metal Pole:									
3		20,000 lumen mercury vapor	158	10.53	11.12	0.58	5.52%	6.03	16.56	17.14	3.51%
4		9,000 lumen high pressure sodium	40	11.02	12.00	0.98	8.89%	1.53	12.54	13.52	7.80%
5		16,000 lumen high pressure sodium	59	11.98	12.90	0.92	7.71%	2.25	14.23	15.15	6.49%
6		22,000 lumen high pressure sodium	84	13.49	14.43	0.94	6.94%	3.20	16.70	17.63	5.61%
7		50,000 lumen high pressure sodium	167	16.63	17.33	0.70	4.20%	6.37	23.01	23.70	3.04%
8		9,000 lumen high pressure sodium (post 1998)	40	24.81	24.64	(0.16)	-0.66%	1.53	26.33	26.17	-0.63%
9		16,000 lumen high pressure sodium (post 199ε	59	25.79	25.55	(0.23)	-0.90%	2.25	28.04	27.80	-0.83%
10		22,000 lumen high pressure sodium (post 199ε	84	27.34	27.02	(0.32)	-1.18%	3.20	30.55	30.22	-1.05%
11		50,000 lumen high pressure sodium (post 199ε	167	30.55	30.37	(0.18)	-0.60%	6.37	36.92	36.74	-0.49%
12											
13		Post Top Unit:									
14		7,000 lumen mercury vapor	72	9.05	9.95	0.90	9.92%	2.75	11.80	12.69	7.61%
15		9,000 lumen high pressure sodium	40	12.94	12.78	(0.15)	-1.19%	1.53	14.46	14.31	-1.06%
16		9,000 lumen high pressure sodium (post 1988)	40	16.52	18.02	1.50	9.08%	1.53	18.04	19.54	8.31%
17											
18		Facilities Charges:									
19		Receptacle Charge	0	2.10	2.41	0.31	14.50%	-	2.10	2.41	14.50%
20											

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original__Updated__Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	RS		0	4.37	9.86	5.49	125.74%	-	4.37	9.86	125.74%
2			30	6.61	12.02	5.42	82.00%	0.95	7.56	12.98	71.65%
3			70	9.59	14.90	5.31	55.42%	2.23	11.81	17.13	44.98%
4			120	13.32	18.50	5.18	38.93%	3.82	17.13	22.32	30.26%
5			200	19.28	24.26	4.98	25.82%	6.36	25.64	30.62	19.41%
6			300	26.74	31.46	4.72	17.65%	9.54	36.28	41.00	13.01%
7			500	41.65	45.85	4.20	10.09%	15.90	57.55	61.75	7.30%
8			800	64.01	67.44	3.43	5.35%	25.44	89.46	92.88	3.83%
9			1,000	76.52	80.90	4.38	5.73%	31.80	108.32	112.70	4.05%
10			1,200	89.02	94.36	5.34	6.00%	38.16	127.18	132.52	4.20%
11			1,500	107.77	114.55	6.78	6.29%	47.70	155.47	162.25	4.36%
12			2,000	139.02	148.19	9.17	6.60%	63.60	202.63	211.80	4.53%
13			4,000	263.12	281.86	18.74	7.12%	127.20	390.32	409.06	4.80%
14			5,000	325.17	348.69	23.53	7.23%	159.01	484.17	507.70	4.86%
15			8,000	511.31	549.19	37.88	7.41%	264.41	765.72	803.60	4.95%
16			10,000	635.40	682.85	47.45	7.47%	318.01	953.42	1,000.87	4.98%
17			12,000	759.50	816.52	57.02	7.51%	381.61	1,141.11	1,198.13	5.00%
18			15,000	945.64	1,017.02	71.38	7.55%	477.02	1,422.66	1,494.03	5.02%
19											
20	RS										
21	SWH	80 gal.	500	31.16	42.00	10.84	34.79%	15.90	47.06	57.91	23.03%
22		80 gal.	800	53.53	63.60	10.07	18.80%	25.44	78.97	89.04	12.75%
23		80 gal.	1,000	68.44	77.99	9.55	13.95%	31.80	100.24	109.79	9.53%
24		80 gal.	1,600	100.30	111.87	11.57	11.54%	47.70	148.00	159.57	7.82%
25		80 gal.	2,000	131.55	145.52	13.97	10.62%	63.60	195.15	209.12	7.16%
26		80 gal.	4,000	255.65	279.18	23.54	9.21%	127.20	382.85	406.39	6.15%
27		80 gal.	6,000	379.74	412.85	33.11	8.72%	190.81	570.55	603.65	5.80%
28		80 gal.	8,000	503.84	546.51	42.68	8.47%	254.41	758.25	800.92	5.63%

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E+C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E+H)
1	RS										
2	SWH	100 gal.	500	27.88	40.05	12.17	43.65%	15.90	43.78	55.95	27.80%
3		100 gal.	800	49.34	62.06	12.72	25.78%	25.44	74.78	87.50	17.01%
4		100 gal.	1,000	64.25	76.45	12.20	19.00%	31.80	96.05	108.25	12.71%
5		100 gal.	1,500	97.31	110.80	13.49	13.86%	47.70	145.01	158.50	9.30%
6		100 gal.	2,000	128.56	144.46	15.88	12.36%	63.60	192.17	208.05	8.27%
7		100 gal.	4,000	252.66	278.11	25.45	10.07%	127.20	379.86	405.32	6.70%
8		100 gal.	6,000	376.75	411.78	35.02	9.30%	190.81	567.56	602.58	6.17%
9		100 gal.	8,000	500.85	545.44	44.59	8.90%	254.41	755.26	799.85	5.90%
10											
11		120 gal.	500	27.88	40.05	12.17	43.65%	15.90	43.78	55.95	27.80%
12		120 gal.	800	45.14	60.52	15.38	34.06%	25.44	70.58	85.96	21.78%
13		120 gal.	1,000	60.05	74.91	14.86	24.74%	31.80	91.86	106.72	16.18%
14		120 gal.	1,500	94.32	109.73	15.41	16.34%	47.70	142.02	157.43	10.85%
15		120 gal.	2,000	125.57	143.38	17.80	14.18%	63.60	189.18	206.98	9.41%
16		120 gal.	4,000	249.67	277.04	27.37	10.96%	127.20	376.87	404.25	7.26%
17		120 gal.	6,000	373.76	410.71	36.94	9.88%	190.81	564.57	601.51	6.54%
18		120 gal.	8,000	497.86	544.37	46.51	9.34%	254.41	752.27	798.78	6.18%
19		120 gal.	10,000	621.95	678.04	56.08	9.02%	318.01	939.97	996.05	5.97%
20											
21											
22	RS-TOD										
23	On - Peak 25%		1,000	62.80	75.24	12.44	19.81%	31.80	94.61	107.05	13.15%
24	Off-Peak 75%		2,000	116.87	139.65	22.78	19.49%	63.60	180.47	203.26	12.62%
25			3,000	170.48	203.60	33.13	19.43%	95.40	265.88	299.01	12.46%
26			4,000	224.08	267.55	43.47	19.40%	127.20	351.29	394.76	12.37%
27			5,000	277.69	331.50	53.82	19.38%	159.01	436.69	490.51	12.32%
28			6,000	331.29	395.45	64.16	19.37%	190.81	522.10	586.26	12.29%
29			7,000	384.90	459.40	74.50	19.36%	222.61	607.51	682.01	12.26%
30			8,000	438.50	523.35	84.85	19.35%	254.41	692.91	777.76	12.24%

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Schedule E-5
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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E+C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E+H)
1	RS-TOD										
2	On - Peak	30%	1,000	67.09	76.81	9.71	14.48%	31.80	98.89	108.61	9.82%
3	Off-Peak	70%	2,000	125.45	142.78	17.33	13.82%	63.60	189.05	206.38	9.17%
4			3,000	183.34	208.29	24.95	13.61%	95.40	278.75	303.70	8.95%
5			4,000	241.24	273.81	32.57	13.50%	127.20	368.44	401.01	8.84%
6			5,000	299.13	339.32	40.19	13.44%	159.01	458.14	498.33	8.77%
7			6,000	357.03	404.83	47.81	13.39%	190.81	547.83	595.64	8.73%
8			7,000	414.92	470.35	55.43	13.36%	222.61	637.53	692.96	8.69%
9			8,000	472.81	535.86	63.05	13.33%	254.41	727.22	790.27	8.67%
10											
11	On - Peak	35%	1,000	71.38	78.37	6.99	9.79%	31.80	103.18	110.17	6.77%
12	Off-Peak	65%	2,000	134.03	145.91	11.88	8.87%	63.60	197.63	209.51	6.01%
13			3,000	196.21	212.99	16.78	8.55%	95.40	291.61	308.39	5.75%
14			4,000	258.39	280.06	21.67	8.39%	127.20	385.60	407.27	5.62%
15			5,000	320.58	347.14	26.56	8.29%	159.01	479.58	506.15	5.54%
16			6,000	382.76	414.22	31.46	8.22%	190.81	573.57	605.02	5.48%
17			7,000	444.94	481.29	36.35	8.17%	222.61	667.55	703.90	5.45%
18			8,000	507.12	548.37	41.25	8.13%	254.41	761.53	802.78	5.42%
19											
20	RS-ES										
21	On - Peak	15%	1,000	54.23	72.12	17.89	32.99%	31.80	86.03	103.92	20.80%
22	Off-Peak	85%	2,000	99.71	133.40	33.68	33.78%	63.60	163.32	197.00	20.62%
23			3,000	144.74	194.22	49.48	34.18%	95.40	240.15	289.62	20.60%
24			4,000	189.77	255.04	65.27	34.40%	127.20	316.98	382.25	20.59%
25			5,000	234.80	315.86	81.07	34.53%	159.01	393.80	474.87	20.59%
26			6,000	279.83	376.69	96.86	34.61%	190.81	470.63	567.49	20.58%
27			7,000	324.85	437.51	112.65	34.68%	222.61	547.46	660.12	20.58%
28			8,000	369.88	498.33	128.45	34.73%	254.41	624.29	752.74	20.58%

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	RS-ES										
2	On - Peak	20%	1,000	58.52	73.68	15.16	25.92%	31.80	90.32	105.48	16.79%
3	Off-Peak	80%	2,000	108.29	136.53	28.23	26.07%	63.60	171.89	200.13	16.42%
4			3,000	157.61	198.91	41.30	26.21%	95.40	253.01	294.32	16.32%
5			4,000	206.93	261.30	54.37	26.28%	127.20	334.13	388.50	16.27%
6			5,000	256.24	323.68	67.44	26.32%	159.01	415.25	482.69	16.24%
7			6,000	305.56	386.07	80.51	26.35%	190.81	496.37	576.88	16.22%
8			7,000	354.88	448.45	93.58	26.37%	222.61	577.48	671.06	16.20%
9			8,000	404.19	510.84	106.65	26.39%	254.41	658.60	765.25	16.19%
10											
11	On - Peak	25%	1,000	62.80	75.24	12.44	19.81%	31.80	94.61	107.05	13.15%
12	Off-Peak	75%	2,000	116.87	139.65	22.78	19.49%	63.60	180.47	203.26	12.62%
13			3,000	170.48	203.60	33.13	19.43%	95.40	265.88	299.01	12.46%
14			4,000	224.08	267.55	43.47	19.40%	127.20	351.29	394.76	12.37%
15			5,000	277.69	331.50	53.82	19.38%	159.01	436.69	490.51	12.32%
16			6,000	331.29	395.45	64.16	19.37%	190.81	522.10	586.26	12.29%
17			7,000	384.90	459.40	74.50	19.36%	222.61	607.51	682.01	12.26%
18			8,000	438.50	523.35	84.65	19.35%	254.41	692.91	777.76	12.24%
19											
20	GS-1										
21	Unmetered		50	11.30	11.93	0.63	5.56%	1.65	12.94	13.57	4.85%
22			100	14.19	15.66	1.47	10.35%	3.29	17.48	18.95	8.40%
23			150	17.08	19.39	2.31	13.51%	4.94	22.02	24.33	10.48%
24			200	19.97	23.12	3.15	15.76%	6.58	26.56	29.70	11.85%
25			400	31.54	38.05	6.51	20.64%	13.17	44.70	51.21	14.56%
26			700	48.89	60.43	11.55	23.62%	23.04	71.93	83.47	16.06%
27			1,000	66.24	82.82	16.59	25.04%	32.91	99.15	115.74	16.73%
28			1,500	95.15	120.14	24.99	26.26%	49.37	144.52	169.51	17.29%
29			2,000	124.06	157.46	33.39	26.91%	65.83	189.89	223.28	17.58%
30			4,000	238.80	305.79	66.99	28.05%	131.65	370.45	437.44	18.08%
31			8,000	468.27	602.46	134.19	28.66%	263.30	731.57	865.76	18.34%
32			10,000	583.01	750.79	167.79	28.78%	329.13	912.14	1,079.92	18.39%
33			15,000	869.84	1,121.63	251.79	28.95%	493.70	1,363.54	1,615.33	18.47%
34			25,000	1,437.92	1,857.71	419.78	29.19%	822.83	2,260.75	2,680.53	18.57%

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-1-ES										
2	On-Peak	10%	500	35.83	39.04	3.21	8.95%	16.46	52.29	55.50	6.13%
3	Off-Peak	90%	1,000	54.42	67.15	12.73	23.38%	32.91	87.33	100.06	14.57%
4			2,000	91.59	123.36	31.76	34.68%	65.83	157.42	189.18	20.18%
5			4,000	165.01	234.85	69.84	42.33%	131.65	296.66	366.51	23.54%
6			6,000	238.43	346.35	107.92	45.26%	197.48	435.91	543.83	24.76%
7			8,000	311.85	457.85	146.00	46.82%	263.30	575.16	721.16	25.38%
8											
9	On-Peak	15%	500	37.11	40.18	3.07	8.26%	16.46	53.57	56.64	5.72%
10	Off-Peak	85%	1,000	56.98	69.43	12.44	21.84%	32.91	89.89	102.34	13.84%
11			2,000	96.71	127.91	31.20	32.26%	65.83	162.54	193.74	19.20%
12			4,000	175.25	243.97	68.72	39.21%	131.65	306.90	375.62	22.39%
13			6,000	253.79	360.03	106.23	41.86%	197.48	451.27	557.51	23.54%
14			8,000	332.33	476.08	143.75	43.25%	263.30	595.64	739.39	24.13%
15											
16	On-Peak	20%	500	38.39	41.32	2.93	7.62%	16.46	54.85	57.78	5.33%
17	Off-Peak	80%	1,000	59.54	71.70	12.16	20.43%	32.91	92.45	104.62	13.16%
18			2,000	101.83	132.47	30.64	30.09%	65.83	167.66	198.30	18.28%
19			4,000	185.49	253.09	67.59	36.44%	131.65	317.14	384.74	21.31%
20			6,000	269.15	373.70	104.55	38.84%	197.48	466.63	571.18	22.40%
21			8,000	352.81	494.31	141.50	40.11%	263.30	616.12	757.62	22.97%
22											

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
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Type of Filing: ▸Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-1										
2			600	49.76	54.74	4.98	10.01%	19.75	69.51	74.49	7.17%
3			700	55.54	62.21	6.66	11.99%	23.04	78.58	85.24	8.48%
4			800	61.33	69.67	8.34	13.60%	26.33	87.66	96.00	9.52%
5			900	67.11	77.13	10.02	14.93%	29.62	96.73	106.75	10.36%
6			1,200	84.46	99.52	15.06	17.83%	39.50	123.95	139.01	12.15%
7			1,400	96.02	114.44	18.42	19.18%	46.08	142.10	160.52	12.96%
8			1,600	107.59	129.37	21.78	20.24%	52.66	160.25	182.03	13.59%
9			1,800	119.15	144.30	25.14	21.10%	59.24	178.40	203.54	14.09%
10			2,100	136.46	166.64	30.18	22.12%	69.12	205.57	235.76	14.68%
11			2,400	153.67	188.89	35.22	22.92%	78.99	232.66	267.88	15.14%
12			2,700	170.88	211.14	40.26	23.56%	88.87	259.74	300.00	15.50%
13			2,800	176.61	218.56	41.94	23.75%	92.16	268.77	310.71	15.60%
14			3,000	188.09	233.39	45.30	24.08%	98.74	286.83	332.13	15.79%
15			3,200	199.56	248.22	48.66	24.38%	105.32	304.88	353.54	15.96%
16			3,500	216.77	270.47	53.70	24.77%	115.20	331.97	385.67	16.18%
17			3,600	222.51	277.89	55.38	24.89%	118.49	341.00	396.38	16.24%
18			4,000	245.46	307.56	62.10	25.30%	131.65	377.11	439.21	16.47%
19			4,500	274.14	344.64	70.50	25.72%	148.11	422.25	492.75	16.70%
20											
21	GS-2-										
22	Rec. Lighting		50	22.87	17.99	(4.88)	-21.34%	1.50	24.37	19.49	-20.03%
23			100	26.03	21.27	(4.76)	-18.28%	3.00	29.03	24.27	-16.40%
24			150	29.20	24.56	(4.64)	-15.89%	4.50	33.70	29.06	-13.77%
25			200	32.36	27.84	(4.52)	-13.96%	6.00	38.36	33.84	-11.78%
26			400	45.01	40.98	(4.03)	-8.96%	12.00	57.01	52.98	-7.07%
27			700	63.99	60.68	(3.30)	-5.16%	21.00	84.99	81.69	-3.89%
28			1,000	82.96	80.39	(2.58)	-3.10%	30.00	112.97	110.39	-2.28%
29			1,500	114.59	113.23	(1.36)	-1.19%	45.01	159.60	158.23	-0.85%
30			2,000	146.22	146.07	(0.15)	-0.10%	60.01	206.22	206.08	-0.07%
31			4,000	271.80	276.51	4.71	1.73%	120.02	391.82	396.53	1.20%
32			8,000	522.98	537.40	14.42	2.76%	240.04	763.01	777.43	1.89%
33			10,000	648.56	667.84	19.28	2.97%	300.05	948.61	967.88	2.03%
34			15,000	962.53	993.94	31.41	3.26%	450.07	1,412.60	1,444.01	2.22%
35			25,000	1,584.86	1,640.56	55.69	3.51%	750.12	2,334.98	2,390.67	2.39%

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▸Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-2										
2	Secondary	10	1,000	113.22	126.85	13.63	12.04%	30.00	143.23	156.85	9.51%
3		10	2,000	160.48	173.75	13.27	8.27%	60.01	220.49	233.76	6.02%
4		10	3,000	207.28	220.20	12.92	6.23%	90.01	297.29	310.21	4.35%
5		25	2,500	243.51	293.38	49.86	20.48%	75.01	318.52	368.39	15.65%
6		25	5,000	360.51	409.49	48.98	13.59%	150.02	510.53	559.51	9.59%
7		25	7,500	477.50	525.60	48.10	10.07%	225.03	702.54	750.64	6.85%
8		50	5,000	459.90	570.15	110.25	23.97%	150.02	609.92	720.18	18.08%
9		50	10,000	693.89	802.38	108.49	15.63%	300.05	993.94	1,102.43	10.92%
10		50	15,000	927.88	1,034.61	106.73	11.50%	450.07	1,377.95	1,484.68	7.75%
11		75	7,500	676.29	846.93	170.64	25.23%	225.03	901.32	1,071.97	18.93%
12		75	15,000	1,027.27	1,195.27	168.00	16.35%	450.07	1,477.34	1,645.34	11.37%
13		75	22,500	1,374.06	1,539.42	165.35	12.03%	675.10	2,049.17	2,214.52	8.07%
14		100	10,000	892.67	1,123.71	231.04	25.88%	300.05	1,192.72	1,423.76	19.37%
15		100	20,000	1,357.86	1,585.37	227.51	16.76%	600.09	1,957.95	2,185.46	11.62%
16		100	30,000	1,820.24	2,044.22	223.98	12.31%	900.14	2,720.38	2,944.36	8.23%
17		200	20,000	1,755.42	2,228.02	472.60	26.92%	600.09	2,355.51	2,828.12	20.06%
18		200	40,000	2,680.19	3,145.74	465.55	17.37%	1,200.18	3,880.37	4,345.92	12.00%
19		200	60,000	3,604.95	4,063.45	458.50	12.72%	1,800.28	5,405.23	5,863.73	8.48%
20		500	50,000	4,335.27	5,532.56	1,197.30	27.62%	1,500.23	5,835.50	7,032.79	20.52%
21		500	100,000	6,647.18	7,826.85	1,179.66	17.75%	3,000.46	9,647.64	10,827.31	12.23%
22		500	150,000	8,959.10	10,121.13	1,162.03	12.97%	4,500.69	13,459.79	14,621.82	8.63%
23		1,000	100,000	8,635.01	11,040.13	2,405.12	27.85%	3,000.46	11,635.47	14,040.59	20.67%
24		1,000	200,000	13,258.84	15,628.70	2,369.86	17.87%	6,000.92	19,259.76	21,629.62	12.30%
25		1,000	300,000	17,882.67	20,217.27	2,334.60	13.06%	9,001.38	26,884.05	29,218.65	8.68%
26		3,000	300,000	25,833.97	33,070.40	7,236.42	28.01%	9,001.38	34,835.35	42,071.78	20.77%
27		3,000	600,000	39,705.46	46,836.10	7,130.64	17.96%	18,002.76	57,708.22	64,838.86	12.36%
28		3,000	900,000	53,415.69	60,450.51	7,034.82	13.17%	27,004.14	80,419.83	87,454.65	8.75%
29		7,000	700,000	60,231.90	77,130.93	16,899.03	28.06%	21,003.22	81,235.12	98,134.15	20.80%
30		7,000	1,400,000	91,234.00	107,970.56	16,736.56	18.34%	42,006.44	133,240.44	149,977.00	12.56%
31		7,000	2,100,000	121,915.99	138,509.87	16,593.88	13.61%	63,009.66	184,925.65	201,519.53	8.97%
32											

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-2										
2	Primary	10	1,000	186.60	158.99	(27.61)	-14.80%	27.23	213.84	186.22	-12.91%
3		10	2,000	233.35	205.39	(27.97)	-11.98%	54.47	287.82	259.85	-9.72%
4		10	3,000	279.64	251.32	(28.32)	-10.13%	81.70	361.34	333.02	-7.84%
5		25	2,500	302.47	305.83	3.16	1.04%	68.08	370.55	373.71	0.85%
6		25	5,000	418.19	420.47	2.28	0.54%	136.17	554.36	556.64	0.41%
7		25	7,500	533.91	535.31	1.40	0.26%	204.25	738.17	739.56	0.19%
8		50	5,000	494.81	549.26	54.45	11.00%	136.17	630.98	685.43	8.63%
9		50	10,000	726.26	778.94	52.68	7.25%	272.34	998.59	1,051.28	5.28%
10		50	15,000	957.70	1,008.62	50.92	5.32%	408.51	1,366.21	1,417.13	3.73%
11		75	7,500	687.16	792.89	105.73	15.39%	204.25	891.41	997.14	11.86%
12		75	15,000	1,034.32	1,137.41	103.09	9.97%	408.51	1,442.83	1,545.92	7.14%
13		75	22,500	1,377.29	1,477.73	100.44	7.29%	612.76	1,990.05	2,090.49	5.05%
14		100	10,000	879.50	1,036.52	157.02	17.85%	272.34	1,151.84	1,308.86	13.63%
15		100	20,000	1,339.59	1,493.08	153.49	11.46%	544.68	1,884.26	2,037.76	8.15%
16		100	30,000	1,796.87	1,946.84	149.97	8.35%	817.02	2,613.89	2,763.86	5.74%
17		200	20,000	1,646.07	2,008.24	362.17	22.00%	544.68	2,190.75	2,552.92	16.53%
18		200	40,000	2,560.65	2,915.76	355.12	13.87%	1,089.36	3,650.00	4,005.12	9.73%
19		200	60,000	3,475.22	3,823.28	348.06	10.02%	1,634.03	5,109.25	5,457.32	6.81%
20		500	50,000	3,937.39	4,915.01	977.61	24.83%	1,361.70	5,299.09	6,276.70	18.45%
21		500	100,000	6,223.82	7,183.81	959.98	15.42%	2,723.39	8,947.21	9,907.20	10.73%
22		500	150,000	8,510.26	9,452.61	942.35	11.07%	4,085.09	12,595.34	13,537.69	7.48%
23		1,000	100,000	7,756.26	9,759.61	2,003.35	25.83%	2,723.39	10,479.65	12,483.00	19.12%
24		1,000	200,000	12,329.12	14,297.22	1,968.09	15.96%	5,446.78	17,775.90	19,744.00	11.07%
25		1,000	300,000	16,901.99	18,834.82	1,932.83	11.44%	8,170.17	25,072.16	27,004.99	7.71%
26		3,000	300,000	23,031.73	29,138.05	6,106.32	26.51%	8,170.17	31,201.90	37,308.22	19.57%
27		3,000	600,000	36,750.32	42,750.85	6,000.53	16.33%	16,340.34	53,090.66	59,091.19	11.30%
28		3,000	900,000	50,307.65	56,212.36	5,904.71	11.74%	24,510.51	74,818.16	80,722.87	7.89%
29		7,000	700,000	53,582.66	67,894.91	14,312.25	26.71%	19,063.73	72,646.39	86,958.64	19.70%
30		7,000	1,400,000	84,228.00	98,377.78	14,149.78	16.80%	38,127.46	122,355.46	136,505.24	11.56%
31		7,000	2,100,000	114,553.22	128,560.32	14,007.10	12.23%	57,191.19	171,744.41	185,751.51	8.16%

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E+C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E+H)
1	GS-2										
2	Subtransmission	10	1,000	383.76	975.56	591.80	154.21%	28.23	411.99	1,003.79	143.64%
3		10	2,000	430.17	1,021.62	591.45	137.49%	56.47	486.64	1,078.09	121.54%
4		10	3,000	476.13	1,067.23	591.10	124.15%	84.70	560.83	1,151.93	105.40%
5		25	2,500	492.31	1,056.12	563.82	114.53%	70.59	562.89	1,126.71	100.16%
6		25	5,000	607.20	1,170.14	562.94	92.71%	141.17	748.37	1,311.31	75.22%
7		25	7,500	722.09	1,284.15	562.06	77.84%	211.76	933.85	1,495.91	60.18%
8		50	5,000	672.45	1,189.64	517.18	76.91%	141.17	813.63	1,330.81	63.57%
9		50	10,000	902.24	1,417.66	515.42	57.13%	282.35	1,184.59	1,700.01	43.51%
10		50	15,000	1,132.03	1,645.69	513.66	45.37%	423.52	1,555.55	2,069.20	33.02%
11		75	7,500	852.60	1,323.15	470.55	55.19%	211.76	1,064.36	1,534.91	44.21%
12		75	15,000	1,197.28	1,665.19	467.90	39.08%	423.52	1,620.80	2,088.70	28.87%
13		75	22,500	1,537.77	2,003.02	465.26	30.26%	635.28	2,173.04	2,638.30	21.41%
14		100	10,000	1,032.75	1,456.66	423.91	41.05%	282.35	1,315.10	1,739.01	32.23%
15		100	20,000	1,489.53	1,909.91	420.38	28.22%	564.69	2,054.22	2,474.60	20.46%
16		100	30,000	1,943.50	2,360.36	416.86	21.45%	847.04	2,790.54	3,207.39	14.94%
17		200	20,000	1,750.55	1,987.91	237.36	13.56%	564.69	2,315.24	2,552.60	10.25%
18		200	40,000	2,658.50	2,888.81	230.31	8.66%	1,129.38	3,787.88	4,018.19	6.08%
19		200	60,000	3,566.45	3,789.71	223.26	6.26%	1,694.07	5,260.52	5,483.78	4.24%
20		500	50,000	3,895.53	3,573.26	(322.27)	-8.27%	1,411.73	5,307.26	4,984.98	-6.07%
21		500	100,000	6,165.41	5,825.50	(339.91)	-5.51%	2,823.45	8,988.86	8,648.95	-3.78%
22		500	150,000	8,435.29	8,077.75	(357.54)	-4.24%	4,235.18	12,670.46	12,312.92	-2.82%
23		1,000	100,000	7,470.51	6,215.50	(1,255.00)	-16.80%	2,823.45	10,293.96	9,038.95	-12.19%
24		1,000	200,000	12,010.26	10,719.99	(1,290.27)	-10.74%	5,646.90	17,657.16	16,366.89	-7.31%
25		1,000	300,000	16,550.01	15,224.48	(1,325.53)	-8.01%	8,470.35	25,020.36	23,694.83	-5.30%
26		3,000	300,000	21,770.41	16,784.48	(4,985.92)	-22.90%	8,470.35	30,240.76	25,254.83	-16.49%
27		3,000	600,000	35,389.67	30,297.96	(5,091.71)	-14.39%	16,940.70	52,330.37	47,238.66	-9.73%
28		3,000	900,000	48,847.67	43,660.14	(5,187.53)	-10.62%	25,411.05	74,258.72	69,071.19	-6.99%
29		7,000	700,000	50,370.21	37,922.45	(12,447.77)	-24.71%	19,764.15	70,134.36	57,686.60	-17.75%
30		7,000	1,400,000	80,783.78	68,173.54	(12,610.24)	-15.61%	39,528.30	120,312.08	107,701.84	-10.48%
31		7,000	2,100,000	110,877.22	98,124.31	(12,752.92)	-11.50%	59,292.45	170,169.67	157,416.76	-7.49%
32											

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-3										
2	Secondary	10	3,500	241.13	238.09	(3.04)	-1.26%	98.86	339.99	336.95	-0.89%
3		10	4,500	256.14	252.75	(3.39)	-1.32%	127.11	383.25	379.85	-0.89%
4		10	5,500	271.15	267.40	(3.75)	-1.38%	155.35	426.50	422.75	-0.88%
5		25	8,750	562.15	570.34	8.19	1.46%	247.15	809.30	817.49	1.01%
6		25	11,250	599.66	606.97	7.31	1.22%	317.77	917.43	924.74	0.80%
7		25	13,750	637.17	643.61	6.43	1.01%	388.38	1,025.56	1,031.99	0.63%
8		50	17,500	1,095.77	1,122.68	26.92	2.46%	494.30	1,590.07	1,616.99	1.69%
9		50	22,500	1,167.99	1,193.15	25.15	2.15%	635.53	1,803.53	1,828.68	1.39%
10		50	27,500	1,240.22	1,263.61	23.39	1.89%	776.76	2,016.98	2,040.38	1.16%
11		75	26,250	1,625.89	1,671.53	45.64	2.81%	741.45	2,367.34	2,412.98	1.93%
12		75	33,750	1,734.23	1,777.23	43.00	2.48%	953.30	2,687.53	2,730.52	1.60%
13		75	41,250	1,842.57	1,882.92	40.35	2.19%	1,165.14	3,007.71	3,048.07	1.34%
14		100	35,000	2,156.01	2,220.37	64.37	2.99%	988.61	3,144.61	3,208.98	2.05%
15		100	45,000	2,300.46	2,361.30	60.84	2.64%	1,271.07	3,571.53	3,632.37	1.70%
16		100	55,000	2,444.92	2,502.23	57.31	2.34%	1,553.52	3,998.44	4,055.76	1.43%
17		200	70,000	4,276.49	4,415.75	139.26	3.26%	1,977.21	6,253.70	6,392.96	2.23%
18		200	90,000	4,565.40	4,697.61	132.21	2.90%	2,542.13	7,107.53	7,239.74	1.86%
19		200	110,000	4,854.31	4,979.47	125.16	2.58%	3,107.05	7,961.36	8,086.51	1.57%
20		500	175,000	10,637.93	11,001.87	363.94	3.42%	4,943.03	15,580.96	15,944.91	2.34%
21		500	225,000	11,360.21	11,706.52	346.31	3.05%	6,355.33	17,715.54	18,061.85	1.95%
22		500	275,000	12,082.49	12,411.17	328.68	2.72%	7,767.62	19,850.11	20,178.79	1.66%
23		1,000	350,000	21,240.33	21,978.75	738.42	3.48%	9,886.07	31,126.40	31,864.82	2.37%
24		1,000	450,000	22,684.89	23,388.05	703.16	3.10%	12,710.66	35,395.54	36,098.70	1.99%
25		1,000	550,000	24,129.44	24,797.34	667.89	2.77%	15,535.25	39,664.69	40,332.58	1.68%
26		3,000	1,050,000	63,127.65	65,396.26	2,268.61	3.59%	29,658.20	92,785.84	95,054.45	2.44%
27		3,000	1,350,000	66,739.25	68,946.70	2,207.46	3.31%	38,131.97	104,871.21	107,078.67	2.10%
28		3,000	1,650,000	70,350.85	72,497.15	2,146.31	3.05%	46,605.74	116,956.58	119,102.89	1.84%
29		7,000	2,450,000	144,577.22	150,049.94	5,472.72	3.79%	69,202.46	213,779.67	219,252.39	2.56%
30		7,000	3,150,000	153,004.28	158,334.32	5,330.04	3.48%	88,974.59	241,978.86	247,308.90	2.20%
31		7,000	3,850,000	161,431.34	166,618.70	5,187.36	3.21%	108,746.72	270,178.06	275,365.42	1.92%
32											

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▸Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E+C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E+H)
1	GS-3										
2	Primary	10	3,500	312.86	269.15	(43.71)	-13.97%	95.32	408.18	364.47	-10.71%
3		10	4,500	328.42	284.36	(44.06)	-13.42%	122.55	450.98	406.92	-9.77%
4		10	5,500	343.99	299.57	(44.41)	-12.91%	149.79	493.77	449.36	-8.99%
5		25	8,750	616.97	579.89	(37.08)	-6.01%	238.30	855.27	818.19	-4.34%
6		25	11,250	655.87	617.91	(37.96)	-5.79%	306.38	962.26	924.29	-3.94%
7		25	13,750	694.78	655.94	(38.84)	-5.59%	374.47	1,069.25	1,030.40	-3.63%
8		50	17,500	1,122.41	1,096.38	(26.03)	-2.32%	476.59	1,599.01	1,572.98	-1.63%
9		50	22,500	1,197.42	1,169.63	(27.79)	-2.32%	612.76	1,810.19	1,782.39	-1.54%
10		50	27,500	1,272.43	1,242.88	(29.56)	-2.32%	748.93	2,021.36	1,991.81	-1.46%
11		75	26,250	1,624.36	1,609.38	(14.98)	-0.92%	714.89	2,339.25	2,324.27	-0.64%
12		75	33,750	1,736.87	1,719.25	(17.62)	-1.01%	919.14	2,656.01	2,638.39	-0.66%
13		75	41,250	1,849.39	1,829.12	(20.27)	-1.10%	1,123.40	2,972.78	2,952.51	-0.68%
14		100	35,000	2,126.30	2,122.37	(3.93)	-0.18%	953.19	3,079.49	3,075.55	-0.13%
15		100	45,000	2,276.32	2,268.86	(7.46)	-0.33%	1,225.53	3,501.84	3,494.39	-0.21%
16		100	55,000	2,426.34	2,415.36	(10.98)	-0.45%	1,497.86	3,924.20	3,913.22	-0.28%
17		200	70,000	4,134.07	4,174.34	40.27	0.97%	1,906.37	6,040.45	6,080.71	0.67%
18		200	90,000	4,434.11	4,467.33	33.21	0.75%	2,451.05	6,885.16	6,918.38	0.48%
19		200	110,000	4,734.15	4,760.31	26.16	0.55%	2,995.73	7,729.88	7,756.04	0.34%
20		500	175,000	10,157.39	10,330.25	172.86	1.70%	4,765.93	14,923.32	15,096.18	1.16%
21		500	225,000	10,907.49	11,062.72	155.23	1.42%	6,127.63	17,035.12	17,190.35	0.91%
22		500	275,000	11,657.59	11,795.19	137.60	1.18%	7,489.32	19,146.92	19,284.51	0.72%
23		1,000	350,000	20,196.26	20,590.11	393.85	1.95%	9,531.87	29,728.12	30,121.97	1.32%
24		1,000	450,000	21,696.46	22,055.04	358.58	1.65%	12,255.26	33,951.71	34,310.30	1.06%
25		1,000	550,000	23,196.66	23,519.98	323.32	1.39%	14,978.65	38,175.31	38,498.63	0.85%
26		3,000	1,050,000	59,829.43	61,139.51	1,310.09	2.19%	28,595.60	88,425.02	89,735.11	1.48%
27		3,000	1,350,000	63,607.96	64,856.90	1,248.94	1.96%	36,765.77	100,373.73	101,622.66	1.24%
28		3,000	1,650,000	67,386.49	68,574.28	1,187.79	1.76%	44,935.94	112,322.43	113,510.21	1.06%
29		7,000	2,450,000	136,770.70	140,057.01	3,286.30	2.40%	66,723.06	203,493.76	206,780.06	1.61%
30		7,000	3,150,000	145,587.28	148,730.90	3,143.62	2.16%	85,786.79	231,374.06	234,517.69	1.36%
31		7,000	3,850,000	154,403.85	157,404.79	3,000.94	1.94%	104,850.52	259,254.36	262,255.31	1.16%

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zeline / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E+C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E+H)
1	GS-3							0.00			
2	Subtransmission	10	3,500	508.64	1,084.34	575.71	113.19%	9.30	517.94	1,093.84	111.15%
3		10	4,500	524.51	1,099.87	575.35	109.69%	11.96	536.47	1,111.83	107.25%
4		10	5,500	540.39	1,115.39	575.00	106.40%	14.62	555.01	1,130.01	103.60%
5		25	8,750	803.36	1,326.94	523.58	65.17%	23.26	826.61	1,350.19	63.34%
6		25	11,250	843.05	1,365.76	522.70	62.00%	29.90	872.95	1,395.65	59.88%
7		25	13,750	882.74	1,404.56	521.82	59.11%	36.55	919.28	1,441.10	56.76%
8		50	17,500	1,293.15	1,729.86	436.71	33.77%	46.51	1,339.67	1,776.38	32.60%
9		50	22,500	1,369.74	1,804.68	434.94	31.75%	59.80	1,429.54	1,864.48	30.43%
10		50	27,500	1,446.32	1,879.50	433.18	29.95%	73.09	1,519.41	1,952.59	28.51%
11		75	26,250	1,779.45	2,129.29	349.83	19.66%	69.77	1,849.22	2,199.06	18.92%
12		75	33,750	1,894.33	2,241.51	347.19	18.33%	89.71	1,984.03	2,331.22	17.50%
13		75	41,250	2,009.20	2,353.74	344.54	17.15%	109.64	2,118.84	2,463.38	16.26%
14		100	35,000	2,265.75	2,528.71	262.96	11.61%	93.03	2,358.78	2,621.74	11.15%
15		100	45,000	2,418.92	2,678.35	259.43	10.73%	119.61	2,538.52	2,797.96	10.22%
16		100	55,000	2,572.08	2,827.99	255.91	9.95%	146.19	2,718.27	2,974.17	9.41%
17		200	70,000	4,210.95	4,126.41	(84.54)	-2.01%	186.06	4,397.00	4,312.47	-1.92%
18		200	90,000	4,517.28	4,425.69	(91.59)	-2.03%	239.22	4,756.49	4,664.90	-1.93%
19		200	110,000	4,823.61	4,724.96	(98.64)	-2.05%	292.37	5,115.98	5,017.34	-1.93%
20		500	175,000	10,046.53	8,919.50	(1,127.03)	-11.22%	465.14	10,511.67	9,384.64	-10.72%
21		500	225,000	10,812.36	9,667.70	(1,144.66)	-10.59%	598.04	11,410.39	10,265.73	-10.03%
22		500	275,000	11,578.18	10,415.89	(1,162.29)	-10.04%	730.94	12,309.11	11,146.82	-9.44%
23		1,000	350,000	19,772.51	16,907.99	(2,864.51)	-14.49%	930.28	20,702.79	17,838.28	-13.84%
24		1,000	450,000	21,304.15	18,404.38	(2,899.78)	-13.61%	1,196.08	22,500.23	19,600.46	-12.89%
25		1,000	550,000	22,835.80	19,900.76	(2,935.04)	-12.85%	1,461.87	24,297.67	21,362.63	-12.08%
26		3,000	1,050,000	58,154.11	48,371.95	(9,782.16)	-16.82%	2,790.85	60,944.96	51,162.80	-16.05%
27		3,000	1,350,000	62,026.98	52,183.67	(9,843.31)	-15.87%	3,588.23	65,615.21	55,771.90	-15.00%
28		3,000	1,650,000	65,899.85	55,995.39	(9,904.46)	-15.03%	4,385.62	70,285.47	60,381.01	-14.09%
29		7,000	2,450,000	132,592.26	109,118.54	(23,473.72)	-17.70%	6,511.98	139,104.24	115,630.52	-16.87%
30		7,000	3,150,000	141,628.95	118,012.56	(23,616.40)	-16.67%	8,372.54	150,001.49	126,385.10	-15.74%
31		7,000	3,850,000	150,665.64	126,906.57	(23,759.08)	-15.77%	10,233.11	160,898.75	137,139.68	-14.77%

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original__Updated__Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-4										
2	Primary	3,000	1,200,000	58,064.81	61,058.91	2,994.10	5.16%	29,216.64	87,281.45	90,275.55	3.43%
3		3,000	1,500,000	60,491.22	63,408.66	2,917.44	4.82%	36,520.80	97,012.02	99,929.46	3.01%
4		3,000	1,800,000	62,917.62	65,758.40	2,840.78	4.52%	43,824.96	106,742.58	109,583.36	2.66%
5		5,000	2,000,000	95,308.08	100,463.93	5,155.85	5.41%	48,694.40	144,002.48	149,158.33	3.58%
6		5,000	2,500,000	99,352.08	104,380.17	5,028.09	5.06%	60,868.00	160,220.08	165,248.17	3.14%
7		5,000	3,000,000	103,396.08	108,296.41	4,900.32	4.74%	73,041.60	176,437.68	181,338.01	2.78%
8		8,000	3,200,000	151,172.97	159,571.44	8,398.47	5.56%	77,911.04	229,084.01	237,482.48	3.67%
9		8,000	4,000,000	157,643.38	165,837.43	8,194.05	5.20%	97,388.80	255,032.18	263,226.23	3.21%
10		8,000	4,800,000	164,113.78	172,103.41	7,989.63	4.87%	116,866.56	280,980.34	288,969.97	2.84%
11		20,000	8,000,000	374,632.55	396,001.52	21,368.97	5.70%	194,777.60	569,410.15	590,779.12	3.75%
12		20,000	10,000,000	390,808.56	411,666.48	20,857.91	5.34%	243,472.00	634,280.56	655,138.48	3.29%
13		20,000	12,000,000	406,984.58	427,331.44	20,346.86	5.00%	292,166.40	699,150.98	719,497.84	2.91%
14		50,000	20,000,000	933,281.49	987,076.71	53,795.21	5.76%	486,944.00	1,420,225.49	1,474,020.71	3.79%
15		50,000	25,000,000	973,721.53	1,026,239.11	52,517.57	5.39%	608,680.00	1,582,401.53	1,634,919.11	3.32%
16		50,000	30,000,000	1,014,161.57	1,065,401.50	51,239.93	5.05%	730,416.00	1,744,577.57	1,795,817.50	2.94%
17		125,000	50,000,000	2,329,903.85	2,464,764.68	134,860.82	5.79%	1,217,360.00	3,547,263.85	3,682,124.68	3.80%
18		125,000	62,500,000	2,431,003.95	2,562,670.67	131,666.72	5.42%	1,521,700.00	3,952,703.95	4,084,370.67	3.33%
19		125,000	75,000,000	2,532,104.06	2,660,576.67	128,472.61	5.07%	1,826,040.00	4,358,144.05	4,486,616.67	2.95%
20											
21	GS-4										
22	Subtransmission	3,000	1,200,000	52,356.98	48,410.30	(3,946.69)	-7.54%	28,514.64	80,871.62	76,924.94	-4.88%
23		3,000	1,500,000	54,903.17	50,879.82	(4,023.34)	-7.33%	35,643.30	90,546.47	86,523.12	-4.44%
24		3,000	1,800,000	57,449.35	53,349.35	(4,100.00)	-7.14%	42,771.96	100,221.31	96,121.31	-4.09%
25		5,000	2,000,000	85,591.17	78,809.16	(6,782.02)	-7.92%	47,524.40	133,115.57	126,333.56	-5.09%
26		5,000	2,500,000	89,834.81	82,925.03	(6,909.78)	-7.69%	59,405.50	149,240.31	142,330.53	-4.63%
27		5,000	3,000,000	94,078.45	87,040.91	(7,037.55)	-7.48%	71,286.60	165,365.05	158,327.51	-4.26%
28		8,000	3,200,000	135,442.46	124,407.44	(11,035.01)	-8.15%	76,039.04	211,481.50	200,446.48	-5.22%
29		8,000	4,000,000	142,232.28	130,992.85	(11,239.44)	-7.90%	95,048.80	237,281.08	226,041.65	-4.74%
30		8,000	4,800,000	149,022.11	137,578.25	(11,443.86)	-7.68%	114,058.56	263,080.67	251,636.81	-4.35%
31		20,000	8,000,000	334,847.60	306,800.60	(28,047.00)	-8.38%	190,097.60	524,945.20	496,898.20	-5.34%
32		20,000	10,000,000	351,822.16	323,264.10	(28,558.06)	-8.12%	237,622.00	589,444.16	560,886.10	-4.84%
33		20,000	12,000,000	368,796.72	339,727.60	(29,069.11)	-7.88%	285,146.40	653,943.12	624,874.00	-4.45%
34		50,000	20,000,000	833,360.44	762,783.47	(70,576.97)	-8.47%	475,244.00	1,308,604.44	1,238,027.47	-5.39%

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ►Original__Updated__Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	GS-4	50,000	25,000,000	875,796.85	803,942.24	(71,854.61)	-8.20%	594,055.00	1,469,851.85	1,397,997.24	-4.89%
2	Subtransmission	50,000	30,000,000	918,233.25	845,101.00	(73,132.25)	-7.96%	712,866.00	1,631,099.25	1,557,967.00	-4.48%
3		125,000	50,000,000	2,079,642.56	1,902,740.67	(176,901.89)	-8.51%	1,188,110.00	3,267,752.56	3,090,850.67	-5.41%
4		125,000	62,500,000	2,185,733.57	2,005,637.57	(180,095.99)	-8.24%	1,485,137.50	3,670,871.07	3,490,775.07	-4.91%
5		125,000	75,000,000	2,291,824.56	2,108,534.46	(183,290.10)	-8.00%	1,782,165.00	4,073,989.58	3,890,699.48	-4.50%
6											
7	GS-4										
8	Transmission	3,000	1,200,000	49,421.90	47,825.86	(1,596.04)	-3.23%	28,514.64	77,936.54	76,340.50	-2.05%
9		3,000	1,500,000	51,955.17	50,282.47	(1,672.70)	-3.22%	35,643.30	87,598.47	85,925.77	-1.91%
10		3,000	1,800,000	54,488.44	52,739.09	(1,749.35)	-3.21%	42,771.96	97,260.40	95,511.05	-1.80%
11		5,000	2,000,000	80,619.28	77,835.09	(2,784.19)	-3.45%	47,524.40	128,143.68	125,359.49	-2.17%
12		5,000	2,500,000	84,841.40	81,929.45	(2,911.96)	-3.43%	59,405.50	144,246.90	141,334.95	-2.02%
13		5,000	3,000,000	89,063.52	86,023.80	(3,039.72)	-3.41%	71,286.60	160,350.12	157,310.40	-1.90%
14		8,000	3,200,000	127,415.36	122,848.94	(4,566.42)	-3.58%	76,039.04	203,454.40	198,887.98	-2.24%
15		8,000	4,000,000	134,170.76	129,399.91	(4,770.84)	-3.56%	95,048.80	229,219.56	224,448.71	-2.08%
16		8,000	4,800,000	140,926.15	135,950.88	(4,975.27)	-3.53%	114,058.56	254,984.71	250,009.44	-1.95%
17		20,000	8,000,000	314,599.69	302,904.34	(11,695.34)	-3.72%	190,097.60	504,697.29	493,001.94	-2.32%
18		20,000	10,000,000	331,488.17	319,281.77	(12,206.40)	-3.68%	237,622.00	569,110.17	556,903.77	-2.14%
19		20,000	12,000,000	348,376.65	335,659.19	(12,717.46)	-3.65%	285,146.40	633,523.05	620,805.59	-2.01%
20		50,000	20,000,000	782,560.49	753,042.84	(29,517.65)	-3.77%	475,244.00	1,257,804.49	1,228,286.84	-2.35%
21		50,000	25,000,000	824,781.89	793,986.40	(30,795.29)	-3.73%	594,055.00	1,418,836.69	1,388,041.40	-2.17%
22		50,000	30,000,000	867,002.89	834,929.96	(32,072.93)	-3.70%	712,866.00	1,579,868.89	1,547,795.96	-2.03%
23		125,000	50,000,000	1,952,462.51	1,878,389.10	(74,073.41)	-3.79%	1,188,110.00	3,140,572.51	3,066,499.10	-2.36%
24		125,000	62,500,000	2,058,015.50	1,980,747.99	(77,267.52)	-3.75%	1,485,137.50	3,543,153.00	3,465,885.49	-2.18%
25		125,000	75,000,000	2,163,568.50	2,083,106.88	(80,461.62)	-3.72%	1,782,165.00	3,945,733.50	3,865,271.88	-2.04%
26											

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Schedule E-5
Page 96 of 100
Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	EHG										
2		30	100	30.43	187.37	156.94	515.77%	3.02	33.45	190.39	469.18%
3		30	500	51.66	202.54	150.88	292.04%	15.11	66.77	217.65	225.97%
4		30	1,000	78.21	221.51	143.31	183.24%	30.21	108.42	251.73	132.18%
5		30	3,000	183.92	296.93	113.01	61.44%	90.64	274.56	387.57	41.16%
6		30	4,500	262.87	353.15	90.28	34.35%	135.96	398.82	489.11	22.64%
7		30	6,000	341.81	409.37	67.56	19.77%	181.28	523.09	590.65	12.92%
8		30	9,000	499.70	521.81	22.12	4.43%	271.91	771.61	793.73	2.87%
9		30	12,000	657.58	634.25	(23.33)	-3.55%	362.55	1,020.13	996.80	-2.29%
10		30	15,000	815.47	746.69	(68.78)	-8.43%	453.19	1,268.66	1,199.88	-5.42%
11		30	20,000	1,075.81	931.29	(144.52)	-13.43%	604.25	1,680.06	1,535.54	-8.60%
12		50	5,000	356.50	524.15	167.65	47.03%	151.06	507.57	675.21	33.03%
13		50	7,500	488.07	617.85	129.77	26.59%	226.60	714.67	844.44	18.16%
14		50	10,000	619.64	711.55	91.90	14.83%	302.13	921.77	1,013.67	9.97%
15		50	15,000	882.79	898.95	16.16	1.83%	453.19	1,335.98	1,352.14	1.21%
16		50	20,000	1,143.13	1,083.54	(59.58)	-5.21%	604.25	1,747.38	1,687.80	-3.41%
17		50	25,000	1,403.47	1,268.14	(135.33)	-9.64%	755.32	2,158.79	2,023.46	-6.27%
18		100	10,000	787.94	1,092.19	304.24	38.61%	302.13	1,090.07	1,394.31	27.91%
19		100	15,000	1,051.09	1,279.59	228.50	21.74%	453.19	1,504.28	1,732.78	15.19%
20		100	20,000	1,311.43	1,464.18	152.75	11.65%	604.25	1,915.68	2,068.44	7.97%
21		100	30,000	1,832.11	1,833.38	1.27	0.07%	906.38	2,738.50	2,739.76	0.05%
22		100	40,000	2,352.80	2,202.58	(150.22)	-6.38%	1,208.51	3,561.31	3,411.09	-4.22%
23		200	20,000	1,648.03	2,225.47	577.43	35.04%	604.25	2,252.28	2,829.72	25.64%
24		200	30,000	2,168.72	2,594.66	425.95	19.64%	906.38	3,075.10	3,501.04	13.85%
25		200	40,000	2,689.40	2,963.86	274.46	10.21%	1,208.51	3,897.91	4,172.37	7.04%
26		200	60,000	3,730.77	3,702.25	(28.52)	-0.76%	1,812.76	5,543.53	5,515.02	-0.51%
27											
28											
29	EHS	55	15,000	325.26	612.18	286.92	88.21%	390.96	716.22	1,003.14	40.06%
30		150	30,000	641.21	1,423.22	782.02	121.96%	781.92	1,423.13	2,205.15	54.95%
31		225	65,000	1,378.40	2,494.83	1,116.42	80.99%	1,694.17	3,072.57	4,189.00	36.34%

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	SS										
2	1,000 sq ft	10	1,500	124.27	138.16	13.89	11.18%	43.66	167.93	181.82	8.27%
3		10	3,000	211.34	203.90	(7.44)	-3.52%	87.31	298.66	291.22	-2.49%
4		10	4,500	298.18	269.41	(28.77)	-9.65%	130.97	429.15	400.39	-6.70%
5											
6	5,000 sq ft	20	2,000	154.74	217.49	62.75	40.55%	58.21	212.95	275.70	29.47%
7		20	4,000	270.53	304.83	34.31	12.68%	116.42	386.94	421.25	8.87%
8		20	6,000	386.31	392.18	5.87	1.52%	174.63	560.94	566.81	1.05%
9											
10	10,000 sq ft	20	2,000	155.28	218.03	62.75	40.41%	58.21	213.49	276.24	29.39%
11		20	4,000	272.14	306.45	34.31	12.61%	116.42	388.56	422.87	8.83%
12		20	6,000	387.92	393.80	5.87	1.51%	174.63	562.55	568.42	1.04%
13		40	5,000	330.03	462.05	132.02	40.00%	145.52	475.56	607.58	27.76%
14		40	7,500	474.76	571.24	96.47	20.32%	218.29	693.05	789.52	13.92%
15		40	10,000	619.49	680.42	60.92	9.83%	291.05	910.54	971.47	6.69%
16											
17	20,000 sq ft	50	10,000	622.72	739.61	116.89	18.77%	291.05	913.77	1,030.66	12.79%
18		50	15,000	912.19	957.98	45.79	5.02%	436.57	1,348.76	1,394.55	3.40%
19		50	20,000	1,198.85	1,173.55	(25.30)	-2.11%	582.10	1,780.94	1,755.64	-1.42%
20											
21	30,000 sq ft	50	10,000	625.95	742.84	116.89	18.67%	291.05	917.00	1,033.89	12.75%
22		50	15,000	915.42	961.21	45.79	5.00%	436.57	1,351.99	1,397.78	3.39%
23		50	20,000	1,202.08	1,176.77	(25.30)	-2.10%	582.10	1,784.17	1,758.87	-1.42%
24		100	20,000	1,202.08	1,456.60	254.53	21.17%	582.10	1,784.17	2,038.70	14.27%
25		100	25,000	1,488.74	1,672.17	183.43	12.32%	727.62	2,216.36	2,399.79	8.28%
26		100	30,000	1,775.40	1,887.73	112.33	6.33%	873.14	2,648.55	2,760.88	4.24%
27											
28	50,000 sq ft	100	15,000	921.87	1,247.50	325.62	35.32%	436.57	1,358.45	1,684.07	23.97%
29		100	30,000	1,781.86	1,894.19	112.33	6.30%	873.14	2,655.00	2,767.34	4.23%
30		200	40,000	2,355.18	2,884.98	529.79	22.49%	1,164.19	3,519.38	4,049.17	15.05%
31		200	60,000	3,501.83	3,747.24	245.41	7.01%	1,746.29	5,248.12	5,493.53	4.68%
32		300	60,000	3,501.83	4,306.90	805.06	22.99%	1,746.29	5,248.12	6,053.19	15.34%
33		300	80,000	4,648.48	5,169.16	520.68	11.20%	2,328.38	6,976.87	7,497.54	7.46%

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: ➤Original___Updated___Revised
Work Paper Reference No(s):

Schedule E-5

Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)		Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	SS											
2	100,000 sq ft		250	60,000	3,517.98	4,043.22	525.24	14.93%	1,746.29	5,264.27	5,789.50	9.98%
3			250	80,000	4,664.63	4,905.48	240.85	5.16%	2,328.38	6,993.01	7,233.86	3.44%
4			400	80,000	4,664.63	5,744.96	1,080.33	23.16%	2,328.38	6,993.01	8,073.35	15.45%
5			400	120,000	6,957.93	7,469.49	511.56	7.35%	3,492.58	10,450.50	10,962.06	4.90%
6												
7	OL											
8		Lamp Size										
9		Mercury Vapor										
10		7,000 Lumen		72	11.10	13.64	2.54	22.85%	3.20	14.30	16.84	17.73%
11		20,000 Lumen		158	16.56	19.81	3.25	19.64%	7.03	23.58	26.83	13.79%
12												
13		High Pressure Sodium										
14		9,000 Lumen		40	9.04	11.88	2.83	31.35%	1.78	10.82	13.66	26.20%
15		22,000 Lumen		84	12.03	15.99	3.96	32.94%	3.73	15.77	19.73	25.14%
16												
17		Incandescent										
18		2,500 Lumen		63	8.55	11.78	3.23	37.77%	2.80	11.36	14.59	28.45%
19		4,000 Lumen		98	9.53	13.01	3.48	36.51%	4.36	13.89	17.37	25.05%
20												
21		MV Floodlight										
22		20,000 Lumen		158	19.51	23.61	4.10	21.04%	7.03	26.53	30.64	15.47%
23		50,000 Lumen		378	28.78	33.47	4.69	16.30%	16.81	45.58	50.28	10.29%
24												
25		HPS Floodlight										
26		22,000 Lumen		84	13.88	17.83	3.95	28.47%	3.73	17.61	21.57	22.44%
27		50,000 Lumen		167	15.68	20.08	4.39	28.02%	7.43	23.11	27.50	19.02%
28												
29		MH Floodlight										
30		17,000 Lumen		100	12.44	16.35	3.91	31.48%	4.45	16.88	20.80	23.19%
31		29,000 Lumen		158	13.05	17.66	4.61	35.33%	7.03	20.08	24.69	22.97%
32												
33		Post Top-MV										
34		7,000 Lumen		72	12.58	16.98	4.40	34.99%	3.20	15.78	20.19	27.89%

Date Prepared: February 28, 2011

POST-MERGER OHIO POWER COMPANY - *OHIO POWER RATE AREA*
Case No. 11-352-EL-AIR
Typical Bill Comparison
(Electric and Gas Utilities)

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E+C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E+H)
1	OL										
2		Post Top-HPS									
3		9,000 Lumen	40	15.90	21.41	5.51	34.66%	1.78	17.68	23.19	31.17%
4											
5		Facilities Charges:									
6		Underground circuit per 25 feet over 30 feet	0	0.63	1.02	0.39	61.58%	-	0.63	1.02	61.58%
7											
8	SL										
9		On Wood Pole									
10		7,000 lumen mercury vapor	72	6.06	6.39	0.33	5.48%	2.75	8.81	9.14	3.77%
11		11,000 lumen mercury vapor	100	7.53	7.88	0.35	4.60%	3.82	11.34	11.69	3.05%
12		20,000 lumen mercury vapor	158	8.81	9.00	0.19	2.11%	6.03	14.84	15.02	1.25%
13		50,000 lumen mercury vapor	378	15.31	15.33	0.02	0.10%	14.42	29.74	29.75	0.05%
14		9,000 lumen high pressure sodium	40	6.87	7.38	0.50	7.33%	1.53	8.40	8.90	6.00%
15		16,000 lumen high pressure sodium	59	7.84	8.29	0.45	5.71%	2.25	10.09	10.54	4.43%
16		22,000 lumen high pressure sodium	84	9.36	9.81	0.45	4.80%	3.20	12.57	13.02	3.57%
17		50,000 lumen high pressure sodium	167	12.50	12.72	0.22	1.78%	6.37	18.87	19.09	1.18%
18		9,000 lumen high pressure sodium (post 1988)	40	12.12	13.76	1.64	13.50%	1.53	13.65	15.28	11.99%
19		16,000 lumen high pressure sodium (post 198ε	59	14.90	16.48	1.58	10.60%	2.25	17.15	18.73	9.21%
20		22,000 lumen high pressure sodium (post 198ε	84	16.33	17.91	1.58	9.69%	3.20	19.53	21.11	8.10%
21		50,000 lumen high pressure sodium (post 198ε	167	22.08	23.44	1.36	6.14%	6.37	28.45	29.81	4.76%
22											
23		On Metal Pole:									
24		7,000 lumen mercury vapor	72	9.13	10.04	0.91	9.96%	2.75	11.88	12.79	7.65%
25		11,000 lumen mercury vapor	100	10.94	11.95	1.01	9.26%	3.82	14.75	15.76	6.87%
26		20,000 lumen mercury vapor	158	12.44	13.34	0.91	7.31%	6.03	18.46	19.37	4.92%
27		50,000 lumen mercury vapor	378	20.19	21.00	0.81	3.99%	14.42	34.62	35.42	2.33%
28		9,000 lumen high pressure sodium	40	15.22	16.67	1.45	9.56%	1.53	16.75	18.20	8.69%
29		16,000 lumen high pressure sodium	59	16.14	17.54	1.40	8.68%	2.25	18.40	19.79	7.60%
30		22,000 lumen high pressure sodium	84	17.69	19.10	1.41	7.98%	3.20	20.89	22.31	6.76%
31		50,000 lumen high pressure sodium	167	20.80	21.98	1.17	5.64%	6.37	27.17	28.35	4.32%
32		9,000 lumen high pressure sodium (post 1998)	40	42.42	42.24	(0.18)	-0.43%	1.53	43.95	43.76	-0.41%
33		16,000 lumen high pressure sodium (post 199ε	59	43.52	43.27	(0.25)	-0.57%	2.25	45.77	45.53	-0.54%
34		22,000 lumen high pressure sodium (post 199ε	84	45.07	44.73	(0.34)	-0.75%	3.20	48.27	47.93	-0.70%

POST-MERGER OHIO POWER COMPANY - OHIO POWER RATE AREA
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Witness Responsible: T. Zelina / A. Moore

Line No.	Rate Code	Level of Demand (A)	Level of Usage (B)	Current Bill (C)	Proposed Bill (D)	Dollar Increase (E=D-C)	% Increase (F = E÷C)	Annualized Fuel Cost Additions to Bill (G)	Current Total Bill Including Fuel (H = C+G)	Proposed Total Bill Including Fuel (I= D+G)	% Change (J=E÷H)
1	SL	50,000 lumen high pressure sodium (post 199ε	167	48.27	47.64	(0.63)	-1.31%	6.37	54.65	54.01	-1.16%
2											
3		Multiple Lamps on Metal Pole:									
4		20,000 lumen mercury vapor	158	10.53	11.12	0.58	5.52%	6.03	16.56	17.14	3.51%
5		9,000 lumen high pressure sodium	40	11.02	12.00	0.98	8.89%	1.53	12.54	13.52	7.80%
6		16,000 lumen high pressure sodium	59	11.98	12.90	0.92	7.71%	2.25	14.23	15.15	6.49%
7		22,000 lumen high pressure sodium	84	13.49	14.43	0.94	6.94%	3.20	16.70	17.63	5.61%
8		50,000 lumen high pressure sodium	167	16.63	17.33	0.70	4.20%	6.37	23.01	23.70	3.04%
9		9,000 lumen high pressure sodium (post 1998)	40	24.81	24.64	(0.16)	-0.66%	1.53	26.33	26.17	-0.63%
10		16,000 lumen high pressure sodium (post 199ε	59	25.79	25.55	(0.23)	-0.90%	2.25	28.04	27.80	-0.83%
11		22,000 lumen high pressure sodium (post 199ε	84	27.34	27.02	(0.32)	-1.18%	3.20	30.55	30.22	-1.05%
12		50,000 lumen high pressure sodium (post 199ε	167	30.55	30.37	(0.18)	-0.60%	6.37	36.92	36.74	-0.49%
13											
14		Post Top Unit:									
15		7,000 lumen mercury vapor	72	9.05	9.95	0.90	9.92%	2.75	11.80	12.69	7.61%
16		9,000 lumen high pressure sodium	40	12.94	12.78	(0.15)	-1.19%	1.53	14.46	14.31	-1.06%
17		9,000 lumen high pressure sodium (post 1988)	40	16.52	18.02	1.50	9.08%	1.53	18.04	19.54	8.31%
18											
19		Facilities Charges:									
20		Receptacle Charge	0	2.10	2.41	0.31	14.50%	-	2.10	2.41	14.50%

Date Prepared: February 28, 2011

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company, Individually and, if Their Proposed Merger is Approved, as a Merged Company (collectively, AEP Ohio) for an Increase in Electric Distribution Rates	))))))	Case No. 11-351-EL-AIR Case No. 11-352-EL-AIR
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company, Individually and, if Their Proposed Merger is Approved, as a Merged Company (collectively AEP Ohio) for Tariff Approval	))))))	Case No. 11-353-EL-ATA Case No. 11-354-EL-ATA
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company, Individually and, if Their Proposed Merger is Approved, as a Merged Company (collectively AEP Ohio) for Approval to Change Accounting Methods	)))))))	Case No. 11-356-EL-AAM Case No. 11-358-EL-AAM

STANDARD FILING REQUIREMENTS

VOLUME 5

S-1 Five Year Capital Budget

S-2 Projected Test Years

S.3 Proposed Legal Notice

S-4.1 Executive Summary

Filed February 28th , 2011

AEP OHIO COMPANIES
COLUMBUS SOUTHERN POWER COMPANY
OHIO POWER COMPANY
11-351-EL-AIR
11-352-EL-AIR

SUPPLEMENTAL FILING REQUIREMENTS

SCHEDULE S-1:

FIVE YEAR DISTRIBUTION CAPITAL FORECAST

COLUMBUS SOUTHERN POWER COMPANY
Case No. 11-351-EL-AIR
Most Recent Five-Year Capital Expenditures Budget
2011-2015
($000)

Case No. 11-351-EL-AIR
Type of Filing: ▶*Original*___*Updated*___*Revised*
Work Paper Reference No(s):

Schedule S-1
Page 1 of 1
Witness Responsible:
O. J. Sever

Line No.	Project / Major Property Grouping	Category of Const. Cost	Budgeted Capital Expenditures 2011	2012	2013	2014	2015
(A)	(B)	(C)	(G)	(H)	(I)	(J)	(K)
1	Total Distribution [1]	Cash Construction	83,596	73,468	74,261	75,015	76,537
2		AFUDC	767	1,634	1,958	3,421	4,626
3		Total with AFUDC	$ 84,363	$ 75,102	$ 76,219	$ 78,435	$ 81,163
4							
5							
6	Projects Over 5% of Annual Construction Budget:						
7							
8	Project: gridSMART®	gridSMART®					
9							
10	Date Project Started:	4/1/2009					
11							
12	Estimated Completion Date:	12/31/2013					
13							
14	Estimated Cost of Cash Construction:		14,466	2,591	709	0	0
15							
16	Accumulated Costs[2]:						
17							
18	Costs from 4/1/2009-12/31/2010	29,902					
19	Cost to Completion 2011-2013	17,766					

[1] Does not Inlcude General or Intangible Plant allocated to Distribution.
[2] Values are net of DOE funds received and DOE billings.

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Most Recent Five-Year Capital Expenditures Budget
2011-2015
($000)

Data: Five (5) Years Projected
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Schedule S-1
Page 1 of 1
Witness Responsible:
O. J. Sever

Line No.	Project / Major Property Grouping	Category of Const. Cost	Budgeted Capital Expenditures 2011	2012	2013	2014	2015
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Note: There are no projects that are greater than or equal to 5% of the annual construction budget for the Company for years 2011 - 2015						
2							
3	Total Distribution [1]	Cash Construction	80,782	81,211	86,331	88,592	90,138
4		AFUDC	1,279	765	1,068	1,855	2,638
5		Total with AFUDC	$ 82,060	$ 81,976	$ 87,399	$ 90,448	$ 92,776

[1] Does not inicude General or Intangible Plant allocated to Distribution.

AEP OHIO COMPANIES
COLUMBUS SOUTHERN POWER COMPANY
OHIO POWER COMPANY
11-351-EL-AIR
11-352-EL-AIR

SUPPLEMENTAL FILING REQUIREMENTS

SCHEDULE S-2:

FIVE YEAR DISTRIBUTION FINANCIAL FORECAST

COLUMBUS SOUTHERN POWER COMPANY
Case No. 11-351-EL-AIR
Projected Distribution Income Statement[1]
2011-2015
($000)

Case No. 11-351-EL-AIR
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Schedule S-2
Page 1 of 4
Witness Responsible:
O. J. Sever

Line No. (A)	Description (B)	2011 (C)	2012 (D)	2013 (E)	2014 (F)	2015 (G)
1	OPERATING REVENUES					
2	Revenues	$ 400,900	$ 417,501	$ 457,133	$ 462,163	$ 470,526
3	Rider Revenues[2]	172,740	173,183	176,313	179,560	182,663
4	Total Revenue	573,640	590,684	633,446	641,723	653,189
5						
6	OPERATING EXPENSES					
7	O&M	148,060	152,140	157,164	162,500	167,596
8	Rider O&M[2]	103,301	106,454	109,701	113,046	116,492
9	Total O&M	251,360	258,593	266,865	275,546	284,088
10	Depreciation / Amortization	72,782	72,222	102,909	104,551	106,247
11	Taxes Other Than Income Taxes	77,264	80,976	83,247	85,668	88,139
12	Rider Taxes Other Than Income Taxes[2]	69,439	66,729	66,612	66,514	66,171
13	Total Taxes Other Than Income Taxes	146,703	147,706	149,859	152,181	154,310
14	Current Income Taxes	30,778	32,724	31,261	31,059	31,736
15	Deferred Income Taxes	(2,961)	(2,050)	(76)	(900)	(1,708)
16	ITC Amortization	(462)	(286)	(127)	(99)	(16)
17	Total Operating Expenses	498,201	508,910	550,692	562,339	574,657
18						
19	Net Operating Income	75,439	81,773	82,754	79,384	78,531
20						
21	Other Income and Deductions	1,644	2,972	2,005	3,208	3,918
22	Net Interest Charges	23,317	24,521	24,711	23,277	22,748
23						
24	Net Income	53,766	60,224	60,048	59,315	59,702
25						
26	(LESS) PREFERRED DIVIDEND					
27						
28	Available for Common	$ 53,766	$ 60,224	$ 60,048	$ 59,315	$ 59,702

[1] This Income Statement represents a projection of revenues necessary to support the required rate of return.
[2] These items represent significant revenues or costs associated with riders that will be treated in a separate proceeding.

COLUMBUS SOUTHERN POWER COMPANY
Case No. 11-351-EL-AIR
Projected Distribution Balance Sheet Statement
At End of Years: 2011-2015
($000)

Case No. 11-351-EL-AIR
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Schedule S-2
Page 2 of 4
Witness Responsible:
O. J. Sever

Line No. (A)	Description (B)	2011 (C)	2012 (D)	2013 (E)	2014 (F)	2015 (G)
1	UTILITY PLANT					
2	Utility Plant	$ 1,957,660	$ 2,044,700	$ 2,083,105	$ 2,123,391	$ 2,164,488
3	Construction Work in Progress	54,148	26,283	46,132	68,171	92,186
4	Total Utility Plant	2,011,808	2,070,984	2,129,237	2,191,562	2,256,674
5	(Less) Accumulated Depreciation	846,757	884,923	922,037	961,828	1,003,165
6	Net Utility Plant	1,165,051	1,186,061	1,207,200	1,229,733	1,253,510
7						
8	CURRENT ASSETS					
9	Cash	1,694	1,694	1,694	1,694	1,694
10	Receivables	32,168	32,168	32,168	32,168	32,168
11	Inventory	7,964	7,964	7,964	7,964	7,964
12	Other Current Assets	104,278	104,278	104,278	104,278	104,278
13	Total Current Assets	146,103	146,103	146,103	146,103	146,103
14						
15	OTHER PROPERTY & INVESTMENTS	5,957	5,957	5,957	5,957	5,957
16						
17	DEFERRED DEBITS					
18	Regulatory Assets	266,771	365,611	335,240	304,870	274,499
19	Other Non-Current Assets	60,226	59,875	59,611	59,387	59,181
20	Total Deferred Debits	326,997	425,486	394,851	364,256	333,680
21						
22	Total Assets and Other Debits	1,644,108	1,763,606	1,754,111	1,746,049	1,739,249
23						
24	PROPRIETARY CAPITAL					
25						
26	Preferred Stock	-	-	-	-	-
27	Total Common Equity	305,626	345,847	386,613	427,818	469,858
28	Retained Earnings	176,583	194,280	151,933	104,155	65,584
29	Total Proprietary Capital	482,209	540,127	538,545	531,973	535,442
30						
31	LONG TERM DEBT	447,130	397,162	313,882	283,153	283,153
32						
33	OTHER NONCURRENT LIABILITIES					
34	Deferred Income Taxes	224,497	222,447	222,371	221,471	219,763
35	ITC Liability/Deferred Tax	535	250	123	24	8
36	Other Noncurrent Liabilities	88,764	88,764	88,764	88,764	88,764
37	Total Noncurrent Liabilities	313,796	311,461	311,258	310,259	308,535
38						
39	CURRENT LIABILITIES					
40	Accounts Payable	212,319	212,319	212,319	212,319	212,319
41	Other Current Liabilities	188,654	302,538	378,107	408,346	399,800
42	Total Current Liabilities	400,973	514,856	590,426	620,664	612,119
43						
44	Total Liabilities and Proprietary Capital	$ 1,644,108	$ 1,763,606	$ 1,754,111	$ 1,746,049	$ 1,739,249

COLUMBUS SOUTHERN POWER COMPANY
Case No. 11-351-EL-AIR
Projected Distribution Cash Flow Summary
2011-2015
($000)

Case No. 11-351-EL-AIR
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s):

Schedule S-2
Page 3 of 4
Witness Responsible:
O. J. Sever

Line No. (A)	Description (B)	2011 (C)	2012 (D)	2013 (E)	2014 (F)	2015 (G)
1	Cash Flows From Operating Activities					
2	Net Income (after preferred stock dividend)	$ 53,766	$ 60,224	$ 60,048	$ 59,315	$ 59,702
3	Depreciation & Amortization	72,782	72,222	102,909	104,551	106,247
4	Regulatory Asset	0	(96,840)	0	0	0
5	Deferred Income Tax	(2,961)	(2,050)	(76)	(900)	(1,708)
6	Deferred Investment Tax Credits	(462)	(286)	(127)	(99)	(16)
7	AFUDC Equity	(1,644)	(2,972)	(2,005)	(3,208)	(3,918)
8	Forecast Net Removal Expenditures	(8,900)	(9,731)	(10,537)	(10,841)	(10,613)
9	Other Current Assets and Liabilities (net)	13,247	113,883	75,570	30,238	(8,545)
10	Net Cash Flow From Operating Activities	125,829	132,452	225,782	179,057	141,148
11						
12	Cash Flows From Investing Activities					
13	Capital Expenditures - Property & Construction	(88,840)	(78,864)	(79,933)	(80,795)	(82,433)
14	Allowance for Borrowed Funds Used During Constr-Cr.	(877)	(1,314)	(939)	(1,646)	(2,483)
15	Net Cash Flow (Used) by Investing Activities	(89,717)	(80,177)	(80,872)	(82,441)	(84,916)
16						
17	Cash Flows From Financing Activities					
18	Proceeds from Issuance of :					
19	Long-Term Debt	0	0	0	0	0
20	Preferred Stock	0	0	0	0	0
21	Payment for Retirement of:					
22	Long-Term Debt	0	(49,968)	(83,280)	(30,729)	0
23	Preferred Stock	0	0	0	0	0
24	Equity infusions between parent and subs	(36,112)	(2,306)	(61,629)	(65,887)	(56,232)
25	Net Cash Flow From Financing Activities	(36,112)	(52,275)	(144,910)	(96,616)	(56,232)
26						
27	INC(DEC) in CASH &CASH EQUIVALENTS	$ 0	$ 0	$ 0	$ 0	$ 0

COLUMBUS SOUTHERN POWER COMPANY
Case No. 11-351-EL-AIR
Forecast Assumptions
2011-2015
GWH

Case No. 11-351-EL-AIR
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s):

Schedule S-2
Page 4 of 4
Witness Responsible:
O. J. Sever

Line No.	Description	2011	2012	2013	2014	2015
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Load Forecat (GWH):**					
2	Residential	7,491	7,482	7,504	7,510	7,495
3	Commercial	5,934	5,000	4,874	4,850	4,805
4	Industrial	4,867	4,935	4,950	4,888	4,800
5	Other Retail	56	57	57	58	58
6	**Retail Sales**	18,349	17,474	17,385	17,306	17,157
7						
8	Munis & Coops	0	0	0	0	0
9	Other Sales for Resale	0	0	0	0	0
10	**Ferc Sales**	0	0	0	0	0
11	**Customer Choice Sales**	2,715	3,732	3,947	3,987	4,026
12	**Total On-System Sales**	21,064	21,207	21,332	21,293	21,183
13						
14	**Employee Growth:**					
15						
16	Employee growth was held flat over the forecast period.					
17						
18	**Known Labor Cost Changes:**					
19						
20	O&M expenses were forecasted by business unit with escalations per year as follows.					
21	Labor: 3% per year					
22	Non-Labor: 2% per year					
23	Fringe Benefits: 3% per year					
24						
25						
26	**Capital Structure Requirements/Assumptions:**					
27	Targets a 49/51 Debt/Equity Capital Structure					

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Projected Distribution Income Statement[1]
2011-2015
($000)

Data: Five (5) Years Projected
Type of Filing: ►Original___Updated___Revised
Work Paper Reference No(s):

Schedule S-2
Page 1 of 4
Witness Responsible:
O. J. Sever

Line No. (A)	Description (B)	2011 (C)	2012 (D)	2013 (E)	2014 (F)	2015 (G)
1	OPERATING REVENUES					
2	Revenues	$ 407,827	$ 420,064	$ 467,282	$ 472,370	$ 481,341
3	Rider Revenues[2]	169,828	174,369	173,978	176,940	179,946
4	Total Revenue	577,655	594,434	641,259	649,310	661,287
5						
6	OPERATING EXPENSES					
7	O&M	157,979	160,788	169,502	175,065	180,315
8	Rider O&M[2]	90,709	95,924	96,090	99,144	102,294
9	Total O&M	248,688	256,711	265,592	274,209	282,609
10	Depreciation / Amortization	75,221	71,298	106,780	108,969	111,323
11	Taxes Other Than Income Taxes	60,724	62,640	64,584	66,579	68,547
12	Rider Taxes Other Than Income Taxes[2]	79,118	78,445	77,887	77,796	77,652
13	Total Taxes Other Than Income Taxes	139,842	141,086	142,471	144,375	146,199
14	Current Income Taxes	35,537	37,722	37,688	37,309	37,596
15	Deferred Income Taxes	(4,195)	(2,697)	(2,695)	(2,906)	(3,337)
16	ITC Amortization	(317)	(94)	(61)	(35)	(11)
17	Total Operating Expenses	494,775	504,027	549,775	561,920	574,380
18						
19	Net Operating Income	82,879	90,407	91,484	87,390	86,907
20						
21	Other Income and Deductions	1,132	1,055	1,633	2,537	3,308
22	Net Interest Charges	24,356	25,265	26,436	23,464	23,273
23						
24	Net Income	59,655	66,197	66,681	66,462	66,942
25						
26	(LESS) PREFERRED DIVIDEND	271	271	271	271	271
27						
28	Available for Common	$ 59,384	$ 65,926	$ 66,410	$ 66,192	$ 66,672

[1] This Income Statement represents a projection of revenues necessary to support the required rate of return.
[2] These items represent significant revenues or costs associated with riders that will be treated in a separate proceeding.

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Projected Distribution Balance Sheet
At End of Years: 2011-2015
($000)

Data: Five (5) Years Projected
Type of Filing: ▶Original__Updated__Revised
Work Paper Reference No(s):

Schedule S-2
Page 2 of 4
Witness Responsible:
O. J. Sever

Line No. (A)	Description (B)	2011 (C)	2012 (D)	2013 (E)	2014 (F)	2015 (G)
1	UTILITY PLANT					
2	Utility Plant	$ 1,827,015	$ 1,881,669	$ 1,928,654	$ 1,976,499	$ 2,025,471
3	Construction Work in Progress	29,935	26,503	39,767	54,154	70,349
4	Total Utility Plant	1,856,950	1,908,172	1,968,421	2,030,653	2,095,820
5	(Less) Accumulated Depreciation	631,855	653,184	678,537	704,720	733,680
6	Net Utility Plant	1,225,095	1,254,988	1,289,884	1,325,934	1,362,140
7						
8	CURRENT ASSETS					
9	Cash	1,363	1,363	1,363	1,363	1,363
10	Receivables	64,206	64,206	64,206	64,206	64,206
11	Inventory	15,484	15,484	15,484	15,484	15,484
12	Other Current Assets	76,572	76,572	76,572	76,572	76,572
13	Total Current Assets	157,625	157,625	157,625	157,625	157,625
14						
15	OTHER PROPERTY & INVESTMENTS	8,104	8,104	8,104	8,104	8,104
16						
17	DEFERRED DEBITS					
18	Regulatory Assets	314,581	388,397	355,172	321,946	288,721
19	Other Non-Current Assets	61,070	60,684	60,366	60,141	59,916
20	Total Deferred Debits	375,651	449,081	415,538	382,087	348,637
21						
22	Total Assets and Other Debits	1,766,476	1,869,799	1,871,152	1,873,750	1,876,507
23						
24	PROPRIETARY CAPITAL					
25						
26	Preferred Stock	6,146	6,146	6,146	6,146	6,146
27	Total Common Equity	387,014	427,205	469,852	513,583	558,102
28	Retained Earnings	145,580	164,062	125,757	80,064	39,849
29	Total Proprietary Capital	538,741	597,413	601,755	599,793	604,098
30						
31	LONG TERM DEBT	418,264	418,264	316,248	270,341	270,341
32						
33	OTHER NONCURRENT LIABILITIES					
34	Deferred Income Taxes	285,058	282,361	279,666	276,760	273,422
35	ITC Liability/Deferred Tax	212	117	56	21	10
36	Other Noncurrent Liabilities	106,428	106,428	106,428	106,428	106,428
37	Total Noncurrent Liabilities	391,697	388,906	386,150	383,208	379,860
38						
39	CURRENT LIABILITIES					
40	Accounts Payable	219,685	219,685	219,685	219,685	219,685
41	Other Current Liabilities	198,090	245,532	347,314	400,723	402,523
42	Total Current Liabilities	417,775	465,217	566,999	620,408	622,208
43						
44	Total Liabilities and Proprietary Capital	$ 1,766,475	$ 1,869,799	$ 1,871,152	$ 1,873,750	$ 1,876,506

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Projected Distribution Statement of Changes in Financial Position
2011-2015
($000)

Data: Five (5) Years Projected
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Schedule S-2

Witness Responsible:
O. J. Sever

Line No.	Description	2011	2012	2013	2014	2015
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Cash Flows From Operating Activities					
2	Net Income (after preferred stock dividend)	$ 59,384	$ 65,926	$ 66,410	$ 66,192	$ 66,672
3	*Depreciation & Amortization*	75,221	71,298	106,780	108,969	111,323
4	Regulatory Asset	0	(73,816)	0	0	0
5	Deferred Income Tax	(4,195)	(2,697)	(2,695)	(2,906)	(3,337)
6	Deferred Investment Tax Credits	(317)	(94)	(61)	(35)	(11)
7	AFUDC Equity	(1,132)	(1,056)	(1,633)	(2,537)	(3,308)
8	Forecast Net Removal Expenditures	(12,326)	(12,002)	(13,217)	(12,992)	(12,488)
9	Other Current Assets and Liabilities (net)	46,022	47,442	101,782	53,409	1,800
10	Net Cash Flow From Operating Activities	162,656	95,003	257,366	210,099	160,653
11						
12	Cash Flows From Investing Activities					
13	Capital Expenditures - Property & Construction	(87,514)	(87,371)	(92,710)	(95,068)	(96,782)
14	Allowance for Borrowed Funds Used During Constr-Cr.	(416)	(378)	(573)	(971)	(1,504)
15	Net Cash Flow (Used) by Investing Activities	(87,930)	(87,749)	(93,283)	(96,038)	(98,286)
16						
17	Cash Flows From Financing Activities					
18	Proceeds from Issuance of :					
19	Long-Term Debt	0	0	0	0	0
20	Preferred Stock	0	0	0	0	0
21	Payment for Retirement of:					
22	Long-Term Debt	0	0	(102,015)	(45,907)	0
23	Preferred Stock	0	0	0	0	0
24	Equity infusions between parent and subs	(74,727)	(7,254)	(62,068)	(68,154)	(62,367)
25	Net Cash Flow From Financing Activities	(74,727)	(7,254)	(164,083)	(114,061)	(62,367)
26						
27	INC(DEC) in CASH &CASH EQUIVALENTS	$ 0	$ 0	$ 0	$ 0	$ 0

OHIO POWER COMPANY
Case No. 11-352-EL-AIR
Forecast Assumptions
2011-2015
GWH

Data: Five (5) Years Projected
Type of Filing: ▶Original___Updated___Revised
Work Paper Reference No(s):

Witness Responsible:
O. J. Sever

Line No.	Description	2011	2012	2013	2014	2015
(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**Load Forecast (GWH):**					
2	Residential	7,494	7,349	7,267	7,187	7,112
3	Commercial	5,637	5,340	5,039	5,026	5,025
4	Industrial	13,008	13,264	13,431	13,503	13,530
5	Other Retail	76	76	75	75	74
6	**Retail Sales**	26,215	26,030	25,811	25,791	25,741
7						
8	Munis & Coops	7	7	7	7	7
9	Other Sales for Resale	2,404	349	666	255	305
10	**Ferc Sales**	2,411	356	672	261	312
11	**Customer Choice Sales**	57	440	752	759	765
12	**Total On-System Sales**	28,684	26,826	27,236	26,811	26,819
13						
14	**Employee Growth:**					
15						
16	Employee growth was held flat over the forecast period.					
17						
18	**Known Labor Cost Changes:**					
19						
20	O&M expenses were forecasted by business unit with escalations per year as follows.					
21	Labor: 3% per year					
22	Non-Labor: 2% per year					
23	Fringe Benefits: 3% per year					
24						
25						
26	**Capital Structure Requirements/Assumptions:**					
27	Targets a 54/46 Debt/Equity Capital Structure					

AEP OHIO COMPANIES
COLUMBUS SOUTHERN POWER COMPANY
OHIO POWER COMPANY
11-351-EL-AIR
11-352-EL-AIR

SUPPLEMENTAL FILING REQUIREMENTS

SCHEDULE S-3:

PROPOSED PUBLIC NOTICE

COLUMBUS SOUTHERN POWER COMPANY

OHIO POWER COMPANY

11-351-EL-AIR

11-352-EL-AIR

SCHEDULE S-3

PROPOSED LEGAL NOTICE

Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo) are subsidiary electric utility operating companies of American Electric Power Company, Inc. They conduct their combined business in Ohio as "AEP Ohio," and they are proposing to merge into one company. AEP Ohio has filed with the Public Utilities Commission of Ohio (PUCO) Case No. 11-351-EL-AIR and 11-352-EL-AIR, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company, Individually and, if Their Proposed Merger is Approved, as a Merged Company (collectively, AEP Ohio) for an Increase in Electric Distribution Rates.* AEP Ohio has also sought to amend its tariffs and obtain accounting approval in connection with the proposed rate increases, through its filing in Case No. 11-353-EL-ATA and 11-354-EL-ATA, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company, Individually and, if Their Proposed Merger is Approved, as a Merged Company (collectively AEP Ohio) for Tariff Approval,* and Case No. 11-356-EL-AAM and 11-358-EL-AAM, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company, Individually and, if Their Proposed Merger is Approved, as a Merged Company (collectively AEP Ohio) for Approval to Change Accounting Methods.*

In these cases the Commission will consider the request for approval of increases in the Companies' electric distribution rates, effective with the first billing cycle of January 2012. It has been nearly two decades since CSP or OPCo filed base distribution rate cases for their respective service areas. This filing seeks to bring base distribution rates in line with the current investment required to provide safe, reliable distribution service to customers and to determine an appropriate return on equity. Costs reviewed in this case are based on a test year, considered to be the period from June 1, 2010, to May 31, 2011. In addition, proposals in the filing, if approved by the PUCO, will provide significant benefits in reliability to customers and expansion of new technology. The company proposes an investment component in this case that will provide capital funding for distribution assets, including but not limited to: support for the distribution asset management programs; distribution capacity and infrastructure additions driven by customer demand; and, the continued implementation of advanced technology and the gridSMART® program.

AEP Ohio proposes changes to the Terms and Conditions of service, including the updated prices for miscellaneous distribution charges and pole attachments. In addition, the company proposes a storm deferral reserve and a Deferred Asset Recovery Rider (DARR). Riders being proposed or modified in this case and in conjunction with the pending Electric Security Plan cases (Case Nos. 11-346-EL-SSO and 11-348-EL-SSO) include the Enhanced Service Reliability Rider (ESRR) and the Distribution Investment Rider (DIR).

The proposed distribution rates are presented in two formats: one, as emanating from a combined company (pending the successful merger application of CSP and OPCo currently under consideration at the PUCO); second, as the individual companies CSP and OPCo.

The average increase in total distribution revenue that each rate schedule would bear over the present rates if the proposed increase is granted in full would be:

	CSP	**OPCo**	**Merged Companies**
Residential	4.4%	20.7%	11.8%
Commercial and Industrial	22.2%	7.6%	14.3%
Lighting	26.5%	38.7%	32.6%
Total	10.6%	16.0%	13.3%

The average increase in total revenue to AEP Ohio if the proposed increase is granted in full would be:

CSP	**OPCo**	**Merged Companies**
1.9%	2.6%	2.3%

AEP Ohio proposes to recover other costs through riders; however, those costs and the subsequent rate impacts are not known at this time.

Recommendations that differ from this application may be made by the PUCO staff or by intervening parties and may be adopted by the Commission. Any person, firm, corporation or association may file, pursuant to section 4909.19 of the Ohio Revised Code, an objection to the proposed electric distribution rate increases by alleging that such proposals are unjust and discriminatory or unreasonable. A copy of the application is available for inspection at the main office of AEP Ohio, 850 Tech Center Drive, Gahanna Ohio 43230, and at the Public Utilities Commission of Ohio, 180 East Broad Street, Columbus, Ohio 43215-3793. The application and supporting documents may also be viewed at the Commission's web page at http://www.puc.state.oh.us.

AEP OHIO COMPANIES
COLUMBUS SOUTHERN POWER COMPANY
OHIO POWER COMPANY
11-351-EL-AIR
11-352-EL-AIR

SUPPLEMENTAL FILING REQUIREMENTS

SCHEDULE S-4.1:

EXECUTIVE SUMMARY OF CORPORATE PROCESSES

American Electric Power

and Subsidiaries

Columbus Southern Power Company and Ohio Power Company

DBA as AEP Ohio

Executive Summary Corporate Process

Schedule S-4.1

American Electric Power
And subsidiaries Columbus Southern Power Company and Ohio Power Company, DBA as AEP Ohio
Summary of Compliance with Ohio Administrative Code
Chapter II Section (B) (8)
Executive Summary Corporate Process Schedule S-4.1

SFR Reference:
(B)(8) *Executive Summary Corporate Process*

Schedule S-4.1: Executive Summary of Corporate Process

This report is intended to comply with the requirements of Standard Filing Requirements (SFR) Chapter II Sections (B) (8) and is identified as Schedule S-4.1. This is part one of a two-part report that discusses not only American Electric Power's corporate process but also the management policies, practices and organization of subsidiaries Columbus Southern Power and Ohio Power, doing business as AEP Ohio. The total report consists of three volumes.

Schedule S-4.1 is an executive summary of the corporate processes used by the boards of directors and corporate officers of AEPSC on behalf of Columbus Southern Power (CSP) and Ohio Power (OP) companies, doing business as AEP Ohio, including descriptions of the roles of each in the integrated AEP System. Areas discussed in this volume are:

I. Policy and Goal Setting
II. Strategic and Long-range Planning
III. Organization Structure
IV. Decision-making
V. Ring Fencing
VI. Controlling Process
VII. Internal and External Communications

An overview of the AEP System – along with a description of corporate functional and structural relationships – also is given. The corporate processes and organizational structure of the AEP System involve a number of factors, including the size, physical and operating characteristics of the AEP System.

Exhibits are provided that include, among other things, organizational charts showing the relationships among AEPSC, CSP and OP, as well as the company's annual accountability report.

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EXECUTIVE SUMMARY OF CORPORATE PROCESS

BACKGROUND

Columbus Southern Power (CSP) and Ohio Power (OP), doing business as AEP Ohio, are wholly-owned operating company subsidiaries of American Electric Power Company Inc. (AEP). CSP and OP -- together with the other six operating company subsidiaries – and the American Electric Power Service Corporation (AEPSC) form the American Electric Power System.

AEP was incorporated under the laws of the State of New York in 1906. It is a public utility holding company that owns, directly or indirectly, all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries.

The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. The generating and transmission facilities of AEP's public utility subsidiaries are interconnected and their operations are coordinated. The public utility subsidiaries of AEP traditionally have provided electric service – consisting of generation, transmission and distribution – on an integrated basis to their retail customers. Restructuring legislation in Michigan and Texas, as well as Ohio, has caused the AEP public utility subsidiaries in those states to unbundle previously integrated regulated rates for their retail customers. Maps showing AEP's and AEP Ohio's service territories are attached as Exhibit 1.

The AEP System is an integrated electric utility system. As a result, the member companies of the AEP System have contractual, financial and other business relationships with the other member companies, such as participation in the AEP System savings and retirement plans and tax returns.

AEPSC

AEPSC renders various services at cost to the AEP System utilities. Because these functions are performed on a centralized basis, economies are achieved because each utility does not need to maintain separate personnel at each company to perform these services. AEPSC provides services to CSP and OP in the following functional areas:

- The Chief Operating Officer group provides services in the areas of customer and distribution services, commercial operations, environmental and safety services, shared services and regulatory services.
- The Shared Services organization provides Human Resources, Information Technology and Business Logistics services.
- The Generation function at AEPSC provides four main services to CSP and OP: fossil and hydro services, engineering services, generation business services, and fuel, emissions and logistics.
- Transmission Services plans and operates the CSP and OP transmission system as part of its responsibility to manage the overall AEP transmission system. It includes Transmission Engineering & Project Services, Transmission System & Region Operations and Transmission Strategy & Business Development.
- The Office of the Chairman provides not only the services of the AEP chairman and chief executive officer, and his administrative staff, but also provides legal, audit, corporate communications and federal/external affairs services.
- The Finance, Accounting and Strategic Planning groups within AEPSC provide corporate accounting, tax research and consultation, planning and budgeting, risk management, cash management, treasury and investor relations services.

MANAGEMENT POLICIES, PROCESSES AND ORGANIZATION

CSP and OP have substantial portions of their corporate processes intermeshed with the parent company. A substantial portion of the senior management of CSP and OP consists of AEP and AEPSC officers. Therefore, it is necessary to examine the corporate processes in those corporations in order to understand more fully the corporate process of CSP and OP.

I. Policy and Goal Setting

AEP's corporate policies are established to maximize AEP System efficiency and effectiveness. This is done with an active involvement on the part of the operating companies and with regard for their individual needs and capabilities.

To facilitate the use of common operating policies, practices and procedures, and to assure the meeting of the AEP System's corporate objectives and goals, the AEP System uses interlocking boards of directors and management. Members of AEPSC senior management serve not only on the boards of the subsidiaries, including CSP and OP, but also as part of their executive management team. The executive officers of AEP all are AEPSC employees.

Establishment of Policy:

The establishment of policy, which is part of the overall planning process, is done at all levels of the AEPSC, CSP and OP organizational units and is not reserved to top management. Higher management sets major policies while progressively lower management levels set derivative or supporting policies.

The AEP Board of Directors establishes broad corporate policies. AEP's Board of Director's Public Policy Committee is responsible for examining the company's policies on major public issues affecting the AEP System.

The AEP Executive Council is the AEP System's top policy making body. AEP's Executive Council is comprised of the presidents of each of the utility operating companies and the following AEPSC officers: the chairman and chief executive officer, the chief operating officer, the president - AEP Transmission, the president - AEP Utilities, the executive vice president and chief financial officer, the executive vice president - Generation, the executive vice president - Environment, Safety & Health, the senior vice president and general counsel, the senior vice president - Commercial Operations, the senior vice president - Regulatory Services and the senior vice president - Shared Services.

AEP's Executive Council establishes goals that challenge employees to meet and exceed objectives associated with the company's business purpose. The Executive Council also sets the earnings per share (EPS) earnings goals. Each business unit establishes its own departmental goals.

The president of CSP and OP is responsible for formulating and recommending policies, practices and procedures governing the operation and maintenance of CSP and OP facilities.

II. Strategic and Long-Range Planning

The AEP System corporate process is designed to achieve AEP System corporate objectives through the use of a series of generally accepted management processes. The operation of the AEP System involves the concerted actions of the AEP, CSP and OP boards of directors; the AEPSC, CSP and OP corporate officers; and AEPSC, CSP and OP employees.

The type of planning by the manager depends on the objective of the organizational unit for which that manager is responsible. While the first line supervisor may be responsible only for day-to-day planning, an executive level officer is responsible for long-range planning. Higher management levels in the AEPSC and CSP and OP organizations deal with strategic planning; establishment of policies; planning for the provision of human resources, physical facilities and financial resources.

Long-range planning involves setting objectives and strategies to achieve those objectives and is continuously affected by factors such as legislative and regulatory developments, technological developments, and economic trends and financial forces. Strategic and long-range planning is done at the AEPSC, CSP and OP higher management levels as well as the departmental levels. Twice a year, the AEP Board of Directors has a two-day retreat at which it reviews the AEP strategic plan. Strategic and long-range financial planning is coordinated by AEP's chief financial officer and AEPSC's senior vice president - Corporate Planning & Budgeting.

III. Organization Structure

There are several layers to the AEP organization structure. Each of the utility subsidiaries is described below. AEP's corporate structure and upper management organization charts are presented in Exhibit 2.

- American Electric Power Company Inc. is the parent company and a registered holding company under the Public Utility Holding Company Act of 2005.
    - AEP and its subsidiaries are engaged in the generation, transmission and distribution of electricity in 11 states.
        - CSP is engaged in the generation, transmission and distribution of electric power to approximately 749,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utilities, municipalities and other market participants. CSP's service area is comprised of two areas in Ohio, which include portions of 25 counties. One area includes the city of Columbus, and the other is a predominantly rural area in south central Ohio.
        - OP is engaged in the generation, transmission and distribution of electric power to approximately 710,000 retail customers in the northwestern, east central, eastern and southern Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants.
        - Appalachian Power Company is engaged in the generation, transmission and distribution of electric power to approximately 959,000 retail customers in southwestern Virginia and southern West Virginia.
        - Indiana Michigan Power Company is engaged in the generation, transmission and distribution of electric power to approximately 583,000 retail customers in northern and eastern Indiana and southwestern Michigan.
        - Kentucky Power Company is engaged in the generation, transmission and distribution of electric power to approximately 175,000 retail customers in eastern Kentucky.
        - Kingsport Power Company provides electric service to approximately 47,000 retail customers in Kingsport and eight neighboring communities in northeastern Tennessee.
        - Public Service Company of Oklahoma is engaged in the generation, transmission and distribution of electric power to approximately 531,000 retail customers in eastern and southwestern Oklahoma.

- Southwestern Electric Power Company is engaged in the generation, transmission and distribution of electric power to approximately 474,000 retail customers in northeastern Texas, northwestern Louisiana and western Arkansas.
- AEP Texas Central Company is engaged in the transmission and distribution of electric power to approximately 766,000 retail customers through regional electric providers in southern Texas.
- AEP Texas North Company is engaged in the transmission and distribution of electric power to approximately 185,000 retail customers through regional electric providers in west and central Texas.
- Wheeling Power Company provides electric service to approximately 41,000 retail customers in northern West Virginia.
- AEP Generating Company is an electric generating company that sells power at wholesale to Indiana Michigan Power Company, CSP and Kentucky Power Company.

IV. Decision Making

AEP Board of Directors

The business of AEP is managed under the broad supervision and direction of the board of directors. The AEP board establishes broad corporate policies and authorizes various specific types of transactions but is not involved in the day-to-day functioning of the AEP System. The AEP Board of Directors exercises its supervisory duties through eight regular meetings, as well as special meetings as required. The AEP board has adopted Principles of Corporate Governance, a copy of which is attached as Exhibit 3 and also can be found on AEP's website at *www.AEP.com/investors/corporategovernance/*

The AEP board has appointed the following seven standing committees to assist it in the fulfillment of its duties:

The ***Audit Committee*** is responsible for, among other things, the appointment of the independent registered public accounting firm for the company; reviewing with the independent auditor the plan and scope of the audit and approving audit fees; monitoring the adequacy of financial reporting and internal control over financial reporting; and meeting periodically with the internal auditor and the independent auditor. A more detailed discussion of the purposes, duties and responsibilities of the Audit Committee is found in the Audit Committee charter, a copy of which is attached as Exhibit 4 and also can be found on AEP's website at *www.AEP.com/investors/corporategovernance/*

The ***Committee on Directors and Corporate Governance*** has the responsibilities set forth in its charter, including recommending selection criteria for nominees for election or appointment to the board, supervising the AEP Corporate Compliance Program and overseeing AEP's Corporate Accountability Report (Exhibit 11). A copy of the charter is attached as Exhibit 5 and also can be found on AEP's website at *www.AEP.com/investors/corporategovernance/*

The ***Executive Committee*** is empowered to exercise all the authority of the AEP board, subject to certain limitations prescribed in its bylaws, during the intervals between meetings of the board.

The ***Finance Committee*** monitors and reports to the AEP Board with respect to the capital requirements and financing plans and programs of AEP and its subsidiaries, including reviewing and making recommendations concerning the short and long-term financing plans and programs of AEP and its subsidiaries. The Finance Committee has the responsibilities set forth in its charter, a copy of which is attached as Exhibit 6 and also can be found on AEP's website at *www.AEP.com/investors/corporategovernance/*

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The ***Human Resources Committee*** annually reviews and approves AEP's executive compensation in the context of the performance of management and the company. The HR Committee has the responsibilities set forth in its charter, a copy of which is attached as Exhibit 7 and also can be found on AEP's website at *www.AEP.com/investors/corporategovernance/*

The ***Nuclear Oversight Committee*** is responsible for overseeing and reporting to the AEP board with respect to the management and operation of AEP's nuclear generation. The Nuclear Oversight Committee has the responsibilities set forth in its charter, a copy of which is attached as Exhibit 8 and also can be found on AEP's website at *www.AEP.com/investors/corporategovernance/*

The ***Policy Committee*** is responsible for examining AEP's policies on major public issues affecting the AEP System, including environmental, technology, fuel supply, industry change and other matters.

CSP Board of Directors

The CSP Board of Directors presently consists of nine members, all of whom are senior officers of AEPSC. The CSP Board of Directors passes upon all the various corporate decisions required of a board. It considers the declaration of dividends, appoints and, when applicable, accepts resignation of officers, approves capital improvement requisitions and lease requisitions. The CSP board also reviews and approves all financing programs for the company. A chart of the CSP directors is shown as Exhibit 9A.

OP Board of Directors

The OP Board of Directors presently consists of nine members, all of whom are senior officers of AEPSC. The OP Board of Directors passes upon all the various corporate decisions required of a board. It considers the declaration of dividends, appoints and, when applicable, accepts resignation of officers, approves capital improvement requisitions and lease requisitions. The OP board also reviews and approves all financing programs for the company. A chart of the OP directors is shown as Exhibit 9B.

V. Ring Fencing

The principles of ring fencing in utility regulation were codified in various provisions of the Public Utility Holding Company Act of 1935, (PUHCA). American Electric Power Company, Inc., (AEP), was a registered public utility holding company under the PUHCA until that act was repealed in 2005. The separation of regulated utility functions from non-regulated businesses required by PUHCA and prevailing throughout the AEP system has not been altered or diluted as it relates to AEP Ohio since the repeal of PUHCA. As a result, AEP Ohio, as constituent public utilities within the AEP system, continues to benefit from the ring fencing protections set forth in the PUHCA. In practical terms, this means that AEP Ohio:

1. has not made any investment in any entity engaged in a non-regulated business;
2. has not made loans or extended credit to AEP or to any affiliate engaged in a non-regulated business; and
3. has not guaranteed the indebtedness or the obligations of AEP or any affiliate engaged in a non-regulated business.

AEP Ohio consists of two separate legal entities, Ohio Power Company and Columbus Southern Power Company. Each AEP Ohio utility is a registered issuer under federal securities acts; each has independent access to public capital markets through which each continually raises capital. Each AEP Ohio utility is independently rated by the nationally recognized statistical credit rating agencies. Each AEP Ohio utility is managed by a board of directors that is responsible for authorizing action, including the acquisition or disposition of material assets, issuances of securities, and declaration of dividends, in such a way as to preserve the credit ratings and creditworthiness of each entity.

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On June 2, 2010, the Commission approved AEP Ohio's corporate separation plans, filed June 1, 2009, and specifically found that the corporate separation plans were adequately implemented by AEP Ohio in accordance with Section 4928.17, Revised Code, Chapter 4901:1-37, O.A.C., and the orders of the Commission. (Opinion and Order in Case No. 09-464-EL-UNC). With its corporate separation plans, AEP Ohio has in place structural safeguards to ensure the independent functioning of the companies and their affiliates in a manner which is consistent with the Commission's Code of Conduct and which rejects cross-subsidization. The companies' accounting protocols, approach to financial arrangements, adherence to the Cost Allocation Manual requirements, employee education and training and internal compliance monitoring each support the goals and policies set out in Section 4928.02, Revised Code.

VI. Controlling Process

Although there are many types of controls being used at each level of the organization, the AEP System and individual operating company annual budgets are a primary managerial control. The control process is an integral part of the entire management process and, by necessity, interrelates with the strategic and long-range planning process that is discussed earlier. Within the AEP System, control also is exercised over the determination and promulgation of and compliance with policies at every level, which also is discussed earlier. Control of the organization also is accomplished through organizational planning, documentation through organizational charts, job descriptions, approval procedures for organizational changes and periodic reviews at all levels of the organization. Control is exercised over the quality of the personnel through selection techniques, training and performance evaluation. Control is exercised over wages and salaries through salary administration practices that include a structured approval process, periodic salary reviews and comparison with outside work forces.

Control over capital expenditures begins with the initial approval of a project through the completion stages. Major capital projects and lease improvement projects are approved by the boards of directors of the respective operating companies. The annual operating forecast is another major tool in the control process. It provides a benchmark for both the AEP System and individual operating company performance. Control also is exercised through the accounting system and its various controls and procedures.

VII. Internal and External Communications

AEP uses a variety of electronic and print media to communicate to its employees. AEP maintains an internal intranet web portal, "AEP Now," which can be accessed online at work or at home by employees. Internal and external news stories of interest to employees are published on AEP Now.

AEP also uses other communications designed around the corporate organizational structure. Special video presentations and other items of critical importance to employees and the company are presented and explained through employee meetings and leadership conferences. Recordings of webcasts also are available to employees for viewing via AEP Now. Information regarding personal benefits and other issues important to employees and their families typically is delivered through printed correspondence sent directly to employees' homes. This information also is available online to employees via the company's internal HR Now website.

External communication is conducted through a variety of media as well. Shareholder meetings, financial and sustainability annual reports, news releases and other special presentations provide updates about the status of the company.

Residential consumers and small businesses receive information via bill inserts. In cases involving larger commercial and industrial customers, customer service representatives may communicate through e-mail or face-to-face meetings. Each individual AEP operating company, such as AEP Ohio, also maintains an external website that is accessible to all customer classes. AEP Ohio customers can access AEP Ohio via the company's dedicated call centers and the AEP and AEP Ohio websites, AEP.com and AEPOhio.com.

VIII. Goal Attainment and Quantification

AEP's success can be measured not only by its earnings but also by other measures that are specific to its business segments. AEP's management team has compiled metrics to assess the performance of each group. Employees' incentive targets typically are based on the AEP corporate EPS target and the employee's departmental goals. A history of significant events in AEP's history of firsts, as well as significant events in AEP Ohio's history, can be found in Exhibits 10A and 10B.

Exhibit 1 – AEP and AEP Ohio Service Territories

Regulated Utility Operations

AEP, with more than 5 million American customers, is one of the country's largest investor-owned utilities, serving parts of 11 states. The service territory covers 197,500 square miles in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

AEP's U.S. customers are served by one of the world's largest transmission and distribution systems. Systemwide there are more than 38,000 circuit miles of transmission lines and more than 186,000 miles of distribution lines. More information about AEP and its operating companies is available under the About Us tab on AEP.com.

AEP Ohio Territory

AEP Ohio, headquartered in Gahanna, Ohio, encompasses the AEP service territories within the state of Ohio and the northern panhandle of West Virginia. AEP Ohio serves the customers of both major AEP subsidiaries in Ohio – Ohio Power Company and Columbus Southern Power Company – and Wheeling Power in West Virginia. AEP Ohio maintains regulatory and external affairs offices in Columbus. More information about AEP Ohio is available under the News & Information tab on AEPOhio.com.

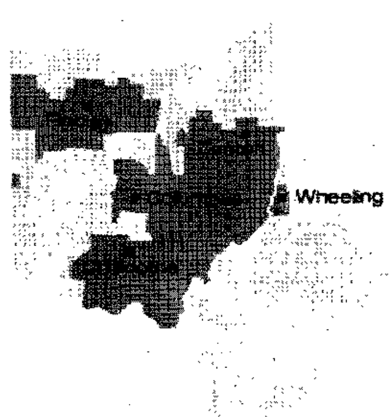


Exhibit 2 – AEP Corporate Structure and Organization Charts

CorpCharts - Subsidiary Chart for American Electric Power Company, Inc.

- American Electric Power Company, Inc.
  - AEP C & I Company, LLC (100%)
    - AEP Retail Energy Partners LLC (100%)
    - *AEP Texas Commercial & Industrial Retail GP, LLC (100%)*
      - AEP Texas Commercial & Industrial Retail Limited Partnership (0.50%)
    - AEP Texas Commercial & Industrial Retail Limited Partnership (99.50%)
    - REP Holdco, LLC (100%)
      - Mutual Energy SWEPCO, LP (99.50%)
      - REP General Partner, L.L.C. (100%)
        - *Mutual Energy SWEPCO, LP (0.50%)*
  - AEP Coal, Inc. (100%)
    - AEP Kentucky Coal, LLC (100%)
    - Snowcap Coal Company, Inc. (100%)
  - AEP Credit, Inc. (100%)
  - AEP Fiber Venture, LLC (100%)
    - *AFN, LLC (50.42%)*
  - AEP Generating Company (100%)
  - AEP Investments, Inc. (100%)
    - Amperion, Inc. (0.11%)
    - IntercontinentalExchange, Inc. (0.48%)
    - Microcell Corporation (12.50%)
    - *Powerspan Corp. (1.17%)*
    - Universal Supercapacitors, LLC (50%)
  - AEP Nonutility Funding LLC (100%)
  - AEP Pro Serv, Inc. (100%)
    - Diversified Energy Contractors Company, LLC (100%)
    - United Sciences Testing, Inc. (100%)
  - AEP Resources, Inc. (100%)
    - AEP Energy Services Limited (100%)
    - AEP Energy Services, Inc. (100%)

American Electric Power Company, Inc.

- AEP Energy Services Gas Holding Company (100%)
- AEP River Operations LLC (100%)
  - AEP Elmwood LLC (100%)
    - Conlease, Inc. (100%)
    - International Marine Terminals Partnership (33.33%)
      - IMT Land Corp. (100%)
- AEP T&D Services, LLC (100%)
- AEP Transmission Holding Company, LLC (100%)
  - AEP Transmission Company, LLC (100%)
    - AEP Appalachian Transmission Company, Inc. (100%)
    - AEP Indiana Michigan Transmission Company, Inc. (100%)
    - AEP Kentucky Transmission Company, Inc. (100%)
    - AEP Ohio Transmission Company, Inc. (100%)
    - AEP Oklahoma Transmission Company, Inc. (100%)
    - AEP Southwestern Transmission Company, Inc. (100%)
    - AEP West Virginia Transmission Company, Inc. (100%)
  - Electric Transmission America, LLC (50%)
    - Prairie Wind Transmission, LLC (50%)
    - Tallgrass Transmission, LLC (50%)
  - Ohio Series, Potomac-Appalachian Transmission Highline, LLC (50%)
    - PATH Ohio Transmission Company, LLC (100%)
  - PATH West Virginia Series (50%)
    - PATH West Virginia Transmission Company, LLC (100%)
      - PATH - WV Land Acquisition Company (100%)
  - Pioneer Transmission, LLC (50%)
  - Potomac-Appalachian Transmission Highline, LLC (50%)
- AEP Utilities, Inc. (100%)
  - AEP Texas Central Company (100%)
    - AEP Texas Central Transition Funding II LLC (100%)
    - AEP Texas Central Transition Funding LLC (100%)
  - AEP Texas North Company (100%)
    - AEP Texas North Generation Company, LLC (100%)

American Electric Power Company, Inc.

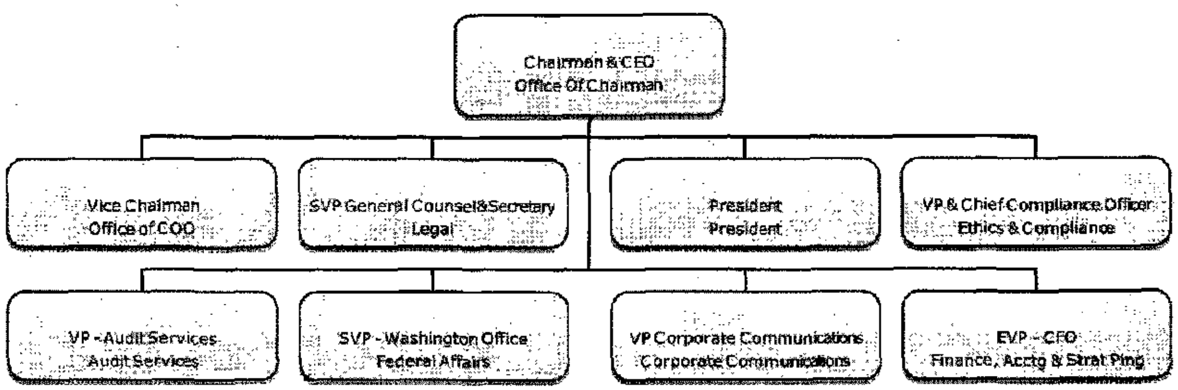
- CSW Energy Services, Inc. (100%)
  - Nuvest, LLC (92.90%)
    - ESG Manufacturing, LLC (100%)
    - ESG, L.L.C. (50%)
    - National Temporary Services, Inc. (100%)
- CSW Energy, Inc. (100%)
  - AEP Desert Sky GP, LLC (100%)
    - Desert Sky Wind Farm LP (1%)
  - AEP Desert Sky LP II, LLC (100%)
    - Desert Sky Wind Farm LP (99%)
  - AEP Energy Partners, Inc. (100%)
  - AEP Wind Holding, LLC (100%)
    - AEP Properties, LLC (100%)
    - AEP Wind GP, LLC (100%)
      - Trent Wind Farm, LP (1%)
    - AEP Wind LP II, LLC (100%)
      - Trent Wind Farm, LP (99%)
- Electric Transmission Texas, LLC (50%)

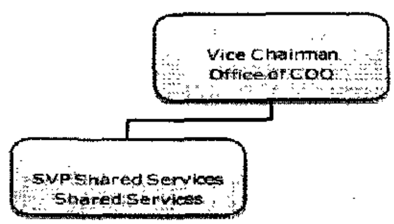
- AEP Utility Funding, LLC (100%)
- American Electric Power Service Corporation (100%)
  - American Electric Power Foundation (100%)
- Appalachian Power Company (98.70%)
  - Cedar Coal Co. (100%)
  - Central Appalachian Coal Company (100%)
  - Central Coal Company (50%)
  - Southern Appalachian Coal Company (100%)
- Columbus Southern Power Company (100%)
  - Conesville Coal Preparation Company (100%)
  - Distribution Vision 2010, LLC (24.30%)
  - Ohio Valley Electric Corporation (4.30%)
    - Indiana-Kentucky Electric Corporation (100%)
- Franklin Real Estate Company (100%)

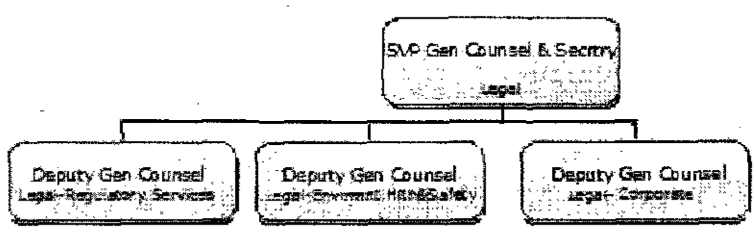
American Electric Power Company, Inc.

- *Indiana Franklin Realty, Inc. (100%)*
- Indiana Michigan Power Company (100%)
  - Blackhawk Coal Company (100%)
  - Price River Coal Company, Inc. (100%)
- Kentucky Power Company (100%)
- Kingsport Power Company (100%)
- Ohio Power Company (99.40%)
  - Cardinal Operating Company (50%)
  - Central Coal Company (50%)
  - OP Gavin, LLC (100%)
- Ohio Valley Electric Corporation (39.17%)
  - Indiana-Kentucky Electric Corporation (100%)
- PowerTree Carbon Company, LLC (9.16%)
- Public Service Company Of Oklahoma (99.40%)
- Southwestern Electric Power Company (99.40%)
  - Dolet Hills Lignite Company, LLC (100%)
  - Oxbow Lignite Company, LLC (50%)
  - SWEPCO Capital Trust I (100%)
  - Southwest Arkansas Utilities Corporation (100%)
  - The Arklahoma Corporation (47.60%)
- Wheeling Power Company (100%)

Organization Charts
American Electric Power
Executives and Direct Reports







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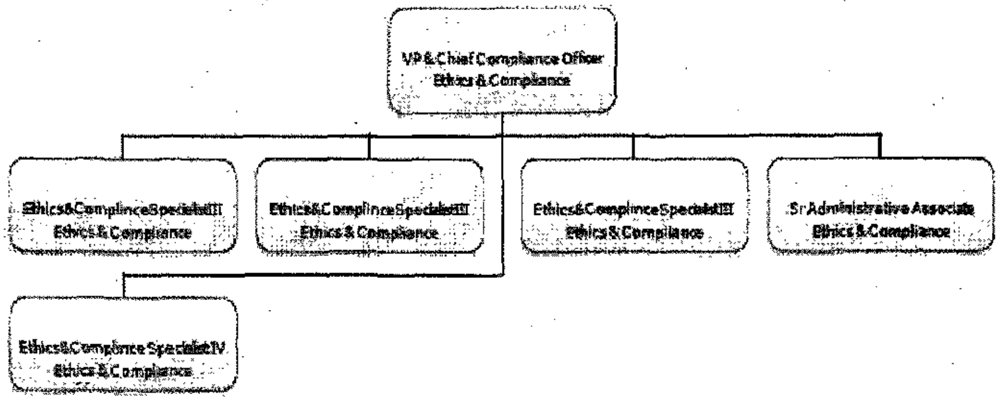
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Sr Administrative Associate
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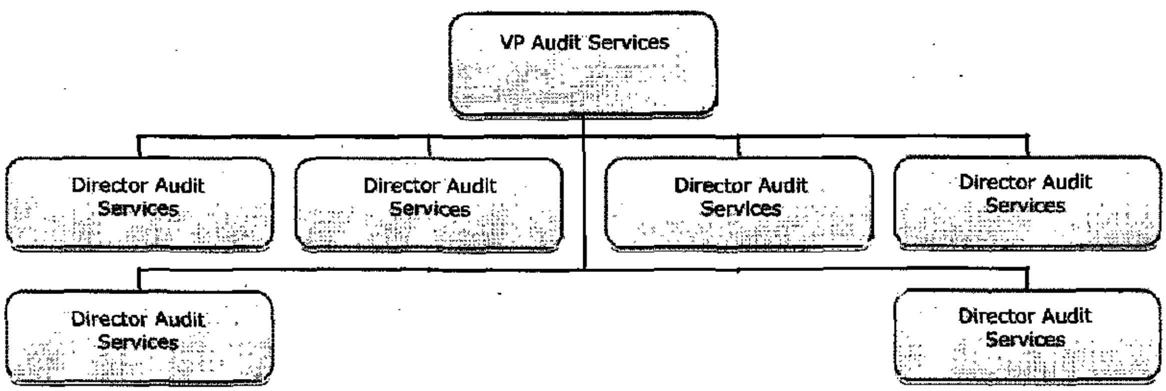
Ethics & Compliance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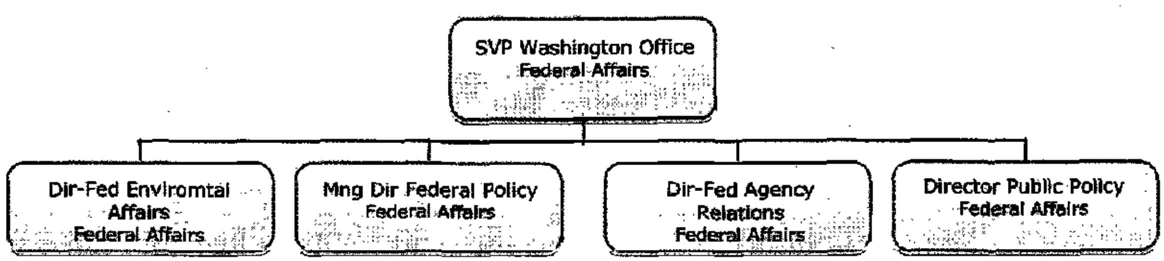
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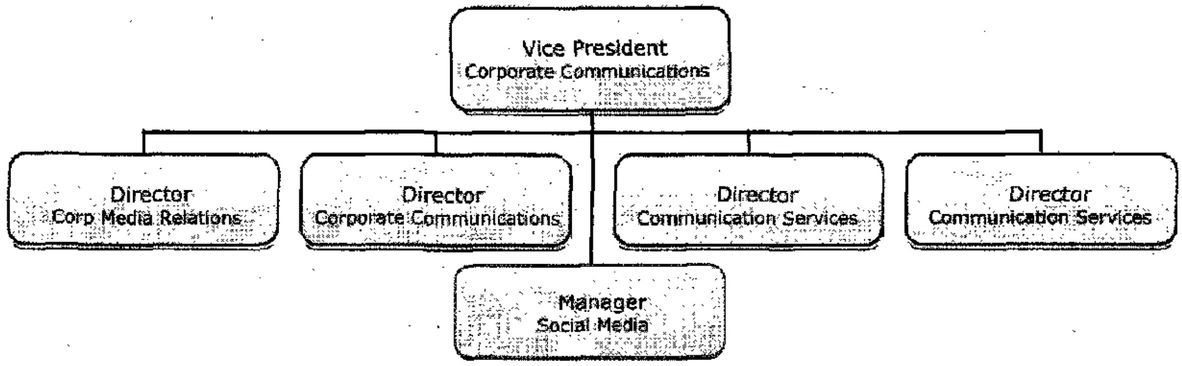
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Director
Corp Media Relations
Director
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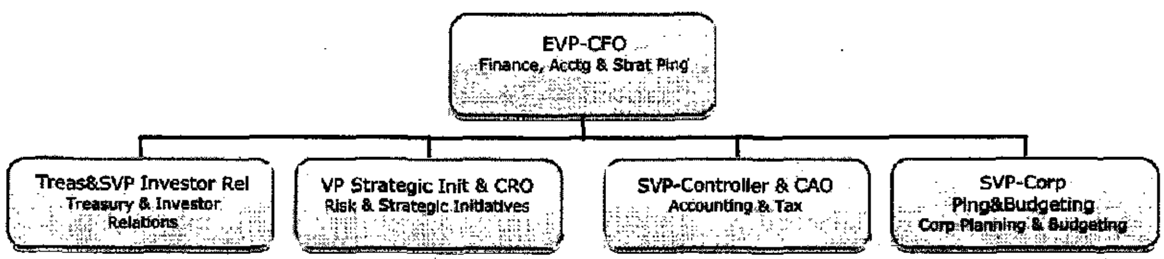
Communication Services
Director
Communication Services
Manager
Social Media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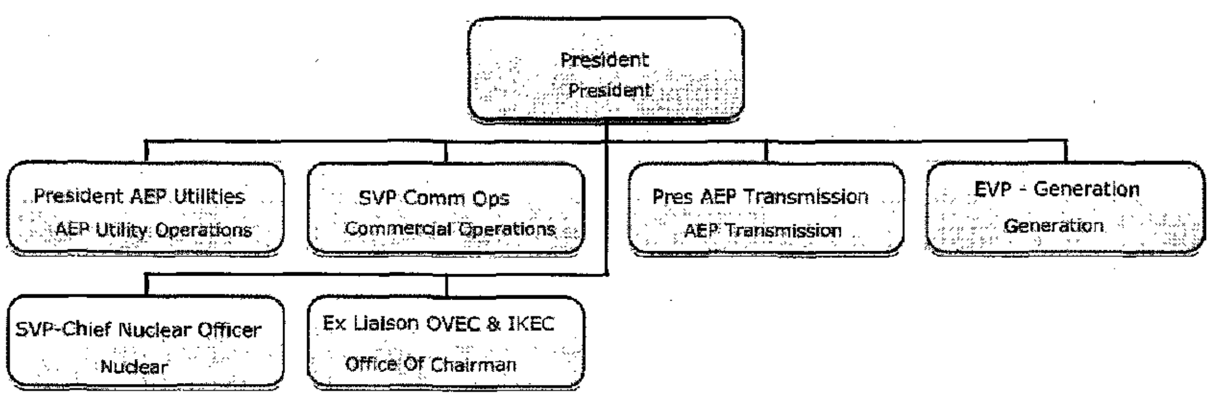
Finance, Acctg & Strat Plng
Treas&SVP Investor Rel
Treasury & Investor Relations
VP Strategic Init & CRO
Risk & Strategic Initiatives
SVP-Controller & CAO
Accounting & Tax
SVP-Corp Plng&Budgeting
Corp Planning & Budgeting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President
President AEP Utilities
AEP Utility Operations
SVP Comm Ops
Commercial Operations
Pres AEP Transmission
AEP Transmission
EVP - Generation
Generation
SVP-Chief Nuclear Officer
Nuclear
Ex Liaison OVEC & IKEC
Office Of Chairman

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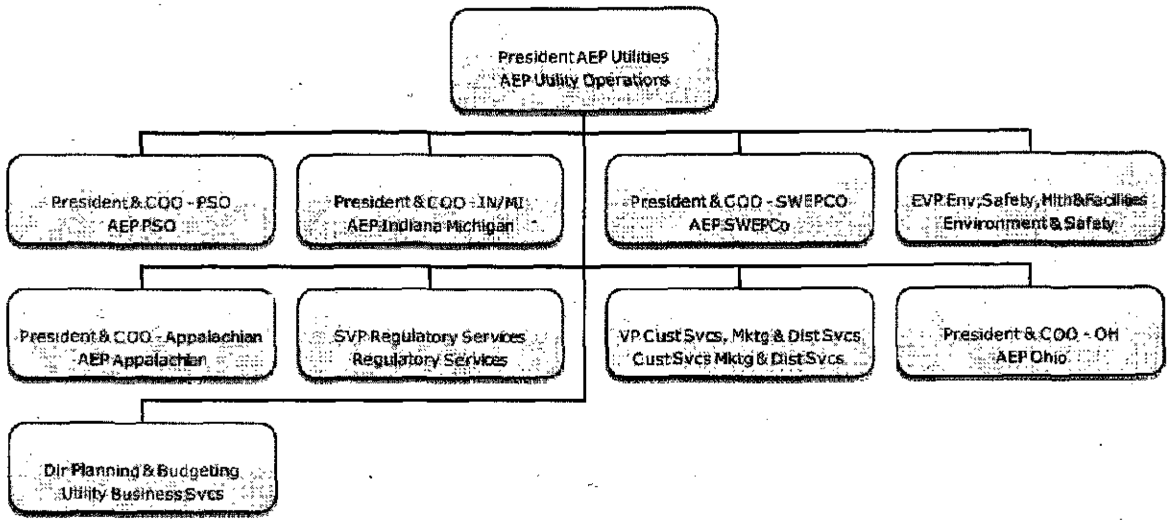
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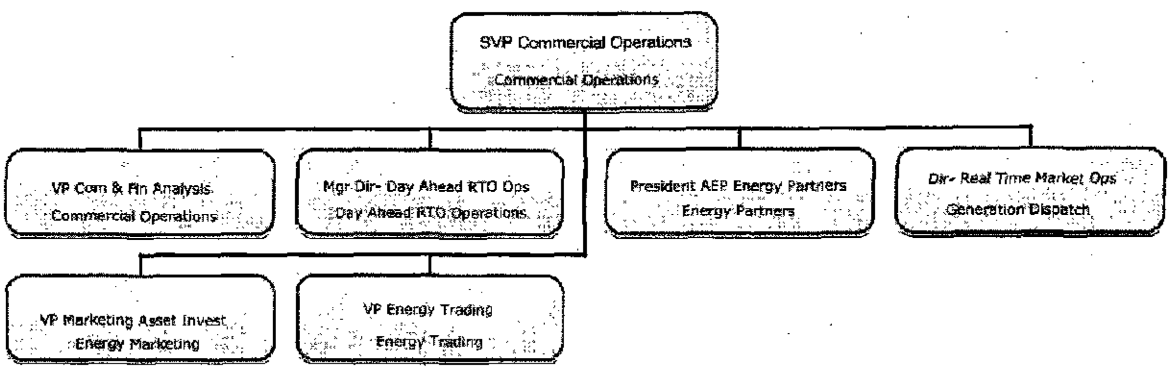
AEP Utility Operations
President & COO - PSO
AEP PSO
President & COO - IN/MI
AEP Indiana Michigan
President & COO - SWEPCO
AEP SWEPCo
EVP Env,Safety,Hlth&Facilities
Environment & Safety
President & COO - Appalachian
AEP Appalachian
SVP Regulatory Services
Regulatory Services
VP Cust Svcs, Mktg & Dist Svcs
Cust Svcs Mktg & Dist Svcs
President & COO - OH
AEP Ohio
Dir Planning & Budgeting
Utility Business Svcs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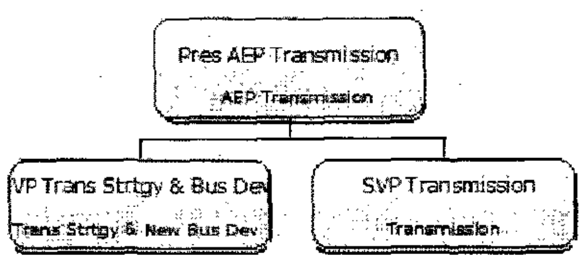
Commercial Operations
VP Com & Fin Analysis
Commercial Operations
Mgr Dir- Day Ahead RTO Ops
Day Ahead RTO Operations
President AEP Energy Partners
Energy Partners
Dir- Real Time Market Ops
Generation Dispatch
VP Marketing Asset Invest
Energy Marketing
VP Energy Trading
Energy Trading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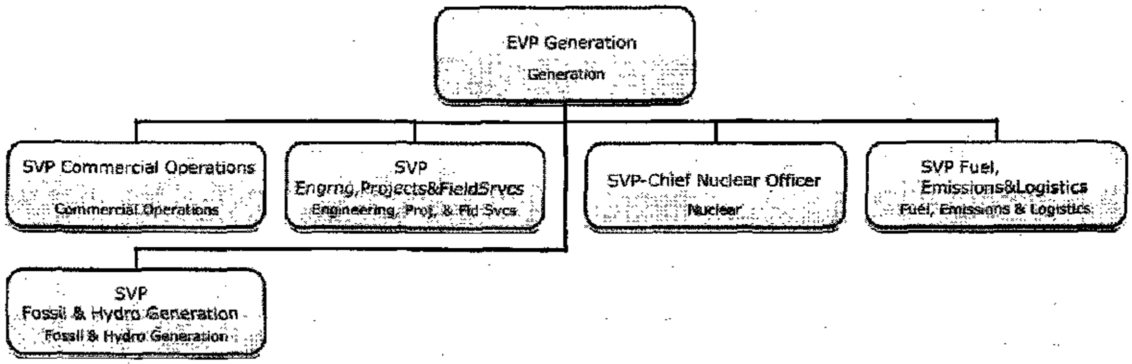
AEP Transmission
VP Trans Strtgy & Bus Dev
Trans Strtgy & New Bus Dev
SVP Transmission
Transmission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Generation
SVP Commercial Operations
Commercial Operations
SVP
Engrng,Projects&FieldSrvcs
Engineering, Proj. & Fld Svcs
SVP-Chief Nuclear Officer
Nuclear
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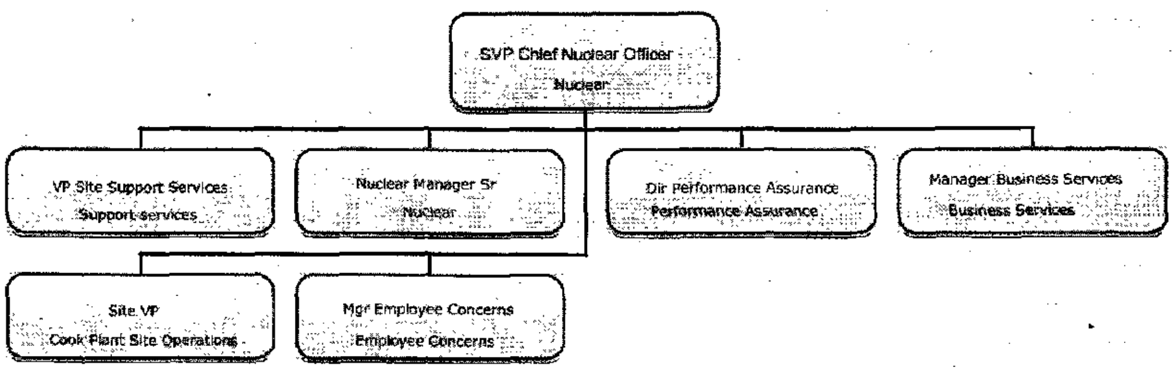
Fossil & Hydro Generation
Fossil & Hydro Generation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Nuclear
VP Site Support Services
Support services
Nuclear Manager Sr
Nuclear
Dir Performance Assurance
Performance Assurance
Manager Business Services
Business Services
Site VP
Cook Plant Site Operations
Mgr Employee Concerns
Employee Concerns

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Organization Structure
AEP Ohio

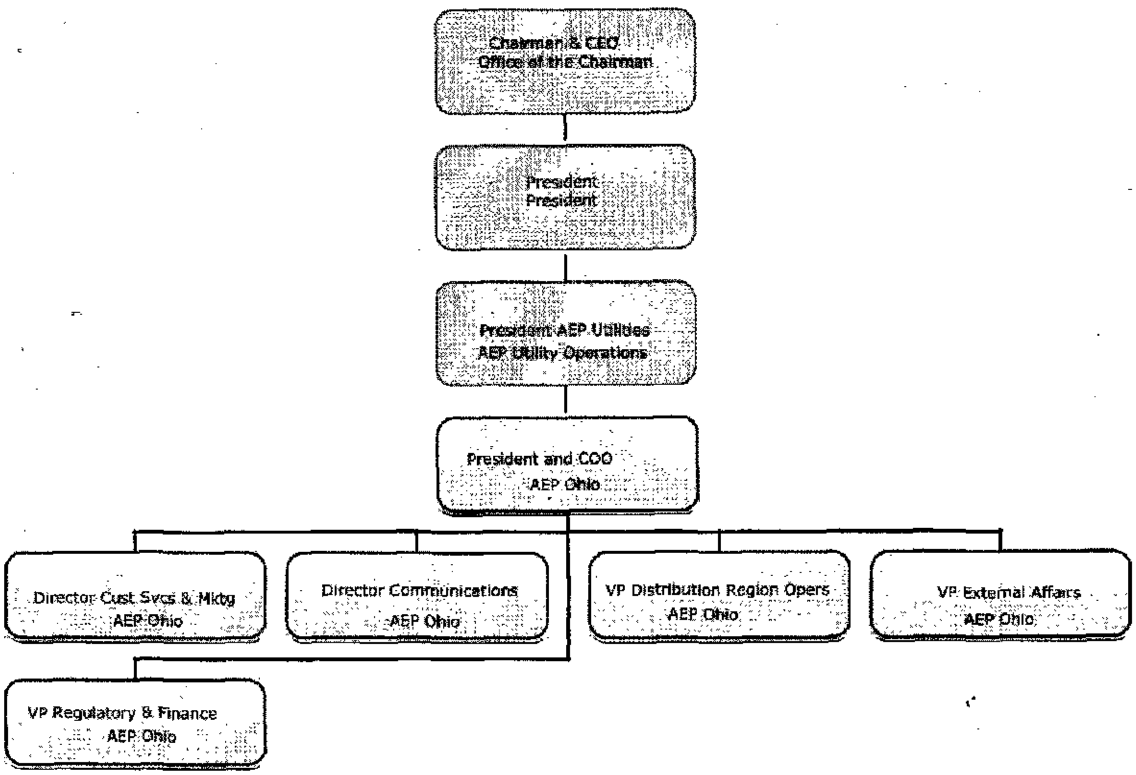

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Exhibit 3 – AEP Principles of Corporate Governance

AMERICAN ELECTRIC POWER COMPANY, INC.
PRINCIPLES OF CORPORATE GOVERNANCE OF
THE BOARD OF DIRECTORS
Amended as of December 13, 2006

Under New York law, the Company is managed under direction of the Board of Directors. The Board of Directors establishes broad corporate policies and authorizes various types of transactions, but it is not involved in day-to-day operational details. Its various responsibilities include the selection and compensation of the Chief Executive Officer ("CEO"), the understanding and approval of corporate strategies and the understanding of the numerous issues and risks the Company faces on an ongoing basis.

I. DIRECTOR QUALIFICATION STANDARDS

A. Selection of Directors

The Board of Directors (the "Board") is responsible for nominating Directors who will be elected annually by the shareholders. In nominating a slate of Directors, the Board's objective, with the assistance of the Committee on Directors and Corporate Governance, is to select individuals with skills and experience that can be of assistance to management in operating the Company's business.

Directors should possess the highest personal and professional ethics, integrity and values, and be committed to representing the long-term interests of the shareholders. They must also have an inquisitive and objective perspective, practical wisdom and mature judgment.

Directors must be willing to devote sufficient time to carrying out their duties and responsibilities effectively.

B. Board Size

The Board determines, with the assistance of the Committee on Directors and Corporate Governance, the appropriate Board size, taking into consideration the parameters set forth in the Company's charter and by-laws, the Company's diversity goals and objectives, and the overall Board composition. The Board should neither be too small to maintain the needed expertise and independence, nor too large to be efficiently functional. If appropriate, the Board should recommend amendments to the Company's charter or by-laws in order to provide for a different Board size than may be set forth therein. The Board should consist of a majority of independent directors as determined by the Committee on Directors and Corporate Governance.

C. Change of Principal Occupation or Business Association

Directors should offer their resignation in the event of any significant change in their principal job responsibilities or business associations. The Committee on Directors and Corporate Governance will recommend to the Board the action to be taken with respect to the resignation.

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D. Term Limits

The Board does not believe it should limit the number of terms for which an individual may serve as a director. Directors who have served on the Board for an extended period of time are able to provide valuable insight into the operations and future of the Company based on their experience with and understanding of the Company's history, policies and objectives. The Board believes that, as an alternative to term limits, it can ensure that the Board continues to evolve and adopt new viewpoints through the evaluation and nomination process described in these guidelines. The Company's Directors are elected annually.

E. Retirement Policy

The Board believes that 72 is an appropriate retirement age for outside directors. Directors generally will not be nominated for re-election at any annual shareholders meeting following their 72nd birthday.

F. Other Boards

Without specific approval from the Board, (i) no director may serve on more than six public company boards (including the Company's Board); (ii) directors who also serve as CEOs of publicly-traded companies should not serve on more than two public company boards in addition to their employer's board; and (iii) no director who serves on the Audit Committee may serve on more than three public company audit committees (including the Company's Audit Committee). The Committee on Directors and Corporate Governance and the Board will take into account the nature of and time involved in a director's service on other boards in evaluating the suitability of individual directors and making its recommendations to Company shareholders.

II. DIRECTOR RESPONSIBILITIES

A. Chairman and CEO

The Board elects its Chairman and appoints the Company's CEO. If the Chairman and CEO positions are held by two different people, the Chairman will be one of the independent directors (an "Independent Chairman"). If the roles of Chairman and CEO are performed by the same person, the Board will establish the position of a Presiding Director.

B. Independent Chairman or Presiding Director

The Independent Chairman or the Presiding Director, as applicable (i) should work closely with the CEO to finalize information flow to the Board, set meeting agendas and arrange meeting schedules and (ii) will chair meetings of the non-management directors and serve as principal liaison between non-management directors and the CEO.

The purpose of the Presiding Director is to promote the independence of the Board of Directors in order to represent the interests of the shareholders. The Presiding Director is selected by non-management Directors. If there is a Presiding Director, his or her name will be communicated to shareholders. His or her responsibilities would be to (i) preside over meetings of non-management and independent Directors; (ii) review and approve the agenda for all Board meetings; (iii) call special meetings of the Board as needed; (iv) serve as a channel of communications between the Directors and the CEO; (v) assure that Directors receive timely and necessary information in advance of meetings; and (vi) receive communications from shareholders on behalf of non-management Directors.

C. Board Meetings

The Board has eight scheduled meetings per year and special meetings are held as required. Every effort should be made to schedule meetings sufficiently in advance to ensure maximum attendance at each meeting. All Directors are expected to participate in all Board meetings, review relevant materials, serve on Board committees, and prepare appropriately for meetings and for discussions with management. Accordingly, each Director is expected to devote the time and attention necessary to properly discharge his or her responsibilities as Director.

D. Conduct of Meetings

Board meetings shall be conducted by the Chairman in accordance with customary practice in a manner that ensures open communication, meaningful participation and timely resolution of issues. All Directors have the opportunity to raise items for consideration to be placed on the agenda. Management and any committees of the Board should provide Directors with materials concerning matters to be acted upon in advance of the applicable meeting. Directors should review such materials carefully prior to the applicable meeting.

E. Executive Sessions of Directors

Those Directors of the Company who are not officers of the Company will meet at least two times a year in executive sessions at which management, including the CEO, is not present. The Independent Chairman or the Presiding Director, as applicable, will chair these executive sessions.

F. Ethics and Conflicts of Interest

The Board expects Directors, as well as officers and employees, to act ethically at all times and to acknowledge their adherence to a Code of Business Conduct and Ethics for Directors after adoption by the Board. The Board will not permit any waiver of any ethics policy for any director or executive officer. If an actual or potential conflict of interest arises for a Director, the Director shall promptly inform the CEO and Chairman of the Committee on Directors and Corporate Governance. If a significant conflict exists and cannot be resolved, the Director should resign. All Directors will recuse themselves from any discussion or decision affecting their personal, business or professional interests.

Anyone who has a concern about the Company's conduct may communicate that concern directly to the Presiding Director. Such communications may be confidential or anonymous, and may be submitted in writing to a special address that will be published on the Company's website.

III. DIRECTOR ACCESS TO MANAGEMENT

Directors shall have complete access to the Company's management in order to become and remain informed about the Company's business and for such other purposes as may be helpful to the Board in fulfilling its responsibilities.

The Board encourages management to, from time to time, invite to Board meetings managers who (a) can provide additional insight into the items being discussed because of responsibility for and/or personal involvement in these areas, and/or (b) are managers with future potential that the senior management believes should be given exposure to the Board.

IV. DIRECTOR COMPENSATION

Compensation Generally

The Board establishes the form and amount of compensation of outside Directors. Outside Directors are called on to devote significant time and energy to the performance of their duties. To attract and retain able and experienced Directors, the Company must compensate them fairly. Directors who are employees of the Company receive no additional compensation for service on the Board.

The Committee on Directors and Corporate Governance is responsible for making recommendations to the Board concerning Director compensation. To assist in setting compensation, the Committee or the full Board may request information from the staff of the Company or from independent consultants on the compensation of boards of comparable corporations. In general, the Board believes that the compensation for outside Directors should consist of both cash and ownership of stock.

The Company shall disclose its policy regarding compensation for Directors in its annual proxy statement. The Board, with the assistance of the Committee on Directors and Corporate Governance, shall periodically review Director compensation (including additional compensation for committee members) in comparison to corporations that are similarly situated to ensure that such compensation is reasonable and competitive.

V. DIRECTOR ORIENTATION AND CONTINUING EDUCATION

Under the direction of the Committee on Directors and Corporate Governance, the Company shall establish an orientation program for all newly elected Directors in order to ensure that the Company's Directors are fully informed as to their responsibilities and the means at their disposal for the effective discharge of those responsibilities. The orientation program shall, at a minimum, familiarize new Directors with the Company's (i) strategic plans; (ii) financial control systems and procedures and any significant financial, accounting and risk-management issues; (iii) compliance programs, including with SEC reporting obligations and NYSE corporate governance listing standards; (iv) code of ethics, conflict policies and other controls; (v) principal officers; and (vi) internal and independent auditors. The new Directors shall be introduced to such management and other personnel, and representatives of the Company's outside legal, accounting and other outside advisors as is appropriate to familiarize them with the resources available to them.

The Company shall also make continuing education opportunities available to the Company's Directors in areas relevant to its business activities and with respect to corporate governance issues. In addition, Directors are encouraged to participate in educational opportunities that will enhance their performance as a director of AEP.

VI. MANAGEMENT SUCCESSION

The Human Resources Committee shall, together with the full Board, establish policies, principles and procedures for the selection of the CEO and his or her successors, including policies regarding succession in the event of an emergency or the retirement of the CEO. The Board, with the assistance of the Human Resources Committee, shall review annually with the CEO management succession planning and development.

VII. ANNUAL PERFORMANCE EVALUATIONS

A. Board Evaluation

The Board shall evaluate annually the effectiveness of the Board and its committees. The purpose of this evaluation is to increase the effectiveness of the Board as a whole, and specifically review areas in which the Board and/or management believes a better contribution could be made from the Board. As appropriate, the Board shall then meet in executive session to discuss these assessments.

B. Evaluation of CEO

The Human Resources Committee shall establish policies, principles and procedures for the evaluation of the CEO. This evaluation shall be made annually by the Board under the oversight of the Human Resources Committee. Such evaluation shall be based on objective criteria including performance of the business, accomplishment of long-term strategic objectives and development of management. The Board shall meet in executive session to discuss the Human Resources Committee's evaluation of the CEO.

VIII. BOARD COMMITTEES

A. Number and Type of Committees

The Board has 7 committees – an Audit Committee, a Human Resources Committee, a Committee on Directors and Corporate Governance, a Nuclear Oversight Committee, a Policy Committee, a Finance Committee and an Executive Committee. The Board may add new committees or remove existing committees as it deems advisable for purposes of fulfilling its primary responsibilities. Each committee will perform its duties as assigned by the Board of Directors in compliance with Company bylaws. These may be described briefly as follows:

- Audit Committee. The Audit Committee oversees and monitors the Company's financial reporting, auditing and accounting process; is directly responsible for the appointment, compensation and oversight of the Company's independent auditors; reviews and oversees the Company's internal audit department, and provides an open avenue of communication among the independent auditors, financial and senior management, the internal auditor and the Board of Directors.

- Human Resources Committee. The Human Resources Committee stays informed as to market levels of compensation, recommends compensation of the CEO and COO to the Board and approves compensation of the other executive officers.

- Committee on Directors and Corporate Governance. The Committee on Directors and Corporate Governance is responsible for recommending to the Board individuals to be nominated as directors. This includes evaluation of new candidates. This committee also takes a leadership role in shaping the corporate governance of the Company and performs other duties as are described in these guidelines.

- Nuclear Oversight Committee. The Nuclear Oversight Committee is responsible for overseeing and reporting to the Board with respect to the management and operation of the Company's nuclear generation.

- Policy Committee. The Policy Committee is responsible for examining the Company's policies on major public issues affecting the AEP System, including environmental, industry change and other matters, as well as established System policies that affect the relationship of the Company and its subsidiaries to their service areas and the general public.

- Finance Committee. The Finance Committee monitors the present and future capital requirements and opportunities pertaining to the Company's business and provides guidance with respect to major financial policies of the Company.

- Executive Committee. The Executive Committee is empowered to exercise all the authority of the Board of Directors, subject to certain limitations prescribed in the By-Laws, during the intervals between meetings of the Board.

B. Selection of Committee Members

The Board shall select the Directors to serve on each committee, giving consideration to the independence and other requirements of the NYSE (and any other applicable law or any rule or regulation of any other regulatory body or self-regulatory body applicable to the Company) and to any recommendations put forth by the Committee on Directors and Corporate Governance.

C. Responsibilities

The Board, or the applicable committee pursuant to a Board delegation of authority, shall adopt a charter for such committee in compliance with all applicable rules and regulations. The charters for each of the Committee on Directors and Corporate Governance, the Human Resources Committee and the Audit Committee shall include, at a minimum, those responsibilities required to be set forth therein by the rules of the NYSE, by law or by the rules or regulations of any other regulatory body or self-regulatory body applicable to the Company.

Exhibit 4 – Audit Committee Charter

AMERICAN ELECTRIC POWER COMPANY, INC.
AUDIT COMMITTEE OF THE BOARD OF DIRECTORS
CHARTER

Amended as of December 13, 2006

I. PURPOSE

The Audit Committee (the "Committee") shall:

A. Provide assistance to the Board of Directors in fulfilling its responsibilities to the shareholders, potential shareholders and investment community with respect to its oversight of:

(i) The quality and integrity of the corporation's financial statements;
(ii) The corporation's compliance with financial reporting-related legal and regulatory requirements including internal control over financial reporting;
(iii) The independent auditor's qualifications, independence and performance; and
(iv) The performance of the corporation's internal auditor.

B. Prepare the report that SEC rules require be included in the corporation's annual proxy statement.

II. STRUCTURE AND OPERATIONS

A. Composition and Qualifications

The Committee shall be comprised of three or more members of the Board of Directors, each of whom is determined by the Board of Directors to be "independent" under the rules of the New York Stock Exchange, Inc. and the Sarbanes-Oxley Act (and any rules promulgated thereunder).

All members of the Committee shall have a working familiarity with basic finance and accounting practices (or acquire such familiarity within a reasonable period after his or her appointment) and at least one member must be a "financial expert" under the requirements of the Sarbanes-Oxley Act (and any rules promulgated thereunder).

B. Appointment and Removal

The members of the Committee shall be appointed by the Board of Directors and shall serve until such member's successor is duly elected and qualified or until such member's earlier resignation or removal. The members of the Committee may be removed, with or without cause, by a majority vote of the Board of Directors.

C. Chairman

The Board of Directors will appoint the Chairman of the Committee. The Chairman shall be entitled to cast a vote to resolve any ties. The Chairman will chair all regular sessions of the Committee and set the agendas for Committee meetings.

III. MEETINGS

The Committee shall meet at least quarterly, or more frequently as circumstances dictate or as requested by the Company's independent auditors, management or internal auditor. As part of its goal to foster open communication, the Committee shall periodically meet separately with the Independent Auditors, Chief Internal Audit Executive, or any other company employee the Committee deems necessary to discuss any matters that the Committee or each of these groups believe would be appropriate to discuss privately. In addition, the Committee shall meet with the Independent Auditors and management quarterly to review the corporation's financial statements in a manner consistent with that outlined in Section IV of this Charter. The Chairman of the Board or any member of the Committee may call meetings of the Committee. Meetings of the Committee may be held telephonically.

All non-management directors that are not members of the Committee may attend meetings of the Committee but may not vote. Additionally, the Committee may invite to its meetings any director, manager of the corporation and such other persons as it deems appropriate in order to carry out its responsibilities. The Committee may also exclude from its meetings any persons it deems appropriate in order to carry out its responsibilities.

IV. RESPONSIBILITIES AND DUTIES

The following functions shall be the common recurring activities of the Committee in carrying out its responsibilities outlined in Section I of this Charter. These functions should serve as a guide with the understanding that the Committee may carry out additional functions and adopt additional policies and procedures as may be appropriate in light of changing business, legislative, regulatory, legal or other conditions. The Committee shall also carry out any other responsibilities and duties delegated to it by the Board of Directors from time to time related to the purposes of the Committee outlined in Section I of this Charter.

The Committee, in discharging its oversight role, is empowered to study or investigate any matter of interest or concern that the Committee deems appropriate. The Committee shall have the authority to retain outside legal, accounting or other advisors for this purpose, including the authority to approve the fees payable to such advisors and any other terms of retention.

The Committee shall be given full access to the corporation's internal audit group, Board of Directors, corporate executives and independent accountants as necessary to carry out these responsibilities. While acting within the scope of its stated purpose, the Committee shall have all the authority of the Board of Directors.

Notwithstanding the foregoing, the Committee is not responsible for certifying the corporation's financial statements or guaranteeing the auditor's report. The fundamental responsibility for the corporation's financial statements and disclosures rests with management and the independent auditors.

A. Financial Reporting

1. Review with management and the independent auditors prior to public dissemination the corporation's annual audited financial statements and quarterly financial statements, including the corporation's disclosures under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and a discussion with the independent auditors of the matters required to be discussed by Statement of Auditing Standards No. 61.

2. In consultation with the independent auditors, management and the internal auditor, review the integrity of the corporation's financial reporting processes. In that connection, the Committee should obtain and discuss with management, the internal auditor and the independent auditor, reports regarding: (i) major issues related to accounting principles and financial statement presentation, including any significant changes in the Company's selection or application of accounting principles; (ii) analyses prepared by management and/or the independent auditor setting forth significant financial reporting issues, estimates and judgments made in connection with the preparation of the financial statements, including alternative treatments of financial information within generally accepted accounting principles; (iii) the effect of regulatory and accounting initiatives, as well as off-balance sheet structures on the financial statements; (iv) any other material written communications between the independent auditor and management; and (v) the scope of internal and independent auditors reviews of internal controls over financial reporting and reports on significant findings and recommendations, together with management's response.

3. Review with the independent auditor (i) any audit problems or other difficulties encountered by the auditor in the course of the audit process, including any restrictions on the scope of the independent auditor's activities or on access to requested information, and any significant disagreements with management and (ii) management's responses to such matters. Without excluding other possibilities, the Committee may wish to review with the independent auditor (i) any accounting adjustments that were noted or proposed by the auditor but were "passed" (as immaterial or otherwise), (ii) any significant communications between the audit team and the audit firm's national office respecting auditing or accounting issues presented by the engagement; (iii) any "management" or "internal control" letter issued, or proposed to be issued, by the independent auditor to the corporation; and, (iv) the responsibilities, performance, budget and staffing of the internal audit group.

4. Review periodically, with the corporation's counsel, any legal matter that could have a significant impact on the corporation's financial statements.

5. Review and discuss with management the corporation's earnings press releases (paying particular attention to the use of any "pro forma" or "adjusted" non-GAAP information), as well as financial information and earnings guidance provided to analysts and rating agencies. The Committee's discussion in this regard may be general in nature (i.e., discussion of the types of information to be disclosed and the type of presentation to be made) and need not take place in advance of each earnings release or each instance in which the corporation may provide earnings guidance.

6. Review and discuss with management, the internal auditor, and the independent auditors the scope of management's and the external auditors review of internal control over financial reporting and steps adopted in light of any material internal control deficiencies identified.

B. Independent Auditor

1. Appoint, approve fees, and oversee the work of the independent auditor engaged (including resolution of disagreements between management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or related work or performing other audit, review or attest services for the corporation. The independent auditor reports directly to the Committee. These oversight responsibilities include the authority to retain (or to terminate) the independent auditor. In addition, in connection with these oversight responsibilities, the Committee has ultimate authority to approve all audit engagement fees and terms, as well as all non-audit engagements of the independent auditor.

2. Evaluate, at least annually, the qualifications, performance and independence of the independent auditors, including an evaluation of the lead partner. In conducting its review and evaluation, the Committee should:

(a) Obtain and review a written report by the independent auditor describing: (i) the auditing firm's internal quality-control procedures; (ii) any material issues raised by the most recent internal quality-control review, or peer review, of the auditing firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the auditing firm, and any steps taken to deal with any such issues; and (iii) all relationships between the independent auditorand the corporation;

(b) Ensure the rotation of partner rules are met and consider whether there should be rotation of the audit firm itself.

C. Internal Auditor

1. Review with management and the chief internal audit executive the charter, plans, activities, staffing and organization structure of the internal audit function.

2. Ensure there are no unjustified restrictions or limitations on the work of the internal auditor.

3. Review and concur with the appointment, replacement, or dismissal of the chief internal audit executive.

D. Legal Compliance/General

1. Discuss with management the corporation's guidelines and policies with respect to risk assessment and risk management. The Committee should discuss the corporation's major financial risk exposures and the steps management has taken to monitor and control such exposures.

2. Set clear hiring policies for employees or former employees of the independent auditors.

3. Establish procedures for: (i) the receipt, retention and treatment of complaints received by the corporation regarding accounting, internal controls over financial reporting, or auditing matters; and (ii) the confidential, anonymous submission by employees of the corporation of concerns regarding questionable accounting or auditing matters.

4. Perform any functions required to be performed by it or otherwise appropriate under applicable law, rules or regulations, the corporation's by-laws and the resolutions or other directives of the Board, including review of any certification required to be reviewed in accordance with applicable law or regulations of the SEC.

5. Initiate inquiries of areas of special interest.

6. Devote one meeting per year, at a minimum, that is focused on improving Committee performance and training of Committee members. In addition, Committee members are encouraged to attend external programs annually.

E. Reports

1. Prepare all Committee reports required to be included in the corporation's proxy statement, pursuant to and in accordance with applicable rules and regulations of the SEC.

2. Report regularly to the full Board of Directors:

(i) with respect to any issues that arise concerning the quality or integrity of the corporation's financial statements, the corporation's compliance with legal or regulatory requirements, the performance and independence of the corporation's independent auditors or the performance of the internal audit function;

(ii) following all meetings of the Committee; and

(iii) with respect to such other matters as are relevant to the Committee's discharge of its responsibilities.

The Committee shall provide such recommendations as the Committee may deem appropriate. The report to the Board of Directors may take the form of an oral report by the Chairman or any other member of the Committee designated by the Committee to make such report.

3. Maintain minutes or other records of meetings and activities of the Committee.

V. ANNUAL PERFORMANCE EVALUATION

The Committee shall evaluate, at least annually, the performance of the Committee and its members. In addition, the Committee shall review and reassess, at least annually, the adequacy of this Charter and recommend to the Board of Directors any modifications to this Charter. The Committee shall conduct such evaluations and reviews in such manner as it deems appropriate.

Exhibit 5 – Committee of Directors and Corporate Governance Charter

AMERICAN ELECTRIC POWER COMPANY, INC.
COMMITTEE ON DIRECTORS AND CORPORATE GOVERNANCE
CHARTER

Amended as of January 27, 2010

I. PURPOSE

The Committee on Directors and Corporate Governance (the "Committee") shall provide assistance to the Board of Directors in fulfilling its responsibility to the shareholders, potential shareholders and investment community by:

A. Identifying individuals qualified to become directors and selecting, or recommending that the Board of Directors select, the candidates for all directorships to be filled by the Board of Directors or by the shareholders;

B. Developing and recommending to the Board of Directors a set of corporate governance principles applicable to the corporation; and

Otherwise taking a leadership role in shaping the corporate governance of the corporation.

II. STRUCTURE AND OPERATIONS

A. Composition and Qualifications

The Committee shall be comprised of three or more members of the Board of Directors, each of whom is determined by the Board of Directors to be "independent" in accordance with the rules of the New York Stock Exchange, Inc. ("NYSE")

B. Appointment and Removal

The members of the Committee shall be appointed by the Board of Directors and shall serve until such member's successor is duly elected and qualified or until such member's earlier resignation or removal. The members of the Committee may be removed, with or without cause, by a majority vote of the Board of Directors.

C. Chairman

The Chairman shall be elected by the full Board of Directors. The Chairman shall be entitled to cast a vote to resolve any ties. The Chairman will chair all regular sessions of the Committee and set the agendas for Committee meetings.

III. MEETINGS

The Committee shall meet at least four times annually, or more frequently as circumstances dictate. The Chairman of the Board or any member of the Committee may call meetings of the Committee. Meetings of the Committee may be held telephonically.

All non-management directors that are not members of the Committee may attend meetings of the Committee but may not vote. Additionally, the Committee may invite to its meetings any director, management of the corporation and such other persons as it deems appropriate in order to carry out its responsibilities. The Committee may also exclude from its meetings any persons it deems appropriate in order to carry out its responsibilities.

IV. RESPONSIBILITIES AND DUTIES

The following functions shall be the common recurring activities of the Committee in carrying out its responsibilities outlined in Section I of this Charter. These functions should serve as a guide with the understanding that the Committee may carry out additional functions and adopt additional policies and procedures as may be appropriate in light of changing business, legislative, regulatory, legal or other conditions. The Committee shall also carry out any other responsibilities and duties delegated to it by the Board of Directors from time to time related to the purposes of the Committee outlined in Section I of this Charter. The Committee shall have access to, and authority to approve the fees of, such independent advisors it deems necessary to carry out its duties and responsibilities.

The Committee, in discharging its oversight role, is empowered to study or investigate any matter of interest or concern that the Committee deems appropriate.

A. Board Selection, Composition, Evaluation and Compensation

1. Establish criteria for the selection of directors to serve on the Board of Directors. Such criteria should include:

- Maintaining the highest personal and professional ethics, integrity and values;
- Being committed to representing the long-term interests of the shareholders;
- Having an inquisitive and objective perspective, practical wisdom and mature judgment; and
- Possessing a willingness to devote sufficient time to carrying out their duties and responsibilities effectively, including attendance at meetings.

2. Identify individuals believed to be qualified as candidates to serve on the Board of Directors and recommend that the Board of Directors select the candidates for all directorships to be filled by the Board of Directors or by the shareholders at an annual or special meeting. Collectively, the Board should be balanced by having complementary knowledge, expertise and skill in areas such as business, finance, accounting, marketing, public policy, manufacturing and operations, government, technology, environmental and other areas that the Board has decided are desirable and helpful to fulfilling its role. Diversity in gender, race, and background of directors, consistent with the Board's requirements for knowledge, standards, and experience, are desirable in the mix of the Board.

3. Review and make recommendations to the full Board of Directors whether members of the Board should stand for re-election. Consider matters relating to the retirement of Board members, including age caps.

4. Conduct all necessary and appropriate inquiries into the backgrounds and qualifications of possible candidates. In that connection, the Committee shall have authority to retain and to terminate any search firm to be used to assist it in identifying candidates to serve as directors of the corporation, including sole authority to approve the fees payable to such search firm and any other terms of retention.

5. Review, at least annually, the independence and possible conflicts of interest of members of the Board of Directors and executive officers.

6. Review and make recommendations, as the Committee deems appropriate, regarding the composition and size of the Board of Directors in order to ensure the Board has the requisite expertise consisting of persons with sufficiently diverse and independent backgrounds.

7. Oversee evaluation of, at least annually, and as circumstances otherwise dictate, the Board of Directors and Committees of the Board.

8. Review and make recommendations to the Board of Directors regarding the compensation of the members of the Board.

9. Review annually the performance of individual directors.

10. Make a recommendation to the Board of Directors whether to accept or reject a tendered resignation of any incumbent director nominee who fails to receive the affirmative vote of a majority of votes cast at a meeting of shareholders in an uncontested election. The affected incumbent director shall be excluded from participating in the Committee's consideration and decision. In making their recommendation, the members of the Committee so acting may consider any and all factors and other information that they consider appropriate and relevant. The members of the full Board of Directors other than the affected incumbent director shall act on the tendered resignation and publicly disclose the decision, and the reasons for such decision, within 90 days from the date of the certification of the election results.

B. Committee Selection and Composition

1. Recommend members of the Board of Directors to serve on the committees of the Board, giving consideration to the criteria for service on each committee as set forth in the charter for such committee, as well as to any other factors the Committee deems relevant, and where appropriate, make recommendations regarding the removal of any member of any committee.

2. Recommend members of the Board of Directors to serve as the Chair of the committees of the Board of Directors.

3. Establish, monitor and recommend the purpose, structure and operations of the various committees of the Board of Directors, the qualifications and criteria for membership on each committee of the Board and, as circumstances dictate, make any recommendations regarding periodic rotation of directors among the committees.

4. Periodically review the charter and composition of each committee of the Board of Directors and make recommendations to the Board for the creation of additional committees or the elimination of Board committees. The Committee shall also, at least annually, evaluate and review the charters of the Human Resources Committee and the Audit Committee to ensure compliance with any law, regulation or rule of any state, local or federal governmental body or the New York Stock Exchange.

C. Corporate Governance

1. Consider the adequacy of the by-laws of the corporation and recommend to the Board of Directors, as conditions dictate, that it propose amendments to the certificate of incorporation and by-laws for consideration by the shareholders.

2. Develop and recommend to the Board of Directors a set of corporate governance principles.

3. Encourage and provide opportunities for outside education for all members of the Board of Directors covering legislation, rules, procedures and best practices relevant to corporate governance issues and best practices training in Board and committee participation, as needed.

4. Supervise on a continuing basis the implementation of the AEP Corporate Compliance Program, including reporting by the chief compliance officer, the development of specific programs of legal compliance in various important areas of concern to the operation of AEP System companies, and the designation of successor chief compliance officers.

5. Supervise on a continuing basis the implementation of the Company's Related Person Policy, which covers material transactions between the Company and any member of the Board of Directors, the Company's executive council members and Section 16 officers and each of their immediate family members.

6. Oversee the Company's Sustainability Report, including the portion of the report that relates to the Company's political contributions.

7. Oversee elements of the Company's risks that are within the scope of this Committee's responsibilities as assigned to it by the Board of Directors from time to time.

D. Reports

1. Report regularly to the Board of Directors with respect to such other matters as are relevant to the Committee's discharge of its responsibilities. The report to the Board of Directors may take the form of an oral report by the Chairman or any other member of the Committee designated by the Committee to make such report.

2. Maintain minutes or other records of meetings and activities of the Committee.

V. ANNUAL PERFORMANCE EVALUATION

The Committee shall perform a review and evaluation, at least annually, of the performance of the Committee, including the compliance of the Committee with this Charter. In addition, the Committee shall review and reassess, at least annually, the adequacy of this Charter and recommend to the Board of Directors any improvements to this Charter that the Committee considers necessary or valuable. The Committee shall conduct such evaluations and reviews in such manner as it deems appropriate.

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Exhibit 6 – Finance Committee Charter

AMERICAN ELECTRIC POWER COMPANY, INC.
FINANCE COMMITTEE OF THE BOARD OF DIRECTORS
CHARTER

I. PURPOSE

The Finance Committee (the "Committee") shall be responsible for monitoring and reporting to the Board with respect to the capital requirements and financing plans and programs of AEP and its subsidiaries including, reviewing and making recommendations concerning the short and long-term financing plans and programs of AEP and its subsidiaries.

II. STRUCTURE AND OPERATIONS

Composition and Qualifications

The Committee shall be comprised of three or more members of the Board of Directors.

Appointment and Removal

The members of the Committee shall be appointed by the Board of Directors and shall serve until such member's successor is duly elected and qualified or until such member's earlier resignation or removal. The members of the Committee may be removed, with or without cause, by a majority vote of the Board of Directors.

Chairman

The Chairman shall be elected by the full Board of Directors. The Chairman shall be entitled to cast a vote to resolve any ties. The Chairman will chair all regular sessions of the Committee and set the agendas for Committee meetings.

III. MEETINGS

The Committee shall meet at least four times annually, or more frequently as circumstances dictate. The Chairman of the Board or any member of the Committee may call meetings of the Committee. All meetings of the Committee may be held telephonically. All non-management directors that are not members of the Committee may attend meetings of the Committee but may not vote. Additionally, the Committee may invite to its meetings any director, management of the corporation and such other persons as it deems appropriate in order to carry out its responsibilities. The Committee may also exclude from its meetings any persons it deems appropriate in order to carry out its responsibilities.

IV. RESPONSIBILITIES AND DUTIES

The following functions shall be the common recurring activities of the Committee in carrying out its responsibilities outlined in Section I of this Charter. These functions should serve as a guide with the understanding that the Committee may carry out additional functions and adopt additional policies and procedures as may be appropriate in light of changing business, legislative, regulatory, legal or other conditions. The Committee shall also carry out any other responsibilities and duties delegated to it by the Board of Directors from time to time related to the purposes of the Committee outlined in Section I of this Charter.

1. Review the financial condition of the Company and make recommendations as it considers appropriate concerning the short and long-term financing plans and programs of the Company and its subsidiaries,

2. Consider and provide recommendations to the Board on dividend policy, including the declaration and payment of dividends,

3. Review and approve the treasury policies of AEP and its subsidiaries (including the Corporate Financing Policy, the Treasury Interest Rate Risk Management Policy, the Treasury Foreign Currency Policy, the Treasury Liquidity Policy and the Short-Term Investment Policy),

4. Review the performance of the investments in the pension fund and other major benefit plans of the Company, and

5. Prepare such reports, plans or recommendations as it may consider appropriate.

Exhibit 7 – Human Resources Committee Charter

AMERICAN ELECTRIC POWER COMPANY, INC.
HUMAN RESOURCES COMMITTEE OF THE BOARD OF DIRECTORS CHARTER
As of October 24, 2006

I. PURPOSE

The Human Resources Committee (the "Committee") shall ensure that the executive officers and other key employees of the Company and its subsidiaries are compensated in a manner consistent with the stated compensation strategy of the Company, internal equity considerations, competitive practices and the requirements of appropriate regulatory bodies. The Committee shall also ensure that the Company's and Board's compensation policies and reasoning behind such policies is communicated to shareholders as required by the Securities and Exchange Commission and other appropriate regulatory bodies. Furthermore, the Committee will play an oversight role in such important matters as employee compensation, employee benefits, safety, workforce diversity and management succession planning.

II. STRUCTURE AND OPERATIONS

Composition and Qualifications

The Committee shall be comprised of three or more members of the Board of Directors, each of whom is determined by the Board of Directors to be "independent" in accordance with the rules of the New York Stock Exchange, Inc.

Appointment and Removal

The members of the Committee shall be appointed by the Board of Directors and shall serve until such member's successor is duly elected and qualified or until such member's earlier resignation or removal. The members of the Committee may be removed, with or without cause, by a majority vote of the Board of Directors.

Chairman

The Chairman shall be elected by the full Board of Directors. The Chairman shall be entitled to cast a vote to resolve any ties. The Chairman will chair all regular sessions of the Committee and set the agendas for Committee meetings.

III. MEETINGS

The Committee shall meet at least five times annually, or more frequently as circumstances dictate. The Chairman of the Board or any member of the Committee may call meetings of the Committee.

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As part of its review and establishment of the performance criteria and compensation of designated key executives, the Committee may meet separately with the Chief Executive Officer ("CEO"), the corporation's principal human resources executive, and any other corporate officers, as it deems appropriate. The Committee also meets regularly without any company officers or other employees present, and such officers shall not be present or shall be excused from meetings at which their performance and compensation are being discussed and determined. Meetings of the Committee may be held telephonically.

All non-management directors who are not members of the Committee may attend meetings of the Committee but may not vote. Additionally, the Committee may invite to its meetings any director, management of the corporation and such other persons as it deems appropriate in order to carry out its responsibilities. The Committee may also exclude from its meetings any persons it deems appropriate in order to carry out its responsibilities.

IV. RESPONSIBILITIES AND DUTIES

The following functions shall be the common recurring activities of the Committee in carrying out its responsibilities outlined in Section I of this Charter. These functions should serve as a guide with the understanding that the Committee may carry out additional functions and adopt additional policies and procedures as may be appropriate in light of changing business, legislative, regulatory, legal or other conditions. The Committee shall also carry out any other responsibilities and duties delegated to it by the Board of Directors from time to time related to the purposes of the Committee outlined in Section I of this Charter.

1. Review and approve the Company's total compensation strategy to ensure that rewards are commensurate with Company success, shareholder value creation and the practices of appropriate peer companies; that a significant amount of executive compensation is placed at risk; and that it supports the achievement of the Company's objectives.

2. Establish goals and objectives pertaining to all annual and long-term incentive compensation plans for the CEO and other executive officers.

3. Review the Company's executive compensation programs to ensure the attraction, retention and appropriate reward of exceptionally knowledgeable, highly qualified and experienced executive officers and other key employees; to motivate the performance of these executives towards the achievement of the Company's business objectives; and to align the interest of AEP's executives with the long-term interests of the Company's shareholders.

4. Review and approve all incentive compensation, long-term compensation and equity based compensation plans of the Company that are not otherwise subject to the approval of the Company's shareholders and any awards to individual employees with a target or potential value in excess of the management approval limit established and, from time to time, adjusted by the Committee.

5. Annually review the performance of the CEO and other executive officers, certify the performance of the Company and management for the purpose of determining incentive compensation for these executive officers. The Committee shall recommend the compensation of the CEO for approval by the independent members of the Board of Directors and approve the compensation of other executive officers after consulting with the CEO.

6. Review the performance of senior management of the Company and its significant majority owned subsidiaries and approve the salaries, annual incentive awards and other significant compensation for all officers at the Senior Vice President level and above and other key employees.

7. Annually report to shareholders the factors on which the CEO's and other executive officer's compensation was based and the relationship between corporate performance and executive compensation as required by the appropriate regulatory bodies.

8. Review and approve the major benefit programs of the Company to ensure that they support the Company's objectives.

9. Select and engage subject matter experts, as needed, to provide independent, external advice to the Committee on matters under their purview, including an annual independent review of the Company's executive compensation programs relative to appropriate peer companies. The Committee shall have the sole authority to approve the fees and terms of engagement of those rendering such advice.

10. Annually review the major elements of the Company's safety efforts and results.

11. Annually review Company workforce diversity planning, results and compliance with equal opportunity laws.

12. Annually review the senior management succession plan and process of the Company and report to the Board.

13. Annually monitor the level of the Company's merit budget.

14. Regularly report to the Board of Directors (i) following meetings of the Committee; (ii) with respect to such matters as are relevant to the Committee's discharge of its responsibilities; and (iii) with respect to such recommendations as the Committee may deem appropriate.

V. ANNUAL PERFORMANCE EVALUATION

The Committee shall perform a review and evaluation, at least annually, of the performance of the Committee and its members, including by reviewing the compliance of the Committee with this Charter. In addition, the Committee shall review and reassess, at least annually, the adequacy of this Charter and recommend to the Board of Directors any improvements to this Charter that the Committee considers necessary or valuable. The Committee shall conduct such evaluations and reviews in such manner as it deems appropriate.

AMERICAN ELECTRIC POWER COMPANY, INC.
NUCLEAR OVERSIGHT COMMITTEE OF THE BOARD OF DIRECTORS CHARTER
As adopted on February 24, 2004

I. PURPOSE

The Nuclear Oversight Committee (the "Committee") shall be responsible for overseeing and reporting to the Board of Directors with respect to the management and operation of the Company's nuclear generation.

II. STRUCTURE AND OPERATIONS

Composition and Qualifications

The Committee shall be comprised of three or more members of the Board of Directors.

Appointment and Removal

The members of the Committee shall be appointed by the Board of Directors and shall serve until such member's successor is duly elected and qualified or until such member's earlier resignation or removal. The members of the Committee may be removed, with or without cause, by a majority vote of the Board of Directors.

Chairman

The Chairman shall be elected by the full Board of Directors. The Chairman shall be entitled to cast a vote to resolve any ties. The Chairman will chair all regular sessions of the Committee and set the agendas for Committee meetings.

III. MEETINGS

The Committee shall meet at least four (4) times annually, or more frequently as circumstances dictate. The Chairman of the Board or any member of the Committee may call meetings of the Committee. All meetings of the Committee may be held telephonically.

All non-management directors that are not members of the Committee may attend meetings of the Committee but may not vote. Additionally, the Committee may invite to its meetings any director, management of the corporation and such other persons as it deems appropriate in order to carry out its responsibilities. The Committee may also exclude from its meetings any persons it deems appropriate in order to carry out its responsibilities.

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IV. RESPONSIBILITIES AND DUTIES

The following functions shall be the common recurring activities of the Committee in carrying out its responsibilities outlined in Section I of this Charter. These functions should serve as a guide with the understanding that the Committee may carry out additional functions and adopt additional policies and procedures as may be appropriate in light of changing business, legislative, regulatory, legal or other conditions. The Committee shall also carry out any other responsibilities and duties delegated to it by the Board of Directors from time to time related to the purposes of the Committee outlined in Section I of this Charter.

The Committee, in discharging its oversight role, is empowered to study or investigate any matter of interest or concern that the Committee deems appropriate.

1. Review and oversee the following nuclear generation areas:

   a. Safety;

   b. Public policy;

   c. Waste and environmental policy;

   d. Industry events and developments;

   e. Compliance with governmental actions and requirements as specified by the Nuclear Regulatory Commission or otherwise;

   f. Conformance with management practices, policies and performance with industry standards;

   g. Compliance with self-regulatory organization requirements as indicated by the Institute of Nuclear Power Operations or otherwise; and

   h. Operational performance.

2. Charter a Nuclear Safety Review Board (NSRB) to evaluate the performance of the Cook Nuclear Plant.

3. Meet from time to time with corporate officers, the Director of Nuclear Performance Assurance, and the Nuclear Safety Review Board to obtain direct perspective on nuclear operations.

V. ANNUAL PERFORMANCE EVALUATION

The Committee shall perform a review and evaluation, at least annually, of the performance of the Committee and its members, including by reviewing the compliance of the Committee with this Charter. In addition, the Committee shall review and reassess, at least annually, the adequacy of this Charter and recommend to the Board of Directors any improvements to this Charter that the Committee considers necessary or valuable. The Committee shall conduct such evaluations and reviews in such manner as it deems appropriate.

Exhibit 9A – Columbus Southern Power Directors

Akins, Nicholas K.	Executive Vice President - Generation
English, Carl L.	Chief Operating Officer
Miller, D. Michael	Senior Vice President/General Counsel/Secretary
Morris, Michael G.	Chairman, President & Chief Executive Officer
Powers, Robert P.	President – AEP Utilities
Radous, Barbara D.	Senior Vice President – Shared Services
Tierney, Brian X.	Executive Vice President / Chief Financial Officer
Tomasky, Susan	President – AEP Transmission
Welch, Dennis E.	Executive Vice President – Environmental, Safety, Health & Facilities

Exhibit 9B – Ohio Power Directors

Akins, Nicholas K.	Executive Vice President - Generation
English, Carl L.	Chief Operating Officer
Miller, D. Michael	Senior Vice President/General Counsel/Secretary
Morris, Michael G.	Chairman, President & Chief Executive Officer
Powers, Robert P.	President – AEP Utilities
Radous, Barbara D.	Senior Vice President – Shared Services
Tierney, Brian X.	Executive Vice President / Chief Financial Officer
Tomasky, Susan	President – AEP Transmission
Welch, Dennis E.	Executive Vice President – Environmental, Safety, Health & Facilities

Exhibit 10A – Significant Events in AEP's History
Reference: "American Electric Power: A Century of Firsts," by Luke Feck. 2006

1917 First major mine-mouth power plant, Windsor Plant, located just north of Wheeling, W.Va., together with long-distance transmission to load center in Canton, Ohio, 55 miles away.

1920 First application of carrier-current telephony to transmission lines for system dispatching.

1924 First reheat generating unit, Philo Plant, Unit 1, Philo, Ohio.

1925 First field tests to check interrupting performance of circuit breakers.

1928 First proposal of coordination of system insulation strength to electric power industry.

1928 First hydrogen cooling of synchronous condenser at Turner Station, West Virginia.

1929 First triple-compound generating unit, Philo Plant, Unit 3.

1929 First high-speed carrier-current relaying.

1929 First use of automatic frequency and tie-line load-control.

1929 First transmission line lightning-protection research.

1930 First new power plant designed for operation at 1,250 psi steam pressure, Deepwater Plant in New Jersey (jointly owned with Philadelphia Electric Co.).

1933 First successful high-speed directional comparison carrier-current relaying.

1933 First electronic exciter for synchronous condenser.

1935 First ultra-high-speed, high-voltage re-closing circuit breaker.

1937 First hydrogen-cooled generator.

1937 First application of water cooling to generator stator, Logan Plant, Logan, W.Va.

1937 First million pounds per hour of steam in high-pressure boiler (1,250 psi), Logan Plant, Logan, W.Va.

1937 First sleet melting of transmission line.

1941 First very-high-pressure (2,300 psi), natural-circulation generating unit, Twin Branch Plant, Unit 3, Mishawaka, Ind.

1942 First 100 percent make-up, 1,350 psi boiler, Deepwater Plant, Unit 7.

1945 First shaft-driven main exciter controlled by amplidyne regulating scheme in steam plant, Tidd Plant, Unit 1, Brilliant, Ohio.

1946 First 500,000-volt transmission line testing, Tidd Project, Brilliant, Ohio.

1946 First commercial use of 1000° F steam, Missouri Avenue Plant, Unit 7, Atlantic City, N.J.

1948 First aerial inspection of transmission line.

1949 First use of highest-pressure, highest-temperature combination (2,000 psi and 1,050 degrees F primary and 1,000 degrees F reheat), Twin Branch Plant, Unit 5, Indiana.

1950 First heat rate below 10,000 Btu per kilowatt-hour, Philip Sporn Plant, New Haven, W.Va.

1953 First electronic carrier current relaying.

1953 First 345,000-volt transmission line placed into commercial operation.

1953 First hot-line maintenance of extra-high-voltage line.

1955 First mass start-up of major generating units -- 11, 215,000-kilowatt units in 13-month period. Ohio Valley Electric Corporation's Clifty Creek and Kyger Creek Plants.

1955 First "tall stacks:" Three 682-foot stacks at Clifty Creek Plant and 538-foot stacks at Kyger Creek Plant.

1956 First time that steam plants designed by same engineering organization rank as Top 5 most efficient in world:

(1) Tanners Creek, Indiana, (2) Kanawha River, West Virginia, (3) Muskingum River, Ohio, (4) Kyger Creek, Ohio, and (5) Clifty Creek, Ohio.

1956 First use of single turbine-driven boiler feed pump integrated in thermodynamic cycle, Glen Lynn Plant Unit 6, Glen Lynn, Va..

1957 First use of supercritical-pressure steam (4,500 psi), Philo Plant, Unit 6, Ohio.

1957 First use of super-high-temperature steam (1,150 degrees F), Philo Plant, Unit 6, Ohio.

1957 First use of double-reheat steam, Philo Plant, Unit 6, Ohio.

1958 First research into application of magnetohydrodynamics in electric power generation.

1958 First extra-high-voltage interconnection (345,000 volts), AEP System and Commonwealth Edison Co.

1958 First static component high-speed, phase-comparison carrier-current relaying.

1958 First solid-state carrier-current relaying.

1960 First major use of helicopters in transmission line construction.

1960 First heat rate below 9,000 Btu per kilowatt-hour, Clinch River Plant, Carbo, Va..

1960 First large, supercritical-pressure generating unit, Breed Plant, Sullivan, Ind.

1960 First bare-hand maintenance of distribution lines.

1960 First 500,000-kilowatt generating unit (later re-rated to 325,000 kilowatts), Breed Plant, Indiana.

1961 First two-cycle, high-voltage (138,000 volts) air-blast circuit breaker.

1961 First static component high-speed directional comparison carrier-current relaying.

1961 First extra-high-voltage bare-hand maintenance.

1961 First 775,000-volt transmission line testing, Apple Grove, W.Va.

1962 First test of bare-hand maintenance on 775,000-volt line.

1962 First two-cycle, extra-high-voltage (345,000 volts) air-blast circuit breaker.

1963 First natural-draft, hyperbolic cooling tower in Western Hemisphere, Big Sandy Plant, Louisa, Ky.

1964 First computer center for automatic handling of economic power dispatching and load frequency, and for automatic customer billing, inventory control and management data.

1965 First major combination pumped-storage and run-of-the-river hydroelectric development, Smith Mountain Lake, Virginia.

1965 First field research in use of sodium as electric conductor in transmission and distribution lines.

1965 First computer installation designed exclusively for utility engineering applications.

1966 First super-high stack (826 feet), Cardinal Plant, Brilliant, Ohio.

1966 First use of control room simulator to train power plant operating personnel, Cardinal Plant, Brilliant, Ohio.

1966 First use of laser beam to monitor transmission line.

1967 First proposal to use ice condenser unit for nuclear reactor containment, Donald C. Cook Nuclear Plant, Bridgman, Mich.

1967 First purchase of commercial nuclear fuel for initial reload from supplier other than reactor manufacturer.

1968 First 1,200-foot stack (1,206 feet), Mitchell Plant, Moundsville, W.Va.

1968 First all electric, totally automated railroad in U.S., Muskingum Electric Railroad, Ohio

1969 First 765,000-volt transmission line in operation.

1969 First 220-cubic-yard walking dragline, world's largest mobile land machine for surface mining of coal, Central

Ohio Coal Company, Ohio

1970 First generating unit of more than 1 million kilowatts by investor-owned utility announced: 1,300,000-kilowatt addition to John E. Amos Plant in St. Albans, W.Va.

1970 First water-cooled EHV synchronous condenser in Western Hemisphere, world's largest, Dumont Station, Indiana.

1971 First 765,000-volt transmission interconnection, AEP System and Commonwealth Edison.

1971 First of its type engineering computer system, AEP Service Corporation, New York.

1973 First wide-scale, minute-to-minute supervisory system for measuring air quality near coal-fired plants, transmitting data electronically to computer center.

1975 First major research program undertaken to study electric thermal storage.

1975 First 3,000,000-kilovolt-ampere transformer bank, Marysville, Ohio.

1976 First sustained operation of full-scale power line at 2,000,000 volts, AEP/ASEA UHV Research Center, North Liberty, Indiana.

1976 First operation of utility-operated rail-to-river coal-transfer terminal, Cook Coal Terminal, Metropolis, Ill.

1976 First major research program in U. S. on pressurized, fluidized bed combustion.

1978 First experiment in utility control of customers' air conditioning and space heating as load-management tool.

1978 First successful testing of current-limiting device to prevent short-circuit currents from reaching unmanageable proportions.

1978 First utility to have in operation 100 high-voltage transmission interconnections.

1979 First operation of 765,000-volt station using sulfur hexafluoride (SF6) gas, rather than air, as insulation.

1979 First investor-owned utility system to generate 100 billion kilowatt-hours in 12-month period.

1979 First use of a solid-state var compensator to maintain transmission voltage, Beaver Creek Station, Kentucky.

1979 First single-phase fault clearing and reclosing of untransposed 765,000-volt line.

1980 First use of microprocessors in substation-protective relaying.

1981 First application of sliding-pressure technique on supercritical-pressure generating unit to maintain uniform efficiency over load range from full to minimal, Gen. James M. Gavin Plant, Cheshire, Ohio.

1984 First use of 765,000-volt live-tank SF6 "puffer" type circuit breaker, Jefferson Station, Indiana.

1987 First steam electric-generating unit to operate for 607 consecutive days, at that time a world record, Mountaineer Plant, New Haven, W.Va.

1990 First combined-cycle operation of a pressurized, fluidized bed combustion plant in North America, Tidd Plant, Ohio

1991 First conversion of a nearly completed nuclear plant to coal-fired operation, William H. Zimmer Generating Station, Moscow, Ohio. It began commercial operation on March 30, 1991.

1991 First 345,000-volt series capacitor east of the Mississippi River with thyristor control, and largest capacitor (788 MVAR) at one location.

1992 First fossil-fired generating unit in the world to produce 10.6 billion killowatt-hours in a single year, William H. Zimmer Plant, Moscow, Ohio.

1998 First unified power flow controller unit is installed at AEP's Inez 138,000-volt station in Kentucky.

1999 First transmission bridge capacitor installed at Leslie Station, Kentucky.

2001 First 800,000-volt SF6 dead-tank circuit breaker installed at Orange Station, Ohio.

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Exhibit 10B – Significant Events for AEP Ohio

1859 – Columbus Street Railway Company is founded (one of the predecessors of Columbus Railway, Power & Light).

November 1883 – The Canton Electric Light Company was incorporated by five city businessmen, including a 40-year-old lawyer named William McKinley.

Aug. 1, 1894 – Principals of Canton Electric Light and Power met to incorporate The Canton Light, Heat and Power Company. Canton Light, Heat & Power was later acquired by the Electric Company of America in 1901.

Dec. 20, 1906 – American Gas and Electric was incorporated in New York.

Jan. 2, 1907 – Opening day of business for AGE. The company acquires various subsidiaries from the Electric Company of America, including Canton, Light, Heat and Power.

April 30, 1907 – Canton Light, Heat & Power and Central Heating & Light Company were consolidated into a newly incorporated firm, Canton Electric Company (forerunner of today's Ohio Power Company).

1923 – Southern Ohio Electric Company is incorporated.

1937 – Columbus and Southern Electric Company is created through the merger of Columbus Railway, Power and Light Company and the Southern Ohio Electric Company.

1980 – AEP relocates its corporate headquarters to Columbus, Ohio, from New York City.

May 9, 1980 – AEP acquires Columbus and Southern Ohio Electric Company.

1993 – CSP and OP began operating as one company.

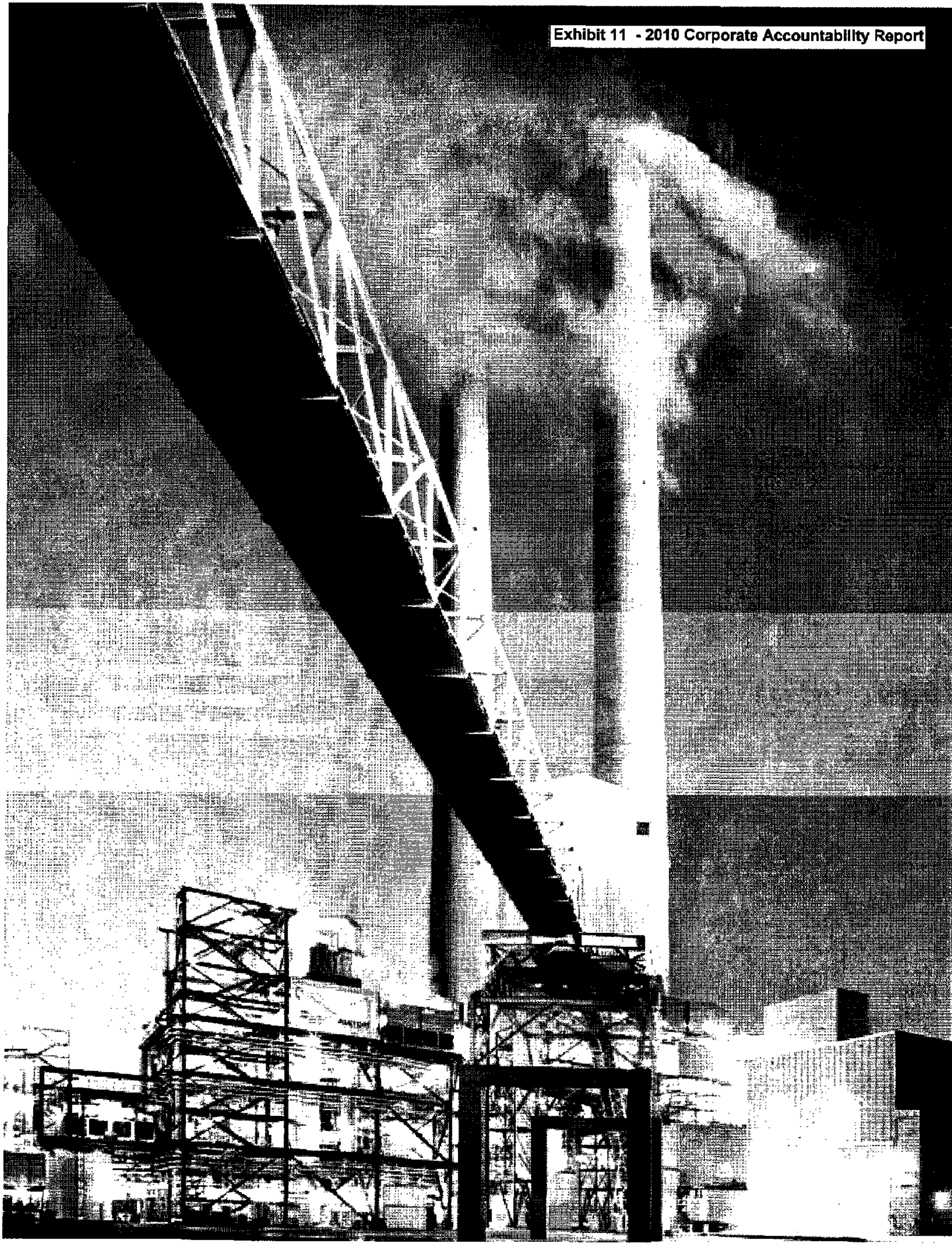
1999 – Ohio Senate Bill 3 initiates electric industry competition in Ohio.

May 26, 2004 – AEP reorganizes its distribution and customer service operations into seven regional utility divisions. AEP Ohio is created.

July 31, 2008 – Ohio Senate Bill 221 took effect, incorporating a system under which rates would be set by the PUCO and outlining a path for electric utilities to implement market-based pricing.

2009 – AEP Ohio was awarded $75 million in federal stimulus funding toward its gridSMART demonstration project, which is estimated to cost $150 million.

Exhibit 11 - 2010 Corporate Accountability Report



COMPANY OVERVIEW 2009

American Electric Power has been providing electric service for more than 100 years and is one of the nation's largest electric utilities, serving 5.2 million customers in 11 states.

Revenues (in billions)	**$13.5**
Net Income (in millions)	**$1,357** [1]
Earnings Per Share	**$2.96** [1]
Cash Dividends Per Share	**$1.64**
Service Territory	**197,500 *square miles***
Transmission	**39,000 miles**
Distribution	**215,800 miles**
Generating Capacity	**38,988 MW** [2]
Generating Stations	**More than 80**
Renewable Portfolio (hydro)	**384 MW** [3]
Pumped Storage	**586 MW**
Renewable Portfolio (wind, solar)	**1,406 MW** [4]
Total *Kilowatt-hour Sales (in millions)*	**195,312**
Total Assets (in billions)	**$48.3**
U.S. Customers (year-end, in thousands)	**5,220**

[1] Generally Accepted Accounting Principles

[2] Represents nominal capacity; includes 270 MW of mothballed/decommissioned generation, AEP's interest in Ohio Valley Electric Corp., purchased power agreements and renewables

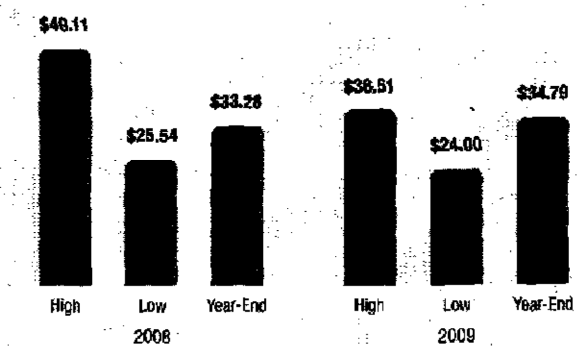
[3] Excludes pumped storage; includes owned capacity and purchased power

[4] Regulated wind and solar capacity on line or under contract

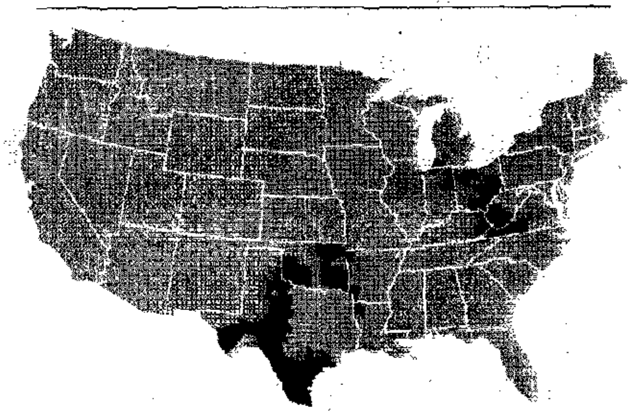
AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Co. (in Arkansas, Louisiana and east Texas).

The company is based in Columbus, Ohio.

MARKET PRICE — COMMON STOCK



SERVICE TERRITORY



Mixed Sources

FSC

Sandy Alexander

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COVER: The carbon capture unit, center left, at AEP's Mountaineer Plant in West Virginia

AEP ECONOMIC IMPACT 2009

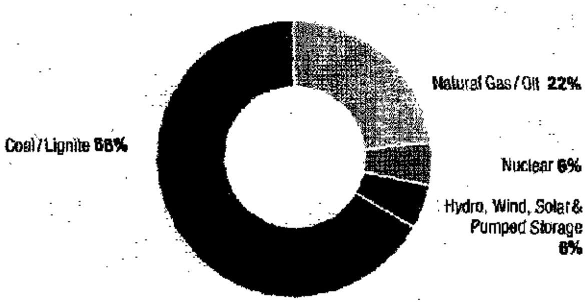
Employees (year-end)	**21,673**
Wages	**$1.9 billion**
Construction Expenses	**$2.8 billion** [1]
Local Taxes	**$469 million**
State Taxes	**$308.7 million**
Federal Taxes	**$123 million**
Goods & Services (does not include fuel)	**$4.3 billion**
Goods & Services from Diverse Suppliers	**$698 million**
Remaining Value of All Contracts	**$4.3 billion** [2]
Coal Purchased (tons)	**75.9 million**
Coal Average Purchase Price (per ton)	**$49.54**
Corporate Giving	**$11.8 million**
AEP Foundation Grants	**$11.6 million**
Economic Development Contributions	**$1.1 million** [3]

[1] Construction Expenses include those expenses listed in the Cash Flow Statement

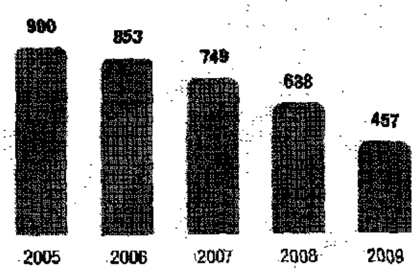
[2] Supply chain purchased contracts and inventory system

[3] Includes all grants and contributions by utility units to support economic development

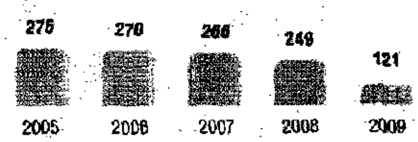
AEP GENERATING CAPACITY BY FUEL



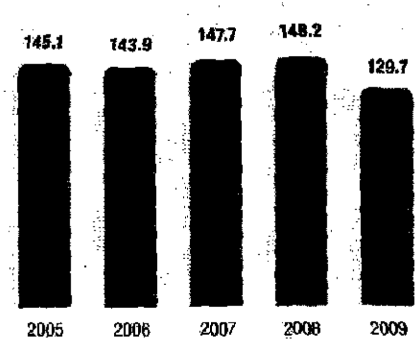
TOTAL SYSTEM – ANNUAL SO_2 EMISSIONS *(in thousand U.S. tons)*



TOTAL SYSTEM – ANNUAL NOx EMISSIONS *(in thousand U.S. tons)*



TOTAL SYSTEM – ANNUAL CO_2 EMISSIONS *(in million metric tons)*



In 2009, AEP's CO_2 emissions decreased 12.5 percent. The decline in SO_2 and NOx emissions reflects, in part, the success of our environmental programs.

INDEX OF TOPICS

STATEMENT OF THE AEP BOARD OF DIRECTORS

The AEP Board of Directors has assigned the responsibility for monitoring and overseeing the company's sustainability initiatives to the Board's Committee on Directors and Corporate Governance. At two of the Committee's meetings in the past year, the Committee and company management reviewed the company's sustainability objectives, challenges, targets and progress. That Committee supported the integration of sustainability reporting with financial reporting and gave management input and guidance for the proposed approach to this corporate accountability report. It reviewed and discussed the final text of this report before recommending its approval by the full Board of Directors.

The AEP Board of Directors has received periodic reports both from management and from the Committee on Directors and Corporate Governance about the company's sustainability initiatives. Many of the topics in this report have been the subject of active discussion at Board and Committee meetings. All members of the Board received copies of this report before it was published, and several directors made suggestions that have been incorporated into the report. Following its review, and upon recommendation of the Committee, the Board of Directors adopted a formal resolution approving the report.

The Board believes this report is a reasonable and transparent presentation of the company's plans and performance and of its environmental, social and financial impacts. The Board realizes that the company must be prepared to make frequent adjustments in response to the difficult economic and financial challenges that the nation and the regions we serve are experiencing. The Board is committed to the company's continuing efforts to increase its transparency and to its sustainability. The Board has emphasized to management that it will be evaluated by its success in executing the company's strategic plan to meet stakeholders' and the Board's expectations, including being agile in responding to changing circumstances while respecting the commitments in this report.

LESTER A. HUDSON, JR.
Presiding Director of the AEP Board of Directors
April 7, 2010

A Climate of Change:

Our Progress, Our Future

ABOUT THIS REPORT

This accountability report combines AEP's Annual Report to Shareholders with its Corporate Sustainability Report. It is divided into three performance sections — Business, Environmental and Social. This printed report is supported by a website — ***www.AEPsustainability.com*** — that includes significant additional data and information about AEP's performance. All performance metrics are located on the website. For more information about AEP, visit ***www.AEP.com***.

GLOBAL REPORTING INITIATIVE

We follow the GRI guidelines for reporting our performance. A complete index of performance indicators begins on Page 48. All of the data supporting these indicators can be found on our website — ***www.AEPsustainability.com***. We also report on electric utility industry-specific indicators.

GIVE US YOUR FEEDBACK

We want to hear from you. Tell us what you think about our integrated reporting approach. E-mail your comments to Sandy Nessing at ***smnessing@AEP.com***.

A Message From The Chairman

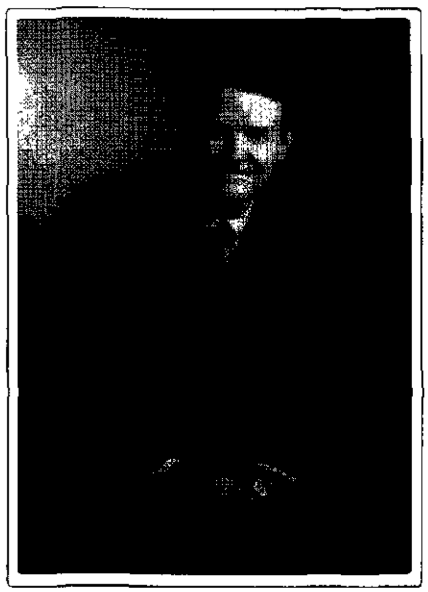
DEAR FRIENDS:

I am pleased to share with you American Electric Power's first Corporate Accountability Report. This report presents our financial, governance, environmental and social performance together for the first time. It contains information we believe to be important to all of our stakeholders in one integrated report.

During the past decade, many businesses have seen how financial, environmental and social performance are connected, and AEP is no exception. Our success is increasingly related to our ability to meet environmental responsibilities; maintain financial strength; deliver safe, reliable electricity to our customers; safeguard our work force; and deepen relationships with communities and key stakeholders. This report demonstrates our efforts to be more transparent and to integrate environmental and social risks and opportunities into everything we do.

We believe that global environmental and social forces will increasingly move corporations toward considering these issues as part of their routine business decisions. That is one reason I am pleased to serve on the executive committee of the World Business Council for Sustainable Development, to learn from and work with other CEOs around the world who share this vision of the future.

Our investors and other stakeholders are urging us toward integrated reporting, seeking more information on a much wider range of issues than ever before. We have brought various stakeholders into some of our most important business discussions. This engagement has influenced our thinking and our actions and has framed our reporting. Our quest to become a more sustainable company is continuous and reflects the efforts of thousands of people within AEP. We made progress in 2009 and are optimistic about 2010 and beyond. Our financial health is good, we expect steady growth, and our shareholders have received quarterly dividends for 100 years. We continue to provide safe, reliable and affordable electricity to our 5.2 million customers. We have achieved significant



new technology advancements, and we remain deeply committed to keeping people safe and healthy while successfully managing our environmental impacts.

We continue to engage and partner with stakeholders in each of our states on critical issues such as global climate change, the future of coal and energy efficiency. We have learned how we are perceived and what is expected of us, and we have created new opportunities for collaboration and business growth. We will work to strengthen these relationships, and we hope that our stakeholders will, too.

BOARD & MANAGEMENT CHANGES

James F. Cordes was elected to our Board of Directors in 2009. He was formerly the executive vice president of The Coastal Corp., president of American Natural Resources Co. and chairman and chief executive officer of ANR Pipeline Co. Sara Martinez Tucker, former undersecretary of the U.S. Department of Education, president and chief executive officer of the Hispanic Scholarship Fund and regional vice president for AT&T Global Business Communications Systems, also was elected to the Board in 2009.

The independence of our Board is integral to our corporate governance. I am pleased to say that, of our 13 directors, I am the only director from within AEP.

Brian X. Tierney was named executive vice president and chief financial officer in 2009. After 41 years of service to AEP, J. Craig Baker, senior vice president – Regulatory Services, retired. Richard E. Munczinski succeeds him. These appointments were among several management changes made last year, some of which were part of our succession planning process.

FINANCIAL PERFORMANCE

In a year of many uncertainties, AEP outperformed expectations in 2009 and ended the year in a strong financial position. Our $2.97 ongoing earnings per share were well within our guidance range. During the year, the management team demonstrated its commitment to maintaining the company's investment-grade ratings by issuing $1.6 billion of equity. Our action was well received in the market.

We had many regulatory successes, securing $725 million of incremental rate increases in 2009 that helped earnings by providing cost recovery for environmental compliance, tree trimming, energy efficiency programs, construction, and other operating costs. Our customers and investors also benefited as we continue to be among the lowest-cost providers of electric service while delivering a 10.4 percent total return, including reinvested dividends, to our shareholders.

The strength of our balance sheet and our liquidity point to our financial health. We are disciplined about our operations and maintenance (O&M) and capital spending. We are moving forward in a financially responsible way, recognizing there are many demands and limited resources. Our employees did not receive merit increases in 2009. With the exception of senior leadership, whose salaries remain frozen, we will be awarding modest pay increases to most employees in 2010. As part of our commitment to being financially disciplined, we have announced a cost reduction initiative that includes reducing our work force by up to 10 percent.

We reduced our utility operation's capital budget by $1.4 billion, from $3.8 billion in 2009 to $2.4 billion in 2009. We plan to hold it at $2 billion in 2010 and 2011. Investments in new infrastructure will increase future earnings strength and potential while allowing us to provide safe, reliable electricity to our customers. Our anticipated $2 billion in capital investments, factoring in depreciation of $1.3 billion, create potential growth in our rate base of $700 million.

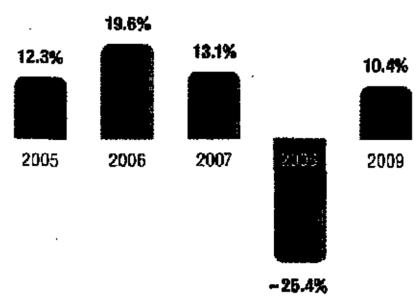
Like many businesses, we faced financial challenges. Electricity demand was down significantly, especially among industrial customers in the metals, transportation, plastics, rubber and paper sectors. Off-system sales volumes – the excess power we sell in the wholesale power markets – dropped by half in 2009.

As the economies in our service territories improve, we expect our retail and wholesale sales to recover as well.

OPERATIONAL PERFORMANCE

We had many successes in 2009, but we also did not meet our expectations in some important areas. The lowest points of the year were when two AEP employees and two AEP contractors lost their lives while on the job. Although we make efforts to educate the public about electrical safety, nine members of the public also died after coming into contact with our electrical facilities.

AEP TOTAL SHAREHOLDER RETURN



There is simply nothing more important to me, and to our company, than the safety and health of our employees, contractors and the public. We missed critical safety goals, tragically, and everyone at AEP regards this as unacceptable. One reason the Board of Directors awarded no incentive compensation to me and my senior management team was because safety is a strategic goal we failed to achieve. All other employees also lost a portion of their incentive compensation.

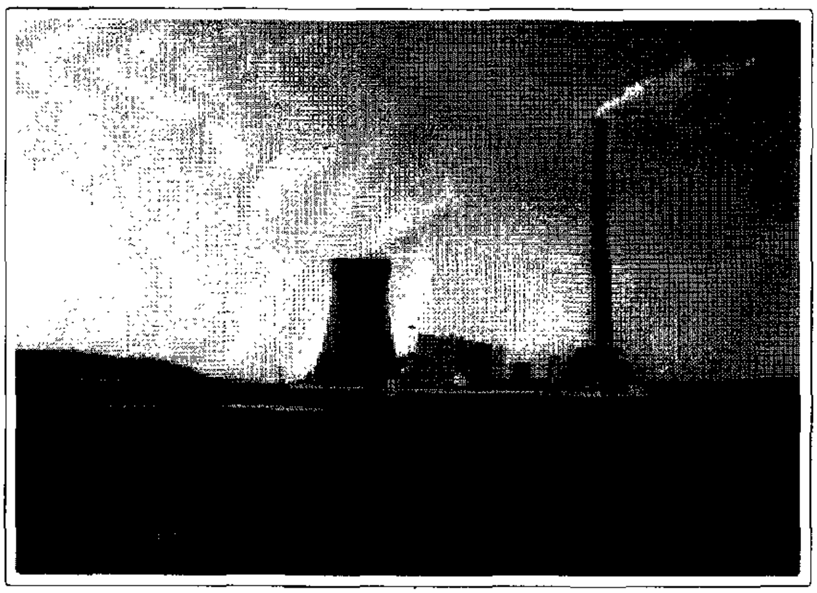
We will learn from these experiences and take corrective and preventive actions, but the pain of these losses cannot be erased. I am determined that we will achieve our goal of zero harm. We will not settle for less; I know our employees feel the same way.

Eight employees went above and beyond the call of duty in 2009 to protect the safety of the public outside of their normal jobs. These employees demonstrated the value we place on safety, and we honored them with the Chairman's Life Saving Award.

Maintaining compliance with laws and regulations is complex and ever changing. We strive for superior performance and recognize that compliance is the cornerstone of everything that we do.

Our business has significant environmental impacts, and managing them responsibly is both our legal obligation and moral responsibility. We devote significant resources to compliance, we have checks and balances in place to measure our performance, and we think our overall record is excellent. We constantly challenge ourselves to be best in class, setting the bar at zero for significant enforcement actions from regulators. Given the complexities of our business, this goal is very difficult to meet, but having it helps us to ensure continuous improvement.

We were involved in five significant enforcement actions related to landfill issues and wastewater discharges in 2009, among other matters. We have learned from these events and have changed practices or procedures to prevent recurrences. Heightened regulatory focus on coal ash presents potentially significant financial and operational challenges. We must maintain beneficial use of this material or dispose of millions of additional tons of coal ash each year. We take strong measures to ensure the safe and proper operation of our coal ash impoundments. Even so, we recently enhanced our monitoring, inspecting and auditing performance and will continue to improve these activities. We oppose classifying coal ash as a hazardous waste, but we understand and agree with the need for greater oversight. As we move toward greater certainty around federal classification of coal ash products and how they affect our facilities, we will work with neighbors so they better understand our operations.



The Mountaineer Plant in West Virginia is the site of the world's first integrated carbon capture and storage project.

Our $5.4 billion environmental investment program has resulted in the lowest emissions of sulfur dioxide (SO_2) and nitrogen oxide (NOx) from our system in two decades. We will further reduce our SO_2 and NOx emissions through emissions caps we agreed to in our New Source Review consent decree. Regulators also recognize the importance of this program and have supported it in customer rates.

Our greatest success in 2009 was the commissioning of the world's first fully integrated carbon dioxide capture and storage validation facility at our Mountaineer Plant in West Virginia. Our next project is to take this technology to commercial scale at Mountaineer and we have been awarded federal funding for 50 percent of the project costs, up to $334 million. We also will seek regulatory support and additional investment partners.

We succeeded in securing the needed permits from the U.S. Army Corps of Engineers and the U.S. Environmental Protection Agency (EPA) for the construction of the 600-megawatt (MW) John W. Turk Jr. Plant in southwest Arkansas. Although legal challenges to our permits are pending, this ultra-supercritical coal plant will be among the most efficient coal plants in the world when it becomes operational in 2012. A new 500-MW natural gas combined-cycle plant begins operation in 2010 in Shreveport, La., to serve our customers in Arkansas, Texas and Louisiana. Both of these plants are critical to meeting the growing demand for electricity in that region and reflect our strategy to use advanced technologies and resources that lessen our carbon emissions.

Our Cook Nuclear Plant Unit 1 came back on line at reduced power at the end of 2009, which is good news for customers and the environment. It is expected to return to full power by the end of 2011, after new low-pressure turbine rotors are installed. The scope of the restoration exceeded anything previously attempted in our industry.

As we consider ways to reduce our carbon emissions, we are studying potential improvements that would allow us to increase the output of the Cook Plant while operating it safely and reliably for its extended operating life. A separate project is addressing the prospects for long-term spent nuclear fuel storage, which continues to be a concern and could challenge the plant's long-term operation.

We rounded out our transmission strategy with the creation of AEP Transmission Co. This allows us to pursue new, on-system transmission opportunities within our service area while preserving the credit quality of our operating companies. Our vision for a national interstate extra-high voltage transmission system, similar to our nation's interstate highway system, is unchanged. We believe the modernization of our transmission system is imperative to our nation's energy future and we are continuing to advance this vision.

Our gridSMART℠ initiative received significant support last year with additional deployment of "smart" meters and other supporting technologies in four states. Two of our companies were awarded federal aid to support these deployments, which help us learn how gridSMART℠ technology works, improve the efficiency of the grid and give our customers more control over their energy use. We set a goal to install 5 million smart meters by 2015, thereby further reducing customer demand and energy use. This will be very challenging to achieve absent regulatory support but is necessary if we want to change how consumers use electricity and to reduce demand. Therefore, we will continue to press forward.

The reliability of our system improved in 2009; there were fewer nonstorm-related outages, and they were shorter in duration. Customer satisfaction also improved.

We began evaluating the environmental, safety and health performance of our non-fuel suppliers in 2008 and extended that assessment to our coal suppliers in 2009. We conducted our first survey of coal suppliers and brought many of them together with environmental groups, regulators and community leaders for an unprecedented stakeholder meeting. It was the beginning of a dialogue on coal issues that we intend to continue.

GLOBAL WARMING

In the public policy arena, the debate about global warming continues to dominate because of the significant financial and operational implications it will have on our business and our customers. Global warming is a controversial issue, and the public policymakers and influencers in Washington, D.C., and in the 11 states we serve have conflicting views. Regardless of the debate about the science and solutions, our position on this issue has not changed. We are taking actions that make sense for AEP and our customers, such as improving energy efficiency, investing in cost-effective and less carbon-intensive technologies and evaluating our options across a range of possible outcomes.

We believe that global warming requires global action that does not disproportionately compromise American jobs or our economy, which will be the case if our trading partners do not follow and participate in a solution. We are encouraged by China's and India's participation in the discussions; it is a step in the right direction.

The U.S. EPA is moving ahead with rules to regulate greenhouse gas emissions, which would affect our power plants. We prefer a legislative solution with an economy-wide cap-and-trade approach, and we supported the Waxman-Markey bill approved last summer by the U.S. House of Representatives. The bill includes several provisions that would help our customers and our company transition to a lower-carbon environment, including the allocation of carbon allowances, use of carbon offsets and incentives for moving carbon capture and storage technology forward. Under EPA regulations, we would lose these benefits for our customers and shareholders. We do not support a sector-by-sector carbon bill because it would unfairly affect customers of coal-based electric utilities.

We are making progress toward achieving our goals in energy efficiency and boosting the use of renewable energy on our system. We have identified the potential for more than 900 MW of energy efficiency and demand-reduction opportunities to help meet our 2012 goal and have contracted to add 1,013 MW of renewable energy to meet a 2011 goal. These important milestones are an integral part of our carbon reduction strategy.

We are considering several options that protect the reliability of the electric system while reducing our carbon emissions. The outcome of the global climate change debate is only one factor that will drive change in how we operate our business. Other considerations include potential new or more stringent regulations on coal plants; the shift toward greater use of natural gas, including shale gas; and the age and efficiency of some of our coal-fired units. But if we are forced to move too quickly in any direction without having sufficient new resources in place, the reliability of our electricity system would be jeopardized and the economy would be imperiled.

OUR VISION FOR THE FUTURE

We believe that reliable, safe and reasonably priced energy is a key to the global economic recovery. Through our state legislatures and public utility commissions and with the collaboration of our partners and many stakeholders, AEP is helping to change the way that electricity is generated, distributed and consumed. We are at the beginning of a new era; we know that bold changes are around the corner, and we embrace them. The men and women of AEP are moving forward. We invite you to join us.

Sincerely,

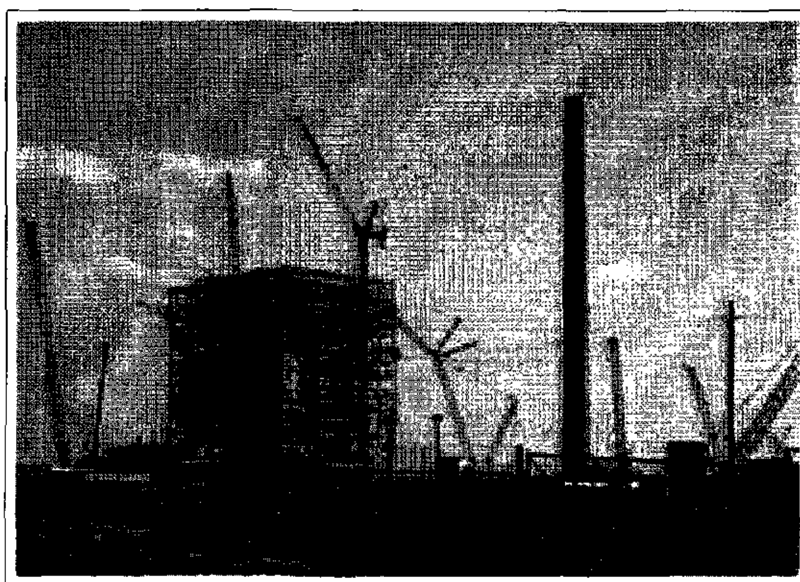
Michael G. Morris

MICHAEL G. MORRIS
Chairman, President & Chief Executive Officer
April 2010

Leadership, Management & Strategy

We are a publicly traded electric utility that must protect and enhance the investments of our shareholders. We do this through our mission of bringing comfort to customers, supporting business and commerce, and building strong communities. Our duty is to provide reliable, safe and affordable electricity for the benefit of the public. This dual purpose is reflected in our corporate directives, management systems and operations.

Our strategy is directed toward aligning our business, environmental and social performance. We manage this strategy by setting explicit goals and objectives in all three areas and by holding ourselves accountable for meeting them. We also have linked our environmental, social and governance disclosure to our financial reporting.



The John W. Turk Jr. Plant in Arkansas will begin operations in 2012.

Affordable, reliable energy has been the backbone of the U.S. economy for decades. It will be critical to our country's economic recovery and growth. At the same time, we realize that fossil fuel emissions are a growing concern and we are weighing all of our options as we prepare for the future.

Our strategy for sustainability is grounded in a commitment to meet our customers' needs as efficiently and cost-effectively as possible without putting our shareholders at undue risk. Although the future is uncertain and there are many challenges, it is clear that the electric utility industry is at the start of a major transformation. This is a consideration in our resource planning process, from the supply side to the customer.

Global climate change is one element driving this change. We may operate fewer coal units in the future, driven by a combination of factors. These include the relative age and efficiency of certain units, carbon reduction mandates, new and more stringent environmental regulations, the cost of compliance, and the potential for increased use of natural gas.

We are exploring many different technology options, such as carbon capture and storage and distributed generation. We are also weighing the possibility of retrofitting older, inefficient coal units to natural gas, preparing to operate a grid that supports energy storage and the electrification of the transportation sector, ramping up energy efficiency, modernizing the grid to enable greater use of renewable energy, and giving customers control over their electricity use.

We expect the focus will sharpen in the next couple of years. Our challenge will be to determine how much and where to invest capital and which technologies to deploy. At the same time, we have to balance the level of investment our customers are able to afford with the ability of our shareholders to earn a fair return on their investment.

The actions we are taking today will position us to meet these challenges while continuing to provide affordable electricity to our customers. These include actions, subject to regulatory approval, to reduce CO_2 emissions; invest in new technologies such as gridSMART℠, community energy storage, advanced coal, and carbon capture and storage; expand our use of biomass, wind and solar power; increase the use of natural gas and nuclear power; and advocate public policies that support modernizing our transmission system.

We are also taking steps to ensure that we have a skilled, diverse work force and can attract and retain the best talent to build, operate and maintain today's technologies as well as the technologies of the future.

We have ongoing dialogue with many stakeholders who have an interest in or are affected by our business. These include shareholders, customers, labor, legislators, regulators, policymakers, employees, prospective employees, retirees, communities and nongovernment organizations. We will continue working with all of our stakeholders to find common ground on these critical issues.

RISK MANAGEMENT

Effective risk management enables us to respond confidently in a rapidly changing environment. From safety risks on the job to financial or operational risks that can affect the company's competitiveness, finances or reputation, risk management is an ongoing process at all levels of AEP.

The Risk and Strategic Initiatives group reviews information about our enterprisewide risks and helps the company understand the internal and external relationships that influence them. The group produces a material risk report based on many information sources, including input from the Risk Executive Committee (REC). The REC considers existing and emerging risks and ensures that controls are in place and mitigation is taken where necessary.

While it is management's responsibility to identify and manage risks, the Board of Directors oversees and reviews the company's risk management process to help ensure that it is effective and responsive to changing circumstances. Some risks, such as changing public policy and potential systemic and catastrophic risk, are considered primarily at the Board level whereas others are delegated for consideration, oversight and recommendation to Board committees.

Under New York Stock Exchange standards and the Sarbanes-Oxley Act of 2002, the Audit Committee must discuss our policies for risk assessment and risk management, as well as risks that pertain specifically to the company's operations and controls and disclosures.

We review all risks and devote significant time and effort to managing risks that relate to our material issues. For example, if we fail to comply with North American Electric Reliability Corp. rules, we could potentially expose the bulk power supply system to reliability problems and the company to significant fines. Many business units are affected by these rules. Therefore, actions to ensure compliance are routinely monitored. The potential impact of environmental policies on our coal-fired generating plants is a material risk, and we weigh potential operational challenges such as a reliance on new technologies against potential cost increases to customers and available resources. For each risk, we consider a range of possible actions in order to assess and react to them effectively.

GOVERNANCE

AEP's commitment to being a profitable, sustainable enterprise is led by our chairman and executive management team with oversight from the Board of Directors and is embedded throughout the organization through goals, incentive plans, measurement and reporting.

The Board's Committee on Directors and Corporate Governance has direct oversight of this report and reviews the company's sustainability objectives, strategies, targets and progress. The committee provides input and guidance to management and holds it accountable for performance. The full Board adopts and issues a statement to that effect, which we publish.

Management formally reports to the Committee on Directors and Corporate Governance twice a year on our progress toward achieving the commitments in this report, but management, the full Board and each committee of the Board regularly discuss the issues that are most material and pose the greatest risk. Many of these issues are directly connected to our sustainability commitments.

The Board has emphasized that it will evaluate management by its success in executing the company's strategic plan to meet stakeholders' and the Board's expectations, including its agility in adapting to the current economic environment while respecting the commitments we make.

We are guided by values and by a set of Principles of Business Conduct that require us to operate with integrity, fairness, respect and care for others and with the highest regard for safety and the environment. All employees are bound by these principles, which also help to ensure legal compliance. A confidential 24/7 hotline allows employees to report concerns anonymously and seek guidance on ethics and compliance issues. Our goal is to maintain a supportive working environment in which employees know that their concerns are being addressed in a respectful and confidential manner.

Scope of This Report

This is our first integrated report, combining information about our financial performance with data on our environmental, social and governance performance. Information contained herein is largely based on calendar year 2009, with exceptions for some early 2010 data as noted. Supporting information can be found on our sustainability website at ***www.AEPsustainability.com*** or on our corporate website at ***www.AEP.com***.

In 2009, per our commitment to stakeholders, we began reporting our progress twice a year. A full update is provided every spring. An update of key commitments is published to the Web in the fall at ***www.AEPsustainability.com***.

REPORTING PRINCIPLES & GUIDANCE

AEP follows the Global Reporting Initiative (GRI) reporting principles in terms of data quality, report content and organizational boundaries. We use the G3 guidelines as well as the GRI Electric Utility Sector Supplement for reporting on industry-specific information. Our report is reviewed by GRI. This year's report was validated as an Application Level A, which reflects the high level of transparency in our reporting.

STAKEHOLDER ENGAGEMENT & MATERIAL ISSUES

Stakeholder engagement is an increasingly important aspect of our business processes. We conducted or participated in seven stakeholder meetings during 2009 that provided us with insight and information related to a wide range of issues that are important to us and to our industry. These meetings helped to shape this report.

Our discussions were candid and helped us identify strategies and actions. This year we focused more deeply on specific issues, such as the future of coal.

Our primary stakeholders are:

- Shareholders, prospective investors and lenders
- Customers, large and small
- AEP employees and retirees
- Labor unions
- Local communities
- Federal and state legislators, regulators, policymakers and other elected leaders
- Prospective employees
- Suppliers and others doing business with AEP
- Nongovernment organizations
- Professionals in industry, government, labor and academia

We define issues material to our sustainability as those that: 1) have or may have a significant impact on the company's finances or operations; 2) have or may have a significant impact on the environment or society, now or in the future; or 3) can substantially influence the assessments, decisions and actions of our stakeholders and shareholders. This report reflects those issues we consider material to our business. For the first time, internal auditors audited the printed report for reliability and consistency.

Financial Performance: Our ability to manage business risks and to maintain a strong financial foundation allows us to deliver returns to our shareholders; provide safe, reliable electricity to our customers; and deliver broader economic, environmental and social benefits to society.

Energy Security, Reliability & Growth: Our electric generation and delivery systems must be modern, reliable, and able to handle a diverse fuel supply as well as diverse technologies. They also must keep pace with customer demand. Collaboration with others is essential to create and maintain these systems and to ensure adequate and timely cost recovery.

Public Policy: We must actively engage legislators, regulators, policymakers and other stakeholders to ensure that public policy, laws and regulations enable us to continue to serve our customers, compensate our shareholders and pursue our vision for sustainability.

Environmental Performance: Although environmental laws and regulations are complex and changing, we are committed to compliance at all times. Our challenge is to achieve compliance, to go beyond compliance when we can, to reduce our impact on the environment and to improve the economic well-being of our communities.

Global Climate Change: AEP has a major role to play in addressing global climate change, including bringing advanced coal and other technologies to commercial scale, securing access to large-scale renewables through transmission development and increasing energy efficiency through our gridSMART℠ initiative. Our company's and our customers' economic well-being requires us to work cooperatively with regulators and policymakers, our stakeholders and our communities to reach a reasonable global solution that will protect the environment and foster economic growth.

Work Force: Protecting the safety and health of our employees and contractors and reducing the severity of work-related injuries and illnesses is a core value. We seek a skilled, diverse and highly motivated work force to support all aspects of our business.

Stakeholder Engagement: All of the material issues and risks we face and our well-being as a company increasingly depend on working closely with our stakeholders, disclosing our intentions, reporting on our performance and engaging in active and forthright dialogue.

CONTACT INFORMATION

For information about this report, the GRI information on our website or AEP's sustainability initiatives, please contact Sandy Nessing at ***smnessing@AEP.com*** or Jerra Thomas at ***jmthomas2@AEP.com.*** ■

AEP Board of Directors

Left to right: Ralph D. Crosby, Jr., Lionel L. Nowell III, James F. Cordes, Linda A. Goodspeed, Dr. Donald M. Carlton, John F. Turner, Thomas E. Hoaglin, Sara Martinez Tucker, Dr. Lester A. Hudson, Jr., Dr. Kathryn D. Sullivan, E.R. Brooks, Dr. Richard L. Sandor, and Michael G. Morris.

Michael G. Morris
Age 63; Elected 2004
Chairman, President and Chief Executive Officer
E, P

E.R. Brooks
Granbury, Texas
Age 72; Elected 2000
Retired Chairman and Chief Executive Officer, Central and South West Corp
A, D, P

Dr. Donald M. Carlton
Austin, Texas
Age 72; Elected 2000
Retired President and Chief Executive Officer, Radian International, LLC
H, N, P

James F. Cordes
The Woodlands, Texas
Age 69; Elected 2009
Retired Executive Vice President, The Coastal Corp.
H, P

Ralph D. Crosby, Jr.
McLean, Va
Age 62; Elected 2006
Chairman and retired Chief Executive Officer, Eads North America, Inc.
H, N, P

Linda A. Goodspeed
Franklin, Tenn
Age 48; Elected 2005
Vice President, Information Systems, Nissan North America
A, N, P

Thomas E. Hoaglin
Columbus, Ohio
Age 60; Elected 2007
Retired Chairman and Chief Executive Officer, Huntington Bancshares, Inc.
D, E, H, P

Dr. Lester A. Hudson, Jr.
Charlotte, N.C
Age 70; Elected 1987
Professor, McColl School of Business, Queens University of Charlotte
D, E, H, P

Lionel L. Nowell III
Cos Cob, Conn.
Age 55; Elected 2004
Retired Senior Vice President and Treasurer, Pepsico, Inc.
A, D, E, F, P

Dr. Richard L. Sandor
Chicago, Ill.
Age 68; Elected 2000
Chairman, Chicago Climate Exchange, Inc.
E, F, P

Dr. Kathryn D. Sullivan
Columbus, Ohio
Age 58; Elected 1997
Director, Battelle Center for Mathematics and Science Education Policy, John Glenn School of Public Affairs, The Ohio State University
F, N, P

Sara Martinez Tucker
San Francisco, Calif.
Age 55; Elected 2009
Former Undersecretary, U.S. Department of Education, and former President and Chief Executive Officer, Hispanic Scholarship Fund
D, F, P

John F. Turner
Moose, Wyo.
Age 68; Elected 2008
Managing Partner, Triangle X Ranch, and former Assistant Secretary, U.S. State Department
A, N, P

Committees of The Board:
The chairman is listed in ( ).
A – Audit (Nowell)
D – Directors and Corporate Governance (Hoaglin)
E – Executive (Morris)
F – Finance (Sandor)
H – Human Resources (Hudson)
N – Nuclear Oversight (Sullivan)
P – Policy (Carlton)

Business Performance: **Financial**

AEP generates, transmits and distributes electricity to businesses and homeowners through an interconnected system that operates in several regions of the country. We also sell power to the wholesale electricity market, including other utilities, municipalities and cooperatives. The rates we charge customers are set by state and federal regulators and are primarily based on the cost of operating the system to provide this service. The rate-setting process gives us the opportunity to earn a reasonable return for our shareholders on prudently incurred investments and to recover our expenses.

One of our central business challenges is to meet our obligation to serve while obtaining recovery of our operating and capital costs — for fuel, environmental compliance, energy efficiency programs, labor, construction and other costs — as soon as possible and to earn returns that are acceptable to our shareholders. In recent years, we have succeeded in recovering costs in a more timely manner through approximately 100 rate adjustment mechanisms approved by regulators across our 11 states. These mechanisms increase our revenues to cover our costs and improve our cash flow.

In order to keep up with customer demand, comply with government environmental mandates, and improve the efficiency and reliability of our system, we invest in new or replacement equipment and technology. Our capital investments constitute a large part of our business and financial condition. Our financial success is based on our ability to obtain capital on favorable terms, which in turn depends on access to the capital markets, the strength of our credit ratings, and prudent management of our balance sheet.

EARNINGS PER SHARE (GAAP)

2007	2008	2009
$2.73	$3.43	$2.96

Includes $0.42 dilutive effect of additional shares issued April 2009

Much of our capital investment is related to environmental protection. We are nearing completion of a $5.4 billion environmental program to retrofit nearly three-quarters of our coal-fired power plants with controls to reduce nitrogen oxide (NOx) and sulfur dioxide (SO_2) emissions to comply with the Clean Air Act Title IV regulations, the NOx State Implementation Plan, and the Clean Air Interstate Rule. As a result, our SO_2 and NOx emissions are at their lowest levels in two decades. We are also developing advanced coal technologies, including carbon capture and storage, to meet anticipated carbon emissions mandates, and are investing in "smart grid" technologies to improve the efficiency and operational abilities of our system and to give customers more control over their energy use.

In general, we consider our overall financial performance to be successful if we can provide a reasonable rate of return to our shareholders, receive timely and appropriate cost recovery from regulators, and keep electricity affordable for our customers.

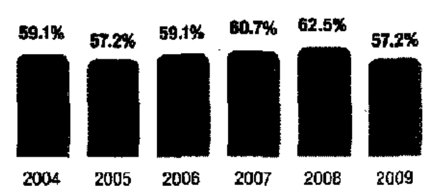
2009 OVERVIEW

AEP had good financial results in 2009, despite the effects of the recession and abnormal weather. During the year, we initiated steps to reduce debt, maintain strong credit ratings, ensure access to capital markets, control costs and improve our cash flows.

Our GAAP (Generally Accepted Accounting Principles) earnings per share totaled $2.96. Our debt ratio improved from 62.5 percent of total capitalization at the end of 2008 to 57.2 percent at year-end 2009. This debt-to-capital ratio improvement was due to a $1.6 billion equity offering, debt reduction, and enhanced discipline in our capital expenditure program.

Shareholders earned a 10.4 percent total return (including reinvested dividends) on their overall investment in 2009. AEP and the electric utility sector did not perform as well as the broader market last year, but our

TOTAL DEBT / CAPITALIZATION (GAAP)



Total circuit miles of 765-kV transmission lines	Years AEP has been paying dividends	Miles of overhead and underground distribution lines in 11 states	Million customers in 11 states
2,116	100	215,800	5.2

company and the overall market showed dramatic improvement from the unfavorable returns of 2008.

AEP's contribution to local economies is important, especially during difficult economic times. In most communities where we operate power plants, for example, we are the largest or among the largest employers, and these communities benefit from the substantial tax revenue we provide. At the end of 2009, we employed 21,673 across our system, and we paid $901 million in federal, state and local taxes.

THE IMPACT OF THE RECESSION

Our revenues come from three primary components: 1) customer electricity usage, 2) retail customer electric rates, and 3) wholesale off-system sales.

The recession hit many of our customers hard in 2009, particularly our industrial customers, and resulted in lower sales for the year. Despite our customer counts remaining stable, we experienced a moderate decline in residential and commercial sales from 2008 but much sharper decreases in industrial sales, which were off 16 percent. Half of that decline was the result of cutbacks or shutdowns for 10 of our largest metal-producing customers. In addition, our sales of electricity in the wholesale market dropped by approximately half in 2009.

The recession adversely affected our fuel inventory costs and related carrying costs. When our power plants run less than we plan during the year, we often end up with an imbalance between the fuel we bought and what we need. Our primary fuel is coal, and our coal consumption declined 14 percent from 2008. This caused coal inventories to increase beyond what was needed at our power plants, particularly at our coal plants in the eastern part of our service territory, where demand was down the most. We worked with our coal suppliers to better match deliveries with consumption in the future.

Weather was also a factor. Cooler than normal summer weather affected sales as customers needed less electricity for air conditioning. Damage to our system from storms, although generally recoverable in rates, also was significant.

The effect of the recession varied from one region to another, which in turn affected our operating companies differently. In our AEP East states, where we serve approximately 3.3 million customers, economic output declined 5 percent, sending the unemployment rate into double digits. Residential and commercial kilowatt-hour (kWh) sales declined from 2008, even after adjusting for weather. Revenues were up because of rate increases associated with fuel and capital investments. None of the eight largest industrial sectors we serve in this region increased their electricity use in 2009. Our AEP East footprint consists of portions of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia.

In our AEP West footprint, where we serve 1.9 million customers, the impacts varied. AEP Texas, a wires-only business, had lower residential and commercial kWh

JOE HAMROCK

President & chief operating officer, AEP Ohio

"After more than 100 years of serving our customers and returning dividends to our shareholders, we continue to adapt to the changing needs of all stakeholders. Today, more than ever, innovation is at the core of AEP's ability to meet the rapidly changing needs of modern society. Through game-changing initiatives such as the Mountaineer carbon capture and storage project and our gridSMART℠ programs, the men and women of AEP are finding new ways to meet customer needs with ever cleaner and more reliable methods of producing and delivering electricity."

LIQUIDITY SUMMARY (in millions)

	Amount*	Maturity
Revolving Credit Facility	$1,500	March 2011
Revolving Credit Facility	$1,454	April 2012
Revolving Credit Facility	$627	April 2011
Total Credit Facilities	**$3,581**	
Plus		
AEP, Inc. cash and investments	$490	
Less		
Commercial Paper Outstanding	($119)	
Letters of credit issued	($568)	
Net Available Liquidity	**$3,384**	

*Actual Dec. 31, 2009

consumption in 2009 but higher revenues due to rate increases. While industrial kWh consumption was down nearly 5 percent in Texas, the largest sector — petroleum refineries — was up slightly from 2008.

Southwestern Electric Power Co. (which operates in Arkansas, Louisiana and Texas) and Public Service Company of Oklahoma had mixed impacts from the recession. Residential and commercial kWh consumption was higher in 2009, on a weather-adjusted basis, and rate increases caused nonfuel revenue growth to out-pace growth in kWh sales. Industrial sales fell 16 percent, however.

The decline in electricity consumption and other factors had a positive environmental benefit. Our emissions of carbon dioxide, SO_2 and NOx in 2009 were all lower than in 2008.

CUSTOMER RATES & COST RECOVERY

In the traditional utility model, a company such as AEP invests capital and operates fixed assets in order to provide electric service. In return, the utility is allowed to earn a reasonable rate of return on its investment while recovering its expenses on a timely basis. Rate increases are essential to maintain the reliability of the system, comply with environmental regulations and cover increases in operating expenses. As these costs are recognized by our operating companies, we routinely file rate cases in each jurisdiction to earn a fair return on our investments and recover our costs.

We received incremental rate increases in 2009 totaling $725 million for investments made and costs incurred across most jurisdictions. Our regulatory risk is diversified because we operate in multiple jurisdictions.

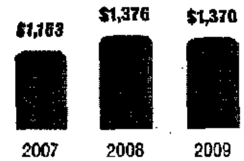
FINANCIAL PERFORMANCE

In 2009, our net income (before discontinued operations and extraordinary loss) was $1.370 billion compared with $1.376 billion in 2008. We ended 2009 with a cash balance of $490 million versus $411 million at the end of 2008, primarily as the result of favorable tax treatments. We issued $2.3 billion in long-term debt to pay for our 2008 draws on credit facilities, fund our construction program and refinance debt maturities. These refinancings, combined with our issuance of 69 million shares of common stock, supported our investment-grade ratings and increased our financial flexibility.

We raised more than $4 billion in debt and equity capital and kept our capital expenditures within our $2.5 billion budget, excluding allowances for funds used during construction, which represented a 38 percent decrease from 2008 capital spending. We expect to reduce total system capital expenditures in 2010 to $2.2 billion. Investing capital to build infrastructure, in excess of annual depreciation, increases our earnings potential.

The weak economy and weather-related loss of customer demand resulted in a revenue decrease of $265 million in 2009.

CONSOLIDATED INCOME BEFORE DISCONTINUED OPERATIONS & EXTRAORDINARY LOSS (in millions)



Income Before Discontinued Operations & Extraordinary Loss decreased $6 million in 2009

Lower demand in the retail and wholesale markets also resulted in excessive coal inventories and a 50 percent reduction in off-system sales volumes — the electricity we sell in the wholesale power market.

UTILITY OPERATIONS

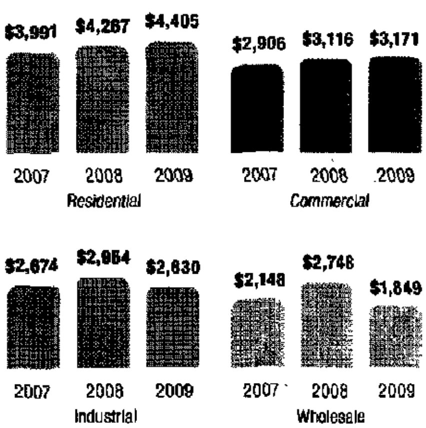
Utility Operations account for most of AEP's business, including the generation, transmission and distribution of electric power to retail and wholesale customers and others. Income from Utility Operations (before discontinued operations and extraordinary loss) increased from $1.1 billion in 2008 to $1.3 billion in 2009 primarily due to rate increases that reflect increased capital investment to provide electricity to our customers. The weak economy, higher depreciation expense, lower customer usage, and higher interest expense due to the additional debt we issued partially offset the increase.

AEP RIVER OPERATIONS

Our River Operations business transports coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi rivers. It is the second-largest full service, dry-bulk carrier in the nation. AEP River Operations' commercial income decreased from $55 million in 2008 to $47 million in 2009 primarily due to lower rates and volumes resulting from a weak import market.

In 2009, our fleet of 2,984 barges,

UTILITY REVENUES BY CLASS (in millions)



66 towboats and 22 harbor boats delivered more than 70 million tons of cargo, of which 32.8 million tons were commercial and 37.5 million tons were coal and consumables for our power plants. This compared with more than 33.9 million tons of commercial freight and 35.3 million tons for the power plants in 2008.

GENERATION & MARKETING

Our Generation and Marketing business includes nonutility generating assets and a competitive power supply and energy trading and marketing business. Income decreased from $65 million in 2008 to $41 million in 2009 mainly due to lower gross margins at the Oklaunion Power Station in Texas. This reflects lower power prices in the Electric Reliability Council of Texas region and decreased generation from our wind farms.

ALL OTHER BUSINESS OPERATIONS

Income from all other business operations (before discontinued operations and extraordinary loss) decreased from $133 million in 2008 to a loss of $47 million in 2009. Part of this disparity was due to the receipt in 2008 of $164 million in after-tax income from a litigation settlement of a purchase power and sale agreement.

2010 OUTLOOK

As the economies in our service territories improve, we expect our retail and wholesale sales to recover as well.

One of our main objectives in 2010 is to obtain rate increases that are fair to both our shareholders and our customers. We are seeking rate relief of approximately $320 million across our system this year; by the end of 2009, we had already received approval for half of that amount.

We anticipate our Board of Directors will declare our 400th consecutive quarterly dividend in April 2010, marking 100 years of paying dividends to our shareholders.

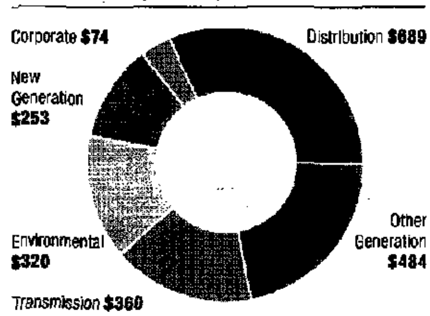
We are committed to maintaining our credit quality and managing our liquidity conservatively. In 2010, we intend to access the debt capital markets for approximately $1.2 billion and renew our $1.5 billion core credit facility that is due in March 2011.

We are disciplined about our capital and operations and maintenance spending. We are moving forward in a financially responsible way, recognizing there are many demands and limited resources. As part of our commitment, we have initiated a cost reduction program that includes reducing our work force by up to 10 percent.

We anticipate spending $2.2 billion in capital in 2010, including approximately $1.4 billion on our base operations. The capital program is highlighted by the following initiatives:

- **New Generation ($253 million):** Completion of the Stall Plant in Louisiana and continued construction of the Turk Plant in Arkansas;
- **Environmental ($320 million):** This includes scrubber projects at our Amos Plant in West Virginia and Conesville Plant in Ohio, and associated projects such as landfills, among other projects;
- **Transmission ($360 million):** $240 million will be invested in our operating companies and approximately $120 million through our new transmission company, AEP Transmission, which will operate within our existing retail service areas;
- **gridSMARTSM ($95 million):** Investments will be primarily related to projects in Ohio, Texas and Oklahoma. ■

2010 PROJECTED CAPITAL INVESTMENT (In millions)



Excludes AFUDC and Joint Venture Transmission Projects

Business Performance:

Energy Security, Reliability & Growth

“ Having the real-time reporting means I can actively monitor which items in my house are the worst energy consumers and do something about them, right there. ”

Paul Ross, gridSMART℠ pilot participant, South Bend, Ind.

Approximate number of customer calls handled each day

50,000

Million times customers logged in to conduct business online

2

Customers in AEP Ohio's gridSMART℠ Demonstration Project

110,000

Consumption of natural gas in billions of cubic feet in 2009

96

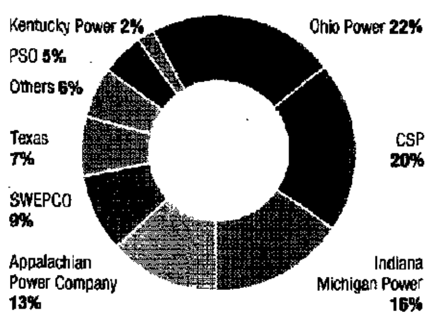
Our business is to produce electricity and deliver it over high-voltage power lines to lower-voltage lines that transport it to our customers. We have a responsibility to deliver electricity to our 5.2 million homes and businesses safely, reliably and cost effectively. While the system we operate is complex and aging, it is vital to the economy and to our quality of life.

Demand for electricity is growing despite energy efficiency programs, largely due to population growth and the rising number of electronic appliances, industrial equipment and other devices that people rely on for everything from entertainment to health care. Although the pace of growth has slowed due to the recession, we must plan for these needs. As the demand for electricity increases, so does the expectation that we will deliver power wherever and whenever it is wanted. We invest significant resources in equipment and processes to meet that expectation.

We use a variety of fuels to reduce emissions and to ensure reliability. Coal is our primary fuel because it is a low-cost, abundant, reliable and secure domestic resource that is often located near our power plants. We also use nuclear, wind, hydro, natural gas, biomass and solar power to generate electricity.

We have begun to lay the foundation to transform our energy delivery system to emit fewer emissions, improve efficiency and reliability, give customers more control over their usage and costs, and ensure energy security. This foundation is being built through our gridSMART℠ initiative, construction of power plants, diversification of our resources and investments in transmission and advanced coal technologies.

2009 OPERATING COMPANY EARNINGS CONTRIBUTIONS



CSP (Columbus Southern Power)
PSO (Public Service Company of Oklahoma)
SWEPCO (Southwestern Electric Power Co.)

ENERGY SECURITY

Ensuring an adequate supply of energy at any given time requires determining the demand for power today, anticipating short-term demand in the days and weeks ahead, and predicting long-term demand in the years to come. The stakes are high in getting this right because of the significant capital and construction costs of new power plants and transmission and distribution systems, not to mention the time it takes for siting new infrastructure and getting regulatory support for cost recovery. Underestimating future demand could create power constraints and higher rates for customers as we scramble to secure power in a tight market. Overestimating demand could burden customers with paying for unneeded and underused infrastructure.

Planning for long-term generation is complicated by the potential for legislative and regulatory actions on climate change (see *Climate Change*). We are uncertain about these possibilities and related future costs. Current environmental regulations are also in a state of flux and could change the way we produce or transmit electricity. It is therefore difficult to determine with certainty whether we can meet future demand with our own generation or will need a combination of our own generation and electricity we purchase.

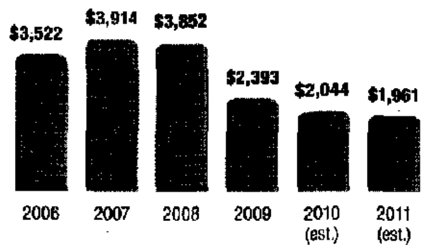
We are developing tools that will help inform this planning process. One component of our gridSMART℠ initiative will allow us to evaluate our infrastructure needs from the power plant to the customer meter. This technology, known as a virtual power plant, helps us to better understand what we will need if we are to deploy a robust smart grid system. It also will allow us to modernize the grid cost-effectively by showing us what we need or don't need.

We already have some generation projects under way that anticipate a lower-carbon future, including the 600-megawatt (MW) John W. Turk Jr. ultra-supercritical coal plant under construction in southwest Arkansas, which is scheduled to be in service by late 2012. The plant was designed to allow for the future installation of carbon capture and storage technology. Read more about this plant in *Climate Change*. Work also continues on the J. Lamar Stall Plant, a 500-MW natural gas combined-cycle facility in Shreveport, La., that will begin operation in 2010. Our use of natural gas has steadily increased as our gas generation has grown; we consume approximately 100 billion cubic feet per year. Between 2005 and the end of 2010, we will have added 4,600 MW of natural gas to our system, further diversifying our fuel mix.

The Federal Energy Regulatory Commission (FERC) granted a 30-year extension of the license for the Smith Mountain 586-MW pumped storage hydroelectric plant on the Roanoke River in Virginia in December 2009. We worked closely with area groups, communities and regulators to address concerns about water level, shore erosion, sediment and endangered species. Hydroelectric power is an important part of our resource base; we operate 16 hydroelectric plants plus Smith Mountain's pumped storage facility on six rivers in five states, generating approximately 1,549 gigawatt hours (GWh) each year. Approximately 940 GWh of that is free of carbon emissions.

Energy security is increasingly important as we become a more energy-

UTILITY CAPITAL INVESTMENTS (In millions)



dependent nation and seek to guard ourselves against the threat of intentional harm. Like all other utilities, AEP is subject to new grid reliability and security compliance standards enacted by the North American Electric Reliability Corp. (NERC), which has been designated by the FERC to ensure grid security. About two-thirds of our power lines and nearly half of our substations are subject to NERC regulations. Although the bulk of NERC standards apply to our Transmission operations, our Generation, Shared Services and Commercial Operations business units are also subject to NERC oversight.

NERC has identified three areas of high risk to the grid: managing the growth of trees or shrubs that could cause outages; system protection and controls, such as maintaining relays, batteries and related equipment critical to the grid; and Critical Infrastructure Protection (CIP). CIP entails ensuring that critical installations such as control centers and substations are secure from tampering or unintentional damage. New CIP standards went into effect Jan. 1, 2010, that significantly increase the number of AEP facilities subject to stricter compliance from a handful to approximately 100. For example, these new standards require more controlled access to critical facilities and stricter controls on the ability to manage certain transmission assets remotely. The intent is to prevent either intentional or unintentional actions that could compromise the nation's bulk power system.

We self-reported grid security-related compliance violations that occurred in 2009 to NERC and expect to pay fines of less than $100,000. Our chairman has since emphasized to all employees the importance of maintaining the security of the bulk power system. If we fail, we could jeopardize system reliability, create financial risk, affect other regions of the country and harm our reputation.

As we add advanced communications capabilities to our system, grid security becomes a more significant and challenging issue. Using U.S. Department of Energy (DOE) grant money from the Ohio gridSMART℠ project, we plan to develop a Cyber Security Operations Center, the first of its kind in the industry. It will correlate multisource public and private

HELEN MURRAY

President & chief operating officer, Indiana Michigan Power Co.

"Today's customers have higher expectations for the reliability and security of energy delivery systems, and that means we must find creative solutions. The gridSMART℠ project implemented in South Bend, Ind., is an excellent example of how innovative ideas will help us meet customer expectations now and in the future."

data and provide threat and risk mitigation information. The data will allow us to identify system vulnerabilities and help prevent network exploitation.

We conduct spot checks of our NERC-related compliance, meet with managers regularly and provide training to all employees to help ensure compliance with NERC rules.

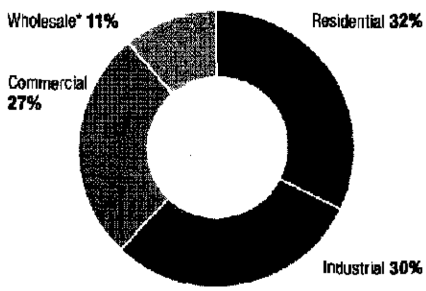
Our recent efforts to enhance grid security include co-founding the Transmission Forum, which will develop transmission security and operations standards, identify best practices and provide support to members in a manner similar to what the Institute of Nuclear Power Operations does for the nuclear energy industry.

ENERGY GROWTH

AEP remains committed to developing an extra-high voltage (EHV) transmission "superhighway" that would facilitate the movement of power among regions of the country. This system would reduce congestion and costs and enable the transmission of renewable power such as wind and solar from where it is generated to where it is needed. We believe that widespread use of renewable energy depends on the ability of the transmission system to transport it.

One way we are tackling this is through a collaborative effort to develop a master plan for transmission that supports the development of renewable energy in the Midwest and enables its delivery to consumers. Electric Transmission America (ETA), a joint venture between AEP and MidAmerican Energy Holdings Co., along with five other utilities and transmission operators have begun a comprehensive study of the transmission system in the

2009 RETAIL LOAD



*Wholesale includes sales to municipal and cooperative power systems, other wholesale, and miscellaneous retail sales

upper Midwest. Called the Strategic Midwest Area Transmission Study, it will identify the transmission needed to harvest the vast clean energy resources in areas such as Minnesota, the Dakotas and Iowa.

Phase 1 of the study focuses on determining the most reliable alternatives based on predetermined metrics. It will be completed this spring. Phase 2 will measure the economic and societal benefits and is due to be completed this summer.

The sponsors of the study believe that an EHV transmission network in the upper Midwest will provide significant economic, environmental and reliability benefits by ensuring access to new generation sources and strengthening the transmission system in the heart of the nation. This study is part of a process we started in 2008 to develop an EHV transmission system in that region.

We formed a wholly owned transmission company to facilitate capital investment within our service areas. The AEP Transmission Co. (AEP Transco) will construct, own and operate only new transmission assets. By setting up a separate company with its own capital structure, we will relieve some of the financing burden on our operating companies because the transmission company ultimately will be able to finance transmission projects on its own. The transmission company already has filed a proposed rate structure with the FERC.

AEP's Transco is just one part of our transmission strategy. We have entered into several joint ventures with other utilities, including two joint ventures with MidAmerican Energy, ETA and Electric Transmission Texas (ETT), to build transmission.

Although the Potomac-Appalachian Transmission Highline project, a joint venture with Allegheny Energy, had filed permits with Maryland, West Virginia and Virginia for permission to build the line, we withdrew the Virginia request in January 2010 based on new information from the regional transmission operator, PJM Interconnection. The grid operator said that preliminary studies showed the line would not be needed in 2014, as originally planned, because of reduced demand brought on by the recession and energy efficiency projects. We plan to resubmit the request when the results of PJM's formal planning process warrant the line.

ENERGY RELIABILITY

Our electric generation and delivery systems must be modern, reliable and able to handle diverse fuels and technologies. They also must be able to keep up with customer demand.

Overall reliability, as recorded by the average number and duration of sustained outages on our distribution system, improved systemwide in 2009.

Rather than focusing on single-year numbers, we have begun using a three-year rolling average, which evens out weather-related outages. We believe this is a more meaningful measure that better reflects changes in the overall status of the system. The three-year SAIFI average was 1.470 in

THREE-YEAR ROLLING AVERAGE SYSTEMWIDE RELIABILITY PERFORMANCE

	2005	2006	2007	2008	2009
SAIFI[1]	1.502	1.527	1.547	1.526	1.470
SAIDI[2]	210.8	202.9	198.9	201.0	198.1

[1] *System Average Interruption Frequency Index is the average number of interruptions a customer experiences.*

[2] System Average Interruption Duration Index is the average outage duration for each customer served.

2009, compared with 1.526 in 2008. The SAIDI average was 198.1 in 2009 versus 201.0 the previous year.

Distribution — the infrastructure and the processes that deliver electricity from high-voltage transmission lines to customers' homes and businesses — continues to improve as we develop better tools and processes to manage our system. Several challenges remain, however.

AEP is more than 100 years old, and many of our assets are at or near the end of their useful and depreciable life. For example, we have more than 5 million distribution poles in service, some of which are more than 40 years old, increasing the likelihood of failure when stressed by wind, snow or ice. To prevent this, we have a pole inspection program to continually evaluate the status of all distribution poles. In addition, 21 percent of our distribution station power transformers and 22 percent of our distribution line transformers are beyond their expected operational life. New, higher efficiency equipment is available that we will use to begin replacing these aging assets while also achieving demand and energy efficiency goals.

Our generation and transmission businesses face similar challenges as equipment ages.

We conduct regular operational risk audits in our Generation business unit to assure equipment reliability, as well as inspecting, testing and monitoring equipment. However, at no time are we compromising safety and health. We also formed an aging asset task force to develop a long-term plan to address the issue in each state in our service territory.

New tools and processes enhance our ability to manage the system. For example, we began using a Line Equipment Analysis Device (LEAD), an electronic "sniffer" developed in our own labs, that detects interference caused by cracked insulation or other difficult-to-detect failures. Combined with GPS technology, this allows crews to check the status of equipment more easily and accurately by driving along our lines. The LEAD can find electrical "leaks" that the human eye cannot, providing us with advance warning about potential imminent failure.

Preventive vegetation management is critical to reliability and is one of the most proactive measures we take to reduce interruptions. Public Service Company of Oklahoma and AEP Ohio adopted four-year trim cycles, and similar requests have been submitted for Kentucky Power, the Texas portion of SWEPCO and in Michigan. In the long run, scheduled tree trimming is more cost effective and provides greater reliability than simply responding to overgrown vegetation. Cutting vegetation once it is entangled in lines requires more time while increasing the risk of injury and customer outages.

Following an employee-led study of outages, we also adopted new maintenance procedures within breaker zones that should lead to increased reliability. The study team determined that breaker zones — the initial 2-to-6-mile segment of a main line coming from a substation before it branches off — account for 35 percent of the sustained interruptions per customer because outages in those areas affect a large number of customers beyond the interruption. By better maintaining breaker zones, we have been able to improve reliability significantly for more customers.

Early in 2010, ETT, a joint venture between AEP and MidAmerican Energy Holdings Co., completed installation of a storage technology that will enhance grid reliability in Presidio, Texas, a small town on the Mexican border. The 4.8-MW sodium sulfur, or NaS, battery is part of a $67 million transmission project to improve grid performance in a remote portion of the state. This is the largest use of battery storage in the nation.

By the end of 2010, we will have installed a total of 11 MW of NaS battery storage in Indiana, Ohio, Texas and West Virginia. NaS battery technology provides up to eight hours of backup power in the event of a transmission failure and also improves power quality. However, NaS technology has become more expensive compared with other storage technologies and we do not plan further installations at this time. The Presidio battery and substation cost approximately $23 million.

Future storage projects will center on community energy storage, which

AEP engineer Jason McCullough holds a patent on the LEAD fault detector.

uses lithium-ion battery technology. That technology is expected to become less expensive as the batteries become widely used in Plug-in Hybrid Electric Vehicles (PHEV). Read more about this in *Climate Change.*

GRIDSMART℠

AEP launched an initiative called gridSMART℠ in 2007. It is designed to give customers greater control over their energy usage and ultimately their bills; improve the efficiency of the electric grid; reduce overall demand, energy consumption and emissions; and improve customer service and internal efficiencies. The technology is still in the pilot stage, but we expect to achieve all of our goals once it is fully deployed.

The initial gridSMART℠ pilot began in 2009 in South Bend, Ind., and confirmed much of what we expected. Among the major insights we learned:

- The technology that allows AEP to manage its grid from our back office systems, such as billing, to the meter and distribution field equipment works. But the technology that goes beyond the meter into the customer's home is still evolving.
- Customers who participated in the time-of-day rate plan did shift their demand to different times, as expected.
- Cost savings from better system management, fewer crew trips, reduced fuel consumption, better theft detection and streamlined billing are being achieved.
- During the cooling season, customers who volunteered allowed us to raise the temperature in their homes using a programmable, communicating thermostat, demonstrating that we can control customer usage directly between the meter and the home through wireless technology.
- Greater education of consumers will be needed in future projects.

AEP is using Plug-in Hybrid Electric Vehicles to validate their performance and see how they will affect our system.

The year-long South Bend pilot involved approximately 10,000 meters and was to end after the 2009 cooling season, but it has been extended to include the 2010 cooling season because of some early technical problems.

A larger and more comprehensive gridSMART℠ demonstration project involves 110,000 customers in central Ohio. Paid for in part with a $75 million grant from the DOE, the $150 million project will include smart meters, distribution automation equipment to better manage the grid, community energy storage devices, smart appliances and home energy management systems, a new cyber security center, PHEVs, and installation of utility-activated control technologies that will reduce demand and energy consumption without requiring customers to take action.

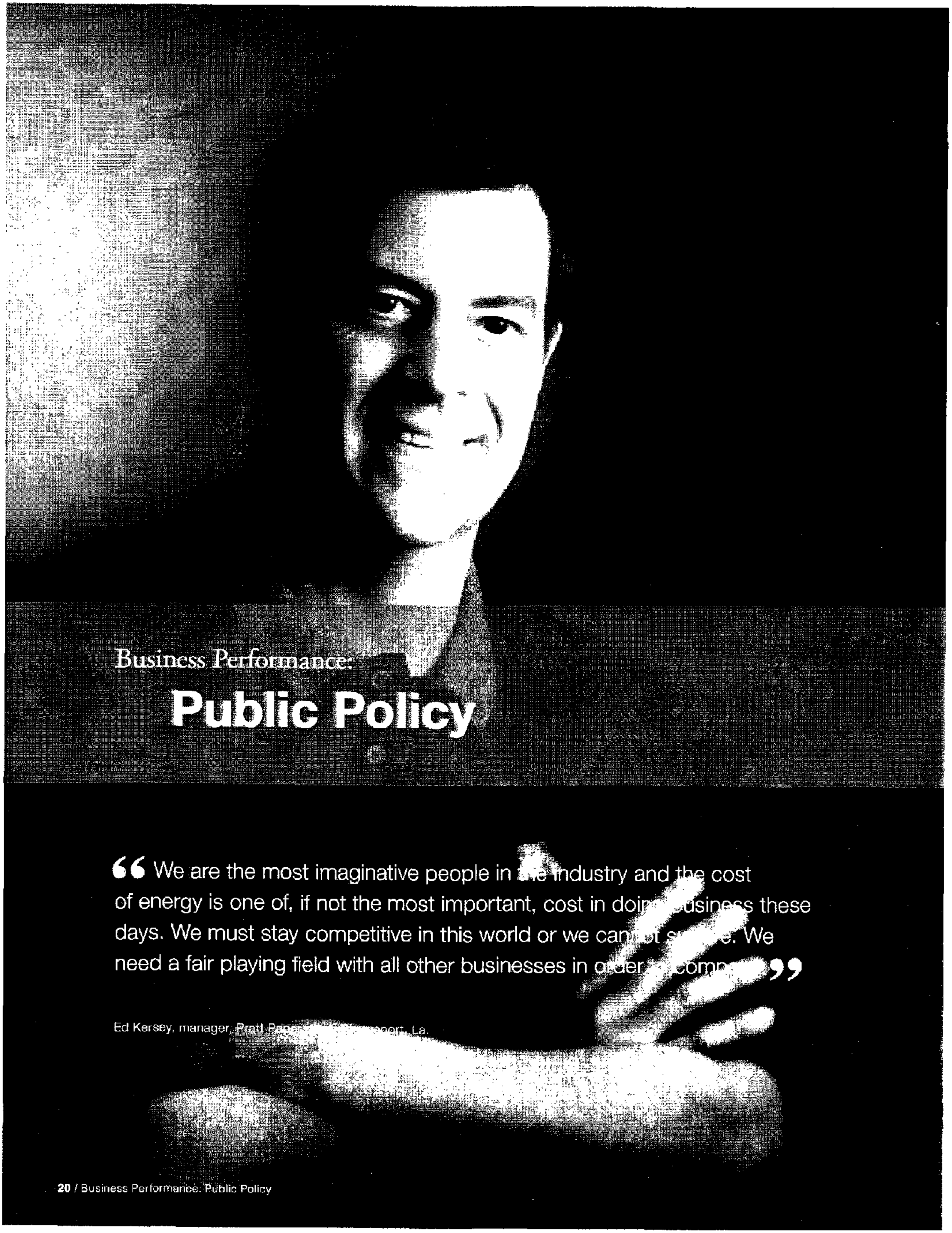
This technology is known as integrated voltage/VaR control, a form of voltage control that allows the grid to operate more efficiently. By controlling voltage more accurately, we estimate that we can reduce demand by approximately 2 percent to 3 percent, and energy that is needed to serve existing customer loads by 3 percent to 4 percent. This allows us to achieve both demand and energy reduction goals.

Meter installation began in December 2009, and installation of utility-activated voltage/VaR control technologies and distribution automation equipment will begin this year.

Working with major appliance manufacturers, we are also testing smart appliances — devices that react to signals from the grid about price and demand — in our Dolan Laboratory in Groveport, Ohio. In the Ohio pilot, we will deploy smart appliances in select homes to determine how they work. Based on the parameters that the homeowner sets, the dishwasher may not run until 7 p.m., after the demand for power has decreased, or the refrigerator may postpone a defrost cycle until the evening, when demand — and prices — are lower. Smart appliances have the potential to help residential customers save energy and money and for utilities to save fuel and reduce emissions.

PHEVs, which many expect to be widely used in the future, will also be part of the Ohio pilot. Read about gridSMART℠ initiatives in Oklahoma and Texas at ***www.AEPsustainability.com***.

Our gridSMART℠ initiatives support our goal to install 5 million smart meters in our service areas by 2015. This goal will be impossible to achieve without regulatory support in all states. However, we believe this initiative is critical to modernizing the electricity delivery system, reducing demand and changing how customers use electricity. Therefore, we will continue to deploy these technologies where regulators are supportive. ■



Business Performance:

Public Policy

"We are the most imaginative people in the industry and the cost of energy is one of, if not the most important, cost in doing business these days. We must stay competitive in this world or we cannot survive. We need a fair playing field with all other businesses in order to compete."

Ed Kersey, manager, Pratt Paper [illegible]eport, La.

Million megawatt-hours energy consumption saved by 2012	Approximate number of rate trackers in place in our 11 states	Corporate political contributions in 2009	Lobbying portion of trade association dues paid in 2009 (in millions)
2.25	100	$229,500	$1.2

Our business is regulated at the federal, state and local levels and is therefore heavily influenced by public policy. We need regulatory approval for the rates we charge, the investments we make, the projects we undertake, the programs and services we can offer to customers, and the actions we must take to protect the environment. For these reasons, we are actively engaged in Washington, D.C., in the 11 state capitals covering our service territory and in the communities where our facilities are located. We strive to work closely with regulators, legislators, environmental agencies, and environmental and consumer groups. Our involvement includes lobbying activities as well as relationship building at all levels.

On the national level, global climate change and energy policy are our top public policy issues because of their potentially far-reaching effects. We are also active in our states on a wide range of issues: building support for investments in our system, potential nuclear power expansion, renewable energy, transmission siting, eminent domain, smart grid deployment, energy efficiency, and legislation that would enable new technologies such as carbon capture and storage.

The recession played a key role in policy development during 2009, and the expectation that customer rates will be higher continued to be a concern in our states. The cost of electricity is increasing due to the need to modernize our infrastructure, the age of much of our transmission and distribution equipment, the need for new plants to meet growing customer demand, higher fuel costs and environmental compliance.

For Ed Kersey at Pratt Paper, the cost of energy is one of his most important business considerations.

We work with utility commissions and state legislatures on policies and regulatory actions that allow us to be as cost-effective and efficient as possible while recovering our costs in a timely and fair manner. State regulators approved $725 million in rate increases in 2009 to address this. These rate increases, while necessary, can cause difficulty for our customers, and we work hard to find ways to reduce the burden.

ALTERNATIVE REGULATION

The electric utility industry requires large amounts of investment to maintain and improve service. AEP is no exception. The Brattle Group, a leading energy think tank, estimates that the industry will spend $1.5 trillion for capital improvements from 2010 to 2030, not including the cost to address carbon emissions.

Our challenge is that we have limited resources to meet our financial obligations and our duty to serve our customers. As equipment on our system ages, it will have to be replaced. Environmental mandates also require significant investment, and that could lead to some coal plant retirements. In addition, power reserves — the additional capacity needed to cover an abnormally high peak load or provide power to a neighboring region — are shrinking across the country. The North American Electric Reliability Corp. projects that, by 2018, all regions of the country will have fallen below these requirements, and investment is needed to address that capacity shortage.

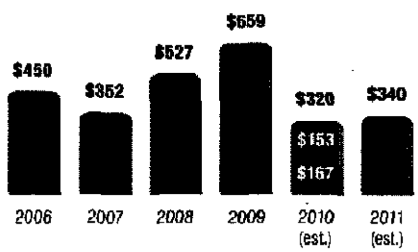
U.S. electricity demand is growing at a slower pace due to the recession and improvements in appliance and building efficiencies. At the same time, the proliferation of new electricity-consuming devices in home, commercial and industrial applications continues to grow. We expect our customers' energy consumption to grow modestly in 2010 as the economy

CHANGE IN ANNUAL NET INTERNAL SUMMER DEMAND — CONTIGUOUS U.S. (in megawatts)

	2004	2005	2006	2007	2008
Net Internal Demand	692,908	746,470	776,479	766,786	744,151
Change from Previous Year	**−0.6%**	**7.73%**	**4.02%**	**−1.25%**	**−2.95%**

Source: Energy Information Administration, *Electric Power Annual 2008*, January 2010

TRACK RECORD OF RATE RELIEF (in millions)



● Secured ● Pending/Future

Note: Rate relief in this chart excludes revenues with offsetting cost

recovers. Energy efficiency programs will help offset some of that growth.

Increased investment inevitably leads to increased rates. Alternative ratemaking (as opposed to the traditional model) is one way we are addressing rising costs. The traditional utility model required us to build and operate the infrastructure and then wait for a state utility commission to determine if we could recover costs. This process created financial hardship for three reasons: a) capital costs became exponentially more expensive than they used to be, making up-front costs prohibitive; b) the time between construction and cost recovery is too long for us to carry those costs; and, c) the possibility that the commission may not approve recovery of any or all of our investment and financial costs was too high a risk for us to bear. These factors made the overall cost of capital too high for us, our shareholders and our customers. We cannot keep up with needed improvements under the traditional approach.

We have been working with regulators to develop alternative regulatory frameworks and are already using a number of them. While we support some, we have concerns about others. For a complete list of alternative regulations under consideration, go to ***www.AEPsustainability.com***.

ENERGY EFFICIENCY

Energy efficiency continues to be a high priority for many of our stakeholders and is increasingly important to us. We believe that energy efficiency can be a cost-effective tool for managing demand and reducing energy consumption, which creates environmental benefits and helps delay the need for new power plants.

When we began conversations with stakeholders about energy efficiency four years ago, we did not have a policy or principles to guide us, and programs were in place only in those states with mandates. We have since set goals to reduce demand and energy consumption by the end of 2012 that led to initiatives within each of our operating companies to assure success. Consequently, we have seen our investments in energy efficiency increase from approximately $13 million in 2008 to a projected $110 million in 2010. We now have a dedicated energy efficiency manager in each operating company responsible for achieving energy efficiency goals, and we are working with regulators and others to develop and implement programs. For example:

- In Texas, we are committed to offset 20 percent of the annual load growth in our service territory, along with a commensurate reduction in energy usage.
- In Ohio, our energy efficiency programs will reduce annual energy consumption, starting at 0.3 percent of retail sales in 2010 and increasing to 2 percent in 2019.
- In Indiana, our energy savings goals start at 0.3 percent of retail sales in 2010 and increase to 2 percent in 2019.
- In Michigan, we are participating with the state's energy efficiency program administrator to reduce energy sales. The goals start at 0.3 percent of retail sales in 2009 and ramp up to 1 percent in 2012.
- In Virginia, our goal is a 10 percent cumulative reduction of baseline retail sales by 2022.
- In West Virginia, energy efficiency is an eligible source to help meet the state's alternative renewable energy requirement.

A state-by-state breakdown of energy efficiency programs, goals and savings achieved is available at ***www.AEPsustainability.com***.

We recognize that more progress is expected in the long term, and we are balancing what may be desirable with what practically can be achieved. We have completed market potential studies and some of the states we serve are finalizing rules regarding energy efficiency, including cost recovery mechanisms. While our initial energy efficiency goals are a good start, we know that we will need to stretch to achieve even better results in the future.

We are working with regulators to ensure that we can recover our energy efficiency investments in rates. So far, we are having good success. We seek approval for three main components when investing in energy efficiency programs: program costs, net lost revenues and an appropriate return on investment.

TRANSMISSION

As global climate change challenges the electric industry and our nation, the role of transmission has been at the forefront of the debate but without resolution. The grid must be transformed soon to ensure that energy delivery, including renewable energy, is efficient, cost-effective and reliable.

The existing transmission system, while functional, is challenged to meet the current demands on the grid and bring large quantities of renewable energy, such

STUART SOLOMON

President & chief operating officer, Public Service Company of Oklahoma

"As a public utility that provides an absolutely essential service, we must be actively engaged with a wide number of stakeholders on public policy issues that impact our customers, our employees and our shareholders. AEP is committed to working collaboratively with all these parties to craft policies and solutions that benefit everyone. We recognize that if we want to achieve our strategies and goals, including meeting our obligations to serve our customers, we must be the leader in public policy dialogues at the local, state and federal levels — and we're dedicated to making that happen."

as wind and solar, from where it can be produced most economically to where it is needed. As demand and availability for renewable energy grows, the grid's limitations become more apparent. At the same time, emerging technologies such as plug-in electric vehicles and the growth of low-emission power generation further challenge the electric delivery system.

Today's U.S. grid operates transmission from as low as 23 kilovolts to as high as 765 kilovolts. This indicates the lack of consistent planning to meet the needs of every region of the country, including the ability to move power from region to region. Any expansion of the system will require more land for rights of way unless planners become more strategic. Siting continues to be a major public concern and an obstacle to upgrading the system. Our ability to be more strategic in our planning becomes increasingly critical if we are to eliminate economic disparities or prevent system reliability risks.

We have been a long-standing advocate for a robust and efficient extra-high voltage grid, one that is planned on the basis of comprehensive and consistent principles. We also support broader regional transmission planning and broad-based cost allocation. We recognize that widespread cost allocation is controversial, but we believe it will help create the most efficient and cost-effective electric grid. It will also better facilitate integration of renewable resources into our nation's fuel portfolio.

Read more about our strategy, actions and vision for transmission on the Web at ***www.AEP.com/about/transmission.***

TRANSMISSION JOINT VENTURE INITIATIVES (estimated cost in thousands)

Project	Location	Completion Date	Owners (Ownership%)	Estimated Cost
ETT	Texas	2017	MEHC Texas Transco, LLC (50%) AEP (50%)	$3,097,000
PATH	West Virginia/ Virginia/Maryland	To be determined	Allegheny (50%) AEP (50%)	$1,800,000
Tallgrass	Oklahoma	2013	OGE Energy (50%) ETA (50%)*	$500,000
Prairie Wind	Kansas	2013	Westar Energy (50%) ETA (50%)*	$400,000
Pioneer	Indiana	2015	Duke Energy (50%) AEP (50%)	$1,000,000

*Electric Transmission America, LLC (ETA) is a 50/50 joint venture with MidAmerican Energy Holdings Co. (MEHC) America Transco, LLC and AEP Transmission Holding Co., LLC. ETA will be utilized as a vehicle to invest in selected transmission projects located in North America, outside of ERCOT. AEP Transmission Holding Co., LLC owns 25 percent of Tallgrass and 25 percent of Prairie Wind through its ownership interest in ETA.

Industry Activity

LOBBYING

Employee and contract lobbyists in our states and at the federal level advocate on our behalf on legislation that is important to business, leads to better public policy and best serves our customers' interests. Many of the company's lobbyists have been with AEP for many years. They understand our values and abide by our strict rules of ethics. All lobbying expenses are reported as required by law and are available on state and federal websites. According to reports filed with the Clerk of the U.S. House, AEP spent $7,297,245 lobbying at the federal level in 2009.

We made a commitment in 2007 to publish the dues we pay to trade associations that are allocated to their lobbying activities and the political contributions we make. We publish this information at ***www.AEPsustainability.com.*** ■

Environmental Performance:

Environment

“ Often one of the most challenging parts of my job is trying to explain to employees why we do what we do in regard to various environmental rules and regulations. **”**

Ginger MacKnight, environmental and lab supervisor, Philip Sporn Plant

Number of AEP facilities that are LEED certified

4

Million gallons of water per year used for ash handling at coal plants

181

Number of environmental audits performed in 2009

21

Land owned by AEP subsidiary companies covered by forests

43%

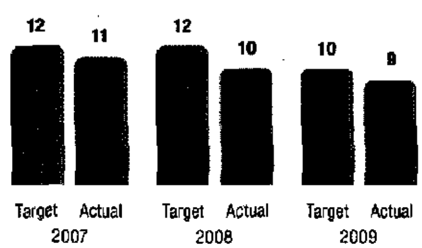
AEP produces and delivers an energy resource that is essential to society. Our success is measured by our ability to meet customers' energy needs while making a profit, do it responsibly, with respect for the environment, in compliance with all laws and regulations, and by engaging with those who have a stake in our business. We believe that our environmental performance overall is excellent, but we know there is room for improvement.

Our $5.4 billion program to retrofit many of our coal-fired power plants with environmental controls is already having significant positive impacts on our performance and the environment. Today, our sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions are at their lowest levels in two decades. These reductions reflect our compliance with the Clean Air Act (CAA) Title IV regulations, the NOx State Implementation Plan Call and the Clean Air Interstate Rule (CAIR).

Environmental regulation is in flux: the U.S. Environmental Protection Agency (EPA) is reviewing or rewriting several key regulations pertaining to air emissions, water quality and waste storage and disposal. Many potential changes are aimed directly at coal-fired power plants and could adversely affect our net income, financial position and the cost of electricity.

If, for example, emission limits become more restrictive, or if additional substances are regulated, we would face significant additional costs to comply. We have obtained cost recovery for our environmental program

ENVIRONMENTAL PERFORMANCE INDEX
(number of incidents per year)



This internal index sets targets for environmental performance that are tied to compensation. It sets goals for opacity, NPDES, and oil and chemical spills at our power plants.

so far, and we expect we would continue to be allowed to do so if new government mandates are imposed.

Compliance Performance & Management

Protecting the environment is the foundation and focus of our environmental activity and daily operations. Our performance baseline is to achieve compliance, but we reach for levels beyond compliance when we believe it is in the best interest of our customers, shareholders and other constituents. Our commitment to protecting the environment is embodied in a target of zero significant enforcement actions. Although our overall performance was very good in 2009, we did not meet our goal of zero significant enforcement actions.[1] We were cited in five enforcement actions involving power plants in Virginia, West Virginia, Kentucky and Arkansas. For details, go to *www.AEPsustainability.com*.

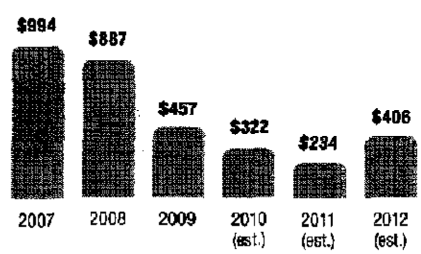
We conduct environmental and safety and health audits to comply with regulations and improve our performance. In 2009, we performed 21 environmental audits and 11 safety and health audits at various locations, including generating plants, service centers, the Dolet Hills lignite mining operation, the Shreveport Chemical Lab and River Operations. Internal audit findings last year ranged from record-keeping and labeling errors to training for new employees and spill management. The audits also identified best practices, including an environmental briefing process to document and communicate with plant employees about events and corrective actions. The audit results are shared internally every quarter as "lessons learned" to improve self-assessment and overall performance.

We use an Internet-based system to manage, record and report environmental information for regulatory compliance. By the end of 2010, we will use the system to

Ginger MacKnight is responsible for the environmental systems at the Philip Sporn Plant in West Virginia.

[1] We define a significant enforcement action as one arising from events that are within our control, have more than a minor environmental impact, and result in a fine greater than $1,000.

AEP HISTORICAL & PROJECTED ENVIRONMENTAL INVESTMENTS (in millions)



manage air and water regulatory programs.

This system complements our efforts to conform our plants to environmental, safety and health management systems standards — ISO 14001 and OHSAS 18001 — to strengthen our compliance performance. Ensuring that our policies and procedures are accurately documented enables us to capture the knowledge and practices of our experienced employees, many of whom are nearing retirement. We are in varying stages of implementation at 39 coal, gas and hydroelectric plants across the AEP system.

REGULATORY LANDSCAPE CHANGING

The U.S. EPA is considering revising many significant regulations that govern our industry. The agency plans to revise the CAIR, develop a new hazardous air pollutant rule for coal-fired power plants, change existing standards for water discharges from steam electric plants, propose new standards for water intake structures at existing power plants, and develop a new rule for the storage and disposal of coal combustion byproducts.

Protecting the environment and the public are our clear priorities. But regulatory uncertainty followed by overly aggressive compliance deadlines could force us to close some coal units prematurely, jeopardizing reliability and forcing us to raise costs to pay for new controls, finance unproven technologies or replace retired units.

Specific Issues

COAL ASH

The December 2008 breach of a coal ash dike at the Tennessee Valley Authority's (TVA) Kingston Station resulted in 5.4 million cubic yards of ash spilling into a nearby river and onto private properties and prompted a federal and state review of laws regulating coal ash. Coal ash disposal facilities around the country came under greater scrutiny as regulators took enforcement actions against TVA and stepped up inspections elsewhere. The U.S. EPA is considering whether coal ash should be classified as a hazardous waste, subjecting it to more stringent storage and disposal rules under the Resource Conservation and Recovery Act. A decision is expected this year.

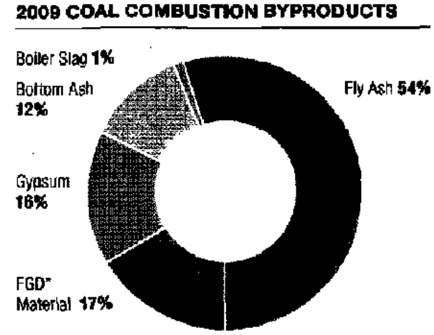
AEP operates 11 large ash impoundments, 26 smaller impoundments and seven "in-ground" ponds (ash ponds that do not have dams) used to store fly ash, bottom ash, boiler slag and other byproducts from flue gas desulfurization systems, also called scrubbers. The management of many of our dry storage facilities includes liners, leachate collection systems and groundwater monitoring. U.S. EPA regulations may lead to entirely dry storage methods, so we are evaluating that possibility and its associated costs, including lost revenue from the sale of coal combustion byproducts. We are in the process of converting one of our largest ash impoundments from wet storage to dry storage within the next couple of years at a cost of approximately $75 million. The change is the result of the remaining life of the current facilities and the opportunity to address future water quality issues.

Our internal impoundment inspection program is based on federal dam safety guidelines and applicable state and local dam safety regulations. We periodically assess and ensure the structural integrity of our storage facilities. After the TVA event, we conducted an additional review of these facilities with independent technical consultants. This helps us ensure that our management practices are sound and that we are not missing something important. These reviews help us improve but also provide assurance that our practices are appropriate and conservative.

We work closely with state agencies to assess risks to the environment and the public and to ensure that we are meeting all permit requirements. We also participate in an industry effort to install groundwater monitoring wells even where they are not required. And we are adding additional audits of our performance to the inspection schedule in 2010.

While we support greater oversight of ash impoundments, we believe that coal ash should not be reclassified as a hazardous waste. Many state regulators and policymakers agree and have shared their views with the EPA. We have met with the EPA and have testified before Congress

2009 COAL COMBUSTION BYPRODUCTS



8,349,267 tons of coal combustion byproducts were produced

*Flue gas desulfurization

about our concerns. This is an important issue to AEP because of the large number of impoundments we operate.

The public is legitimately concerned about coal ash impoundments and the beneficial use of coal ash. We seek to be both transparent and persuasive about the steps we are taking to protect public safety and the environment, and we are developing a plan that will include better and more frequent outreach and dialogue with stakeholders.

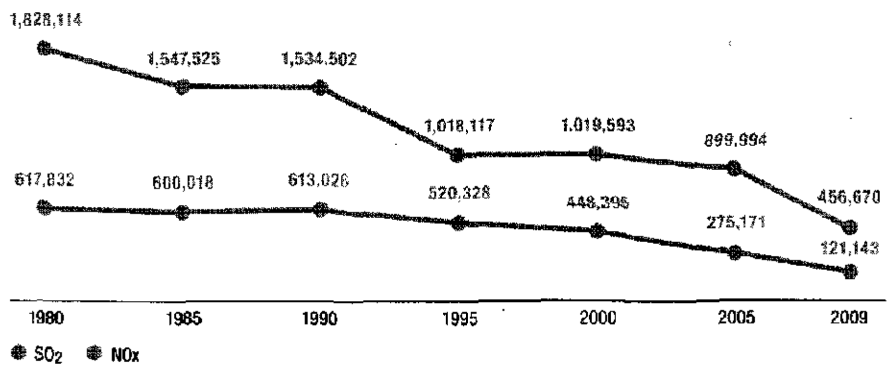
Approximately 40 percent of AEP's coal combustion byproducts are recycled as raw materials in road construction and concrete. By selling coal ash, we avoid approximately $14 million in disposal costs and net about $8 million in revenues.

AIR QUALITY

The $5.4 billion environmental control construction program at our coal-fired power plants is nearly complete. We began operating two new scrubbers in 2009 at the Conesville Plant in Ohio and the John Amos Plant in West Virginia. We also began operating a selective catalytic reduction system to reduce NOx emissions at Conesville.

We met a new limit on total NOx emissions that took effect at our eastern coal-burning plants in 2009, and we will also meet a cap for SO_2 that takes effect in 2010 as part of our 2007 New Source Review consent decree. Under this agreement, SO_2 emissions from our eastern coal plants will be reduced to 174,000 tons per year by 2019, a reduction of more than 650,000 tons per year compared with emissions prior to the agreement. In addition, NOx emissions will be reduced to 72,000 tons per year, a decrease of 159,000 tons per year prior to the agreement.

SO_2 & NOx EMISSION TRENDS AT AEP-OWNED PLANTS (measured in U.S. tons)



Several key regulations the EPA is considering for revision would have significant impact on our coal-fired power plants and on our customers. The EPA is developing a replacement for the CAIR that will reduce SO_2 and NOx emissions from our power plants. An earlier EPA decision about the CAIR was remanded to the agency by the D.C. Circuit Court of Appeals in 2008 but remains in effect during the additional rule-making activities. We devoted 6.7 million work-hours to CAIR-related construction in 2009.

The EPA also is working on a replacement for the Clean Air Mercury Rule, including collecting detailed information regarding a wide range of hazardous air pollutant emissions for its rule development analysis. Twenty-one of our coal-fired units are among approximately 500 units nationwide that are providing air sampling information about mercury to the EPA. Although we don't expect the rule to be final until 2011, we have begun installing mercury monitoring equipment on nearly all of our coal-fired power plants. But the technology is not achieving the needed reliability and requires daily technical adjustments. Consequently, we slowed the installations until we can resolve the equipment issues.

An additional benefit of the SO_2 and NOx controls we installed on a number of our larger coal-fired power plants is that they also significantly reduce mercury emissions.

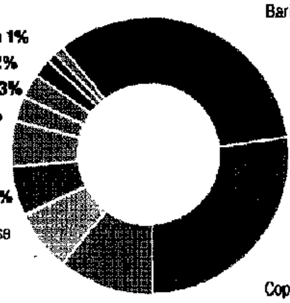
While we don't know precisely what the new rules will require, we continue to work with the EPA to establish requirements that are realistic, achievable and allow enough time to implement.

WATER ISSUES

For more than 50 years, the federal government has protected water quality in the United States by regulating discharges into streams and water bodies. Restructured in the 1970s under the Clean Water Act, these regulations established the National Pollutant Discharge Elimination System (NPDES) permit program to set discharge limits. This program is administered by state environmental agencies with U.S. EPA oversight. We work closely with regulators to ensure we do not exceed our permit limits.

The EPA intends to revamp the Clean Water Act's compliance and enforcement program. The agency also plans to revise the steam electric effluent guidelines, which govern the standards for water discharges at coal-fired power plants, including discharges from coal ash ponds, coal piles, air

2008 AEP SYSTEMWIDE RELEASES TO WATER (192,639 pounds)



pollution control systems and other sources. We are committed to working with the agency to assure that any new standards are achievable and affordable.

When coal is burned to produce electricity, the effects on the environment extend beyond air quality. For example, the installation of scrubbers to remove SO_2 from air emissions also results in the capture of other pollutants such as mercury and selenium, which end up in the wastewater and scrubber byproduct. The byproduct is managed in well-designed landfills, but to protect water quality and ensure that we remain compliant, AEP installed wastewater treatment facilities at each power plant with air emission controls. We also are leading an industry effort to develop treatment technologies for removing mercury from power plant wastewater discharges.

The Cook Nuclear Plant is effectively monitoring tritium levels in groundwater and recently installed five multi-level wells to further improve groundwater monitoring. No tritium levels have been detected at the site that require reporting in accordance with the Nuclear Energy Institute 07-07 "Groundwater Protection Initiative."

The outcome of the EPA's deliberations about how to implement Section 316(b) of the Clean Water Act is very important to us. The U.S. Supreme Court ruled that the Clean Water Act allows the EPA to use cost-benefit analysis in setting standards related to cooling water intake systems at power plants to better protect fish and shellfish. That decision paves the way for our industry to protect the environment in ways that take costs into account. The potential price tag may be significant for us, but without this balance of cost and benefit, it could be cost-prohibitive with limited environmental benefit. We continue to work with the EPA and others to reach a reasonable outcome.

Stakeholders have raised concerns about the amount of water that is needed to produce electricity. Our air emissions challenges take higher priority than our water use challenges because our air emissions create greater financial, environmental and operational risks. However, water conservation is important to us, and we are investigating new technologies and other conservation opportunities.

We formed an internal water study group to identify opportunities to address our water use. We also are participating in a three-year research project with the Electric Power Research Institute and other utilities to develop, test and deploy efficient, advanced cooling technologies. We do not have specific water use metrics for our existing power plants; our focus is on maximizing generating unit operating efficiency to help reduce the amount of water we use for cooling purposes. Opportunities to incorporate specific water use metrics may come with new construction, such as replacing older steam electric facilities when they are retired with new facilities. However, new power plants today typically have cooling towers, which reduce overall water use but increase water consumption from local resources. We also consider water consumption in evaluating pollution control technology. For example, a "wet" SO_2 scrubber will consume more water than a "dry" scrubber. We also are studying potential impacts related to carbon capture and storage. Read more online at ***www.AEPsustainability.com***.

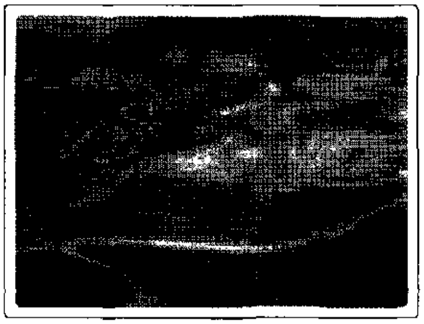
WASTE REDUCTION & LAND ISSUES

We seek to reduce and properly manage

PAUL CHODAK

President & chief operating officer, Southwestern Electric Power Co.

"Today's sustainability challenges require us to work even more closely with customers, regulators, environmental groups, legislators and our own employees to achieve the best results. Challenges abound in meeting ever-changing environmental laws and complex regulations, yet our responsibility remains the same as it has been since SWEPCO's inception in 1912: to support our customers and communities by providing them with reliable, cost-effective power in a responsible and responsive manner. Our goal going forward is to fulfill customer expectations while balancing the needs of all our stakeholders."



An aerial view of an area surface mine in eastern Kentucky; about 7 percent of AEP's coal supply comes from mountaintop mining operations.

the waste that we produce, including its disposal and the remediation of contaminated land. We extend this vigilance to our suppliers whenever possible. In 2009, we disposed of more than 110,000 pounds of hazardous waste and recycled 1.8 million pounds of paper, 51 million pounds of metal, 250,000 light bulbs and 1.7 million gallons of oil. We also recycled or reused approximately 135,000 pounds of electronic equipment, such as computers and phones, keeping it out of landfills. Read more about this issue at ***www.AEPsustainability.com***.

Working With Our Suppliers

COAL SUPPLIERS

The life cycle of coal is of great concern to many of our stakeholders because of the full range of environmental impacts, from mining to combustion for energy production to combustion byproducts. As part of our stakeholder engagement process, we made a commitment in 2008 to begin evaluating the environmental, safety and health performance of our coal suppliers. We conducted our first survey of coal suppliers in 2009, seeking information about their mining practices, environmental and safety and health performance, and contributions to local communities. We also used the survey to help us learn what percentage of our coal supply comes from mountaintop removal mining.

We hired a mining consultant to help develop and conduct the survey and included numerous performance indicators from the GRI's Mining and Metals Sector Supplement. Twenty-four of our 31 coal suppliers responded to the survey, representing about half of the nation's coal production and 82 percent of our 2008 coal deliveries. We used the survey results as a core component of a stakeholder meeting that brought coal suppliers together with environmental groups, regulators, elected officials, community leaders, academics and AEP executives. We believe this was the first time these groups had met face-to-face to discuss coal production issues.

We learned a lot about our suppliers. The survey showed that the safety and health performance of those responding was better than the national average for their industry. Their environmental performance also was generally good, but in the absence of a national database or other benchmark, we found it difficult to identify important trends or make meaningful comparisons beyond those who responded. We also confirmed that roughly 7 percent of our coal comes from mountaintop mining.

An AEP River Operations tugboat assembles coal barges at the Cook Coal Terminal, Metropolis, Ill.

We discussed the survey results, mountaintop mining, the economic importance of mining and the challenges of reducing coal production in light of its status as a low-cost fuel. The meeting participants agreed that coal is necessary to keep the lights on in this nation, but there was disagreement about how and when to transition to other sources of energy.

We intend to conduct the survey annually and our goal is for all suppliers to participate. Through the survey, we identified certain companies whose environmental, safety and health performance was exemplary. We also identified companies whose performance was below the norm. We intend to reach out to companies from both groups to learn what factors they believe influence their performance. From these discussions, we hope to share nonconfidential information with all of our coal suppliers that could help improve the overall environmental, safety and health performance of the group.

We are initiating conversations with public utility regulators in our states to test their receptivity to including environmental, safety and health performance considerations in our fuel bid evaluations. In the interim, we will revisit the survey to enhance it and continue to engage stakeholders on these issues.

Read more about what two stakeholders have to say about coal mining, in their own words, in *Stakeholder Engagement* and at ***www.AEPsustainability.com***. More information about the survey and next steps, along with our work with nonfuel suppliers, is on the Web. ■

Environmental Performance:

Climate Change

“When the United States develops legislation or regulations that require a reduction in CO_2 emissions, there is no doubt in my mind that CCS will be an integral part of compliance for the coal-fired power generation industry. While efficiency improvements to the power generation process can take us part of the way toward a lower carbon footprint, there will be no substitute for advanced CCS technology deployment.”

Gary O. Spitznogle, manager of IGCC and Gas Plant Engineering

Generating capacity from renewable energy

6%

Million metric tons of CO_2 emissions in 2009

130

Generating capacity from coal

66%

SF_6 emissions rate of total system capacity in 2009

2%

For more than 100 years, AEP has produced low-cost electricity by burning coal — a plentiful, domestic and cost-effective source of energy. Coal-fired electricity has played a vital role in expanding the American economy, creating well-paying jobs and assuring the safety, health and well-being of our customers. Nearly half of the nation's daily electricity comes from coal. We firmly believe that coal will continue to be a significant component of America's energy mix for the foreseeable future.

At the same time, we recognize that the carbon dioxide (CO_2) emissions created through the combustion of fossil fuels, including coal, are a matter of concern. AEP has the largest portfolio of coal-based generation in the United States, so we have a responsibility to lead our industry in proactively addressing this issue. We are doing so through our investments in clean-coal technology and carbon offsets and in our vocal support for responsible federal legislation, including cap-and-trade policies.

We are leading in terms of our measurable, voluntary efforts to reduce our carbon emissions and use more renewable fuels, and through our efforts to modernize the electric grid, put more control of energy use in consumers' hands, and increase energy efficiency. And we are leading in the international arena as well, working with the World Business Council for Sustainable Development and International Emissions Trading Association, and by participating in the international climate treaty discussions in Copenhagen, Denmark.

From left, Frances Beinecke, president of the Natural Resources Defense Council, AEP Executive Vice President Dennis Welch, and Mark Tercek, president and chief executive officer, The Nature Conservancy, discuss deforestation at the United Nations' climate change conference in Copenhagen, Denmark.

We expect the makeup of our generation portfolio to change in response to several external factors, including global climate change. The number of coal-fired units we operate in the future will be determined by new or more stringent environmental regulations; greater potential use of natural gas, including shale gas; the age and efficiency of some of our coal units; and the outcome of the climate change debate. The transition to other fuel sources will take time and will be expensive, but we are preparing for it.

STRATEGY & APPROACH

Our strategy is to pursue multiple options, including renewable energy, new technologies, offsets, natural gas, energy efficiency, and increasing the output of our nuclear units. At the same time, we will continue to improve the efficiency of our plants; retire or mothball some older, smaller coal units when factors warrant; and complete our environmental retrofit program.

Stakeholders have asked us if we consider a carbon price when making capital investment decisions. Our assumptions take into account the many different options being considered for legislating or regulating CO_2 emissions. If CO_2 and other emission standards are imposed,

A team of employees and contractors completed the Mountaineer carbon capture project on time and on budget.

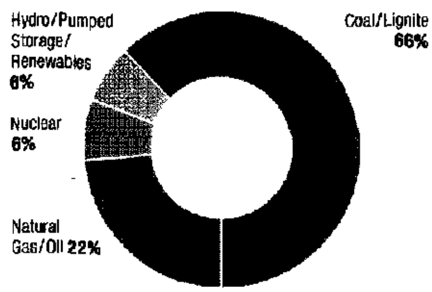
they could require significant increases in capital investments and operating costs. We don't know with any certainty what those might be, but we believe that the costs of compliance would be allowed in customer rates, as they have been in the past.

Our CO_2 emissions in 2010 and beyond will be affected by continued changes in our generation portfolio, market prices, the pace and scale of the economic recovery, available capital, weather and other factors. We expect that our CO_2 emissions between 2010 and 2012 will remain largely flat despite sales rebounding from the recession lows of 2009. During the next decade, we expect our CO_2 emissions growth to decline due to retirements of some older coal units and increased use of renewable energy, among other things. Our capital investment decisions take all of these factors, including public policy, risks, cost to customers and available resources, into consideration in the planning and decision-making process.

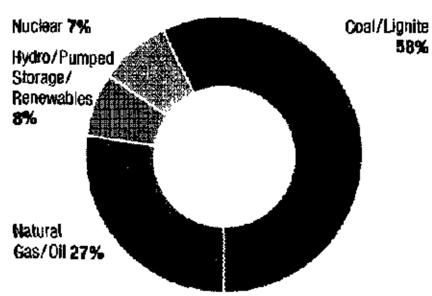
We are voluntarily taking actions that help us reduce or offset our CO_2 emissions. As a founding member of the Chicago Climate Exchange (CCX), AEP committed to cumulatively reduce or offset 46 million metric tons of CO_2 from 2003 to 2010. Through 2009, we had already reduced or offset more than 70 million metric tons of CO_2. We achieved this through the purchase of CO_2 credits and verifiable offsets and by improving the efficiency of our power plants; by increasing our renewable, natural gas and nuclear generation; and by retiring less efficient fossil units, among other actions.

Though AEP's commitment to CCX runs only through the end of this year, we expect to continue voluntary actions that help us reduce our carbon emissions in the absence of mandatory legislation or regulations. These voluntary actions could include an extension of our commitment to CCX as an interim solution until mandatory legislation or regulation does take effect, if this is a viable option. As with other voluntary actions, we are working with legislators, regulators, policymakers and other stakeholders to gain support for regulatory cost recovery. In the long run, when carbon mandates are issued, our early actions will help us comply.

2009 AEP GENERATION CAPACITY BY FUEL



2017 PROJECTED AEP GENERATION CAPACITY BY FUEL



PUBLIC POLICY & FEDERAL LEGISLATION

Climate change is a global issue. The United States and its trading partners must take action together, otherwise the U.S. economy will be placed at a competitive disadvantage. It is encouraging that China and India have agreed to be part of the Copenhagen Accord, along with other developing countries. The accord, reached during international treaty negotiations in Copenhagen in December 2009, sets a nonbinding goal of limiting global warming to less than 2 degrees Celsius above pre-industrial times. It is a step in the right direction toward a global solution. And President Obama's pledge of a 17 percent reduction in greenhouse gas emissions by 2020 for our nation is a signal of where the United States likely is headed.

Read more about our international work at ***www.AEPsustainabilty.com***.

We believe that a U.S. climate policy should include a federal cap-and-trade system to reduce greenhouse gases (GHGs), provide incentives to develop and deploy new technologies, create targets for emissions reductions that match available technology, and allow for unrestricted use of real, verifiable domestic and international offsets. For more details on our position, please visit ***www.AEPsustainabilty.com***.

Legislation that targets only specific sectors of the economy, including the electric utility sector, has been suggested. We do not support this. We do not believe that a single industry and its customers should shoulder the weight of this global issue.

We supported the American Clean Energy and Security Act of 2009 (the Waxman-Markey bill) that was passed by the U.S. House of Representatives. The bill included important provisions that addressed jobs, costs and the economy. Given the large number of future administrative actions the bill would create, there is still too much uncertainty about the potential outcomes to be able to predict the impact on electricity rates or the level of capital investment that may be needed. However, we believe that under the current provisions, the bill would likely drive up costs to our customers significantly while also providing important incentives for technology development.

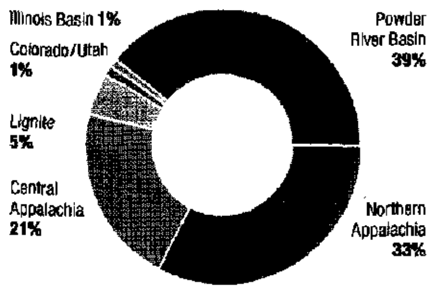
OFFSETS, ALLOCATIONS, AUCTIONS

Emission "offsets" include emission reductions, avoided emissions or sequestration at sources that are not subject to emission reduction requirements under cap-and-trade legislation. Under a flexible cap-and-trade system, emission offsets can play an important role in lowering compliance costs while at the same time assuring the emission reduction goals are met. Offsets are generally less expensive than direct reductions in emissions from power plants, factories or vehicles. They can also deliver valuable ancillary economic and environmental benefits. We plan to use them to assure compliance until new clean-energy technologies are ready for commercial deployment and become more economical.

We have voluntarily invested in offsets, including forestry and agricultural methane destruction, and purchased credits through the CCX. The offsets we purchase are verified and fully accredited by third parties and reputable registries.

Our position on CO_2 allowance allocations and auctions has not changed. The distribution of valuable emission allowances will have serious implications throughout the economy and enormous financial consequences for our customers. Although we recognize there may be a need for some auctioned allowances from the overall allocation to support complementary climate change efforts, we seek a full allocation of allowances to the electric utility sector (equal to the sector's total share of the U.S. emissions cap) in order to minimize the cost and subsequent rate impact on our customers. Without sufficient allocations, the

2010 PROJECTED COAL PROCUREMENT



effects on local economies struggling to emerge from the recession would be harsher.

Our responsibility to our customers is paramount, and we are passionate about seeking a legislative approach that considers the cost and economic impacts upon them.

POTENTIAL REGULATION UNDER CURRENT LAW

The U.S. Environmental Protection Agency (EPA) is preparing to regulate GHGs under the Clean Air Act (CAA). In 2007, the U.S. Supreme Court found in Massachusetts v. EPA that GHGs can be regulated as air pollutants under existing law. The EPA issued a Public Endangerment Finding in December 2009 stating that GHGs are "reasonably anticipated to endanger public health and welfare." In response to concerns raised by state agencies and the regulated community that the EPA was moving too fast, the agency in February 2010 announced its intent to phase in the program.

We strongly believe regulating GHGs through the CAA is the wrong approach. We support a cap-and-trade legislative approach, similar to the Waxman-Markey bill, and we have advocated this to Congress. Provisions in legislation that allocate allowances, offer incentives for technology development and provide other benefits that allow us to continue to cost-effectively transition to a lower carbon economy are critical for our customers, our company and our shareholders.

When this rule takes effect, GHG emissions from stationary sources, such as power plants, could be considered a "regulated air pollutant" under the CAA's permitting programs. This could bring CO_2 and other GHGs into the existing regulatory program for stationary sources and require that these gases be considered in permits when building new units or modifying existing ones.

The standard would likely trigger a requirement to apply best available control technology (BACT) to GHGs to meet the regulations. However, it is not yet clear what the BACT for GHGs will be. In addition, the EPA is likely to move forward with the development of New Source Performance standards for electric generating units and other stationary sources.

We have been working with the EPA through industry trade associations as well as participating in the agency's Clean Air Act Advisory Committee, and we are looking closely at how these new rules would affect our ability to continue operating existing coal units that are not already equipped with environmental controls. We are also monitoring the development of technologies that could be considered in a BACT analysis for our power plants.

Federal and state regulations or legislation limiting the emission of GHGs could result in significant increases in capital expenditures, financing and operating costs. This higher level of investment could also lead to an increase in earnings because of the higher value of our rate base. The cost of additional regulatory requirements would ultimately be borne by consumers through higher prices for energy.

TECHNOLOGY

AEP is leading the U.S. utility industry in advancing carbon capture and storage (CCS) technologies. We successfully captured, transported and geologically stored carbon dioxide emissions from an existing coal-fired power plant for the first time in October 2009, demonstrating the capability of fully integrated carbon capture and storage technology at our 1,300-megawatt (MW) Mountaineer Plant in West Virginia. The project uses Alstom's *patented chilled ammonia technology* to capture the CO_2 from a 20-MW portion of the plant's flue gas — a major technology achievement. It is the largest integrated CCS demonstration applied to an operating power plant. Approximately 90 percent of the CO_2 from the flue gas stream is being captured and stored underground.

CCS – HOW IT WORKS

To be able to store the CO_2 underground, the Mountaineer Plant received West Virginia's first-ever CO_2 storage permit from the West Virginia Department of Environmental Protection. The permit allows the demonstration facility to inject a maximum of 165,000 metric tons of CO_2 per year for up to five years.

The next project — to install the nation's first commercial-scale, coal-derived CO_2 capture and storage system at Mountaineer — will be partially funded through the U.S. Department of Energy's (DOE) Clean Coal Power Initiative. AEP was awarded 50 percent of the cost of the project, up to $334 million. This will reduce the costs to our customers for the first commercial deployment of this technology. We are seeking additional partners to help pay the remaining cost of the project.

This commercial-scale project will capture approximately 90 percent of the CO_2 from 235 MW of the plant's 1,300-MW capacity. The captured CO_2, approximately 1.5 million metric tons per year, would be treated, compressed and stored underground. We intend to begin this commercial-scale operation in 2015; if the technology is successful, can be commercialized and is cost-effective, we would seek regulatory support to begin retrofitting existing coal plants.

Chairman Mike Morris and U.S. Sen. Jay Rockefeller (D-W.Va.) at the Mountaineer CCS commissioning event.

For more information about the CCS technology at Mountaineer Plant and our project partners, visit our website at ***www.AEPsustainability.com***.

MAKING THE ECONOMICS WORK FOR CUSTOMERS

Developing new technologies such as CCS can impose significant costs on customers, particularly in the early development stages. But as the technology matures, the costs should decline. For example, Mountaineer's 20-MW project cost more than $5,000 per kilowatt (kW), but the proposed 235-MW system is estimated to cost less than $3,000 per kW. When the government subsidies are factored in, the cost falls to approximately $1,500 per kW.

We are able to be a first mover of technology because of our engineering, technical and construction expertise. First movers always pay an initial premium with respect to cost and risk. However, they also gain valuable knowledge and understanding as the technology develops. This particularly benefits AEP and our customers, but also the industry by being a driving force for cost reductions, increased reliability and improved availability for all users. It is not clear what the cost-reduction curve will be for CCS technology over time, but we are seeing it head in the right direction as we move past the demonstration phase to full commercial availability in 2020.

OTHER ADVANCED TECHNOLOGIES

We made significant progress in 2009 on the 600-MW John W. Turk Jr. ultra-supercritical pulverized coal plant under construction in southwest Arkansas. Southwestern Electric Power Co. successfully secured all major construction permits but still faces legal challenges to the process used by the Arkansas Public Service Commission to approve construction of the plant.

We set a goal two years ago to deploy 25 MW of sodium sulfur (NaS) battery storage on our system by 2010. Instead, we have a capacity of 11 MW with the completion of a project in Presidio, Texas. We stopped installing these batteries because the technology became cost-prohibitive. We are now focusing on community energy storage (CES), which uses lithium-ion battery technology — the

DANA WALDO

President & chief operating officer, Appalachian Power Co.

"Meeting the challenge of reducing the carbon impacts of the nation's electric infrastructure will require thoughtful engagement with every level of our stakeholders. We must be at the table to help identify, develop and support policy pathways that balance reductions in greenhouse gas emissions with our ongoing commitment to provide reliable, affordable and environmentally responsible electricity to our customers."

same type of batteries used in electric vehicles — making them more widely available and cost-effective. We are installing 2 MW of CES as part of the AEP Ohio gridSMART℠ Demonstration Project. Read more about CES online at ***www.AEPsustainability.com***.

VOLUNTARY ACTIONS MATTER

Wind energy accounts for 2 percent of the total power generation in the United States. The U.S. wind industry installed a record 9,922 MW of generating capacity in 2009, helped by federal tax subsidies.

We committed to add 2,000 MW of renewable resources between 2007 and the end of 2011, assuming regulatory approval. We are making progress. We have secured 1,013 MW of renewable energy through power purchase agreements, including 10 MW of solar power. Our integrated resource plan contains a 10 percent renewable energy target by 2020, based on the expectation that additional federal or state requirements may be enacted. Renewable energy requirements ranging from 9 percent to 15 percent by 2021 have already been part of federal energy and climate legislation in the House and Senate.

In the states that have renewable energy mandates, there is regulatory support for cost recovery. This is not necessarily true in states without such requirements. We are working with regulators and policymakers in service territory states without mandates to help ensure cost recovery; if they approve it, we will move forward, but if they don't, we will not. Read more about voluntary actions online at ***www.AEPsustainability.com***.

ENERGY EFFICIENCY

Energy efficiency is a high priority for us and for many AEP stakeholders. We believe energy efficiency is an important, cost-effective way to reduce GHGs and can possibly delay the need to build new power plants. We work closely with legislators, regulators, environmental groups, technical experts and others to develop and implement efficiency and demand response programs. Despite challenges, we are seeing signs of success.

Market potential studies completed in 10 states help us identify the technical, economic and achievable energy and demand reduction potential in homes, businesses, schools and other facilities. Our investment in energy efficiency programs has steadily increased from about $13 million in 2008 to a projected $110 million in 2010 and $218 million in 2012. This year, we anticipate more than two dozen regulatory filings in our states.

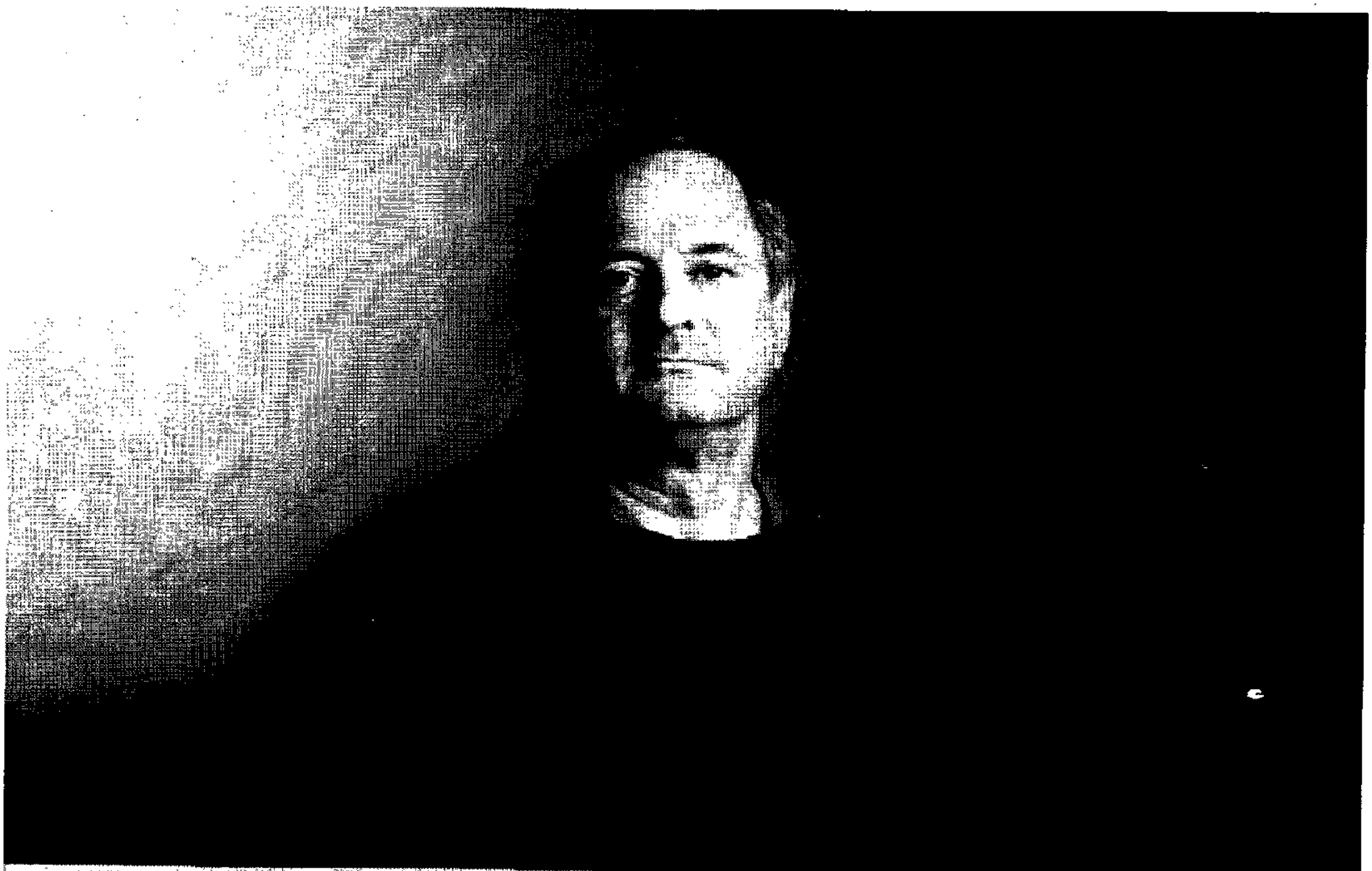
TOTAL COAL DELIVERED TO AEP PLANTS

	2007	2008	2009
Thousands of tons	72,644	77,054	75,909
Average price per ton	$36.65	$47.14	$49.54

These initiatives, and others we hope to implement, will help us to achieve our 2012 goal to reduce demand by 1,000 MW and energy consumption by 2,250,000 megawatt-hours (MWh). We already have identified the potential for more than 900 MW of demand reduction and approximately 2,800,000 MWh of energy reduction. We are actively seeking regulatory approval of our plans, which will be necessary if we are to meet our goals. We recognize that in the longer term more is expected, and we are pursuing additional programs and demand reduction opportunities that may be practical in many of our jurisdictions.

We are also beginning to investigate energy efficiency in wholesale markets.

Our ability to move forward relies on regulatory approval that includes recovery of program costs and lost revenues and a return on investment. Learn more about gridSMART℠ and energy efficiency efforts in our states at ***www.AEPsustainability.com***. ■



Work Force

“The (employee) fatality reminded me that an accident can happen at any given time, to anyone. It made me change my way of thinking and be more aware of my surroundings. Something like this sticks with you.”

Richard Worsham, heavy equipment operator, Dolet Hills Lignite Mine

Average age of AEP employees	Number of injuries, illnesses or fatalities we strive for	Work force represented by labor unions	Number of employees receiving the Chairman's Life Saving Award in 2009
45.9	0	28%	8

The most important aspect of our operations is to make sure everyone who works for us returns home safe and sound at the end of each workday. Our health and safety management systems failed tragically in 2009 when two of our employees and two contractors working for us were fatally injured on the job. This is unacceptable to us, and our entire company felt these losses.

We have programs and specific measures in place to avoid injuries, but it is clear that we have much more work to do to strengthen our safety culture if we are to reach our goal of having no fatalities, no injuries and no occupational illnesses — a condition we call "zero harm." A highly skilled work force that actively pursues zero harm and is deeply committed to mutual care and peer protection is the key to success. Our Human Performance initiative is dedicated to eliminating hazards and human errors that cause accidents. Although this culture change is taking hold, we are still concerned that productivity takes precedence over safety and health in some cases, and we are working to change that.

Our incentive plan for executive management includes a substantial penalty if there are employee fatalities. As a result of the deaths that occurred in 2009 and other factors, executive management did not receive any incentive compensation. All employees lost a portion of their incentive compensation because of the fatalities.

We have other work force challenges, particularly as we reduce our work force to address new economic realities and the need to find and retain the best talent to meet our future business goals. We must fully engage our employees and find ways to foster an environment that makes people want to work and stay here.

One of Richard Worsham's primary responsibilities at the Dolet Hills lignite mine is operating the pumps that keep the mine dry.

REACHING FOR ZERO HARM

Two employees and two AEP contractors were fatally injured on the job last year. We deeply regret each of these incidents and the grief they caused for so many.

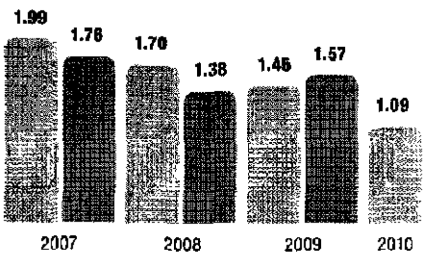
An employee at our Dolet Hills lignite mine in Louisiana was killed in March 2009 while working on heavy machinery, called a walking dragline, used to extract coal. What caused him to fall or to be in the location he was in is unknown. However, we now prohibit employees and contractors from having contact with the dragline when it is in motion. Physical barriers such as gravity gates and safety chains have been installed at all access points, and tripping hazards have been removed. Employees are now equipped with radios to ensure continuous communication between those on the ground and the equipment operator.

A River Operations employee lost his life in November when he fell from a barge into the Mississippi River. As a result, teams of employees are evaluating vessel operating practices with the goal of reducing deck crew exposure. Approximately 1,000 River Operations employees are receiving training in hazard recognition, safe work practices and job safety briefings to enhance awareness and increase focus on job responsibilities. We also are working with marine consultants and engineers to consider installing grab-bar devices on our barges as another layer of protection against going overboard. We will champion barge construction safety standards aimed at reducing the risk of personal injury and fall-overboard events across the industry.

Our two contractor fatalities occurred in January and July of 2009. One contractor died while unloading pole sections during the rebuilding of a transmission line. Another contractor was fatally injured while acting as

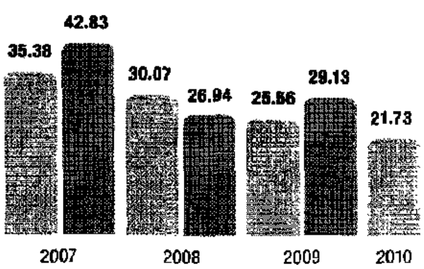
EMPLOYEE SAFETY & HEALTH "PATH TO EXCELLENCE"

Recordable Injury Rates



Recordable injury rate = total deaths + lost work injuries + lost work illnesses x 200,000 ÷ hours worked

Injury Severity Rates



Average severity rate = lost work days + restricted activity days x 200,000 ÷ hours worked

Annual Targets based on EEI Index

Actual Performance

a spotter for a backing vehicle. We are working more closely with our contractors to share our safety culture and expectations with them. We hold a contractor safety summit each year that is attended by hundreds of contractors and senior management. Our selection process and contract terms and conditions also spell out safety and health expectations, and we conduct job site audits to ensure compliance. We have removed contractors from bid lists and job sites for noncompliance.

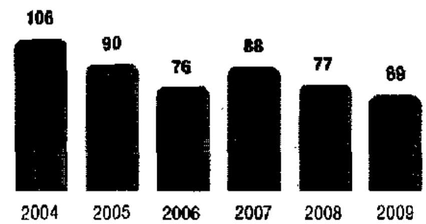
The number of injuries among our contractors is declining. We set a contractor recordable injury goal for the first time in 2009 that is tied to our executives' compensation, and contractors outperformed it. This goal applies only to contractors working directly for AEP.

Public fatalities are more difficult to address because we have no direct control over what the public does. We use paid advertisements, the news media, videos, online learning tools, training sessions and social networks to educate the public about electrical safety. Yet nine people died in 2009 after coming into contact with electrical facilities. We will continue our outreach and public safety education to help us achieve our public safety goals.

While we met our employee "Path to Excellence" recordable injury target, we missed the target when hearing loss incidents are included. Because hearing loss is usually a long-term occurrence, it is not currently in our incentive compensation plans. However, we monitor hearing loss very closely and hold ourselves accountable for continually improving our hearing conservation activities. In 2009, our injury severity rate also exceeded our target. Employees incurred more lost work days in 2009 than in 2008 because of slips, trips, falls and incidents of being struck by objects, which continued to be the leading causes of injury. Injuries tend to occur most frequently in late morning and early afternoon, suggesting that employees may be distracted before and after their lunch break.

We foster a zero harm culture by celebrating employees and work groups who demonstrate exemplary safety performance and who provide life-saving assistance. The first John P. DesBarres Safety & Health Award was given in 2010 to our transmission business unit for exemplary safety and health performance. The award honors John DesBarres, an AEP board member who died in December 2008 and was a staunch advocate of making AEP a safer place to work.

NUMBER OF RECORDABLE INJURIES SYSTEMWIDE CAUSED BY SLIPS/TRIPS/FALLS



Our transmission group improved both safety and operational performance by embracing the error-reduction methods of the Human Performance initiative. By focusing on reducing errors, we reduced the number of recordable injuries as well as customer outages caused by transmission station switching errors.

The Chairman's Life Saving Award recognizes employees for extraordinary efforts in life-threatening situations. It has been presented to 39 employees since 2004, including eight in 2009. Their acts of heroism included rescuing an electrical contact victim who was performing work for a telecommunications company, helping a victim of a head-on vehicle collision who was trapped in her car, and rescuing a boy from a burning apartment building.

We also reinforce a zero harm environment with programs such as peer-to-peer coaching, incident reporting, pre-job briefings and clear, unmistakable messages about safety. The Human Performance initiative is one of our most important safety and health efforts. It is directed toward building best practices, reducing mistakes and preventing those that do occur from causing injuries.

AEP formed a corporatewide Human Performance oversight team and steering committee in 2008 and expanded the effort in 2009. Our focus on error reduction is having a measurable impact. The severity rate in our Fossil/Hydro generation business unit improved from 32.3 in 2008 to 19.4 in 2009, but we believe this is just the beginning and we intend to continue to improve. In our Transmission business unit, a commitment to Human Performance resulted in a decline in the recordable injury rate from 4.0 a decade ago to nearly 1.0 in 2009. We are finding that when we eliminate errors that can cause injuries, we also eliminate operational errors, which improves our overall performance.

Approximately 2,500 electrical distribution line employees who were trained in Human Performance principles are now learning specific ways to prevent errors and are sharing their knowledge with their co-workers. These employees are adjusting to an environment that encourages them to stop working when they are unsure whether a certain practice or working condition is safe.

As our employees gain a better understanding of the risks in their jobs and what they can do to eliminate them, we must overcome a perception that still exists in some parts of the company that productivity is more important than safety and health. We have an obligation to deliver safe, reliable electricity to our customers, but never at the expense of safety and health.

Cook Plant employees learn control room operations in a new exact replica of Unit 1's control room that opened last fall.

SPECIFIC SAFETY INITIATIVES

Combustible dust can be a significant workplace hazard, and we are being proactive in our efforts to prevent harm. A U.S. Chemical Safety Board combustible dust hazard study found that nearly 280 dust fires and explosions have occurred in the United States during the past 25 years, resulting in 199 fatalities and more than 700 injuries. Among the types of dust involved were sugar, paper, aluminum, wood, plastic and coal.

We are working closely with the Occupational Safety and Health Administration (OSHA) to validate our compliance with the agency's proposed combustible dust restrictions through audits at our power plants. Because we burn coal, we are aggressively working to comply with the proposed standard. Elements of OSHA's program include electrical and fire protection, ignition control, an emergency action plan, personal protective equipment and hazard communication.

During the past two years, we conducted a study of the potential health hazards of welding, a common task throughout our industry and especially in our power plants. The study, consisting of 555 air samples from various types of welding, is one of the largest ever conducted in the electric utility industry. While study recommendations remain under review, it is apparent that either local exhaust ventilation or respiratory protection will be needed for many of our welding activities in the future. OSHA currently does not have a specific welding exposure regulation, in part because of the difficulty in measuring exposure fume levels.

Mandatory fall restraint devices and 19 other pole safety recommendations from an employee-led team in 2008 resulted in a 56 percent reduction in incidents related to falls from poles, compared with the previous four-year average.

We are reducing the probability of interactions with threatening animals by attaching special codes to customer accounts where such animals are known to be present and with new equipment that

PABLO VEGAS

President & chief operating officer, AEP Texas

"AEP Texas employees are the company's greatest assets. That's why we place a tremendous emphasis on our safety and work cultures. Our safety goal is for every employee to return home in the evening in the same condition in which he or she came to work in the morning. Nothing less will do. Our work culture embraces a skilled, diverse work force. Diversity in all of its varied forms, including experience, ethnicity, age and gender, provides a broader and richer context to our business challenges and opportunities. This, in turn, allows us to understand and serve the many and equally varied needs of our customers to the very best of our abilities."

gives our employees advance warning.

To help employees avoid some of the common causes of injury, we developed training in safe truck cab and bed access and started a program to prevent slips, trips and other walking hazards through error reduction methods. One-third of all slips and trips become recordable injuries, and these account for approximately 16 percent of recordable events companywide.

A study of AEP work practices showed that if a power line with a safety ground accidentally becomes re-energized, a worker could be exposed to hazardous voltage levels depending on his or her location in relation to the equipment. Consequently, we have stepped up our efforts to encourage workers to wear rubber gloves in those situations, giving them extra protection.

Lifting and rigging practices are another area of concern. At AEP, an employee was killed in late 2006 while using a crane at a power plant. Our analysis found that crane-related policies and new procedures, including training, were inconsistent and outdated across the enterprise. New policies and procedures took effect in January 2010 with a one-year grace period to allow for proper training.

We also are strengthening the process by which safety and health issues are considered when projects are engineered. This will prevent costly future retrofits to achieve safety and health compliance and will provide protection from the start. AEP's Safety and Health team works closely with Engineering and other functions to review designs of new construction projects. In addition, several safety- and health-related factors have already been incorporated into design standards for new construction. The end result will be a safer work environment.

A safer environment has resulted from converting boilers at coal-fired power plants that are retrofitted for sulfur dioxide control from forced-draft design to balanced-draft design. Any leaks that occur in the boiler at these plants now introduce outside air into the boiler rather than causing gases and ash to leak out. The equipment and vicinity do not become contaminated, creating a much safer, cleaner work area.

Our effort to conform our power plants to environmental, safety and health management systems standards will help us move toward zero harm. These systems will help ensure that our policies and procedures are accurately documented. In so doing, they will enable us to capture the knowledge and practices of our experienced employees, many of whom are nearing retirement.

DEALING WITH H1N1

The threat of the H1N1 virus has been a challenge for AEP as it has been for other companies. The virus ultimately has had little impact on our operations except for a somewhat higher-than-usual level of absences. Cases of the flu—including H1N1 and seasonal flu—reached a three-year peak in 2009, totaling 947, according to AEP's Human Resources Recovery Center. Seasonal flu vaccines were administered to approximately 13,325 employees, spouses and domestic partners in 2009 during company-sponsored health screenings. We also provided H1N1 vaccines as soon as they became available to us in 2010.

PROTECTING THE PUBLIC

Zero harm includes no harm to the public. Although it is more difficult to reach the public with safety information, we have initiated a significant outreach and education campaign that we believe will move us closer to our goal. We know this will take time, and that is why we have set a Path to Excellence for public safety. It is imperative that we succeed: All of the nine public fatalities and 34 electrical contacts that occurred in 2009 could have been prevented had basic electrical safety practices been followed.

Copper theft declined in 2009, possibly because of declining copper prices and increased public education. While none of the fatalities last year involved copper theft, two of the electrical contacts did. However, we are starting to see an increase in copper theft in some parts of our service territory, and we are stepping up our public education and outreach efforts to address this.

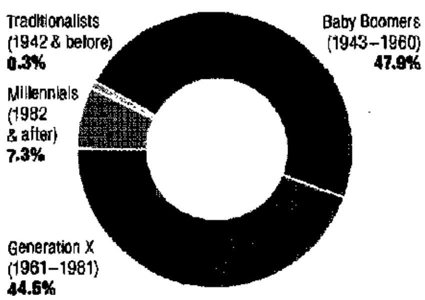
2009 EMPLOYMENT DATA — EEO-1 (as of Aug. 31, 2009)

	Employees	Females (%)		Minorities (%)	
Total Employment	21,737	4,013	(18.5%)	3,174	(14.6%)
Officials & Managers	3,629	382	(10.5%)	305	(8.4%)
Professionals	5,544	1,450	(26.2%)	836	(15.1%)

2008 EMPLOYMENT DATA — EEO-1 (as of Aug. 31, 2008)

	Employees	Females (%)		Minorities (%)	
Total Employment	22,746	4,119	(18.1%)	3,433	(15.1%)
Officials & Managers	3,711	368	(9.9%)	319	(8.6%)
Professionals	5,625	1,456	(25.9%)	827	(14.7%)

2009 AEP WORK FORCE DEMOGRAPHICS



WORKING TOWARD A SUSTAINABLE WORK FORCE

AEP's future success hinges largely on the availability of a skilled, motivated and diverse work force. Many challenges face us, from employee retention and morale to ensuring that employees have the skills to perform the required work in an ever-changing environment. We strive to be certain we have the resources and tools to succeed in the decades ahead despite uncertainty about the economic, policy and regulatory landscape.

ATTRACTING & RETAINING TALENT

Our work force is aging, which increases the risk of a talent shortage in the future. For the past five years, the average age of our retirees has been 60 or 61. Today, the average age of our employees is 45.9 years. The economic downturn has delayed some retirements and reduced hiring and advancement opportunities. Even so, we expect to reduce our work force by 5 percent to 10 percent in 2010 to better align our company to the new economic realities.

Elimination of a merit pay increase in 2009 and the relatively small increase planned for 2010 also could affect our future ability to offer a competitive compensation package to prospective and current employees. Given these challenges, we are working to retain an optimal, productive and engaged work force. For employees seeking advancement and development, we continually explore opportunities to offer job rotations, temporary "job swaps" and developmental tasks that usually are not part of a particular job.

We remain hopeful the economic recovery will pick up steam and we are seeing some companies begin to hire again. The risk we face is that they may try to hire away our best performers. We continue to offer employee development programs and to put a strong emphasis on AEP's Performance Review and Feedback process, which focuses on goal alignment, employee engagement and developing a culture of accountability.

Read more about work force development at ***www.AEPsustainability.com***.

VALUING DIVERSITY

We recognize that a diverse work force gives us the best opportunity to succeed. The greater the variety of ages, cultures, backgrounds and skills brought to a project or task, the greater the likelihood the best possible decisions will be made.

One-third of our employees are minorities or females. In 2009 as in past years, we set diversity targets for females and minorities for management, professional and front-line employees. Placement rates in four of the six job categories exceeded target, but two fell short. For the first time ever, we met our placement target for females in front-line jobs, even though the 2009 level of hiring from outside the company was lower than usual. We were just shy of target in that job category for minorities. But we were far from target in the placement rate for minorities in management-level posts.

Our efforts to increase diversity will continue, and we expect the progress we've made to be sustainable.

ORGANIZED LABOR AT AEP

Labor Union	Number of Employees
International Brotherhood of Electrical Workers	3,816
Utility Workers Union of America	1,342
United Steelworkers of America	525
United Mine Workers of America	377
International Union of Operating Engineers	2

Jenny Goodman, an AEP electrical contractor, works on the Mountaineer CCS project.

WORK/LIFE BALANCE

Employees and prospective employees view AEP's more than 30 work/life programs as an important benefit. Among them are flexible work schedules for some jobs, parental leave, alternative family benefits and a wellness program. In the second year of our "AEP Wellness... Energy for Life" program, approximately 39 percent of eligible employees and their spouses or domestic partners completed health risk assessments. The participants learn about health risks and can take advantage of programs to help address them. ■

> **“** Federal support for energy assistance and weatherization is at an all-time high. But despite our progress, neither the federal and state governments nor the utility and nonprofit sectors, by themselves, can solve the problem of unaffordable energy for low-income customers. **”**

David Fox, executive director, National Low Income Energy Consortium

Live employee webcasts to keep management connected to employees

39

Charitable giving in 2009, including AEP Foundation (in millions)

$23.4

Number of stakeholder meetings in 2009

7

Approximate number of investors we met with during 2009

400

As a provider of an essential service, we hold a public trust that requires a level of accountability and openness. We operate in a world that is far more interdependent than ever before. Like many companies, we deal with controversial and complex issues that have a real impact on people's lives, beyond the power that we provide.

Many groups and individuals have a legitimate stake in our business. We believe that open, trusting relationships with our investors, our community leaders and other stakeholders are critical to our credibility and our business success. Our stakeholders make us stronger and more resilient by:

- Keeping us well-informed about issues of concern and interest to people who make a difference to us.
- Providing us with important insights and points of view that we may not have fully considered on our own.
- Giving us an opportunity to discuss our points of view and, in some cases, to be persuasive about them.
- Helping us to find common ground and gain assistance in advancing common objectives.
- Providing us with incentives and additional accountability for commitments and performance.
- Reinforcing our integrity by knowing that what we say and do will be held up to public scrutiny.

Stakeholder engagement has helped us to transform one-way communication into two-way communication, dialogue into working relationships, and working relationships into partnerships. It has changed our culture; we are less inwardly focused and more externally focused. Engagement is considered a core competency and a matter of material import to our company.

David Fox of the National Low Income Energy Consortium works with utilities, government and nonprofits to address energy affordability issues.

HOW WE ENGAGE

We engage with a number of stakeholders on many levels, from face-to-face meetings to conferences and social networking sites, conference calls and briefings on specific topics. We have a dedicated sustainability website (***www.AEPsustainability.com***) to report on our activities, and our operating companies also hold stakeholder meetings to address state and local issues.

To fulfill a commitment to report more frequently about progress on our sustainability issues, we recently published our first Web-based mid-year update on key commitments and will continue to do so semiannually. We are expanding our channels of engagement to enable us to reach many more people who have an interest in our business.

For the past four years, we have collaborated with Ceres, a national network of investors, environmental organizations and other public interest groups working with companies and investors, to address sustainability challenges. Ceres facilitates a multi-stakeholder meeting with AEP executives at our Columbus, Ohio, headquarters. Our discussions typically focus on climate change, the future of coal, and energy efficiency. In 2009, we expanded our discussions to include water risks. Stakeholders who participate represent environmental organizations, labor, socially responsible investors (SRI) and other public interest groups.

This year marked the team's fourth meeting with AEP, giving us an opportunity to review our progress as well as to discuss areas where we still have work to do. We talked about our business strategy and how it is evolving as we prepare for a transformation of the electric utility industry. We agreed to further clarify our strategy and to convene a stakeholder conference call later this year to provide an update. We recognize we need to be clearer about where we stand on some issues to keep the dialogue going and prevent misperceptions.

THE ISSUES ON WHICH WE ENGAGE

We have begun to focus intently on specific

STAKEHOLDER PROFILES

We held an unprecedented stakeholder meeting on coal issues and the environmental, safety and health performance of our coal suppliers in 2009 as we brought together 10 coal suppliers, environmental groups, regulators and community leaders. The meeting was based on a supplier survey we conducted, but much of the conversation also focused on mountaintop removal mining. We invited two stakeholders from that meeting to share their views about coal in this report.

BILL RANEY, president of the West Virginia Coal Association

"Coal is truly the answer to America's long-term security. Coal practices have significantly improved over the last 40 years, and that demonstrates our ability and ambition to mine and ship coal in a safe manner while advancing environmental stewardship. If those who oppose coal would focus their energy on making coal a better resource, the entire world would benefit. Prohibiting mining and coal use would have detrimental effects on our economy."

MATT WASSON, director of programs, Appalachian Voices

"Since the industrial revolution, coal has played a central role in improving the quality of life of Americans and people across the world. Looking ahead, it will continue to play a transitional role as America begins to face the economic and environmental imperative of shifting to a clean energy economy. However, we should never call coal 'clean' without accounting for the huge range of health and environmental costs associated with the complete life cycle of coal, from mining and transportation to the disposal of post-combustion waste. Until the most destructive mining practices like mountaintop removal in Appalachia are eliminated, the subject of coal will remain controversial and polarizing in the debate over America's energy future."

Read more about the perspectives shared by these stakeholders at ***www.AEPsustainability.com***.

issues that our public policy stakeholders have repeatedly said are most important to them, including energy efficiency, global climate change, the cost of electricity and conservation. These are high priorities for us as well.

We agree that energy efficiency is an important tool that can delay the construction of new power plants. We work with state-based collaboratives of utilities, regulators, environmental and community groups and customers to identify and develop energy efficiency programs in Ohio, Indiana, West Virginia, Kentucky and Texas. In all of our jurisdictions where we are implementing energy efficiency, we have programs designed specifically to target low-income customers. In some programs, we partner with local weatherization agencies that are trained to provide education and energy efficiency resources directly to customers. AEP Ohio, for example, distributed approximately 20,000 energy efficiency kits this way.

We are creating an external Energy Efficiency Advisory Council of experts from manufacturing, trade groups, home builders, government, nongovernment agencies and others willing to work with us to address this issue. We will report on our progress.

Engagement in Action

ENGAGING OUR INVESTORS

Our success as an investor-owned electric utility includes a track record of 100 years of paying dividends to our shareholders and is grounded in our ability to continue delivering reliable, reasonably priced electricity. Approximately 70 percent of our outstanding shares are owned by investors who have an investment horizon of greater than two years. Because of this, we hope that these investors understand our commitment to being a sustainable company is also in their long-term financial interest. Our challenge remains that many investors and analysts still focus on quarterly earnings rather than long-term performance related to sustainability. Analysts are beginning to pay attention to sustainability issues, particularly environmental issues. However, generally they are not factoring them into their recommendations with any regularity, unlike SRIs.

We continue to explain our sustainability agenda with traditional investors while also meeting the social objectives of SRIs. We make an effort to increase AEP's inclusion in various sustainability-focused market indexes. In January 2010, we learned that AEP was included in the Maplecroft Climate Innovation Index (CII) Leaders, which includes the top 100 performers in the Maplecroft CII. This index evaluates and rates company performance in climate-related innovation and carbon management. Read more about our investor outreach at ***www.AEPsustainability.com***.

ASSISTANCE PROVIDED IN 2009 TO HELP CUSTOMERS PAY THEIR ELECTRIC BILLS

Company	Government Programs	Private Programs	Total Funds
Appalachian Power	$35,278,265	$655,129	$35,933,394
Kentucky Power	$4,334,503	—	$4,334,503
Indiana Michigan Power	$9,192,443	$52,438	$9,244,881
AEP Ohio	$18,991,427	$2,111,842	$21,103,269
Public Service Company of Oklahoma	$8,451,354	$1,964,409	$10,415,763
Southwestern Electric Power Co.	$4,784,118	$348,461	$5,132,579
Totals	**$81,032,110**	**$5,132,279**	**$86,164,389**

CONNECTING WITH CUSTOMERS

Customer communications is a critical issue. Our customer service centers handle approximately 50,000 calls daily; in 2009, we responded to 17.8 million calls. When customers called us in 2009, they waited an average of 48 seconds before speaking with an AEP representative — up slightly from 47 seconds in 2008. Many more customers reached us online through our customer service websites. In 2009, registered customers logged in more than 2 million times to conduct business.

We receive quarterly data on customer satisfaction from Market Strategies International, an independent vendor that conducts benchmarking for a peer group of more than 100 electric and gas utilities. In 2009, five of AEP's seven operating companies placed in the first quartile relative to the national peer group in residential overall satisfaction; six of our operating companies placed in the first quartile for commercial overall satisfaction.

We saw the economic downturn affect our customers in 2009. While customer consumption of electricity declined, more customers had difficulty paying their bills. Account delinquencies among residential customers increased 6 percent from 2008. The hardship was not so severe for nonresidential customers, whose average delinquent account balances declined 7 percent from 2008.

As a result, we increased our support for low-income energy assistance programs. The primary source of assistance for low-income customers is LIHEAP. In 2009, AEP customers received more than $86 million from these programs. The total assistance received by customers was approximately 91 percent higher than in 2008.

The primary reason for this unusual increase was that LIHEAP became fully funded at $5.1 billion for the first time in history during the 2008–2009 heating season. In prior years, funding for this program ranged between $1.8 billion and $3 billion.

ENGAGING OUR EMPLOYEES

Our employees are our most valuable resource and our most passionate advocates; we stay connected with them in many ways — new and old. We now host 12 internal blogs — twice what we had in 2008 — that give employees an additional opportunity to voice their opinions and that allow our leaders and managers to respond or introduce topics of their own. One blog is hosted by Mike Morris, our chairman, president and chief executive officer. He focuses on the company's performance as well as how factors such as the economy or global climate change are affecting the company. Other blogs are devoted to sustainability, ethics and compliance, transmission and other business issues.

2009 CUSTOMER SATISFACTION RESULTS

Survey Type	% Satisfied	Quartile Ranking vs. National Peer Group
Residential	83.8%	1st
Commercial	90.9%	1st
Managed/Key Accounts	79.7%	1st
Call Center Transactions	87.4%	NA

We held our first employee Sustainability Awareness Week in 2009 to highlight our material issues and how they relate to AEP's sustainability. More than 60 events at 38 work locations in nine states were held, including test drives of Plug-in Hybrid Electric Vehicles, health screenings, electronic equipment recycling, developing energy efficiency e-cards, and town hall meetings. As a result of these and other activities, 67 percent of employees who responded to a follow-up survey said they understood AEP's strategy for sustainability and how they contribute to it.

ENGAGING OUR COMMUNITIES

Our employees donated more than 78,000 hours of volunteer service to dozens of organizations and educational institutions on their own time during 2009. We support these activities with $150 AEP Connects volunteer grants to an organization to which an employee has donated at least 40 hours *during the year. We made 894 grants* totaling more than $134,000 in 2009. The hours donated by our employees have an economic value of more than $1.5 million (using the Independent Sector estimated value of volunteer time of $20.25 per hour) and an indirect contribution that is much greater.

Education is an important community endeavor, and we provide small grants to teachers to support them in the classroom. These Teacher Vision Grants range from $100 to $500 and are provided to educators in grades pre-K through 12 who live or teach in AEP's service area or in communities with major AEP facilities. In 2009, we awarded nearly $53,000 in Teacher Vision Grants.

ENGAGING POLICY LEADERS

Being a large, highly regulated electric utility requires us to engage frequently with policymakers, legislators and other elected officials as well as regulators. We do so at the federal, state and local levels. We also engage internationally through the e8, at the international climate change negotiations, and through the World Business Council for Sustainable Development. Read more about our engagement with policy leaders in *Public Policy.*

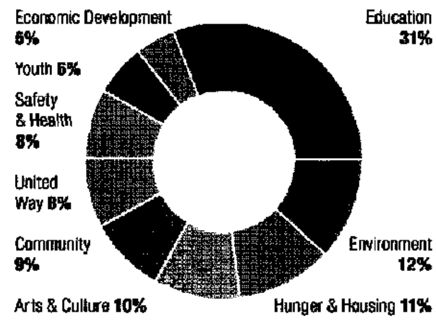
***CONTRIBUTING TO* ECONOMIC PROSPERITY**

We are committed to the prosperity of the communities we serve and in which we operate. Our operating companies partner with state and local organizations to provide economic development grants and work with communities and other companies to create jobs and spur economic growth. In 2009, we provided more than $1 million to nearly 200 organizations. Learn about our efforts at ***www.AEPsustainability.com.***

CHARITABLE GIVING

In addition to economic development grants, in 2009 the company and the American Electric Power Foundation provided more than $23.4 million in charitable giving. These social investments are most important during difficult economic times, particularly in communities hit hardest by the recession. We donated $11.8 million to hundreds of local and nonprofit organizations. The AEP Foundation contributed $11.6 million to 111 organizations. ■

2009 GIVING BY AREA OF FOCUS



TOTAL PHILANTHROPIC GIVING
(Corporate and AEP Foundation)

State	2009
Arkansas	$354,920
Indiana	$2,228,164
Kentucky	$650,000
Louisiana	$421,884
Michigan	$1,257,338
Ohio	$10,434,443
Oklahoma	$843,409
Tennessee	$30,048
Texas	$2,315,510
Virginia	$2,160,028
West Virginia	$1,060,218
Other*	$1,662,209
Total	**$23,418,171**

*Giving to organizations outside AEP's service area or those that benefit multiple states

TIM MOSHER

President & chief operating officer, Kentucky Power Co.

"Reliability and reasonable pricing are two of the most important aspects of providing service to our customers. Our customers expect consistent, safe and reliable service at an affordable price. It is important for us to regularly measure how we're doing relative to those expectations with satisfaction surveys. Listening to our stakeholders' perspectives is another excellent way to understand how our performance is perceived. It makes sense for us to do that; to operate in a vacuum would be a colossal mistake."

Corporate & Shareholder Information

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing: The Company's common stock is traded principally on the New York Stock Exchange under the ticker symbol AEP.

Internet Home Page: Information about AEP, including financial documents, Securities and Exchange Commission filings, news releases, investor presentations, shareholder information and customer service information, is available at *www.AEP.com*.

Inquiries Regarding Your Stock Holdings: Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
Telephone Response Group: 1-800-328-6955
Internet address: ***www.computershare.com/investor***
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders: (Stock held in a bank or brokerage account) — When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment & Direct Stock Purchase Plan: A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent.

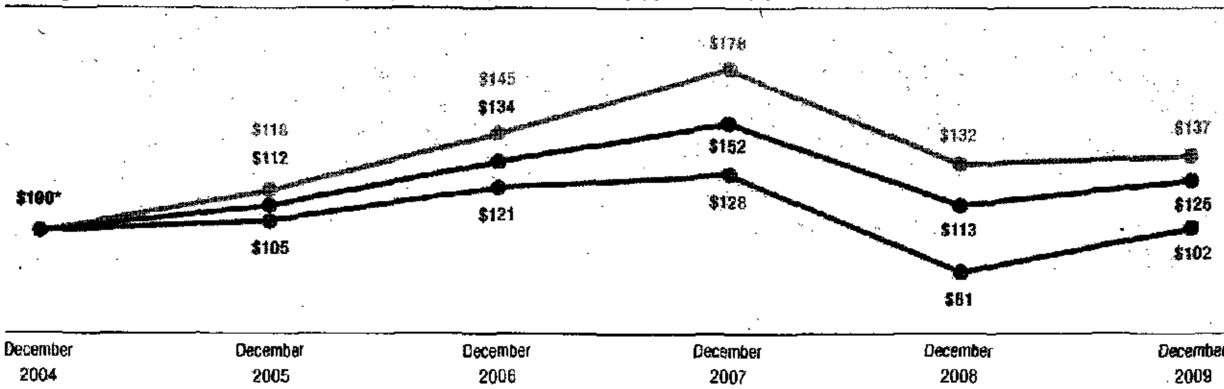
Financial Community Inquiries: Institutional investors or securities analysts who have questions about the Company should direct inquiries to Bette Jo Rozsa, 614-716-2840, *bjrozsa@AEP.com;* Julie Sherwood, 614-716-2663, *jasherwood@AEP.com;* or Jana Croom, 614-716-3175, *jtcroom@AEP.com.* Individual shareholders should contact Kathleen Kozero, 614-716-2819, *klkozero@AEP.com*.

Number of Shareholders: As of Dec. 31, 2009, there were approximately 96,000 registered shareholders and approximately 271,000 shareholders holding stock in street name through a bank or broker. There were 478,054,407 shares outstanding at Dec. 31, 2009.

Form 10-K: Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended Dec. 31, 2009. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at *klkozero@AEP.com*.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN

Among American Electric Power Co., Inc., The S&P 500 Index & The S&P Electric Utilities Index



*$100 invested on 12/31/04 in stock or index, including reinvestment of dividends.
Fiscal year ending Dec. 31.

GRI TABLE OF CONTENTS / KEY INDICATORS

Key: CAR 2010 = Report Page Number
EU = Electric Utility Sector Supplement

Note: All GRI information and data are on the Web unless noted below

CAR 2010

CAR 2010

Electric Utility Sector Supplement Index

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load and customer growth.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation (including our dispute with Bank of America).
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities.
- Changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

AEP

AMERICAN®
ELECTRIC
POWER

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1 Riverside Plaza
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