Large Filing Separator Sheet

CASE NUMBER: 10 - 268 - EL - FAC
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SECTION: 2 OF 2

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IEU-Ohio Exhibit 1

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-02 Section 7-71 of the 2010 Audit Report states, "In data request LA-2010-2-130, Larkin asked for a summary of the non-energy components related to Lawrenceburg that were included in the FAC during 2010 and to also show how the capacity factor associated with Lawrenceburg was derived. In response, AEP Ohio provided a schedule which showed a breakout (by amount and account) of the Lawrenceburg related costs included in the FAC for each month of 2010." Produce a copy of the schedule that shows the "Lawrenceburg related costs included in the FAC for each month of 2010."

RESPONSE

See LA-2010-2-130 on the enclosed CD.

Lawrenceburg Non-Energy Components included in CSP Fuel Cost

Account	Jan	Feb	Mar	Apr	May
5550105	$ 3,047,847.00	$ 3,047,847.00	$ 3,047,847.00	$ 3,047,847.00	$ 3,047,847.00
5550104	$ (153,129.00)	$ (153,129.00)	$ (153,129.00)	$ (153,129.00)	$ (153,129.00)
5550046	$ 17,237.00	$ 15,696.00	$ 9,995.00	$ 12,335.00	$ 11,489.00
5550086	$ 970,750.63	$ 964,584.21	$ 1,239,019.57	$ 1,512,445.33	$ 1,284,435.51
5550087	$ 1,201,981.18	$ 749,616.03	$ 1,187,080.55	$ 577,049.44	$ 744,153.41
	$ 5,084,686.81	$ 4,624,614.24	$ 5,330,813.12	$ 4,996,547.77	$ 4,934,795.92

Jun	Jul	Aug	Sep	Oct	Nov
$ 3,047,847.00	$ 3,047,847.00	$ 3,047,847.00	$ 3,047,847.00	$ 3,047,847.00	$ 3,047,847.00
$ (153,129.00)	$ (153,129.00)	$ (153,129.00)	$ (153,129.00)	$ (153,129.00)	$ (153,129.00)
$ 17,854.00	$ 22,374.00	$ 18,313.00	$ 18,286.00	$ 23,217.00	$ 17,483.00
$ 1,971,439.13	$ 1,361,817.19	$ 1,124,907.11	$ 1,266,120.67	$ 1,388,452.31	$ 1,035,253.86
$ 760,137.85	$ 753,394.32	$ 738,070.51	$ 787,719.78	$ 860,300.09	$ 978,807.98
$ 5,644,148.98	$ 5,032,303.51	$ 4,776,008.62	$ 4,966,844.45	$ 5,166,687.40	$ 4,926,262.84

Dec	Total
$ 3,047,847.00	$ 36,574,164.00
$ (153,129.00)	$ (1,837,548.00)
$ 217,605.00	$ 401,884.00
$ 1,608,361.04	$ 15,727,586.56
$ 931,621.83	$ 10,269,932.97
$ 5,652,305.87	$ 61,136,019.53

IEU-Ohio Exhibit 2

		ACTUAL CYCLE					EXH CSP-1	
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)						
		JANUARY 2010						
Line	A	B	C	D	E	F	G	H
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail
2					Assigned	Assigned	Allocation	FAC Cost
3	Account	Description	Notes	Total	Off-System	To Firm Load		
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 24,183,342	$ 3,694,017	$ 20,489,325		
6	5010009	Fuel Consumed - No Load (CV4)	(2)			-		
7	5010013	Fuel Survey Activity	(2)	-	-	-		
8	5010019	Fuel Oil Consumed	(2)	513,262		513,262		
9	5010020/5010036	Natural Gas Consumed	(2)	18,269	-	18,269		
10	5470001	Fuel - Gas Turbine	(2)	-	-	-		
11		**Subtotal - Generation Fuel**		**$ 24,714,873**	**$ 3,694,017**	**$ 21,020,856**		
12	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	(3)	$ 1,344,091	$ 169,204	$ 1,174,887		
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	21,224,897	-	21,224,897		
15	5550080	PJM Energy Purchases (Fuel)	(3)	4,376,054	4,059,440	316,614		
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	1,294,782	791,180	503,602		
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	54,185	53,000	1,185		
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	(3)	101,369	8,953	92,416		
19	5550032	Purchased Pwr - Mone (Fuel)	(3)	-	-	-		
20		**Subtotal - Purchased Power Fuel**		**$ 28,395,378**	**$ 5,081,777**	**$ 23,313,601**		
21		**Total NEC Fuel**		**$ 53,110,251**	**$ 8,775,794**	**$ 44,334,457**	100.000%	$ 44,334,457
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount		
24	Emission Allowance Expense				EXH CSP 2			
25	5090000/2	Allowance Consumption - SO2	(1)	$ 499,853	91.79%	$ 458,815		
26	5090001	Allowance Consumption - Seasonal NOx	(1)		91.79%	-		
27	5090005	Allowance Expenses - Annual NOx	(1)	47,558	91.79%	43,654		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)		91.79%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)	$ 196	91.79%	$ 179		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)		91.79%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)		91.79%	-		
33	4119000	Loss Disposition of Allowances	(1)		91.79%	-		
34		**Total Allowance Dollars**		**$ 547,607**		**$ 502,648**	100.000%	$ 502,648
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC				
36						Firm Load		
37	Account	Description	Notes		Allocation Factor	Allocated Amount		
38	Incremental Fuel Handling/Ash/Gypsum				EXH CSP 2			
39	5010000	Fuel (Ash Handling)	(1)	$ 107,615	91.79%	$ 98,780	100.000%	$ 98,780
40	5010003	Fuel - Procurement, Unloading & Handling	(1)	775,558	91.79%	711,884	100.000%	$ 711,884
41	5010011	Fuel Handling - No Load (CV4)	(1)	19,985	91.79%	18,344	100.000%	$ 18,344
42	5010012	Ash Sales Proceeds	(1)	(23,530)	91.79%	(21,598)	100.000%	$ (21,598)
43	5010027	Gypsum handling/disposal costs	(1)	75,539	91.79%	69,337	100.000%	$ 69,337
44	5010028	Gypsum Sales Proceeds	(1)	(31,060)	91.79%	(28,510)	100.000%	$ (28,510)
45	5010032	Coal Procurement-Aff	(1)		91.79%	-	100.000%	$ -
46	5010033	Coal Procurement-NA	(1)		91.79%	-	100.000%	$ -
47	Incremental purchased power - Non Fuel			PSUM	PSUM			
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	(3)	$ -	$ -	$ -	100.000%	$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	148,060	13,764	134,295	100.000%	$ 134,295
50	5550032 - in part	PP - Mone - Non-Fuel	(3)	14,639	-	14,639	100.000%	$ 14,639
51	5550098 INACTIVE	PP - PJM - Non-Fuel	(3)		-	-	100.000%	$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	(3)		-	-	100.000%	$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source OVEC bill)	(3)	842,688	100%	842,688	100.000%	$ 842,688
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	(1)	3,607,040	100%	3,607,040	100.000%	$ 3,607,040
55	5550004	Purchased Power - Pool Capacity	(1)		100%	-	100.000%	$ -
56	5550023	Purchase Power - Capacity	(1)	175,851	100%	175,851	100.000%	$ 175,851
57	5550040	PJM Inadvertent - LSE (only)	(1)	(40,419)	100%	(40,419)	100.000%	$ (40,419)
58	5550093	Peak Hour Avail Charge - LSE	(1)		100%	-	100.000%	$ -
59	Lawrenceburg purchased power - Non-Fuel							
60	5550105	Depr & Capacity portion-Affil (Lawrenceburg)	(1)	$ 3,047,847	100%	$ 3,047,847	100.000%	$ 3,047,847
61	5550104	Defd Depr & Capacity portion-Affil (Lawrenceburg)	(1)	(153,129)	100%	(153,129)	100.000%	$ (153,129)
62	5550046 - in part	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)	(3) (5)	17,237	81.34%	14,020	100.000%	$ 14,020
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)	(1) (5)	970,751	81.34%	789,580	100.000%	$ 789,580
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)	(1) (5)	1,201,981	81.34%	977,656	100.000%	$ 977,656
65	Renewables							
66	5550047	Purchased Power - Wind	(1)	$ 1,041,502	100%	1,041,501	100.000%	$ 1,041,501
67	5550109	Purchased Power - Solar	(1)		100%	$ -	100.000%	$ -
68	5570007	Renewable Energy Credit Exp.	(1)	1,797	100%	$ 1,797	100.000%	$ 1,797
69	5570008	Renewable Energy Credit Exp. (Green Power)	(1)		100%	$ -	100.000%	$ -
70	Environmental Material & Expense							
71	5020001	Lime Expense	(1)	$ 1,292,656	91.79%	$ 1,186,529	100.000%	$ 1,186,529
72	5020002	Urea Expense	(1)	108,995	91.79%	100,047	100.000%	$ 100,047
73	5020003	Trona Expense	(1)	144,543	91.79%	132,676	100.000%	$ 132,676
74	5020004	Limestone Expense	(1)	185,858	91.79%	170,599	100.000%	$ 170,599
75	5020005	Polymer expense	(1)	31	91.79%	28	100.000%	$ 28
76	5020007	Lime Hydrate Expense	(1)	14,558	91.79%	13,363	100.000%	$ 13,363
77	5020007	Activated Carbon	(1)	7	91.79%	6	100.000%	$ 6
78	5020025	Steam Exp Environmental	(1)	261	91.79%	240	100.000%	$ 240
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
80	5550035	PJM Normal Purchases (Non ECR OSS)	(1)		0%	$ -		
81	5550039	PJM Inadvertent - OSS (only)	(1)	(2,893)	0%	-		
82	5550088	PJM Capacity Charge (OSS only)	(1)		0%	-		
83	5550099	PJM Purchases - NonECR (Auction)	(1)	2,957,798	0%	-		
84	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	228,156	0%	-		
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)	(1)	10,512,743	0%	-		
86	5550107	Capacity Purchases -Trading	(1)	321,417	0%	-		
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)	(1)		0%	-		
88	5550069	PP - Monon. Power (2008 PPA only)	(1)		0%	-		
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
90	5550075	PJM Reactive Credit	(1)	$ (495,105)	0%	$ -		
91	5550077	PJM Black Start Credit	(1)	(5,004)	0%	-		
92	5550079	PJM Regulation Credit	(1)	(271,083)	0%	-		
93	5550084	PJM Spinning Reserve Credit	(1)	(9,744)	0%	-		
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)		0%	-		
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
96	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ 52,521	0%	$ -		
97	5550041	PJM Synchronous Cond. Charge	(1)	4,763	0%	-		
98	5550074	PJM Reactive Charge	(1)	538,702	0%	-		
99	5550076	PJM BlackStart Charge	(1)	11,067	0%	-		
100	5550078	PJM Regulation Charge	(1)	874,461	0%	-		
101	5550083	PJM Spinning Reserve Charge	(1)	82,356	0%	-		
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	45	0%	-		
103		**Total Additional FAC**		**$ 28,347,058**		**$ 12,905,090**		**$ 12,905,090**
104		**TOTAL**		$ 82,004,916		$ 57,742,195		$ 57,742,195
105								
106	NOTATIONS:							
107	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
108	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
109	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
110	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
111	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						PIVOT
112								82,804,474

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

JANUARY 2010

Line	A	B	C	D	E	F	G	H
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			Net Energy Cost (NEC) in EFC				
2					Assigned	Assigned	Retail	Retail
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 124,774,693	$ 63,824,171	$ 60,950,522		
6	5010009	Fuel Consumed - No Load (CV4)	(2)			-		
7	5010013	Fuel Survey Activity	(2)	-		-		
8	5010019	Fuel Oil Consumed	(2)	1,157,496		1,157,496		
9	5010020	Natural Gas Consumed	(2)			-		
10	5010022	Fuel Consumed - Sawdust	(2)	-		-		
11	5470001	Fuel - Gas Turbine	(2)			-		
12		Subtotal - Generation Plant		$ 125,932,189	$ 63,824,171	$ 62,108,018		
13	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	(3)	$ 4,543,850	$ 211,689	$ 4,332,161		
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	-	-	-		
16	5550080	PJM Energy Purchases (Fuel)	(3)	5,095,449	4,726,786	368,663		
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	1,507,630	921,243	586,387		
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	63,093	61,712	1,381		
19	5550031/32	Purchased Pwr - Mone (Fuel)	(3)	-	-	-		
20		Subtotal - Purchased Power Fuel		$ 11,210,022	$ 5,921,430	$ 5,288,592		
21		Total NEC Fuel		$ 137,142,211	$ 69,745,601	$ 67,396,610	92.085%	$ 62,062,168
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt		
24	Emission Allowance Expense				EXH CSP 2			
25	5090000	Allowance Consumption SO2	(1)	$ 425,243	49.70%	$ 211,346		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	-	49.70%	-		
27	5090005	Allowance Expenses - Annual NOx	(1)	-	49.70%	-		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)		49.70%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)	228	49.70%	113		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)	-	49.70%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)	(145,930)	49.70%	(72,527)		
33	4119000	Loss Disposition of Allowances	(1)		49.70%	-		
34	4119002	Comp. Allow. Loss - SO2	(1)	-	49.70%	-		
35		Total Allowance Dollars		$ 279,541		$ 138,932	92.085%	$ 127,935
36	**Additional S.B. 221 FAC Accounts Forecast for 2009**			Additional Fuel and Environmental Accounts in FAC				
37						Firm Load		
38	Account	Description	Notes		Allocation Factor	Allocated Amount		
39	Incremental Fuel Handling/Ash/Gypsum				EXH CSP 2			
40	5010000	Fuel (Ash Handling)	(1)	$ 1,356,271	49.70%	$ 674,067	92.085%	$ 620,715
41	5010003	Fuel - Procurement, Unloading & Handling	(1)	3,695,339	49.70%	1,836,583	92.085%	$ 1,691,218
42	5010012	Ash Sales Proceeds	(1)	(41,290)	49.70%	(20,521)	92.085%	$ (18,897)
43	5010027	Gypsum handling/disposal costs	(1)	309,612	49.70%	153,877	92.085%	$ 141,698
44	5010028	Gypsum Sales Proceeds	(1)	(106,061)	49.70%	(52,712)	92.085%	$ (48,540)
45	5010029	Gypsum handling/displ-Affiliat	(1)	111,107	49.70%	55,220	92.085%	$ 50,849
46	Incremental purchased power - Non Fuel			PSUM	PSUM			
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	(3)	$ -	-	$ -	92.085%	$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	513,759	17,643	496,116	92.085%	$ 456,848
49	5550032	PP - Mone - Non-Fuel	(3)	17,046	-	17,046	92.085%	$ 15,697
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	(3)	-	-	-	92.085%	$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	(3)	-	-	-	92.085%	$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:OVEC bill)	(3)	2,939,917	100%	2,939,917	92.085%	$ 2,707,223
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	(1)	-	100%		92.085%	$ -
54	5550023	PP Capacity - Non Affil.	(1)	204,760	100%	204,760	92.085%	$ 188,553
55	5550040	PJM Inadvertent - LSE (only)	(1)	(47,064)	100%	(47,064)	92.085%	$ (43,338)
56	5550003	PP - Cogeneration	(1)	-	100%	-	92.085%	$ -
57	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	92.085%	$ -
58	Lawrenceburg purchased power - Non-Fuel (NA)							
59	Renewables							
60	5550047	Purchased Power - Wind	(1)	1,041,502	100%	$ 1,041,502	100.00%	$ 1,041,502
61	5550109	Purchased Power - Solar Energy	(1)		100%	-	100.00%	$ -
62	5570007	Other Pwr Exp - RECs	(1)	2,092	100%	2,092	100.00%	$ 2,092
63	5570008	Renewable Energy Credit Exp.	(1)		100%	-	100.00%	$ -
64	Environmental Material & Expense							
65	5020001	Lime Expense	(1)	$ 3,499,351	49.70%	$ 1,739,177	92.085%	$ 1,601,522
66	5020002	Urea Expense	(1)	2,014,938	49.70%	1,001,424	92.085%	$ 922,161
67	5020003	Trona Expense	(1)	760,285	49.70%	377,861	92.085%	$ 347,954
68	5020004	Limestone Expense	(1)	1,426,431	49.70%	708,936	92.085%	$ 652,824
69	5020005	Polymer expense	(1)	334,695	49.70%	166,343	92.085%	$ 153,177
70	5020007	Lime Hydrate Expense	(1)	(127)	49.70%	(63)	92.085%	$ (58)
71	5020008	Activated Carbon	(1)	28	49.70%	14	92.085%	$ 13
72	5020025	Steam Exp Environmental	(1)	59,587	49.70%	29,615	92.085%	$ 27,271
73	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
74	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -	92.085%	$ -
75	5550039	PJM Inadvertent - OSS (only)	(1)	(3,369)	0%	-	92.085%	$ -
76	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-	92.085%	$ -
77	5550099	PJM Purchases - NonECR (Auction)	(1)	3,444,041	0%	-	92.085%	$ -
78	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	265,663	0%	-	92.085%	$ -
79	5550102	PP Pool Non Fuel - OSS Aff	(1)	9,463,977	0%	-	92.085%	$ -
80	5550107	Capacity Purchases - Trading	(1)	374,256	0%	-	92.085%	$ -
81	5550002	PP - Assocated (PPA only - discontinued after Jan09)	(1)	-	0%	-	92.085%	$ -
82	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
83	5550075	PJM Reactive Credit	(1)	$ (576,497)	0%	$ -	92.085%	$ -
84	5550077	PJM Black Start Credit	(1)	(5,827)	0%	-	92.085%	$ -
85	5550079	PJM Regulation Credit	(1)	(315,648)	0%	-	92.085%	$ -
86	5550084	PJM Spinning Reserve Credit	(1)	(11,345)	0%	-	92.085%	$ -
87	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-	92.085%	$ -
88	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
89	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ 61,155	0%	$ -	92.085%	$ -
90	5550041	PJM Synchronous Cond. Charge	(1)	5,547	0%	-	92.085%	$ -
91	5550074	PJM Reactive Charge	(1)	627,261	0%	-	92.085%	$ -
92	5550076	PJM BlackStart Charge	(1)	12,886	0%	-	92.085%	$ -
93	5550078	PJM Regulation Charge	(1)	1,018,216	0%	-	92.085%	$ -
94	5550083	PJM Spinning Reserve Charge	(1)	95,895	0%	-	92.085%	$ -
95	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	53	0%	-	92.085%	$ -
96		Total Additional FAC		$ 32,548,442		$ 11,324,192		$ 10,510,482
97		TOTAL		$ 169,970,194		$ 78,859,734		$ 72,700,586
98								
99	NOTATIONS:							
100	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
101	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
102	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
103	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys (ECR))						
104	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						
105								

ACTUAL CYCLE | **EXH CSP-1**

COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)

FEBRUARY 2010

Line	A	B	C	D	E	F	G	H
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail
2					Assigned	Assigned	Allocation	FAC Cost
3	Account	Description	Notes	Total	Off-System	To Firm Load		
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 26,893,690	$ 4,393,842	$ 22,499,848		
6	5010009	Fuel Consumed - No Load (CV4)	(2)	504,273		504,273		
7	5010013	Fuel Survey Activity	(2)	-	-	-		
8	5010019	Fuel Oil Consumed	(2)	238,340		238,340		
9	5010020/5010036	Natural Gas Consumed	(2)	40,286	-	40,286		
10	5470001	Fuel - Gas Turbine	(2)	-	$ -	-		
11		Subtotal - Generation Fuel		$ 27,676,589	$ 4,393,842	$ 23,282,747		
12	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	(3)	$ 1,081,508	$ 70,273	$ 1,011,235		
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	15,322,267	-	15,322,267		
15	5550080	*PJM Energy Purchases (Fuel)*	(3)	*2,223,826*	*2,054,405*	*169,421*		
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	5,577,199	5,257,158	320,041		
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	64,550	53,078	11,472		
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	(3)	21,658	-	21,658		
19	5550032	Purchased Pwr - Mone (Fuel)	(3)	3,078	3,078	-		
20		Subtotal - Purchased Power Fuel		$ 24,294,086	$ 7,437,992	$ 16,856,094		
21		Total NEC Fuel		$ 51,970,675	$ 11,831,834	$ 40,138,841	100.000%	$ 40,138,841
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount		
24	Emission Allowance Expense				EXH CSP 2			
25	5090000/2	Allowance Consumption - SO2	(1)	$ 278,503	89.65%	$ 249,678		
26	5090001	Allowance Consumption - Seasonal NOx	(1)		89.65%	-		
27	5090005	Allowance Expenses - Annual NOx	(1)	48,044	89.65%	43,071		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)		89.65%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)		89.65%	$ -		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)		89.65%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)		89.65%	-		
33	4119000	Loss Disposition of Allowances	(1)		89.65%	-		
34		Total Allowance Dollars		$ 326,547		$ 292,749	100.000%	$ 292,749
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC				
36						Firm Load		
37	Account	Description	Notes		Allocation Factor	Allocated Amount		
38	Incremental Fuel Handling/Ash/Gypsum				EXH CSP 2			
39	5010000	Fuel (Ash Handling)	(1)	$ 1,150,131	89.65%	$ 1,031,092	100.000%	$ 1,031,092
40	5010003	Fuel - Procurement, Unloading & Handling	(1)	786,220	89.65%	704,846	100.000%	$ 704,846
41	5010011	Fuel Handling - No Load (CV4)	(1)	11,280	89.65%	10,113	100.000%	$ 10,113
42	5010012	Ash Sales Proceeds	(1)	(16,866)	89.65%	(15,121)	100.000%	$ (15,121)
43	5010027	Gypsum handling/disposal costs	(1)	132,787	89.65%	119,043	100.000%	$ 119,043
44	5010028	Gypsum Sales Proceeds	(1)	(33,465)	89.65%	(30,001)	100.000%	$ (30,001)
45	5010032	Coal Procurement-Aff	(1)		89.65%	-	100.000%	$ -
46	5010033	Coal Procurement-NA	(1)		89.65%	-	100.000%	$ -
47	Incremental purchased power - Non Fuel			PSUM	PSUM			
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	(3)	$ -	$ -	$ -	100.000%	$ -
49	*5550096 - in part*	*PP - Non Trade - Non-Fuel (OVEC, 3rd party)*	(3)	*254,589*	*6,770*	247,819	100.000%	$ 247,819
50	5550032	PP - Mone - Non-Fuel	(3)	15,697	15,697	(0)	100.000%	$ (0)
51	5550098 INACTIVE	PP - PJM - Non-Fuel	(3)		-	-	100.000%	$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	(3)		-	-	100.000%	$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)	(3)	978,537	100%	978,537	100.000%	$ 978,537
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	(1)	542,446	100%	542,446	100.000%	$ 542,446
55	5550004	Purchased Power - Pool Capacity	(1)	640,362	100%	640,362	100.000%	$ 640,362
56	5550023	Purchase Power - Capacity	(1)	179,800	100%	179,800	100.000%	$ 179,800
57	5550040	PJM Inadvertent - LSE (only)	(1)	(30,593)	100%	(30,593)	100.000%	$ (30,593)
58	5550093	Peak Hour Avail Charge - LSE	(1)		100%	-	100.000%	$ -
59	Lawrenceburg purchased power - Non-Fuel							
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)	(1)	$ 3,047,847	100%	$ 3,047,847	100.000%	$ 3,047,847
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)	(1)	(153,129)	100%	(153,129)	100.000%	$ (153,129)
62	5550046 in part	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)	(3) (5)	15,696	100.00%	15,696	100.000%	$ 15,696
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)	(1) (5)	964,584	100.00%	964,584	100.000%	$ 964,584
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)	(1) (5)	749,616	100.00%	749,616	100.000%	$ 749,616
65	Renewables							
66	5550047	Purchased Power - Wind	(1)	$ 802,557	100%	802,556	100.000%	$ 802,556
67	5550109	Purchased Power - Solar	(1)		100%	$ -	100.000%	$ -
68	5570007	Renewable Energy Credit Exp.	(1)	(550,755)	100%	$ (550,755)	100.000%	$ (550,755)
69	5570008	Renewable Energy Credit Exp. (Green Power)	(1)	666,182	100%	$ 666,182	100.000%	$ 666,182
70	Environmental Material & Expense							
71	5020001	Lime Expense	(1)	$ 1,725,302	89.65%	$ 1,546,733	100.000%	$ 1,546,733
72	5020002	Urea Expense	(1)	245,874	89.65%	220,426	100.000%	$ 220,426
73	5020003	Trona Expense	(1)	88,701	89.65%	79,521	100.000%	$ 79,521
74	5020004	Limestone Expense	(1)	361,695	89.65%	324,260	100.000%	$ 324,260
75	5020005	Polymer expense	(1)	122	89.65%	110	100.000%	$ 110
76	5020007	Lime Hydrate Expense	(1)	8,164	89.65%	7,319	100.000%	$ 7,319
77	5020008	Activated Carbon	(1)	(4)	89.65%	(3)	100.000%	$ (3)
78	5020025	Steam Exp Environmental	(1)	(10)	89.65%	(9)	100.000%	$ (9)
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
80	5550035	PJM Normal Purchases (Non ECR OSS)	(1)		0%	$ -		
81	5550039	PJM Inadvertent - OSS (only)	(1)	(1,716)	0%	-		
82	5550088	PJM Capacity Charge (OSS only)	(1)		0%	-		
83	5550099	*PJM Purchases - NonECR (Auction)*	(1)	1,959,260	0%	-		
84	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	233,791	0%	-		
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)	(1)	7,275,683	0%	-		
86	5550107	Capacity Purchases -Trading	(1)	103,469	0%	-		
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)	(1)		0%	-		
88	5550069	PP - Monon. Power (2008 PPA only)	(1)		0%	-		
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
90	5550075	PJM Reactive Credit	(1)	$ (506,223)	0%	$ -		
91	5550077	PJM Black Start Credit	(1)	(5,117)	0%	-		
92	5550079	PJM Regulation Credit	(1)	(108,542)	0%	-		
93	5550084	PJM Spinning Reserve Credit	(1)	(10)	0%	-		
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)		0%	-		
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
96	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ 17,552	0%	$ -		
97	5550041	PJM Synchronous Cond. Charge	(1)	1,717	0%	-		
98	5550074	PJM Reactive Charge	(1)	496,354	0%	-		
99	5550076	PJM BlackStart Charge	(1)	10,494	0%	-		
100	5550078	PJM Regulation Charge	(1)	676,969	0%	-		
101	5550083	PJM Spinning Reserve Charge	(1)	23,771	0%	-		
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	44	0%	-		
103		Total Additional FAC		$ 22,760,865		$ 12,099,296		$ 12,099,296
104		TOTAL		$ 75,058,087		$ 52,530,887		$ 52,530,887
105								
106	NOTATIONS:							
107	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
108	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
109	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
110	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
111	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						PIVOT
112								74,405,410

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

FEBRUARY 2010

Line	A	B	C	D	E	F	G	H
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			Net Energy Cost (NEC) in EFC				
2					Assigned	Assigned	Retail	Retail
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 103,552,799	$ 50,900,352	$ 52,652,447		
6	5010009	Fuel Consumed - No Load (CV4)	(2)			-		
7	5010013	Fuel Survey Activity	(2)	(659,523)		(659,523)		
8	5010019	Fuel Oil Consumed	(2)	1,250,280		1,250,280		
9	5010020	Natural Gas Consumed	(2)			-		
10	5010022	Fuel Consumed - Sawdust	(2)	-		-		
11	5470001	Fuel - Gas Turbine	(2)			-		
12		Subtotal - Generation Plant		$ 104,143,556	$ 50,900,352	$ 53,243,204		
13	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	(3)	$ 3,645,208	$ 92,811	$ 3,552,397		
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	2,030	-	2,030		
16	5550080	PJM Energy Purchases (Fuel)	(3)	2,559,312	2,364,329	194,983		
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	6,418,557	6,050,240	368,317		
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	74,288	61,085	13,203		
19	5550031/32	Purchased Pwr - Mone (Fuel)	(3)	3,542	3,542	-		
20		Subtotal - Purchased Power Fuel		$ 12,702,937	$ 8,572,007	$ 4,130,930		
21		Total NEC Fuel		$ 116,846,493	$ 59,472,359	$ 57,374,134	92.087%	$ 52,834,119
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt		
24	Emission Allowance Expense				EXH CSP 2			
25	5090000	Allowance Consumption SO2	(1)	$ 353,391	51.98%	$ 183,693		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	-	51.98%	-		
27	5090005	Allowance Expenses - Annual NOx	(1)	10,078	51.98%	5,239		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)		51.98%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)	-	51.98%	-		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)	-	51.98%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)	-	51.98%	-		
33	4119000	Loss Disposition of Allowances	(1)		51.98%	-		
34	4119002	Comp. Allow. Loss - SO2	(1)	-	51.98%	-		
35		Total Allowance Dollars		$ 363,469		$ 188,931	92.087%	$ 173,981
36	**Additional S.B. 221 FAC Accounts Forecast for 2009**			Additional Fuel and Environmental Accounts in FAC				
37						Firm Load		
38	Account	Description	Notes		Allocation Factor	Allocated Amount		
39	Incremental Fuel Handling/Ash/Gypsum				EXH CSP 2			
40	5010000	Fuel (Ash Handling)	(1)	$ 1,053,875	51.98%	$ 547,804	92.087%	$ 504,456
41	5010003	Fuel - Procurement, Unloading & Handling	(1)	3,286,083	51.98%	1,708,106	92.087%	$ 1,572,944
42	5010012	Ash Sales Proceeds	(1)	(107,175)	51.98%	(55,709)	92.087%	$ (51,301)
43	5010027	Gypsum handling/disposal costs	(1)	381,226	51.98%	198,161	92.087%	$ 182,481
44	5010028	Gypsum Sales Proceeds	(1)	(100,752)	51.98%	(52,371)	92.087%	$ (48,227)
45	5010029	Gypsum handling/displ-Affiliat	(1)	12,373	51.98%	6,431	92.087%	$ 5,922
46	Incremental purchased power - Non Fuel			PSUM	PSUM			
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	(3)	$ -	-	$ -	92.087%	$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	888,010	10,750	877,260	92.087%	$ 807,842
49	5550032	PP - Mone - Non-Fuel	(3)	18,065	18,065	-	92.087%	$ -
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	(3)	-	-	-	92.087%	$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	(3)	-	-	-	92.087%	$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:OVEC bill)	(3)	3,413,859	100%	3,413,859	92.087%	$ 3,143,720
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	(1)	995	100%	995	92.087%	$ 916
54	5550023	PP Capacity - Non Affil.	(1)	206,924	100%	206,924	92.087%	$ 190,550
55	5550040	PJM Inadvertent - LSE (only)	(1)	(35,208)	100%	(35,208)	92.087%	$ (32,422)
56	5550003	PP - Cogeneration	(1)	48,565	100%	48,565	92.087%	$ 44,722
57	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	92.087%	$ -
58	Lawrenceburg purchased power - Non-Fuel (NA)							
59	Renewables							
60	5550047	Purchased Power - Wind	(1)	802,557	100%	$ 802,557	100.00%	$ 802,557
61	5550109	Purchased Power - Solar Energy	(1)		100%	-	100.00%	$ -
62	5570007	Other Pwr Exp - RECs	(1)	(735,193)	100%	(735,193)	100.00%	$ (735,193)
63	5570008	Renewable Energy Credit Exp.	(1)	883,008	100%	883,008	100.00%	$ 883,008
64	Environmental Material & Expense							
65	5020001	Lime Expense	(1)	$ 2,671,842	51.98%	$ 1,388,824	92.087%	$ 1,278,926
66	5020002	Urea Expense	(1)	1,965,107	51.98%	1,021,463	92.087%	$ 940,635
67	5020003	Trona Expense	(1)	663,646	51.98%	344,963	92.087%	$ 317,666
68	5020004	Limestone Expense	(1)	1,473,065	51.98%	765,699	92.087%	$ 705,110
69	5020005	Polymer expense	(1)	303,267	51.98%	157,638	92.087%	$ 145,164
70	5020007	Lime Hydrate Expense	(1)	10,040	51.98%	5,219	92.087%	$ 4,806
71	5020008	Activated Carbon	(1)	(14)	51.98%	(8)	92.087%	$ (7)
72	5020025	Steam Exp Environmental	(1)	55,848	51.98%	29,030	92.087%	$ 26,732
73	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
74	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -	92.087%	$ -
75	5550039	PJM Inadvertent - OSS (only)	(1)	(1,970)	0%	-	92.087%	$ -
76	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-	92.087%	$ -
77	5550099	PJM Purchases - NonECR (Auction)	(1)	2,252,822	0%	-	92.087%	$ -
78	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	269,175	0%	-	92.087%	$ -
79	5550102	PP Pool Non Fuel - OSS Aff	(1)	6,618,767	0%	-	92.087%	$ -
80	5550107	Capacity Purchases - Trading	(1)	117,699	0%	-	92.087%	$ -
81	5550002	PP - Assocated (PPA only - discontinued after Jan09)	(1)	-	0%	-	92.087%	$ -
82	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
83	5550075	PJM Reactive Credit	(1)	$ (582,591)	0%	$ -	92.087%	$ -
84	5550077	PJM Black Start Credit	(1)	(5,889)	0%	-	92.087%	$ -
85	5550079	PJM Regulation Credit	(1)	(125,166)	0%	-	92.087%	$ -
86	5550084	PJM Spinning Reserve Credit	(1)	(11)	0%	-	92.087%	$ -
87	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-	92.087%	$ -
88	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
89	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ 20,200	0%	$ -	92.087%	$ -
90	5550041	PJM Synchronous Cond. Charge	(1)	1,976	0%	-	92.087%	$ -
91	5550074	PJM Reactive Charge	(1)	570,856	0%	-	92.087%	$ -
92	5550076	PJM BlackStart Charge	(1)	12,071	0%	-	92.087%	$ -
93	5550078	PJM Regulation Charge	(1)	780,476	0%	-	92.087%	$ -
94	5550083	PJM Spinning Reserve Charge	(1)	27,375	0%	-	92.087%	$ -
95	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	50	0%	-	92.087%	$ -
96		Total Additional FAC		$ 27,115,854		$ 11,528,018		$ 10,691,009
97		TOTAL		$ 144,325,817		$ 69,091,083		$ 63,699,109
98								
99	NOTATIONS:							
100	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
101	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
102	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
103	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
104	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						
105								

ACTUAL CYCLE | EXH CSP-1

COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)

MARCH 2010

Line	A	B	C	D	E	F	G	H
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			Net Energy Cost (NEC) in EFC			Retail	Retail
2					Assigned	Assigned	Allocation	FAC Cost
3	Account	Description	Notes	Total	Off-System	To Firm Load		
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 22,150,327	$ 2,475,524	$ 19,674,803		
6	5010009	Fuel Consumed - No Load (CV4)	(2)	825,656		825,656		
7	5010013	Fuel Survey Activity	(2)	-	-	-		
8	5010019	Fuel Oil Consumed	(2)	176,190		176,190		
9	5010020/5010036	Natural Gas Consumed	(2)	7,767	-	7,767		
10	5470001	Fuel - Gas Turbine	(2)	-	$ -	-		
11		Subtotal - Generation Fuel		$ 23,159,940	$ 2,475,524	$ 20,684,416		
12	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	(3)	$ 1,368,707	$ 161,466	$ 1,207,241		
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	15,864,089	-	15,864,089		
15	5550080	PJM Energy Purchases (Fuel)	(3)	2,177,602	1,777,392	400,210		
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	6,298,809	5,854,655	444,154		
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	34,038	25,792	8,246		
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	(3)	3,305	-	3,305		
19	5550032	Purchased Pwr - Mone (Fuel)	(3)	-	-	-		
20		Subtotal - Purchased Power Fuel		$ 25,746,550	$ 7,819,305	$ 17,927,245		
21		Total NEC Fuel		$ 48,906,490	$ 10,294,829	$ 38,611,661	100.000%	$ 38,611,661
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount		
24	Emission Allowance Expense				EXH CSP 2			
25	5090000/2	Allowance Consumption - SO2	(1)	$ 423,981	93.57%	$ 396,719		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	669	93.57%	626		
27	5090005	Allowance Expenses - Annual NOx	(1)	24,714	93.57%	23,125		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)		93.57%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)	$ (34,406)	93.57%	$ (32,193)		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)		93.57%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)		93.57%	-		
33	4119000	Loss Disposition of Allowances	(1)		93.57%	-		
34		Total Allowance Dollars		$ 414,958		$ 388,276	100.000%	$ 388,276
35	**Additional S.B. 221 FAC Accounts for 2009**			Additional Fuel and Environmental Accounts in FAC				
36						Firm Load		
37	Account	Description	Notes		Allocation Factor	Allocated Amount		
38	Incremental Fuel Handling/Ash/Gypsum				EXH CSP 2			
39	5010000	Fuel (Ash Handling)	(1)	$ 574,546	93.57%	$ 537,602	100.000%	$ 537,602
40	5010003	Fuel - Procurement, Unloading & Handling	(1)	663,483	93.57%	620,821	100.000%	$ 620,821
41	5010011	Fuel Handling - No Load (CV4)	(1)	20,001	93.57%	18,715	100.000%	$ 18,715
42	5010012	Ash Sales Proceeds	(1)	(11,314)	93.57%	(10,586)	100.000%	$ (10,586)
43	5010027	Gypsum handling/disposal costs	(1)	55,284	93.57%	51,729	100.000%	$ 51,729
44	5010028	Gypsum Sales Proceeds	(1)	(34,473)	93.57%	(32,256)	100.000%	$ (32,256)
45	5010032	Coal Procurement-Aff	(1)		93.57%	-	100.000%	$ -
46	5010033	Coal Procurement-NA	(1)		93.57%	-	100.000%	$ -
47	Incremental purchased power - Non Fuel			PSUM	PSUM			
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	(3)	$ -	$ -	$ -	100.000%	$ -
49	*5550096 - in part*	*PP - Non Trade - Non-Fuel (OVEC, 3rd party)*	(3)	85,809	7,142	78,667	100.000%	$ 78,667
50	5550032	PP - Mone - Non-Fuel	(3)	19,194	-	19,194	100.000%	$ 19,194
51	5550098 INACTIVE	PP - PJM - Non-Fuel	(3)		-	-	100.000%	$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	(3)		-	-	100.000%	$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source OVEC bill)	(3)	1,272,637	100%	1,272,637	100.000%	$ 1,272,637
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	(1)	1,280,740	100%	1,280,740	100.000%	$ 1,280,740
55	5550004	Purchased Power - Pool Capacity	(1)	2,050,967	100%	2,050,967	100.000%	$ 2,050,967
56	5550023	Purchase Power - Capacity	(1)	184,080	100%	184,080	100.000%	$ 184,080
57	5550040	PJM Inadvertent - LSE (only)	(1)	(38,214)	100%	(38,214)	100.000%	$ (38,214)
58	5550093	Peak Hour Avail Charge - LSE	(1)		100%	-	100.000%	$ -
59	Lawrenceburg purchased power - Non-Fuel							
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)	(1)	$ 3,047,847	100%	$ 3,047,847	100.000%	$ 3,047,847
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)	(1)	(153,129)	100%	(153,129)	100.000%	$ (153,129)
62	5550046 In part	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)	(3) (5)	9,995	100.00%	9,995	100.000%	$ 9,995
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)	(1) (5)	1,239,020	100.00%	1,239,020	100.000%	$ 1,239,020
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)	(1) (5)	1,187,081	100.00%	1,187,081	100.000%	$ 1,187,081
65	Renewables							
66	5550047	Purchased Power - Wind	(1)	$ 859,248	100%	859,247	100.000%	$ 859,247
67	5550109	Purchased Power - Solar	(1)		100%	$ -	100.000%	$ -
68	5570007	Renewable Energy Credit Exp.	(1)		100%	$ -	100.000%	$ -
69	5570008	Renewable Energy Credit Exp. (Green Power)	(1)	683,898	100%	$ 683,898	100.000%	$ 683,898
70	Environmental Material & Expense							
71	5020001	Lime Expense	(1)	$ 1,521,099	93.57%	$ 1,423,293	100.000%	$ 1,423,293
72	5020002	Urea Expense	(1)	345,043	93.57%	322,857	100.000%	$ 322,857
73	5020003	Trona Expense	(1)	61,615	93.57%	57,653	100.000%	$ 57,653
74	5020004	Limestone Expense	(1)	284,874	93.57%	266,557	100.000%	$ 266,557
75	5020005	Polymer expense	(1)	131	93.57%	123	100.000%	$ 123
76	5020007	Lime Hydrate Expense	(1)	-	93.57%	-	100.000%	$ -
77	5020008	Activated Carbon	(1)	6	93.57%	6	100.000%	$ 6
78	5020025	Steam Exp Environmental	(1)	130	93.57%	121	100.000%	$ 121
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
80	5550035	PJM Normal Purchases (Non ECR OSS)	(1)		0%	$ -		
81	5550039	PJM Inadvertent - OSS (only)	(1)	(2,879)	0%	-		
82	5550088	PJM Capacity Charge (OSS only)	(1)		0%	-		
83	5550099	PJM Purchases - NonECR (Auction)	(1)	1,564,166	0%	-		
84	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	124,245	0%	-		
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)	(1)	5,210,619	0%	-		
86	5550107	Capacity Purchases -Trading	(1)	641,212	0%	-		
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)	(1)		0%	-		
88	5550069	PP - Monon. Power (2008 PPA only)	(1)		0%	-		
89	555 Purchased Power Ancillary Credits Included in Base "G" Rates (Excluded from FAC)							
90	5550075	PJM Reactive Credit	(1)	$ (511,887)	0%	$ -		
91	5550077	PJM Black Start Credit	(1)	(5,232)	0%	-		
92	5550079	PJM Regulation Credit	(1)	(165,084)	0%	-		
93	5550084	PJM Spinning Reserve Credit	(1)	(56)	0%	-		
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)		0%	-		
95	555 Purchased Power Accounts Included in ETCRR (Excluded from FAC)							
96	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -		
97	5550041	PJM Synchronous Cond. Charge	(1)	(128)	0%	-		
98	5550074	PJM Reactive Charge	(1)	557,392	0%	-		
99	5550076	PJM BlackStart Charge	(1)	11,575	0%	-		
100	5550078	PJM Regulation Charge	(1)	461,465	0%	-		
101	5550083	PJM Spinning Reserve Charge	(1)	1,162	0%	-		
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	7,624	0%	-		
103		Total Additional FAC		$ 23,103,789		$ 14,978,663		$ 14,978,663
104		TOTAL		$ 72,425,237		$ 53,978,600		$ 53,978,600
105								
106	NOTATIONS:							
107	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
108	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
109	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
110	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
111	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						PIVOT
112								72,296,696

C:\Users\joliker\AppData\Local\Temp\Temp4_LA-2010-43 CONFIDENTIAL.zip\[LA-2010-43, CC (OPCO FAC Calculation 0310 AC					ACTUAL		EXH OPCo-1	
		OHIO POWER COMPANY - NET ENERGY COST (NEC)						
		MARCH 2010						
Line	A	B	C	D	E	F	G	H
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			Net Energy Cost (NEC) in EFC				
2					Assigned	Assigned	Retail	Retail
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 99,528,280	$ 49,468,545	$ 50,059,735		
6	5010009	Fuel Consumed - No Load (CV4)	(2)			-		
7	5010013	Fuel Survey Activity	(2)	-		- \		
8	5010019	Fuel Oil Consumed	(2)	1,406,282		1,406,282		
9	5010020	Natural Gas Consumed	(2)			-		
10	5010022	Fuel Consumed - Sawdust	(2)	-		-		
11	5470001	Fuel - Gas Turbine	(2)			-		
12		Subtotal - Generation Plant		$ 100,934,562	$ 49,468,545	$ 51,466,017		
13	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	(3)	$ 4,621,169	$ 300,501	$ 4,320,668		
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	(1,486)	-	$ (1,486)		
16	5550080	PJM Energy Purchases (Fuel)	(3)	2,506,087	2,045,504	$ 460,583		
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	7,248,968	6,737,798	511,170		
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	39,173	29,683	9,490		
19	5550031/32	Purchased Pwr - Mone (Fuel)	(3)	-	-	-		
20		Subtotal - Purchased Power Fuel		$ 14,413,911	$ 9,113,486	$ 5,300,425		
21		Total NEC Fuel		$ 115,348,473	$ 58,582,031	$ 56,766,442	91.840%	$ 52,134,300
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt		
24	Emission Allowance Expense				EXH CSP 2			
25	5090000	Allowance Consumption SO2	(1)	$ 239,260	51.38%	$ 122,932		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	-	51.38%	-		
27	5090005	Allowance Expenses - Annual NOx	(1)	9,111	51.38%	4,681		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)		51.38%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)	(130,020)	51.38%	(66,804)		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)	-	51.38%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)	(163,712)	51.38%	(84,115)		
33	4119000	Loss Disposition of Allowances	(1)		51.38%	-		
34	4119002	Comp. Allow. Loss - SO2	(1)	-	51.38%	-		
35		Total Allowance Dollars		$ (45,361)		$ (23,306)	91.840%	$ (21,405)
36	**Additional S.B. 221 FAC Accounts Forecast for 2009**			Additional Fuel and Environmental Accounts in FAC				
37						Firm Load		
38	Account	Description	Notes		Allocation Factor	Allocated Amount		
39	Incremental Fuel Handling/Ash/Gypsum				EXH CSP 2			
40	5010000	Fuel (Ash Handling)	(1)	$ 553,462	51.38%	$ 284,369	91.840%	$ 261,164
41	5010003	Fuel - Procurement, Unloading & Handling	(1)	3,152,454	51.38%	1,619,731	91.840%	$ 1,487,561
42	5010012	Ash Sales Proceeds	(1)	(29,486)	51.38%	(15,150)	91.840%	$ (13,914)
43	5010027	Gypsum handling/disposal costs	(1)	284,566	51.38%	146,210	91.840%	$ 134,279
44	5010028	Gypsum Sales Proceeds	(1)	(112,211)	51.38%	(57,654)	91.840%	$ (52,949)
45	5010029	Gypsum handling/displ-Affiliat	(1)	42,396	51.38%	21,783	91.840%	$ 20,005
46	Incremental purchased power - Non Fuel			PSUM	PSUM			
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	(3)	$ -	-	$ -	91.840%	$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	298,589	15,737	282,852	91.840%	$ 259,771
49	5550032	PP - Mone - Non-Fuel	(3)	22,089	-	22,089	91.840%	$ 20,287
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	(3)	-	-	-	91.840%	$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	(3)	-	-	-	91.840%	$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:OVEC bill)	(3)	4,439,898	100%	4,439,898	91.840%	$ 4,077,603
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	(1)	(693)	100%	(693)	91.840%	$ (636)
54	5550023	PP Capacity - Non Affil.	(1)	211,848	100%	211,848	91.840%	$ 194,561
55	5550040	PJM Inadvertent - LSE (only)	(1)	(43,979)	100%	(43,979)	91.840%	$ (40,390)
56	5550003	PP - Cogeneration	(1)	197,374	100%	197,374	91.840%	$ 181,268
57	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	91.840%	$ -
58	Lawrenceburg purchased power - Non-Fuel (NA)							
59	Renewables							
60	5550047	Purchased Power - Wind	(1)	859,248	100%	$ 859,248	100.00%	$ 859,248
61	5550109	Purchased Power - Solar Energy	(1)		100%	-	100.00%	$ -
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010	(1)	-	100%	-	100.00%	$ -
63	5570008	Renewable Energy Credit Exp.	(1)	864,316	100%	864,316	100.00%	$ 864,316
64	Environmental Material & Expense							
65	5020001	Lime Expense	(1)	$ 3,609,611	51.38%	$ 1,854,618	91.840%	$ 1,703,281
66	5020002	Urea Expense	(1)	2,507,767	51.38%	1,288,491	91.840%	$ 1,183,350
67	5020003	Trona Expense	(1)	416,756	51.38%	214,129	91.840%	$ 196,656
68	5020004	Limestone Expense	(1)	1,295,530	51.38%	665,643	91.840%	$ 611,327
69	5020005	Polymer expense	(1)	295,310	51.38%	151,731	91.840%	$ 139,349
70	5020007	Lime Hydrate Expense	(1)	4,983	51.38%	2,560	91.840%	$ 2,351
71	5020008	Activated Carbon	(1)	21	51.38%	11	91.840%	$ 10
72	5020025	Steam Exp Environmental	(1)	43,474	51.38%	22,337	91.840%	$ 20,514
73	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
74	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -	91.840%	$ -
75	5550039	PJM Inadvertent - OSS (only)	(1)	(3,312)	0%	-	91.840%	$ -
76	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-	91.840%	$ -
77	5550099	PJM Purchases - NonECR (Auction)	(1)	1,800,115	0%	-	91.840%	$ -
78	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	142,986	0%	-	91.840%	$ -
79	5550102	PP Pool Non Fuel - OSS Aff	(1)	5,914,070	0%	-	91.840%	$ -
80	5550107	Capacity Purchases - Trading	(1)	737,937	0%	-	91.840%	$ -
81	5550002	PP - Assocated (PPA only - discontinued after Jan09)	(1)	-	0%	-	91.840%	$ -
82	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
83	5550075	PJM Reactive Credit	(1)	$ (589,104)	0%	$ -	91.840%	$ -
84	5550077	PJM Black Start Credit	(1)	(6,021)	0%	-	91.840%	$ -
85	5550079	PJM Regulation Credit	(1)	(189,987)	0%	-	91.840%	$ -
86	5550084	PJM Spinning Reserve Credit	(1)	(65)	0%	-	91.840%	$ -
87	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-	91.840%	$ -
88	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
89	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -	91.840%	$ -
90	5550041	PJM Synchronous Cond. Charge	(1)	(148)	0%	-	91.840%	$ -
91	5550074	PJM Reactive Charge	(1)	641,473	0%	-	91.840%	$ -
92	5550076	PJM BlackStart Charge	(1)	13,321	0%	-	91.840%	$ -
93	5550078	PJM Regulation Charge	(1)	531,075	0%	-	91.840%	$ -
94	5550083	PJM Spinning Reserve Charge	(1)	1,337	0%	-	91.840%	$ -
95	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	8,774	0%	-	91.840%	$ -
96		Total Additional FAC		$ 27,915,778		$ 13,031,763		$ 12,109,014
97		TOTAL		$ 143,218,890		$ 69,774,898		$ 64,221,909
98								
99	NOTATIONS:							
100	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
101	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
102	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
103	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
104	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						
105								

ACTUAL CYCLE — EXH CSP-1

COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)

APRIL 2010

Line	A	B	C	D	E	F	G	H
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			**Net Energy Cost (NEC) in EFC**			**Retail**	**Retail**
2					**Assigned**	**Assigned**	**Allocation**	**FAC Cost**
3	***Account***	***Description***	***Notes***	***Total***	***Off-System***	***To Firm Load***		
4	**Generation Fuel**			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 22,852,473	$ 2,698,687	$ 20,153,786		
6	5010009	Fuel Consumed - No Load (CV4)	(2)	631,666		631,666		
7	5010013	Fuel Survey Activity	(2)	-	-	-		
8	5010019	Fuel Oil Consumed	(2)	356,447		356,447		
9	5010020/5010036	Natural Gas Consumed	(2)	1,141	-	1,141		
10	5470001	Fuel - Gas Turbine	(2)	-	$ -	-		
11		**Subtotal - Generation Fuel**		$ 23,841,727	$ 2,698,687	$ 21,143,040		
12	**Purchases Power - Fuel portion**			NEC (4)	NEC (4)			
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	(3)	$ 1,143,120	$ 331,040	$ 812,080		
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	11,722,521	-	11,722,521		
15	5550080	PJM Energy Purchases (Fuel)	(3)	2,309,828	1,986,355	323,473		
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	3,368,719	3,276,355	92,364		
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	9,852	9,852	-		
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	(3)	107,359	30,369	76,990		
19	5550032	Purchased Pwr - Mone (Fuel)	(3)	-	-	-		
20		***Subtotal - Purchased Power Fuel***		$ 18,661,399	$ 5,633,971	$ 13,027,428		
21		**Total NEC Fuel**		$ 42,503,126	$ 8,332,658	$ 34,170,468	100.000%	$ 34,170,468
22						**Firm Load**		
23	***Allowance Accounts in FAC:***				**Allocation Factor**	**Allocated Amount**		
24	**Emission Allowance Expense**				EXH CSP 2			
25	*5090000/2*	*Allowance Consumption - SO2*	(1)	$ 469,876	92.06%	$ 432,568		
26	5090001	Allowance Consumption - Seasonal NOx	(1)		92.06%	-		
27	5090005	Allowance Expenses - Annual NOx	(1)	38,784	92.06%	35,704		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)		92.06%	-		
29	**Allowance Gains/Losses**							
30	4118002	Comp. Allow. Gains SO2	(1)		92.06%	$ -		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)		92.06%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)		92.06%	-		
33	4119000	*Loss Disposition of Allowances*	(1)		92.06%	-		
34		**Total Allowance Dollars**		$ 508,660		$ 468,272	100.000%	$ 468,272
35	**Additional S.B. 221 FAC Accounts for 2009**			**Additional Fuel and Environmental Accounts in FAC**				
36						**Firm Load**		
37	**Account**	***Description***	***Notes***		**Allocation Factor**	**Allocated Amount**		
38	**Incremental Fuel Handling/Ash/Gypsum**				EXH CSP 2			
39	5010000	Fuel (Ash Handling)	(1)	$ 674,223	92.06%	$ 620,690	100.000%	$ 620,690
40	5010003	Fuel - Procurement, Unloading & Handling	(1)	747,453	92.06%	688,106	100.000%	$ 688,106
41	5010011	Fuel Handling - No Load (CV4)	(1)	12,703	92.06%	11,694	100.000%	$ 11,694
42	5010012	Ash Sales Proceeds	(1)	(14,210)	92.06%	(13,082)	100.000%	$ (13,082)
43	5010027	Gypsum handling/disposal costs	(1)	67,901	92.06%	62,509	100.000%	$ 62,509
44	5010028	Gypsum Sales Proceeds	(1)	(43,434)	92.06%	(39,986)	100.000%	$ (39,986)
45	5010032	Coal Procurement-Aff	(1)		92.06%	-	100.000%	$ -
46	5010033	Coal Procurement-NA	(1)		92.06%	-	100.000%	$ -
47	**Incremental purchased power - Non Fuel**			PSUM	PSUM			
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	(3)	$ -	$ -	$ -	100.000%	$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	181,275	43,274	138,001	100.000%	$ 138,001
50	5550032	PP - Mone - Non-Fuel	(3)	42,070	-	42,070	100.000%	$ 42,070
51	5550098 INACTIVE	PP - PJM - Non-Fuel	(3)		-	-	100.000%	$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	(3)		-	-	100.000%	$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source OVEC bill)	(3)	1,441,506	100%	1,441,506	100.000%	$ 1,441,506
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	(1)	1,934,909	100%	1,934,909	100.000%	$ 1,934,909
55	5550004	Purchased Power - Pool Capacity	(1)	2,302,589	100%	2,302,589	100.000%	$ 2,302,589
56	5550023	Purchase Power - Capacity	(1)	184,187	100%	184,187	100.000%	$ 184,187
57	5550040	PJM Inadvertent - LSE (only)	(1)	(17,113)	100%	(17,113)	100.000%	$ (17,113)
58	5550093	Peak Hour Avail Charge - LSE	(1)		100%	-	100.000%	$ -
59	**Lawrenceburg purchased power - Non-Fuel**							
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)	(1)	$ 3,047,847	100%	$ 3,047,847	100.000%	$ 3,047,847
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)	(1)	(153,129)	100%	(153,129)	100.000%	$ (153,129)
62	5550046 in part	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)	(3) (5)	12,335	61.81%	7,624	100.000%	$ 7,624
63	*5550086*	*PurchPwr-O&M portion-Affiliate (Lawrenceburg)*	(1) (5)	1,512,445	61.81%	934,779	100.000%	$ 934,779
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)	(1) (5)	577,049	61.81%	356,650	100.000%	$ 356,650
65	**Renewables**							
66	5550047	Purchased Power - Wind/Solar	(1)	$ 1,194,084	100%	1,194,083	100.000%	$ 1,194,083
67	5550109	Purchased Power - Solar	(1)	12,760	100%	$ 12,760	100.000%	$ 12,760
68	5570007	Renewable Energy Credit Exp.	(1)	-	100%	$ -	100.000%	$ -
69	5570008	Renewable Energy Credit Exp. (Green Power)	(1)	22,114	100%	$ 22,114	100.000%	$ 22,114
70	**Environmental Material & Expense**							
71	5020001	Lime Expense	(1)	$ 1,753,819	92.06%	$ 1,614,566	100.000%	$ 1,614,566
72	5020002	Urea Expense	(1)	170,636	92.06%	157,088	100.000%	$ 157,088
73	5020003	Trona Expense	(1)	81,520	92.06%	75,047	100.000%	$ 75,047
74	5020004	Limestone Expense	(1)	279,303	92.06%	257,126	100.000%	$ 257,126
75	5020005	Polymer expense	(1)	136	92.06%	125	100.000%	$ 125
76	5020007	*Lime Hydrate Expense*	(1)	2,080	92.06%	1,915	100.000%	$ 1,915
77	5020008	Activated Carbon	(1)	(8)	92.06%	(7)	100.000%	$ (7)
78	5020025	Steam Exp Environmental	(1)	25	92.06%	23	100.000%	$ 23
79	**555 Purchased Power Accounts only for OSS (Excluded from FAC)**							
80	5550035	PJM Normal Purchases (Non ECR OSS)	(1)		0%	$ -		
81	5550039	PJM Inadvertent - OSS (only)	(1)	(2,217)	0%	-		
82	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-		
83	5550099	PJM Purchases - NonECR (Auction)	(1)	1,286,251	0%	-		
84	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	135,313	0%	-		
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)	(1)	5,540,777	0%	-		
86	5550107	Capacity Purchases -Trading	(1)	655,751	0%	-		
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)	(1)		0%	-		
88	5550069	PP - Monon. Power (2008 PPA only)	(1)	-	0%	-		
89	***555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)***							
90	5550075	PJM Reactive Credit	(1)	$ (525,412)	0%	$ -		
91	5550077	PJM Black Start Credit	(1)	(5,249)	0%	-		
92	5550079	PJM Regulation Credit	(1)	(211,798)	0%	-		
93	5550084	PJM Spinning Reserve Credit	(1)	(21,427)	0%	-		
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-		
95	**555 Purchased Power Accounts included in ETCRR (Excluded from FAC)**							
96	5550036	PJM Emergency Purchases (Demand Response Program)	(1)		0%	$ -		
97	5550041	PJM Synchronous Cond. Charge	(1)	5,193	0%	-		
98	5550074	PJM Reactive Charge	(1)	507,038	0%	-		
99	5550076	PJM BlackStart Charge	(1)	10,539	0%	-		
100	5550078	PJM Regulation Charge	(1)	378,625	0%	-		
101	5550083	PJM Spinning Reserve Charge	(1)	53,678	0%	-		
102	*5550090*	*PJM 30 min Suppl. Reserve Charge - LSE*	(1)	3,757	0%	-		
103		**Total Additional FAC**		$ 23,837,894		$ 14,884,691		$ 14,884,691
104		**TOTAL**		$ 66,849,680		$ 49,523,431		$ 49,523,431
105								
106	NOTATIONS:							
107	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
108	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
109	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
110	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
111	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						PIVOT
112								67,539,809

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

APRIL 2010

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					ACT	Applicable	Diff. To GL NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	**Generation Fuel**			NEC	NEC (4)						
5	5010001	Fuel Consumed	(2)	$ 64,544,622	$ 20,134,965	$ 44,409,657			$ 64,544,622	$ 64,311,425	$ 233,197
6	5010009	Fuel Consumed - No Load (CV4)	(2)			-			-	-	-
7	5010013	Fuel Survey Activity	(2)	2,874,540		2,874,540			2,874,540	3,107,738	(233,198)
8	5010019	Fuel Oil Consumed	(2)	718,678		718,678			718,678	718,678	(0)
9	5010020	Natural Gas Consumed	(2)			-			-	-	-
10	5010022	Fuel Consumed - Sawdust	(2)	-		-			-	-	-
11	5470001	Fuel - Gas Turbine	(2)			-			-	-	-
12		Subtotal - Generation Plant		$ 68,137,840	$ 20,134,965	$ 48,002,875			68,137,840	68,137,840	(0)
13	**Purchases Power - Fuel portion**			NEC (4)	NEC (4)						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	(3)	$ 3,789,427	$ 644,814	$ 3,144,613			3,789,427	5,215,748	(1,426,321)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	88,275	-	$ 88,275			88,275	27,486	60,789
16	5550080	PJM Energy Purchases (Fuel)	(3)	2,658,179	2,285,921	$ 372,258			2,658,179	2,242,515	415,664
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	3,876,766	3,770,449	106,317			3,876,766	3,528,707	348,059
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	11,337	11,337	-			11,337	10,954	383
19	5550031/32	Purchased Pwr - Mone (Fuel)	(3)	-	-	-			-	48,577	(48,577)
20		Subtotal - Purchased Power Fuel		$ 10,423,984	$ 6,712,521	$ 3,711,463			10,423,984	11,073,987	(650,003)
21		Total NEC Fuel		$ 78,561,824	$ 26,847,486	$ 51,714,338	90.784%	$ 46,948,345	78,561,824	79,211,827	(650,003)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt			(a) Report diffs. due to timing of GL recording of est./actuals		
24	**Emission Allowance Expense**				EXH CSP 2						
25	5090000	Allowance Consumption SO2	(1)	$ 139,178	70.31%	$ 97,856					
26	5090001	Allowance Consumption - Seasonal NOx	(1)	-	70.31%	-					
27	5090002	Allowance Expense	(1)	60	70.31%	42					
28	5090005	Allowance Expenses - Annual NOx	(1)	5,936	70.31%	4,174					
29	5090003	CO2 Allowance Consumption (none in this a/c currently)			70.31%	-					
30	**Allowance Gains/Losses**		(1)								
31	4118002	Comp. Allow. Gains SO2	(1)	-	70.31%	-					
32	4118003	Comp. Allow. Gains-Seas NOx	(1)	(22,107)	70.31%	(15,543)					
33	4118004	Comp. Allow. Gains-Ann NOx	(1)	(507,050)	70.31%	(356,507)					
34	4119000	Loss Disposition of Allowances	(1)		70.31%	-					
35	4119002	Comp. Allow. Loss - SO2		-	70.31%	-					
36		Total Allowance Dollars		$ (383,982)		$ (269,978)	90.784%	$ (245,097)			
37	**Additional S.B. 221 FAC Accounts Forecast for 2009**			Additional Fuel and Environmental Accounts in FAC							
38						Firm Load					
39	Account	Description	Notes		Allocation Factor	Allocated Amount					
40	**Incremental Fuel Handling/Ash/Gypsum**				EXH CSP 2						
41	5010000	Fuel (Ash Handling)	(1)	$ 1,339,851	70.31%	$ 942,049	90.784%	$ 855,230			
42	5010003	Fuel - Procurement, Unloading & Handling	(1)	1,910,736	70.31%	1,343,440	90.784%	$ 1,219,629			
43	5010012	Ash Sales Proceeds	(1)	(104,898)	70.31%	(73,754)	90.784%	$ (66,956)			
44	5010027	Gypsum handling/disposal costs	(1)	189,693	70.31%	133,373	90.784%	$ 121,081			
45	5010028	Gypsum Sales Proceeds	(1)	(169,225)	70.31%	(118,982)	90.784%	$ (108,016)			
46	5010029	Gypsum handling/displ-Affilat	(1)	43,782	70.31%	30,783	90.784%	$ 27,946			
47	**Incremental purchased power - Non Fuel**			PSUM	PSUM						
48	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	(3)	$ -	-	$ -	90.784%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	632,139	94,613	537,526	90.784%	$ 487,988	$ 632,139	$ 4,211,575	$ (3,579,436)
50	5550032	PP - Mone - Non-Fuel	(3)	48,415	-	48,415	90.784%	$ 43,953	$ 48,415	$ -	$ 48,415
51	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	(3)	-	-	-	90.784%	$ -	$ -		$ -
52	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	(3)	-	-	-	90.784%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source:OVEC bill)	(3)	5,029,038	100%	5,028,038	90.784%	$ 4,565,562	5,029,038		5,029,038
54	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	(1)	5,908	100%	5,908	90.784%	$ 5,364	5,709,592	4,211,575	1,498,017
55	5550023	PP Capacity - Non Affil.	(1)	211,965	100%	211,965	90.784%	$ 192,430			
56	5550040	PJM Inadvertent - LSE (only)	(1)	(19,694)	100%	(19,694)	90.784%	$ (17,879)			
57	5550003	PP - Copeneration	(1)	-	100%	-	90.784%	$ -			
58	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	90.784%	$ -			
59	**Lawrenceburg purchased power - Non-Fuel (NA)**										
60	**Renewables**										
61	5550047	Purchased Power - Wind	(1)	1,194,084	100%	$ 1,194,084	100.00%	$ 1,194,084	$ 1,194,084.00	$ 1,194,083.98	$ 0.02
62	5550109	Purchased Power - Solar Energy	(1)	16,240	100%	16,240	100.00%	$ 16,240	$ 16,240.07	$ 16,240.07	$ -
63	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010	(1)	-	100%	-	100.00%	$ -			
64	5570008	Renewable Energy Credit Exp.	(1)	29,167	100%	29,167	100.00%	$ 29,167			
65	**Environmental Material & Expense**										
66	5020001	Lime Expense	(1)	$ 1,558,985	70.31%	$ 1,096,123	90.784%	$ 995,104			
67	5020002	Urea Expense	(1)	1,268,215	70.31%	891,682	90.784%	$ 809,504			
68	5020003	Trona Expense	(1)	379,783	70.31%	267,025	90.784%	$ 242,416			
69	5020004	Limestone Expense	(1)	821,788	70.31%	577,799	90.784%	$ 524,549			
70	5020005	Polymer expense	(1)	292,677	70.31%	205,781	90.784%	$ 186,816			
71	5020007	Lime Hydrate Expense	(1)	4,154	70.31%	2,921	90.784%	$ 2,652			
72	5020008	Activated Carbon	(1)	(25)	70.31%	(17)	90.784%	$ (16)			
73	5020025	Steam Exp Environmental	(1)	44,605	70.31%	31,362	90.784%	$ 28,471			
74	**555 Purchased Power Accounts only for OSS (Excluded from FAC)**										
75	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -	90.784%	$ -			
76	5550039	PJM Inadvertent - OSS (only)	(1)	(2,551)	0%	-	90.784%	$ -			
77	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-	90.784%	$ -			
78	5550099	PJM Purchases - NonECR (Auction)	(1)	1,480,234	0%	-	90.784%	$ -			
79	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	155,719	0%	-	90.784%	$ -			
80	5550102	PP Pool Non Fuel - OSS Aff	(1)	6,337,689	0%	-	90.784%	$ -			
81	5550107	Capacity Purchases - Trading	(1)	754,647	0%	-	90.784%	$ -			
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)	(1)	-	0%	-	90.784%	$ -			
83	**555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)**										
84	5550075	PJM Reactive Credit	(1)	$ (604,651)	0%	$ -	90.784%	$ -			
85	5550077	PJM Black Start Credit	(1)	(6,040)	0%	-	90.784%	$ -			
86	5550079	PJM Regulation Credit	(1)	(243,740)	0%	-	90.784%	$ -			
87	5550084	PJM Spinning Reserve Credit	(1)	(24,660)	0%	-	90.784%	$ -			
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-	90.784%	$ -			
89	**555 Purchased Power Accounts included in ETCRR (Excluded from FAC)**										
90	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -	90.784%	$ -			
91	5550041	PJM Synchronous Cond. Charge	(1)	5,976	0%	-	90.784%	$ -			
92	5550074	PJM Reactive Charge	(1)	583,505	0%	-	90.784%	$ -			
93	5550076	PJM BlackStart Charge	(1)	12,128	0%	-	90.784%	$ -			
94	5550078	PJM Regulation Charge	(1)	435,726	0%	-	90.784%	$ -			
95	5550083	PJM Spinning Reserve Charge	(1)	61,775	0%	-	90.784%	$ -			
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	4,324	0%	-	90.784%	$ -			
97		Total Additional FAC		$ 23,677,468		$ 12,382,234		$ 11,355,319	GL AMOUNTS	$ 101,007,296.62	
98		TOTAL		$ 101,855,310		$ 63,826,594		$ 58,058,567	EXCL 5010032/33	$ 372,125.60	
99									TOTAL GL QUERY	$ 101,379,422.22	
100	NOTATIONS:										
101	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.							
102	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.									
103	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs									
104	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))									
105	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.									
106											

		ACTUAL CYCLE					EXH CSP-1	
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)						
		MAY 2010						
Line	A	B	C	D	E	F	G	H
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail
2					Assigned	Assigned	Allocation	FAC Cost
3	Account	Description	Notes	Total	Off-System	To Firm Load		
4	Generation Fuel			NEC	NEC (4)			
5	5010001/5010022	Fuel Consumed	(2)	$ 26,003,262	$ 2,510,573	$ 23,492,689		
6	5010009	Fuel Consumed - No Load (CV4)	(2)	202,845		202,845		
7	5010013	Fuel Survey Activity	(2)	-	-	-		
8	5010019	Fuel Oil Consumed	(2)	319,453		319,453		
9	5010020/5010036	Natural Gas Consumed	(2)	3,146,051	-	3,146,051		
10	5470001	Fuel - Gas Turbine	(2)	-	$ -	-		
11		Subtotal - Generation Fuel		$ 29,671,611	$ 2,510,573	$ 27,161,038		
12	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	(3)	$ 1,038,640	$ 285,641	$ 752,999		
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	9,326,862	-	9,326,862		
15	5550080	PJM Energy Purchases (Fuel)	(3)	3,797,303	2,771,629	1,025,674		
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	3,527,910	3,056,110	471,800		
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	76,696	44,618	32,078		
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	(3)	1,332,134	13,007	1,319,127		
19	5550032	Purchased Pwr - Mone (Fuel)	(3)	-	-	-		
20		Subtotal - Purchased Power Fuel		$ 19,099,545	$ 6,171,005	$ 12,928,540		
21		Total NEC Fuel		$ 48,771,156	$ 8,681,578	$ 40,089,578	100.000%	$ 40,089,578
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount		
24	Emission Allowance Expense				EXH CSP 2			
25	5090000/2	Allowance Consumption - SO2	(1)	$ 503,077	93.47%	$ 470,226		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	132,344	93.47%	123,702		
27	5090005	Allowance Expenses - Annual NOx	(1)	38,746	93.47%	36,216		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)	-	93.47%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)		93.47%	$ -		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)		93.47%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)		93.47%	-		
33	4119000	Loss Disposition of Allowances	(1)		93.47%	-		
34		Total Allowance Dollars		$ 674,167		$ 630,143	100.000%	$ 630,143
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC				
36						Firm Load		
37	Account	Description	Notes		Allocation Factor	Allocated Amount		
38	Incremental Fuel Handling/Ash/Gypsum				EXH CSP 2			
39	5010000	Fuel (Ash Handling)	(1)	$ 604,802	93.47%	$ 565,308	100.000%	$ 565,308
40	5010003	Fuel - Procurement, Unloading & Handling	(1)	713,306	93.47%	666,727	100.000%	$ 666,727
41	5010011	Fuel Handling - No Load (CV4)	(1)	18,602	93.47%	17,388	100.000%	$ 17,388
42	5010012	Ash Sales Proceeds	(1)	(17,610)	93.47%	(16,460)	100.000%	$ (16,460)
43	5010027	Gypsum handling/disposal costs	(1)	286,609	93.47%	267,894	100.000%	$ 267,894
44	5010028	Gypsum Sales Proceeds	(1)	(33,778)	93.47%	(31,572)	100.000%	$ (31,572)
45	5010032	Coal Procurement-Aff	(1)		93.47%	-	100.000%	$ -
46	5010033	Coal Procurement-NA	(1)		93.47%	-	100.000%	$ -
47	Incremental purchased power - Non Fuel			PSUM	PSUM			
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	(3)	$ -	$ -	$ -	100.000%	$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	139,166	38,307	100,859	100.000%	$ 100,859
50	5550032	PP - Mone - Non-Fuel	(3)	17,579	17,582	(3)	100.000%	$ (3)
51	5550098 INACTIVE	PP - PJM - Non-Fuel	(3)		-	-	100.000%	$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	(3)		-	-	100.000%	$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source OVEC bill)	(3)	1,213,757	100%	1,213,757	100.000%	$ 1,213,757
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	(1)	2,277,121	100%	2,277,121	100.000%	$ 2,277,121
55	5550004	Purchased Power - Pool Capacity	(1)	2,175,504	100%	2,175,504	100.000%	$ 2,175,504
56	5550023	Purchase Power - Capacity	(1)	184,187	100%	184,187	100.000%	$ 184,187
57	5550040	PJM Inadvertent - LSE (only)	(1)	(19,250)	100%	(19,250)	100.000%	$ (19,250)
58	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	100.000%	$ -
59	Lawrenceburg purchased power - Non-Fuel							
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)	(1)	$ 3,047,847	100%	$ 3,047,847	100.000%	$ 3,047,847
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)	(1)	(153,129)	100%	(153,129)	100.000%	$ (153,129)
62	5550046 in part	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)	(3) (5)	11,489	92.32%	10,607	100.000%	$ 10,607
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)	(1) (5)	1,284,436	92.32%	1,185,795	100.000%	$ 1,185,795
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)	(1) (5)	744,153	92.32%	687,005	100.000%	$ 687,005
65	Renewables							
66	5550047	Purchased Power - Wind/Solar	(1)	$ 811,250	100%	811,249	100.000%	$ 811,249
67	5550109	Purchased Power - Solar	(1)	56,197	100%	$ 56,197	100.000%	$ 56,197
68	5570007	Renewable Energy Credit Exp.	(1)	-	100%	$ -	100.000%	$ -
69	5570008	Renewable Energy Credit Exp. (Green Power)	(1)	825,752	100%	$ 825,752	100.000%	$ 825,752
70	Environmental Material & Expense							
71	5020001	Lime Expense	(1)	$ 1,512,598	93.47%	$ 1,413,825	100.000%	$ 1,413,825
72	5020002	Urea Expense	(1)	205,977	93.47%	192,527	100.000%	$ 192,527
73	5020003	Trona Expense	(1)	113,775	93.47%	106,345	100.000%	$ 106,345
74	5020004	Limestone Expense	(1)	130,643	93.47%	122,112	100.000%	$ 122,112
75	5020005	Polymer expense	(1)	1,512	93.47%	1,413	100.000%	$ 1,413
76	5020007	Lime Hydrate Expense	(1)	(1,762)	93.47%	(1,647)	100.000%	$ (1,647)
77	5020008	Activated Carbon	(1)	1	93.47%	1	100.000%	$ 1
78	5020025	Steam Exp Environmental	(1)	(22)	93.47%	(21)	100.000%	$ (21)
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
80	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -		
81	5550039	PJM Inadvertent - OSS (only)	(1)	(2,519)	0%	-		
82	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-		
83	5550099	PJM Purchases - NonECR (Auction)	(1)	1,479,839	0%	-		
84	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	122,170	0%	-		
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)	(1)	4,541,936	0%	-		
86	5550107	Capacity Purchases -Trading	(1)	693,497	0%	-		
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)	(1)	-	0%	-		
88	5550069	PP - Monon. Power (2006 PPA only)	(1)	-	0%	-		
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
90	5550075	PJM Reactive Credit	(1)	$ (518,575)	0%	$ -		
91	5550077	PJM Black Start Credit	(1)	(5,242)	0%	-		
92	5550079	PJM Regulation Credit	(1)	(282,062)	0%	-		
93	5550084	PJM Spinning Reserve Credit	(1)	(3,920)	0%	-		
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-		
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
96	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -		
97	5550041	PJM Synchronous Cond. Charge	(1)	3,489	0%	-		
98	5550074	PJM Reactive Charge	(1)	559,435	0%	-		
99	5550076	PJM BlackStart Charge	(1)	11,630	0%	-		
100	5550078	PJM Regulation Charge	(1)	485,970	0%	-		
101	5550083	PJM Spinning Reserve Charge	(1)	22,380	0%	-		
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	1,374	0%	-		
103		Total Additional FAC		$ 23,260,114		$ 15,707,338		$ 15,707,338
104		TOTAL		$ 72,705,436		$ 56,427,059		$ 56,427,059
105								
106	NOTATIONS:							
107	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
108	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
109	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
110	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
111	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						PIVOT
112								72,369,438

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

MAY 2010

Line	A	B	C	D	E	F	G	H
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC				
2					Assigned	Assigned	Retail	Retail
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 68,076,915	$ 20,170,503	$ 47,906,412		
6	5010009	Fuel Consumed - No Load (CV4)	(2)			-		
7	5010013	Fuel Survey Activity	(2)	-		-		
8	5010019	Fuel Oil Consumed	(2)	2,402,463		2,402,463		
9	5010020	Natural Gas Consumed	(2)			-		
10	5010022	Fuel Consumed - Sawdust	(2)	-		-		
11	5470001	Fuel - Gas Turbine	(2)			-		
12		Subtotal - Generation Plant		$ 70,479,378	$ 20,170,503	$ 50,308,875		
13	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	(3)	$ 3,618,369	$ 826,076	$ 2,792,293		
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	5,701	-	$ 5,701		
16	5550080	PJM Energy Purchases (Fuel)	(3)	4,369,984	3,189,624	$ 1,180,360		
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	4,059,975	3,517,012	542,963		
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	88,262	51,347	36,915		
19	5550031/32	Purchased Pwr - Mone (Fuel)	(3)	37,532	37,532	-		
20		Subtotal - Purchased Power Fuel		$ 12,179,823	$ 7,621,591	$ 4,558,232		
21		Total NEC Fuel		$ 82,659,201	$ 27,792,094	$ 54,867,107	91.922%	$ 50,434,942
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt		
24	Emission Allowance Expense				EXH OPCO 2			
25	5090000	Allowance Consumption SO2	(1)	$ 215,876	71.55%	$ 154,459		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	26,457	71.55%	18,930		
27	5090005	Allowance Expenses - Annual NOx	(1)	8,189	71.55%	5,859		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)		71.55%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)	-	71.55%	-		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)	-	71.55%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)	-	71.55%	-		
33	4119000	Loss Disposition of Allowances	(1)		71.55%	-		
34	4119002	Comp. Allow. Loss - SO2	(1)	-	71.55%	-		
35		Total Allowance Dollars		$ 250,521		$ 179,248	91.922%	$ 164,768
36	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC				
37						Firm Load		
38	Account	Description	Notes		Allocation Factor	Allocated Amount		
39	Incremental Fuel Handling/Ash/Gypsum				EXH OPCO 2			
40	5010000	Fuel (Ash Handling)	(1)	$ 942,926	71.55%	$ 674,664	91.922%	$ 620,164
41	5010003	Fuel - Procurement, Unloading & Handling	(1)	2,227,323	71.55%	1,593,650	91.922%	$ 1,464,915
42	5010012	Ash Sales Proceeds	(1)	(93,312)	71.55%	(66,765)	91.922%	$ (61,371)
43	5010027	Gypsum handling/disposal costs	(1)	242,874	71.55%	173,776	91.922%	$ 159,739
44	5010028	Gypsum Sales Proceeds	(1)	(87,693)	71.55%	(62,744)	91.922%	$ (57,676)
45	5010029	Gypsum handling/displ-Affiliat	(1)	33,461	71.55%	23,942	91.922%	$ 22,008
46	Incremental purchased power - Non Fuel			PSUM	PSUM			
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	(3)	$ -	-	$ -	91.922%	$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	485,976	111,034	374,942	91.922%	$ 344,654
49	5550032	PP - Mone - Non-Fuel	(3)	20,230	20,234	(4)	91.922%	$ (4)
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	(3)	-	-	-	91.922%	$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	(3)	-	-	-	91.922%	$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:OVEC bill)	(3)	4,234,480	100%	4,234,480	91.922%	$ 3,892,418
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	(1)	14,175	100%	14,175	91.922%	$ 13,030
54	5550023	PP Capacity - Non Affil.	(1)	211,965	100%	211,965	91.922%	$ 194,842
55	5550040	PJM Inadvertent - LSE (only)	(1)	(22,153)	100%	(22,153)	91.922%	$ (20,364)
56	5550003	PP - Cogeneration	(1)	-	100%	-	91.922%	$ -
57	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	91.922%	$ -
58	Lawrenceburg purchased power - Non-Fuel (NA)							
59	Renewables							
60	5550047	Purchased Power - Wind	(1)	811,250	100%	$ 811,250	100.00%	$ 811,250
61	5550109	Purchased Power - Solar Energy	(1)	71,523	100%	71,523	100.00%	$ 71,523
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010	(1)	-	100%	-	100.00%	$ -
63	5570008	Renewable Energy Credit Exp.	(1)	101,836	100%	101,836	100.00%	$ 101,836
64	Environmental Material & Expense							
65	5020001	Lime Expense	(1)	$ 1,977,483	71.55%	$ 1,414,889	91.922%	$ 1,300,594
66	5020002	Urea Expense	(1)	1,361,757	71.55%	974,337	91.922%	$ 895,630
67	5020003	Trona Expense	(1)	2,488,207	71.55%	1,780,312	91.922%	$ 1,636,498
68	5020004	Limestone Expense	(1)	1,082,203	71.55%	774,316	91.922%	$ 711,767
69	5020005	Polymer expense	(1)	236,966	71.55%	169,549	91.922%	$ 155,853
70	5020007	Lime Hydrate Expense	(1)	5,914	71.55%	4,232	91.922%	$ 3,890
71	5020008	Activated Carbon	(1)	3	71.55%	2	91.922%	$ 2
72	5020025	Steam Exp Environmental	(1)	35,555	71.55%	25,439	91.922%	$ 23,384
73	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
74	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -	91.922%	$ -
75	5550039	PJM Inadvertent - OSS (only)	(1)	(2,899)	0%	-	91.922%	$ -
76	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-	91.922%	$ -
77	5550099	PJM Purchases - NonECR (Auction)	(1)	1,703,015	0%	-	91.922%	$ -
78	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	140,595	0%	-	91.922%	$ -
79	5550102	PP Pool Non Fuel - OSS Aff	(1)	4,565,321	0%	-	91.922%	$ -
80	5550107	Capacity Purchases - Trading	(1)	798,086	0%	-	91.922%	$ -
81	5550002	PP - Assocated (PPA only - discontinued after Jan09)	(1)	-	0%	-	91.922%	$ -
82	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
83	5550075	PJM Reactive Credit	(1)	$ (596,783)	0%	$ -	91.922%	$ -
84	5550077	PJM Black Start Credit	(1)	(6,032)	0%	-	91.922%	$ -
85	5550079	PJM Regulation Credit	(1)	(324,600)	0%	-	91.922%	$ -
86	5550084	PJM Spinning Reserve Credit	(1)	(4,511)	0%	-	91.922%	$ -
87	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-	91.922%	$ -
88	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
89	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -	91.922%	$ -
90	5550041	PJM Synchronous Cond. Charge	(1)	4,015	0%	-	91.922%	$ -
91	5550074	PJM Reactive Charge	(1)	643,805	0%	-	91.922%	$ -
92	5550076	PJM BlackStart Charge	(1)	13,384	0%	-	91.922%	$ -
93	5550078	PJM Regulation Charge	(1)	559,261	0%	-	91.922%	$ -
94	5550083	PJM Spinning Reserve Charge	(1)	25,755	0%	-	91.922%	$ -
95	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	1,581	0%	-	91.922%	$ -
96		Total Additional FAC		$ 23,902,940		$ 13,277,613		$ 12,284,584
97		TOTAL		$ 106,812,662		$ 68,323,968		$ 62,884,294
98								
99	NOTATIONS:							
100	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
101	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
102	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
103	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
104	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						
105								

Line	A	B	C	D	E	F	G	H
-		ACTUAL CYCLE					EXH CSP-1	
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)						
		JUNE 2010						
Line	A	B	C	D	E	F	G	H
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail
2					Assigned	Assigned	Allocation	FAC Cost
3	Account	Description	Notes	Total	Off-System	To Firm Load		
4	Generation Fuel			NEC	NEC (4)			
5	*5010001/5010022*	*Fuel Consumed*	(2)	$ 27,365,773	$ 5,721,006	$ 21,644,767		
6	5010009	Fuel Consumed - No Load (CV4)	(2)	519,418		519,418		
7	5010013	Fuel Survey Activity	(2)	193,902	-	193,902		
8	5010019	Fuel Oil Consumed	(2)	665,232		665,232		
9	5010020/5010036	Natural Gas Consumed	(2)	4,568,159	-	4,568,159		
10	5470001/5470003	Fuel - Gas Turbine	(2)	-	-	-		
11		**Subtotal - Generation Fuel**		$ 33,312,484	$ 5,721,006	$ 27,591,478		
12	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	(3)	$ 1,300,908	$ 591,578	$ 709,330		
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	15,048,022	-	15,048,022		
15	5550080	PJM Energy Purchases (Fuel)	(3)	2,910,686	2,806,450	104,236		
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	4,630,440	4,442,450	187,990		
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	33,939	22,774	11,165		
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	(3)	4,459,414	709,149	3,750,265		
19	5550032	Purchased Pwr - Mone (Fuel)	(3)	13,412	5,512	7,900		
20		**Subtotal - Purchased Power Fuel**		$ 28,396,821	$ 8,577,913	$ 19,818,908		
21		**Total NEC Fuel**		$ 61,709,305	$ 14,298,919	$ 47,410,386	100.000%	$ 47,410,386
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount		
24	Emission Allowance Expense				EXH CSP 2			
25	5090000/2	Allowance Consumption - SO2	(1)	$ 630,592	87.70%	$ 553,029		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	159,039	87.70%	139,477		
27	5090005	Allowance Expenses - Annual NOx	(1)	47,734	87.70%	41,863		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)	-	87.70%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)		87.70%	$ -		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)		87.70%	-		
32	*4118004*	*Comp. Allow. Gains-Ann NOx*	(1)		87.70%	-		
33	4119000	Loss Disposition of Allowances	(1)		87.70%	-		
34		**Total Allowance Dollars**		$ 837,365		$ 734,370	100.000%	$ 734,370
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC				
36						Firm Load		
37	Account	Description	Notes		Allocation Factor	Allocated Amount		
38	Incremental Fuel Handling/Ash/Gypsum				EXH CSP 2			
39	5010000	Fuel (Ash Handling)	(1)	$ 692,312	87.70%	$ 607,158	100.000%	$ 607,158
40	5010003	Fuel - Procurement, Unloading & Handling	(1)	819,246	87.70%	718,479	100.000%	$ 718,479
41	5010011	Fuel Handling - No Load (CV4)	(1)	18,775	87.70%	16,465	100.000%	$ 16,465
42	5010012	Ash Sales Proceeds	(1)	(11,332)	87.70%	(9,938)	100.000%	$ (9,938)
43	5010027	Gypsum handling/disposal costs	(1)	(22,011)	87.70%	(19,304)	100.000%	$ (19,304)
44	5010028	Gypsum Sales Proceeds	(1)	(68,061)	87.70%	(59,690)	100.000%	$ (59,690)
45	5010032	Coal Procurement-Aff	(1)		87.70%	-	100.000%	$ -
46	5010033	Coal Procurement-NA	(1)		87.70%	-	100.000%	$ -
47	Incremental purchased power - Non Fuel			PSUM	PSUM			
48	*5550095 INACTIVE*	*Purch Pwr-Trading-Nonassoc (Non-Fuel)*	(3)	$ -	$ -	$ -	100.000%	$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	159,376	72,470	86,906	100.000%	$ 86,906
50	5550032	PP - Mone - Non-Fuel	(3)	17,513	7,197	10,316	100.000%	$ 10,316
51	5550098 INACTIVE	PP - PJM - Non-Fuel	(3)		-	-	100.000%	$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	(3)		-	-	100.000%	$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source OVEC bill)	(3)	1,179,789	100%	1,179,789	100.000%	$ 1,179,789
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	(1)	1,911,082	100%	1,911,082	100.000%	$ 1,911,082
55	5550004	Purchased Power - Pool Capacity	(1)	2,209,117	100%	2,209,117	100.000%	$ 2,209,117
56	5550023	Purchase Power - Capacity	(1)	184,187	100%	184,187	100.000%	$ 184,187
57	5550040	PJM Inadvertent - LSE (only)	(1)	(63,088)	100%	(63,088)	100.000%	$ (63,088)
58	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	100.000%	$ -
59	Lawrenceburg purchased power - Non-Fuel							
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)	(1)	$ 3,047,847	100%	$ 3,047,847	100.000%	$ 3,047,847
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)	(1)	(153,129)	100%	(153,129)	100.000%	$ (153,129)
62	5550046 in part	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)	(3) (5)	17,854	73.69%	13,156	100.000%	$ 13,156
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)	(1) (5)	1,971,439	73.69%	1,452,725	100.000%	$ 1,452,725
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)	(1) (5)	760,138	73.69%	560,135	100.000%	$ 560,135
65	Renewables							
66	5550047	Purchased Power - Wind/Solar	(1)	$ 528,759	100%	528,758	100.000%	$ 528,758
67	5550109	Purchased Power - Solar	(1)	63,236	100%	$ 63,236	100.000%	$ 63,236
68	5570007	Renewable Energy Credit Exp.	(1)	547,551	100%	$ 547,551	100.000%	$ 547,551
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)	(1)	(975,443)	100%	$ (975,443)	100.000%	$ (975,443)
70	Environmental Material & Expense							
71	5020001	Lime Expense	(1)	$ 1,375,779	87.70%	$ 1,206,558	100.000%	$ 1,206,558
72	5020002	Urea Expense	(1)	265,048	87.70%	232,447	100.000%	$ 232,447
73	5020003	Trona Expense	(1)	144,158	87.70%	126,426	100.000%	$ 126,426
74	5020004	Limestone Expense	(1)	272,787	87.70%	239,235	100.000%	$ 239,235
75	5020005	Polymer expense	(1)	135	87.70%	118	100.000%	$ 118
76	5020007	Lime Hydrate Expense	(1)	-	87.70%	-	100.000%	$ -
77	5020008	Activated Carbon	(1)	(3)	87.70%	(3)	100.000%	$ (3)
78	5020025	Steam Exp Environmental	(1)	3,659	87.70%	3,209	100.000%	$ 3,209
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
80	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -		
81	5550039	PJM Inadvertent - OSS (only)	(1)	(6,670)	0%	-		
82	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-		
83	5550099	PJM Purchases - NonECR (Auction)	(1)	2,759,517	0%	-		
84	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	224,299	0%	-		
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)	(1)	9,375,392	0%	-		
86	5550107	*Capacity Purchases -Trading*	(1)	578,278	0%	-		
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)	(1)	-	0%	-		
88	5550069	PP - Monon. Power (2008 PPA only)	(1)	-	0%	-		
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
90	5550075	PJM Reactive Credit	(1)	$ (518,576)	0%	$ -		
91	5550077	PJM Black Start Credit	(1)	(5,085)	0%	-		
92	5550079	PJM Regulation Credit	(1)	(254,662)	0%	-		
93	5550084	PJM Spinning Reserve Credit	(1)	(5,902)	0%	-		
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-		
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
96	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -		
97	5550041	*PJM Synchronous Cond. Charge*	(1)	5,310	0%	-		
98	5550074	PJM Reactive Charge	(1)	510,111	0%	-		
99	5550076	PJM BlackStart Charge	(1)	10,605	0%	-		
100	5550078	PJM Regulation Charge	(1)	620,858	0%	-		
101	5550083	PJM Spinning Reserve Charge	(1)	54,304	0%	-		
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	5,047	0%	-		
103		**Total Additional FAC**		$ 28,249,545		$ 13,664,305		$ 13,664,305
104		TOTAL		$ 90,796,215		$ 61,809,060		$ 61,809,060
105								
106	NOTATIONS:							
107	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
108	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
109	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
110	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
111	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						PIVOT
112								91,751,536

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

JUNE 2010

Line	A	B	C	D	E	F	G	H
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			Net Energy Cost (NEC) in EFC				
2					Assigned	Assigned	Retail	Retail
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 94,124,587	$ 38,901,839	$ 55,222,748		
6	5010009	Fuel Consumed - No Load (CV4)	(2)			-		
7	5010013	Fuel Survey Activity	(2)	(6,533,186)		(6,533,186)		
8	5010019	Fuel Oil Consumed	(2)	196,997		196,997		
9	5010020	Natural Gas Consumed	(2)			-		
10	5010022	Fuel Consumed - Sawdust	(2)	-		-		
11	5470001	Fuel - Gas Turbine	(2)			-		
12		Subtotal - Generation Plant		$ 87,788,398	$ 38,901,839	$ 48,886,559		
13	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	(3)	$ 4,538,411	$ 1,757,943	$ 2,780,468		
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	-	-	$ -		
16	5550080	PJM Energy Purchases (Fuel)	(3)	3,349,653	3,229,699	$ 119,954		
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	5,328,766	5,112,439	216,327		
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	39,058	26,209	12,849		
19	5550031/32	Purchased Pwr - Mone (Fuel)	(3)	15,435	6,343	9,092		
20		Subtotal - Purchased Power Fuel		$ 13,271,323	$ 10,132,633	$ 3,138,690		
21		Total NEC Fuel		$ 101,059,721	$ 49,034,472	$ 52,025,249	92.581%	$ 48,165,496
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt		
24	Emission Allowance Expense				EXH OPCO 2			
25	5090000	Allowance Consumption SO2	(1)	$ 457,742	56.97%	$ 260,775		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	32,512	56.97%	18,522		
27	5090005	Allowance Expenses - Annual NOx	(1)	10,068	56.97%	5,736		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)		56.97%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)	-	56.97%	-		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)	(40,329)	56.97%	(22,976)		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)	(294,012)	56.97%	(167,498)		
33	4119000	Loss Disposition of Allowances	(1)		56.97%	-		
34	4119002	Comp. Allow. Loss - SO2	(1)	-	56.97%	-		
35		Total Allowance Dollars		$ 165,980		$ 94,559	92.581%	$ 87,544
36	**Additional S.B. 221 FAC Accounts Forecast for 2009**			Additional Fuel and Environmental Accounts in FAC				
37						Firm Load		
38	Account	Description	Notes		Allocation Factor	Allocated Amount		
39	Incremental Fuel Handling/Ash/Gypsum				EXH OPCO 2			
40	5010000	Fuel (Ash Handling)	(1)	$ 783,406	56.97%	$ 446,306	92.581%	$ 413,195
41	5010003	Fuel - Procurement, Unloading & Handling	(1)	2,871,651	56.97%	1,635,979	92.581%	$ 1,514,606
42	5010012	Ash Sales Proceeds	(1)	(196,955)	56.97%	(112,205)	92.581%	$ (103,881)
43	5010027	Gypsum handling/disposal costs	(1)	254,079	56.97%	144,749	92.581%	$ 134,010
44	5010028	Gypsum Sales Proceeds	(1)	(109,441)	56.97%	(62,349)	92.581%	$ (57,723)
45	5010029	Gypsum handling/displ-Affiliat	(1)	36,884	56.97%	21,013	92.581%	$ 19,454
46	Incremental purchased power - Non Fuel			PSUM	PSUM			
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	(3)	$ -	-	$ -	92.581%	$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	556,010	215,355	340,655	92.581%	$ 315,382
49	5550032	PP - Mone - Non-Fuel	(3)	20,154	8,282	11,872	92.581%	$ 10,991
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	(3)	-	-	-	92.581%	$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	(3)	-	-	-	92.581%	$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:OVEC bill)	(3)	4,115,976	100%	4,115,976	92.581%	$ 3,810,611
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	(1)	944	100%	944	92.581%	$ 874
54	5550023	PP Capacity - Non Affil.	(1)	211,965	100%	211,965	92.581%	$ 196,239
55	5550040	PJM Inadvertent - LSE (only)	(1)	(72,602)	100%	(72,602)	92.581%	$ (67,216)
56	5550003	PP - Cogeneration	(1)	176,634	100%	176,634	92.581%	$ 163,530
57	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	92.581%	$ -
58	Lawrenceburg purchased power - Non-Fuel (NA)							
59	Renewables							
60	5550047	Purchased Power - Wind	(1)	528,759	100%	$ 528,759	100.00%	$ 528,759
61	5550109	Purchased Power - Solar Energy	(1)	80,482	100%	80,482	100.00%	$ 80,482
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010 (b)	(1)	731,462	100%	731,462	100.00%	$ 731,462
63	5570008	Renewable Energy Credit Exp.	(1)	(1,878,327)	100%	(1,878,327)	100.00%	$ (1,878,327)
64	5570009	Other Pwr Exp - REC's - RETAIL	(1)	1,529,387	100%	1,529,387	100.00%	$ 1,529,387
65	Environmental Material & Expense							
66	5020001	Lime Expense	(1)	$ 2,984,025	56.97%	$ 1,699,999	92.581%	$ 1,573,876
67	5020002	Urea Expense	(1)	2,134,217	56.97%	1,215,863	92.581%	$ 1,125,658
68	5020003	Trona Expense	(1)	1,049,085	56.97%	597,664	92.581%	$ 553,323
69	5020004	Limestone Expense	(1)	1,349,055	56.97%	768,556	92.581%	$ 711,537
70	5020005	Polymer expense	(1)	190,344	56.97%	108,439	92.581%	$ 100,394
71	5020007	Lime Hydrate Expense	(1)	4,972	56.97%	2,833	92.581%	$ 2,622
72	5020008	Activated Carbon	(1)	(10)	56.97%	(6)	92.581%	$ (5)
73	5020025	Steam Exp Environmental	(1)	38,576	56.97%	21,977	92.581%	$ 20,346
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
75	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -	92.581%	$ -
76	5550039	PJM Inadvertent - OSS (only)	(1)	(7,676)	0%	-	92.581%	$ -
77	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-	92.581%	$ -
78	5550099	PJM Purchases - NonECR (Auction)	(1)	3,175,688	0%	-	92.581%	$ -
79	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	258,126	0%	-	92.581%	$ -
80	5550102	PP Pool Non Fuel - OSS Aff	(1)	10,187,658	0%	-	92.581%	$ -
81	5550107	Capacity Purchases - Trading	(1)	665,490	0%	-	92.581%	$ -
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)	(1)	-	0%	-	92.581%	$ -
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
84	5550075	PJM Reactive Credit	(1)	$ (596,783)	0%	$ -	92.581%	$ -
85	5550077	PJM Black Start Credit	(1)	(5,852)	0%	-	92.581%	$ -
86	5550079	PJM Regulation Credit	(1)	(293,068)	0%	-	92.581%	$ -
87	5550084	PJM Spinning Reserve Credit	(1)	(6,792)	0%	-	92.581%	$ -
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-	92.581%	$ -
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
90	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -	92.581%	$ -
91	5550041	PJM Synchronous Cond. Charge	(1)	6,110	0%	-	92.581%	$ -
92	5550074	PJM Reactive Charge	(1)	587,042	0%	-	92.581%	$ -
93	5550076	PJM BlackStart Charge	(1)	12,204	0%	-	92.581%	$ -
94	5550078	PJM Regulation Charge	(1)	714,491	0%	-	92.581%	$ -
95	5550083	PJM Spinning Reserve Charge	(1)	62,493	0%	-	92.581%	$ -
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	5,808	0%	-	92.581%	$ -
97		Total Additional FAC		$ 32,155,670		$ 12,266,025		$ 11,429,587
98		TOTAL		$ 133,381,372		$ 64,385,833		$ 59,682,627
99								
100	NOTATIONS:							
101	(1)	Total Co amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
102	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c	(b)	only included to properly reflect REC adjustments recorded by account.				
103	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
104	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
105	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						
106								

Line	A	B	C	D	E	F	G	H
		ACTUAL CYCLE					EXH CSP-1	
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)						
		JULY 2010						
Line	A	B	C	D	E	F	G	H
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail
2					Assigned	Assigned	Allocation	FAC Cost
3	Account	Description	Notes	Total	Off-System	To Firm Load		
4	Generation Fuel			NEC	NEC (4)			
5	5010001/5010022/501002	Fuel Consumed	(2)	$ 27,417,148	$ 10,340,185	$ 17,076,963		
6	5010009	Fuel Consumed - No Load (CV4)	(2)	165,770		165,770		
7	5010013	Fuel Survey Activity	(2)	-	-	-		
8	5010019	Fuel Oil Consumed	(2)	617,486		617,486		
9	5010020/5010036	Natural Gas Consumed	(2)	9,127,618	-	9,127,618		
10	5470001/5470003	Fuel - Gas Turbine	(2)	-	$ -	-		
11		Subtotal - Generation Fuel		$ 37,328,022	$ 10,340,185	$ 26,987,837		
12	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	(3)	$ 1,009,861	$ 696,403	$ 313,458		
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	18,961,999	-	18,961,999		
15	5550080	PJM Energy Purchases (Fuel)	(3)	2,780,931	2,770,131	10,800		
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	6,281,229	6,258,287	22,942		
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	43,116	43,116	-		
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	(3)	13,113,160	1,320,939	11,792,221		
19	5550032	Purchased Pwr - Mone (Fuel)	(3)	143,070	143,070	-		
20		Subtotal - Purchased Power Fuel		$ 42,333,366	$ 11,231,946	$ 31,101,420		
21		Total NEC Fuel		$ 79,661,388	$ 21,572,131	$ 58,089,257	100.000%	$ 58,089,257
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt		
24	Emission Allowance Expense				(EXH CSP 2)			
25	5090000/2	Allowance Consumption - SO2	(1)	$ 151,488	81.31%	$ 123,175		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	171,128	81.31%	139,144		
27	5090005	Allowance Expenses - Annual NOx	(1)	51,322	81.31%	41,730		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)	-	81.31%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)		81.31%	$ -		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)		81.31%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)		81.31%	-		
33	4119000	Loss Disposition of Allowances	(1)		81.31%	-		
34		Total Allowance Dollars		$ 373,937		$ 304,048	100.000%	$ 304,048
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC				
36						Firm Load		
37	Account	Description	Notes		Allocation Factor	Allocated Amt		
38	Incremental Fuel Handling/Ash/Gypsum				(EXH CSP 2)			
39	5010000	Fuel (Ash Handling)	(1)	$ 675,964	81.31%	$ 549,626	100.000%	$ 549,626
40	5010003	Fuel - Procurement, Unloading & Handling	(1)	723,666	81.31%	588,412	100.000%	$ 588,412
41	5010011	Fuel Handling - No Load (CV4)	(1)	20,513	81.31%	16,679	100.000%	$ 16,679
42	5010012	Ash Sales Proceeds	(1)	(6,603)	81.31%	(5,369)	100.000%	$ (5,369)
43	5010027	Gypsum handling/disposal costs	(1)	183,706	81.31%	149,372	100.000%	$ 149,372
44	5010028	Gypsum Sales Proceeds	(1)	(54,203)	81.31%	(44,072)	100.000%	$ (44,072)
45	5010032	Coal Procurement-Aff	(1)		81.31%	-	100.000%	$ -
46	5010033	Coal Procurement-NA	(1)		81.31%	-	100.000%	$ -
47	Incremental purchased power - Non Fuel			PSUM	PSUM			
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	(3)	$ -	$ -	$ -	100.000%	$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	95,854	66,110	29,744	100.000%	$ 29,744
50	5550032 - in part	PP - Mone - Non-Fuel	(3)	20,485	20,484	1	100.000%	$ 1
51	5550098 INACTIVE	PP - PJM - Non-Fuel	(3)		-	-	100.000%	$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	(3)		-	-	100.000%	$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source OVEC bill)	(3)	956,625	100%	956,625	100.000%	$ 956,625
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	(1)	1,842,144	100%	1,842,144	100.000%	$ 1,842,144
55	5550004	Purchased Power - *Pool Capacity*	(1)	2,540,502	100%	2,540,502	100.000%	$ 2,540,502
56	5550023	Purchase Power - Capacity	(1)	183,836	100%	183,836	100.000%	$ 183,836
57	5550040	PJM Inadvertent - LSE (only)	(1)	(50,090)	100%	(50,090)	100.000%	$ (50,090)
58	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	100.000%	$ -
59	Lawrenceburg purchased power - Non-Fuel							
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)	(1)	$ 3,047,847	100%	$ 3,047,847	100.000%	$ 3,047,847
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)	(1)	(153,129)	100%	(153,129)	100.000%	$ (153,129)
62	5550046 - in part	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)	(3) (5)	22,374	79.74%	17,840	100.000%	$ 17,840
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)	(1) (5)	1,361,817	79.74%	1,085,861	100.000%	$ 1,085,861
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)	(1) (5)	753,394	79.74%	600,728	100.000%	$ 600,728
65	Renewables							
66	5550047	Purchased Power - Wind/Solar	(1)	$ 392,378	100%	392,377	100.000%	$ 392,377
67	5550109	Purchased Power - Solar	(1)	41,918	100%	$ 41,918	100.000%	$ 41,918
68	5570007	Renewable Energy Credit Exp.	(1)	-	100%	$ -	100.000%	$ -
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)	(1)	163,167	100%	$ 163,167	100.000%	$ 163,167
70	Environmental Material & Expense							
71	5020001	Lime Expense	(1)	$ 1,994,131	81.31%	$ 1,621,428	100.000%	$ 1,621,428
72	5020002	Urea Expense	(1)	262,250	81.31%	213,236	100.000%	$ 213,236
73	5020003	Trona Expense	(1)	51,987	81.31%	42,271	100.000%	$ 42,271
74	5020004	Limestone Expense	(1)	135,659	81.31%	110,305	100.000%	$ 110,305
75	5020005	Polymer expense	(1)	78	81.31%	63	100.000%	$ 63
76	5020007	Lime Hydrate Expense	(1)	-	81.31%	-	100.000%	$ -
77	5020008	Activated Carbon	(1)	-	81.31%	-	100.000%	$ -
78	5020025	Steam Exp Environmental	(1)	3,455	81.31%	2,809	100.000%	$ 2,809
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
80	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -		
81	5550039	PJM Inadvertent - OSS (only)	(1)	(5,100)	0%	-		
82	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-		
83	5550099	PJM Purchases - NonECR (Auction)	(1)	3,430,118	0%	-		
84	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	412,074	0%	-		
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)	(1)	14,895,330	0%	-		
86	5550107	Capacity Purchases -Trading	(1)	389,672	0%	-		
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)	(1)	-	0%	-		
88	5550069	PP - Monon. Power (2008 PPA only)	(1)	-	0%	-		
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
90	5550075	PJM Reactive Credit	(1)	$ (517,587)	0%	$ -		
91	5550077	PJM Black Start Credit	(1)	(5,384)	0%	-		
92	5550079	PJM Regulation Credit	(1)	(354,324)	0%	-		
93	5550084	PJM Spinning Reserve Credit	(1)	(49,600)	0%	-		
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-		
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
96	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -		
97	5550041	PJM Synchronous Cond. Charge	(1)	36	0%	-		
98	5550074	PJM Reactive Charge	(1)	502,184	0%	-		
99	5550076	PJM BlackStart Charge	(1)	10,224	0%	-		
100	5550078	PJM Regulation Charge	(1)	1,016,368	0%	-		
101	5550083	PJM Spinning Reserve Charge	(1)	23,253	0%	-		
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	24,789	0%	-		
103		Total Additional FAC		$ 34,781,778		$ 13,944,131		$ 13,944,131
104		TOTAL		$ 114,817,103		$ 72,337,436		$ 72,337,436
105								
106	NOTATIONS:							
107	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
108	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
109	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
110	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
111	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						PIVOT
112								113,649,681

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

JULY 2010

Line	A	B	C	D	E	F	G	H
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			Net Energy Cost (NEC) in EFC				
2					Assigned	Assigned	Retail	Retail
3	**Account**	**Description**	**Notes**	**Total**	**Off-System**	**To Firm Load**	**Allocation**	**FAC Cost**
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 105,196,511	$ 45,526,790	$ 59,669,721		
6	5010009	Fuel Consumed - No Load (CV4)	(2)			-		
7	5010013	Fuel Survey Activity	(2)	(158,025)		(158,025)		
8	5010019	Fuel Oil Consumed	(2)	1,060,161		1,060,161		
9	5010020	Natural Gas Consumed	(2)			-		
10	5010022	Fuel Consumed - Sawdust	(2)	-		-		
11	5470001	Fuel - Gas Turbine	(2)			-		
12		**Subtotal - Generation Plant**		**$ 106,098,647**	**$ 45,526,790**	**$ 60,571,857**		
13	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	(3)	$ 3,517,153	$ 2,120,425	$ 1,396,728		
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	-	-	$ -		
16	5550080	PJM Energy Purchases (Fuel)	(3)	3,238,151	3,225,575	$ 12,576		
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	7,313,944	7,287,230	26,714		
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	50,204	50,204	-		
19	5550031/32	Purchased Pwr - Mone (Fuel)	(3)	166,592	166,592	-		
20		**Subtotal - Purchased Power Fuel**		**$ 14,286,044**	**$ 12,850,026**	**$ 1,436,018**		
21		**Total NEC Fuel**		**$ 120,384,691**	**$ 58,376,816**	**$ 62,007,875**	92.220%	$ 57,183,662
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt		
24	Emission Allowance Expense				EXH OPCo 2			
25	5090000	Allowance Consumption SO2	(1)	$ 995,571	57.11%	$ 568,571		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	36,864	57.11%	21,053		
27	5090005	Allowance Expenses - Annual NOx	(1)	11,416	57.11%	6,520		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)		57.11%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)	-	57.11%	-		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)	-	57.11%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)	(180,750)	57.11%	(103,226)		
33	4119000	Loss Disposition of Allowances	(1)		57.11%	-		
34	4119002	Comp. Allow. Loss - SO2	(1)	-	57.11%	-		
35		**Total Allowance Dollars**		**$ 863,101**		**$ 492,917**	92.220%	$ 454,568
36	**Additional S.B. 221 FAC Accounts Forecast for 2009**			Additional Fuel and Environmental Accounts in FAC				
37						Firm Load		
38	**Account**	**Description**	**Notes**		**Allocation Factor**	**Allocated Amount**		
39	Incremental Fuel Handling/Ash/Gypsum				EXH OPCo 2			
40	5010000	Fuel (Ash Handling)	(1)	$ 1,380,671	57.11%	$ 788,501	92.220%	$ 727,156
41	5010003	Fuel - Procurement, Unloading & Handling	(1)	3,429,937	57.11%	1,958,837	92.220%	$ 1,806,439
42	5010012	Ash Sales Proceeds	(1)	(103,833)	57.11%	(59,299)	92.220%	$ (54,685)
43	5010027	Gypsum handling/disposal costs	(1)	308,429	57.11%	176,144	92.220%	$ 162,440
44	5010028	Gypsum Sales Proceeds	(1)	(116,973)	57.11%	(66,803)	92.220%	$ (61,606)
45	5010029	Gypsum handling/displ-Affiliat	(1)	41,810	57.11%	23,878	92.220%	$ 22,020
46	Incremental purchased power - Non Fuel			PSUM	PSUM			
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	(3)	$ -	-	$ -	92.220%	$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	333,999	201,403	132,596	92.220%	$ 122,280
49	5550032	PP - Mone - Non-Fuel	(3)	23,853	23,852	1	92.220%	$ 1
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	(3)	-	-	-	92.220%	$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	(3)	-	-	-	92.220%	$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:OVEC bill)	(3)	3,337,415	100%	3,337,415	92.220%	$ 3,077,764
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	(1)	-	100%	-	92.220%	$ -
54	5550023	PP Capacity - Non Affil.	(1)	214,061	100%	214,061	92.220%	$ 197,407
55	5550040	PJM Inadvertent - LSE (only)	(1)	(58,207)	100%	(58,207)	92.220%	$ (53,679)
56	5550003	PP - Cogeneration	(1)	-	100%	-	92.220%	$ -
57	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	92.220%	$ -
58	Lawrenceburg purchased power - Non-Fuel (NA)							
59	Renewables							
60	5550047	Purchased Power - Wind	(1)	392,378	100%	$ 392,378	100.00%	$ 392,378
61	5550109	Purchased Power - Solar Energy	(1)	53,351	100%	53,351	100.00%	$ 53,351
62	5570007	Other Pwr Exp - RECs	(1)	-	100%	-	100.00%	$ -
63	5570008	Renewable Energy Credit Exp.	(1)	-	100%	-	100.00%	$ -
64	5570009	Other Pwr Exp - REC's - RETAIL	(1)	202,747	100%	202,747	100.00%	$ 202,747
65	Environmental Material & Expense							
66	5020001	Lime Expense	(1)	$ 3,738,186	57.11%	$ 2,134,878	92.220%	$ 1,968,785
67	5020002	Urea Expense	(1)	2,116,987	57.11%	1,209,011	92.220%	$ 1,114,950
68	5020003	Trona Expense	(1)	209,162	57.11%	119,453	92.220%	$ 110,159
69	5020004	Limestone Expense	(1)	1,416,842	57.11%	809,158	92.220%	$ 746,206
70	5020005	Polymer expense	(1)	265,106	57.11%	151,402	92.220%	$ 139,623
71	5020007	Lime Hydrate Expense	(1)	(0)	57.11%	(0)	92.220%	$ (0)
72	5020008	Activated Carbon	(1)	-	57.11%	-	92.220%	$ -
73	5020025	Steam Exp Environmental	(1)	45,695	57.11%	26,096	92.220%	$ 24,066
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
75	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -	92.220%	$ -
76	5550039	PJM Inadvertent - OSS (only)	(1)	(5,919)	0%	-	92.220%	$ -
77	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-	92.220%	$ -
78	5550099	PJM Purchases - NonECR (Auction)	(1)	3,994,255	0%	-	92.220%	$ -
79	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	479,234	0%	-	92.220%	$ -
80	5550102	PP Pool Non Fuel - OSS Aff	(1)	16,247,398	0%	-	92.220%	$ -
81	5550107	Capacity Purchases - Trading	(1)	455,124	0%	-	92.220%	$ -
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)	(1)	-	0%	-	92.220%	$ -
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
84	5550075	PJM Reactive Credit	(1)	$ (602,685)	0%	$ -	92.220%	$ -
85	5550077	PJM Black Start Credit	(1)	(6,269)	0%	-	92.220%	$ -
86	5550079	PJM Regulation Credit	(1)	(412,571)	0%	-	92.220%	$ -
87	5550084	PJM Spinning Reserve Credit	(1)	(57,081)	0%	-	92.220%	$ -
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-	92.220%	$ -
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
90	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -	92.220%	$ -
91	5550041	PJM Synchronous Cond. Charge	(1)	79	0%	-	92.220%	$ -
92	5550074	PJM Reactive Charge	(1)	585,188	0%	-	92.220%	$ -
93	5550076	PJM BlackStart Charge	(1)	11,917	0%	-	92.220%	$ -
94	5550078	PJM Regulation Charge	(1)	1,181,399	0%	-	92.220%	$ -
95	5550083	PJM Spinning Reserve Charge	(1)	26,759	0%	-	92.220%	$ -
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	28,528	0%	-	92.220%	$ -
97		**Total Additional FAC**		$ 39,156,972		$ 11,545,597		$ 10,697,801
98		**TOTAL**		$ 160,404,764		$ 74,046,389		$ 68,336,032
99								
100	NOTATIONS:							
101	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
102	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
103	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
104	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
105	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						
106								

		ACTUAL CYCLE					EXH CSP-1	
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)						
		AUGUST 2010						
Line	A	B	C	D	E	F	G	H
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail
2					Assigned	Assigned	Allocation	FAC Cost
3	Account	Description	Notes	Total	Off-System	To Firm Load		
4	Generation Fuel			NEC	NEC (4)			
5	5010001/5010022	Fuel Consumed	(2)	$ 27,592,176	$ 8,689,615	$ 18,902,561		
6	5010009	Fuel Consumed - No Load (CV4)	(2)	719,889		719,889		
7	5010013	Fuel Survey Activity	(2)	-	-	-		
8	5010019	Fuel Oil Consumed	(2)	457,865		457,865		
9	5010020/5010036	Natural Gas Consumed	(2)	8,743,218	-	8,743,218		
10	5470001/5470003	Fuel - Gas Turbine	(2)	-	$ -	-		
11		Subtotal - Generation Fuel		$ 37,513,148	$ 8,689,615	$ 28,823,533		
12	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	(3)	$ 1,303,447	$ 616,657	$ 686,790		
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	15,050,929	-	15,050,929		
15	5550080	PJM Energy Purchases (Fuel)	(3)	3,055,678	2,979,265	76,413		
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	5,246,530	5,217,861	28,669		
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	54,511	54,511	-		
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	(3)	12,461,417	1,788,717	10,672,700		
19	5550032	Purchased Pwr - Mone (Fuel)	(3)	183,046	181,409	1,637		
20		Subtotal - Purchased Power Fuel		$ 37,355,558	$ 10,838,420	$ 26,517,138		
21		Total NEC Fuel		$ 74,868,705	$ 19,528,035	$ 55,340,670	100.000%	$ 55,340,670
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount		
24	Emission Allowance Expense				EXH CSP 2			
25	5090000/2	Allowance Consumption - SO2	(1)	$ (235,695)	83.35%	$ (196,452)		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	131,060	83.35%	109,239		
27	5090005	Allowance Expenses - Annual NOx	(1)	44,432	83.35%	37,034		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)	-	83.35%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)		83.35%	$ -		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)		83.35%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)		83.35%	-		
33	4119000	Loss Disposition of Allowances	(1)		83.35%	-		
34		Total Allowance Dollars		$ (60,203)		$ (50,179)	100.000%	$ (50,179)
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC				
36						Firm Load		
37	Account	Description	Notes		Allocation Factor	Allocated Amount		
38	Incremental Fuel Handling/Ash/Gypsum				EXH CSP 2			
39	5010000	Fuel (Ash Handling)	(1)	$ 776,255	83.35%	$ 647,009	100.000%	$ 647,009
40	5010003	Fuel - Procurement, Unloading & Handling	(1)	1,016,426	83.35%	847,191	100.000%	$ 847,191
41	5010011	Fuel Handling - No Load (CV4)	(1)	(1,997)	83.35%	(1,665)	100.000%	$ (1,665)
42	5010012	Ash Sales Proceeds	(1)	(7,379)	83.35%	(6,151)	100.000%	$ (6,151)
43	5010027	Gypsum handling/disposal costs	(1)	98,555	83.35%	82,146	100.000%	$ 82,146
44	5010028	Gypsum Sales Proceeds	(1)	(42,521)	83.35%	(35,441)	100.000%	$ (35,441)
45	5010032	Coal Procurement-Aff	(1)		83.35%	-	100.000%	$ -
46	5010033	Coal Procurement-NA	(1)		83.35%	-	100.000%	$ -
47	Incremental purchased power - Non Fuel			PSUM	PSUM			
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	(3)	$ -	$ -	$ -	100.000%	$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	110,531	52,293	58,238	100.000%	$ 58,238
50	5550032	PP - Mone - Non-Fuel	(3)	17,020	16,888	132	100.000%	$ 132
51	5550098 INACTIVE	PP - PJM - Non-Fuel	(3)		-	-	100.000%	$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	(3)		-	-	100.000%	$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source OVEC bill)	(3)	1,075,452	100%	1,075,452	100.000%	$ 1,075,452
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	(1)	1,420,671	100%	1,420,671	100.000%	$ 1,420,671
55	5550004	Purchased Power - Pool Capacity	(1)	1,533,841	100%	1,533,841	100.000%	$ 1,533,841
56	5550023	Purchase Power - Capacity	(1)	181,964	100%	181,964	100.000%	$ 181,964
57	5550040	PJM Inadvertent - LSE (only)	(1)	(52,446)	100%	(52,446)	100.000%	$ (52,446)
58	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	100.000%	$ -
59	Lawrenceburg purchased power - Non-Fuel							
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)	(1)	$ 3,047,847	100%	$ 3,047,847	100.000%	$ 3,047,847
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)	(1)	(153,129)	100%	(153,129)	100.000%	$ (153,129)
62	5550046 in part	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)	(3) (5)	18,313	84.45%	15,465	100.000%	$ 15,465
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)	(1) (5)	1,124,907	84.45%	949,948	100.000%	$ 949,948
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)	(1) (5)	738,071	84.45%	623,277	100.000%	$ 623,277
65	Renewables							
66	5550047	Purchased Power - Wind/Solar	(1)	$ 334,108	100%	334,107	100.000%	$ 334,107
67	5550109	Purchased Power - Solar	(1)	77,079	100%	$ 77,079	100.000%	$ 77,079
68	5570007	Renewable Energy Credit Exp.	(1)	-	100%	$ -	100.000%	$ -
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)	(1)	149,949	100%	$ 149,949	100.000%	$ 149,949
70	Environmental Material & Expense							
71	5020001	Lime Expense	(1)	$ 1,537,991	83.35%	$ 1,281,916	100.000%	$ 1,281,916
72	5020002	Urea Expense	(1)	304,833	83.35%	254,079	100.000%	$ 254,079
73	5020003	Trona Expense	(1)	189,486	83.35%	157,936	100.000%	$ 157,936
74	5020004	Limestone Expense	(1)	472,589	83.35%	393,903	100.000%	$ 393,903
75	5020005	Polymer expense	(1)	105	83.35%	87	100.000%	$ 87
76	5020007	Lime Hydrate Expense	(1)	-	83.35%	-	100.000%	$ -
77	5020008	Activated Carbon	(1)	-	83.35%	-	100.000%	$ -
78	5020025	Steam Exp Environmental	(1)	2,639	83.35%	2,200	100.000%	$ 2,200
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
80	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -		
81	5550039	PJM Inadvertent - OSS (only)	(1)	(7,062)	0%	-		
82	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-		
83	5550099	PJM Purchases - NonECR (Auction)	(1)	2,878,411	0%	-		
84	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	304,243	0%	-		
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)	(1)	10,885,942	0%	-		
86	5550107	Capacity Purchases -Trading	(1)	494,470	0%	-		
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)	(1)	-	0%	-		
88	5550069	PP - Monon. Power (2008 PPA only)	(1)	-	0%	-		
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
90	5550075	PJM Reactive Credit	(1)	$ (512,317)	0%	$ -		
91	5550077	PJM Black Start Credit	(1)	(6,292)	0%	-		
92	5550079	PJM Regulation Credit	(1)	(323,825)	0%	-		
93	5550084	PJM Spinning Reserve Credit	(1)	(12,979)	0%	-		
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-		
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
96	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -		
97	5550041	PJM Synchronous Cond. Charge	(1)	2,367	0%	-		
98	5550074	PJM Reactive Charge	(1)	450,419	0%	-		
99	5550076	PJM BlackStart Charge	(1)	4,667	0%	-		
100	5550078	PJM Regulation Charge	(1)	854,760	0%	-		
101	5550083	PJM Spinning Reserve Charge	(1)	49,913	0%	-		
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	104,596	0%	-		
103		Total Additional FAC		$ 29,136,471		$ 12,885,603		$ 12,885,603
104		TOTAL		$ 103,946,974		$ 68,176,095		$ 68,176,095
105								
106	NOTATIONS:							
107	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
108	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
109	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
110	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
111	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						PIVOT
112								103,812,661

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

AUGUST 2010

Line	A	B	C	D	E	F	G	H
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			**Net Energy Cost (NEC) in EFC**				
2					**Assigned**	**Assigned**	**Retail**	**Retail**
3	**Account**	**Description**	**Notes**	**Total**	**Off-System**	**To Firm Load**	**Allocation**	**FAC Cost**
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 96,699,592	$ 40,788,465	$ 55,911,127		
6	5010009	Fuel Consumed - No Load (CV4)	(2)			-		
7	5010013	Fuel Survey Activity	(2)	1,648,644		1,648,644		
8	5010019	Fuel Oil Consumed	(2)	1,639,297		1,639,297		
9	5010020	Natural Gas Consumed	(2)			-		
10	5010022	Fuel Consumed - Sawdust	(2)	-		-		
11	5470001	Fuel - Gas Turbine	(2)			-		
12		**Subtotal - Generation Plant**		**$ 99,987,533**	**$ 40,788,465**	**$ 59,199,068**		
13	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	(3)	$ 4,542,958	$ 1,810,203	$ 2,732,755		
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	-	-	$ -		
16	5550080	PJM Energy Purchases (Fuel)	(3)	3,729,751	3,636,481	$ 93,270		
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	6,403,890	6,368,907	34,983		
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	66,537	66,536	1		
19	5550031/32	Purchased Pwr - Mone (Fuel)	(3)	223,425	221,427	1,998		
20		**Subtotal - Purchased Power Fuel**		**$ 14,966,561**	**$ 12,103,554**	**$ 2,863,007**		
21		**Total NEC Fuel**		**$ 114,954,094**	**$ 52,892,019**	**$ 62,062,075**	92.636%	$ 57,491,824
22						**Firm Load**		
23	*Allowance Accounts In FAC:*				**Allocation Factor**	**Allocated Amt**		
24	Emission Allowance Expense				EXH OPCO 2			
25	5090000	Allowance Consumption SO2	(1)	$ 1,843,216	58.70%	$ 1,081,968		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	30,298	58.70%	17,785		
27	5090005	Allowance Expenses - Annual NOx	(1)	9,920	58.70%	5,823		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)	-	58.70%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)	-	58.70%	-		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)	-	58.70%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)	(179,642)	58.70%	(105,450)		
33	4119000	Loss Disposition of Allowances	(1)		58.70%	-		
34	4119002	Comp. Allow. Loss - SO2	(1)	-	58.70%	-		
35		**Total Allowance Dollars**		**$ 1,703,791**		**$ 1,000,125**	92.636%	$ 926,476
36	**Additional S.B. 221 FAC Accounts Forecast for 2009**			**Additional Fuel and Environmental Accounts in FAC**				
37						**Firm Load**		
38	**Account**	**Description**	**Notes**		**Allocation Factor**	**Allocated Amount**		
39	Incremental Fuel Handling/Ash/Gypsum				EXH OPCO 2			
40	5010000	Fuel (Ash Handling)	(1)	$ 1,092,217	58.70%	$ 641,131	92.636%	$ 593,918
41	5010003	Fuel - Procurement, Unloading & Handling	(1)	3,029,102	58.70%	1,778,083	92.636%	$ 1,647,145
42	5010012	Ash Sales Proceeds	(1)	(183,813)	58.70%	(107,898)	92.636%	$ (99,952)
43	5010027	Gypsum handling/disposal costs	(1)	444,700	58.70%	261,039	92.636%	$ 241,816
44	5010028	Gypsum Sales Proceeds	(1)	(70,627)	58.70%	(41,458)	92.636%	$ (38,405)
45	5010029	Gypsum handling/displ-Affiliat	(1)	41,768	58.70%	24,518	92.636%	$ 22,713
46	Incremental purchased power - Non Fuel			PSUM	PSUM			
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	(3)	$ -	-	$ -	92.636%	$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	386,886	154,172	232,714	92.636%	$ 215,577
49	5550032	PP - Mone - Non-Fuel	(3)	20,775	20,614	161	92.636%	$ 149
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	(3)	-	-	-	92.636%	$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	(3)	-	-	-	92.636%	$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:OVEC bill)	(3)	3,751,971	100%	3,751,971	92.636%	$ 3,475,676
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	(1)	-	100%	-	92.636%	$ -
54	5550023	PP Capacity - Non Affil.	(1)	222,105	100%	222,105	92.636%	$ 205,749
55	5550040	PJM Inadvertent - LSE (only)	(1)	(63,846)	100%	(63,846)	92.636%	$ (59,144)
56	5550003	PP - Cogeneration	(1)	503,866	100%	503,866	92.636%	$ 466,761
57	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	92.636%	$ -
58	Lawrenceburg purchased power - Non-Fuel (NA)							
59	Renewables							
60	5550047	Purchased Power - Wind	(1)	334,108	100%	$ 334,108	100.00%	$ 334,108
61	5550109	Purchased Power - Solar Energy	(1)	98,100	100%	98,100	100.00%	$ 98,100
62	5570007	Other Pwr Exp - RECs	(1)	-	100%	-	100.00%	$ -
63	5570008	Renewable Energy Credit Exp.	(1)	-	100%	-	100.00%	$ -
64	5570009	Other Pwr Exp - REC's - RETAIL	(1)	207,771	100%	207,771	100.00%	$ 207,771
65	Environmental Material & Expense							
66	5020001	Lime Expense	(1)	$ 3,097,503	58.70%	$ 1,818,234	92.636%	$ 1,684,340
67	5020002	Urea Expense	(1)	1,966,717	58.70%	1,154,463	92.636%	$ 1,069,448
68	5020003	Trona Expense	(1)	834,270	58.70%	489,716	92.636%	$ 453,654
69	5020004	Limestone Expense	(1)	1,403,703	58.70%	823,974	92.636%	$ 763,296
70	5020005	Polymer expense	(1)	198,969	58.70%	116,795	92.636%	$ 108,194
71	5020007	Lime Hydrate Expense	(1)	3,435	58.70%	2,016	92.636%	$ 1,868
72	5020008	Activated Carbon	(1)	-	58.70%	-	92.636%	$ -
73	5020025	Steam Exp Environmental	(1)	45,644	58.70%	26,793	92.636%	$ 24,820
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
75	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -	92.636%	$ -
76	5550039	PJM Inadvertent - OSS (only)	(1)	(8,461)	0%	-	92.636%	$ -
77	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-	92.636%	$ -
78	5550099	PJM Purchases - NonECR (Auction)	(1)	3,516,467	0%	-	92.636%	$ -
79	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	371,622	0%	-	92.636%	$ -
80	5550102	PP Pool Non Fuel - OSS Aff	(1)	12,345,167	0%	-	92.636%	$ -
81	5550107	Capacity Purchases - Trading	(1)	603,663	0%	-	92.636%	$ -
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)	(1)	-	0%	-	92.636%	$ -
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
84	5550075	PJM Reactive Credit	(1)	$ (625,332)	0%	$ -	92.636%	$ -
85	5550077	PJM Black Start Credit	(1)	(7,615)	0%	-	92.636%	$ -
86	5550079	PJM Regulation Credit	(1)	(395,707)	0%	-	92.636%	$ -
87	5550084	PJM Spinning Reserve Credit	(1)	(15,113)	0%	-	92.636%	$ -
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-	92.636%	$ -
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
90	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -	92.636%	$ -
91	5550041	PJM Synchronous Cond. Charge	(1)	2,904	0%	-	92.636%	$ -
92	5550074	PJM Reactive Charge	(1)	553,700	0%	-	92.636%	$ -
93	5550076	PJM BlackStart Charge	(1)	6,038	0%	-	92.636%	$ -
94	5550078	PJM Regulation Charge	(1)	1,036,253	0%	-	92.636%	$ -
95	5550083	PJM Spinning Reserve Charge	(1)	58,119	0%	-	92.636%	$ -
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	121,795	0%	-	92.636%	$ -
97		**Total Additional FAC**		$ 34,928,825		$ 12,274,357		$ 11,417,602
98		**TOTAL**		$ 151,586,710		$ 75,336,558		$ 69,835,902
99								
100	NOTATIONS:							
101	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
102	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
103	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
104	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
105	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						
106								

		ACTUAL CYCLE					EXH CSP-1	
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)						
		SEPT 2010						
Line	A	B	C	D	E	F	G	H
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail
2					Assigned	Assigned	Allocation	FAC Cost
3	Account	Description	Notes	Total	Off-System	To Firm Load		
4	Generation Fuel			NEC	NEC (4)			
5	5010001/5010022	Fuel Consumed	(2)	$ 17,290,685	$ 2,044,813	$ 15,245,872		
6	5010009	Fuel Consumed - No Load (CV4)	(2)	719,889		719,889		
7	5010013	Fuel Survey Activity	(2)	-	-	-		
8	5010019	Fuel Oil Consumed	(2)	547,014		547,014		
9	5010020/5010036	Natural Gas Consumed	(2)	2,959,288	-	2,959,288		
10	5470001/5470003	Fuel - Gas Turbine	(2)	26,914	$ -	26,914		
11		Subtotal - Generation Fuel		$ 21,543,790	$ 2,044,813	$ 19,498,977		
12	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	(3)	$ 1,201,572	$ 561,126	$ 640,446		
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	14,166,793	-	14,166,793		
15	5550080	PJM Energy Purchases (Fuel)	(3)	4,002,914	3,311,210	691,704		
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	1,677,382	1,512,428	164,954		
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	18,161	10,918	7,243		
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	(3)	4,109,161	316,278	3,792,883		
19	5550032	Purchased Pwr - Mone (Fuel)	(3)	21,868	21,868	-		
20		Subtotal - Purchased Power Fuel		$ 25,197,851	$ 5,733,828	$ 19,464,023		
21		Total NEC Fuel		$ 46,741,640	$ 7,778,641	$ 38,962,999	100.000%	$ 38,962,999
22						Firm Load		
23	Allowance Accounts in FAC:				Allocation Factor	Allocated Amount		
24	Emission Allowance Expense				EXH CSP 2			
25	5090000/2	Allowance Consumption - SO2	(1)	$ 414,332	93.47%	$ 387,276		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	84,659	93.47%	79,131		
27	5090005	Allowance Expenses - Annual NOx	(1)	28,421	93.47%	26,565		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)	-	93.47%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)		93.47%	$ -		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)		93.47%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)		93.47%	-		
33	4119000	Loss Disposition of Allowances	(1)		93.47%	-		
34		Total Allowance Dollars		$ 527,413		$ 492,973	100.000%	$ 492,973
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC				
36						Firm Load		
37	Account	Description	Notes		Allocation Factor	Allocated Amount		
38	Incremental Fuel Handling/Ash/Gypsum				EXH CSP 2			
39	5010000	Fuel (Ash Handling)	(1)	$ 746,006	93.47%	$ 697,292	100.000%	$ 697,292
40	5010003	Fuel - Procurement, Unloading & Handling	(1)	582,174	93.47%	544,158	100.000%	$ 544,158
41	5010011	Fuel Handling - No Load (CV4)	(1)	53,726	93.47%	50,218	100.000%	$ 50,218
42	5010012	Ash Sales Proceeds	(1)	(21,077)	93.47%	(19,700)	100.000%	$ (19,700)
43	5010027	Gypsum handling/disposal costs	(1)	149,687	93.47%	139,913	100.000%	$ 139,913
44	5010028	Gypsum Sales Proceeds	(1)	(35,234)	93.47%	(32,933)	100.000%	$ (32,933)
45	5010032	Coal Procurement-Aff	(1)		93.47%	-	100.000%	$ -
46	5010033	Coal Procurement-NA	(1)		93.47%	-	100.000%	$ -
47	Incremental purchased power - Non Fuel			PSUM	PSUM			
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	(3)	$ -	$ -	$ -	100.000%	$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	112,090	52,189	59,901	100.000%	$ 59,901
50	5550032	PP - Mone - Non-Fuel	(3)	31,166	31,167	(1)	100.000%	$ (1)
51	5550098 INACTIVE	PP - PJM - Non-Fuel	(3)		-	-	100.000%	$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	(3)		-	-	100.000%	$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source OVEC bill)	(3)	919,917	100%	919,917	100.000%	$ 919,917
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	(1)	2,030,146	100%	2,030,146	100.000%	$ 2,030,146
55	5550004	Purchased Power - Pool Capacity	(1)	1,469,063	100%	1,469,063	100.000%	$ 1,469,063
56	5550023	Purchase Power - Capacity	(1)	181,964	100%	181,964	100.000%	$ 181,964
57	5550040	PJM Inadvertent - LSE (only)	(1)	(46,243)	100%	(46,243)	100.000%	$ (46,243)
58	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	100.000%	$ -
59	Lawrenceburg purchased power - Non-Fuel							
60	5550105	Depr & Capacity portion-Affil (Lawrenceburg)	(1)	$ 3,047,847	100%	$ 3,047,847	100.000%	$ 3,047,847
61	5550104	Defd Depr & Capacity portion-Affil (Lawrenceburg)	(1)	(153,129)	100%	(153,129)	100.000%	$ (153,129)
62	5550046 - in part	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)	(3) (5)	18,286	92.11%	16,843	100.000%	$ 16,843
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)	(1) (5)	1,266,121	92.11%	1,166,212	100.000%	$ 1,166,212
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)	(1) (5)	787,720	92.11%	725,561	100.000%	$ 725,561
65	Renewables							
66	5550047	Purchased Power - Wind/Solar	(1)	772,228	100%	$ 772,228	100.000%	$ 772,228
67	5550109	Purchased Power - Solar	(1)	63,947	100%	$ 63,947	100.000%	$ 63,947
68	5570007	Renewable Energy Credit Exp.	(1)	-	100%	$ -	100.000%	$ -
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)	(1)	184,524	100%	$ 184,524	100.000%	$ 184,524
70	Environmental Material & Expense							
71	5020001	Lime Expense	(1)	$ 1,225,871	93.47%	$ 1,145,822	100.000%	$ 1,145,822
72	5020002	Urea Expense	(1)	275,887	93.47%	257,872	100.000%	$ 257,872
73	5020003	Trona Expense	(1)	2,873	93.47%	2,685	100.000%	$ 2,685
74	5020004	Limestone Expense	(1)	190,531	93.47%	178,089	100.000%	$ 178,089
75	5020005	Polymer expense	(1)	1,487	93.47%	1,390	100.000%	$ 1,390
76	5020007	Lime Hydrate Expense	(1)	-	93.47%	-	100.000%	$ -
77	5020008	Activated Carbon	(1)	-	93.47%	-	100.000%	$ -
78	5020025	Steam Exp Environmental	(1)	3,711	93.47%	3,469	100.000%	$ 3,469
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
80	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -		
81	5550039	PJM Inadvertent - OSS (only)	(1)	(2,921)	0%	-		
82	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-		
83	5550099	PJM Purchases - NonECR (Auction)	(1)	1,738,259	0%	-		
84	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	212,505	0%	-		
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)	(1)	5,339,559	0%	-		
86	5550107	Capacity Purchases -Trading	(1)	637,638	0%	-		
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)	(1)	-	0%	-		
88	5550069	PP - Monon. Power (2008 PPA only)	(1)	-	0%	-		
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
90	5550075	PJM Reactive Credit	(1)	$ (512,317)	0%	$ -		
91	5550077	PJM Black Start Credit	(1)	(6,024)	0%	-		
92	5550079	PJM Regulation Credit	(1)	(245,921)	0%	-		
93	5550084	PJM Spinning Reserve Credit	(1)	112	0%	-		
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-		
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
96	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -		
97	5550041	PJM Synchronous Cond. Charge	(1)	724	0%	-		
98	5550074	PJM Reactive Charge	(1)	493,809	0%	-		
99	5550076	PJM BlackStart Charge	(1)	6,543	0%	-		
100	5550078	PJM Regulation Charge	(1)	704,869	0%	-		
101	5550083	PJM Spinning Reserve Charge	(1)	29,627	0%	-		
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	51,579	0%	-		
103		Total Additional FAC		$ 22,309,335		$ 13,407,055		$ 13,407,055
104		TOTAL		$ 69,578,388		$ 52,863,028		$ 52,863,028
105								
106	NOTATIONS:							
107	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
108	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
109	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
110	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
111	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						PIVOT
112								70,898,869

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

SEPTEMBER 2010

Line	A	B	C	D	E	F	G	H
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			Net Energy Cost (NEC) in EFC				
2					Assigned	Assigned	Retail	Retail
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 77,575,254	$ 32,248,976	$ 45,326,278		
6	5010009	Fuel Consumed - No Load (CV4)	(2)			-		
7	5010013	Fuel Survey Activity	(2)	(201,374)		(201,374)		
8	5010019	Fuel Oil Consumed	(2)	1,676,847		1,676,847		
9	5010020	Natural Gas Consumed	(2)			-		
10	5010022	Fuel Consumed - Sawdust	(2)	-		-		
11	5470001	Fuel - Gas Turbine	(2)			-		
12		Subtotal - Generation Plant		$ 79,050,727	$ 32,248,976	$ 46,801,751		
13	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	(3)	$ 4,200,785	$ 1,635,346	$ 2,565,439		
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	35,268	-	$ 35,268		
16	5550080	PJM Energy Purchases (Fuel)	(3)	4,885,944	4,041,653	$ 844,291		
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	2,047,409	1,846,050	201,359		
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	22,168	13,327	8,841		
19	5550031/32	Purchased Pwr - Mone (Fuel)	(3)	26,692	26,692	-		
20		Subtotal - Purchased Power Fuel		$ 11,218,266	$ 7,563,068	$ 3,655,198		
21		Total NEC Fuel		$ 90,268,993	$ 39,812,044	$ 50,456,949	91.971%	$ 46,405,761
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt		
24	Emission Allowance Expense				EXH OPCO 2			
25	5090000	Allowance Consumption SO2	(1)	$ 584,965	59.00%	$ 345,129		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	22,884	59.00%	13,502		
27	5090005	Allowance Expenses - Annual NOx	(1)	7,501	59.00%	4,425		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)	-	59.00%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)	-	59.00%	-		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)	(16,456)	59.00%	(9,709)		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)	(145,439)	59.00%	(85,809)		
33	4119000	Loss Disposition of Allowances	(1)		59.00%	-		
34	4119002	Comp. Allow. Loss - SO2	(1)	-	59.00%	-		
35		Total Allowance Dollars		$ 453,454		$ 267,538	91.971%	$ 246,057
36	**Additional S.B. 221 FAC Accounts Forecast for 2009**			Additional Fuel and Environmental Accounts in FAC				
37						Firm Load		
38	Account	Description	Notes		Allocation Factor	Allocated Amount		
39	Incremental Fuel Handling/Ash/Gypsum				EXH OPCO 2			
40	5010000	Fuel (Ash Handling)	(1)	$ 1,100,434	59.00%	$ 649,256	91.971%	$ 597,128
41	5010003	Fuel - Procurement, Unloading & Handling	(1)	2,649,589	59.00%	1,563,257	91.971%	$ 1,437,744
42	5010012	Ash Sales Proceeds	(1)	(143,920)	59.00%	(84,913)	91.971%	$ (78,095)
43	5010027	Gypsum handling/disposal costs	(1)	(517,364)	59.00%	(305,245)	91.971%	$ (280,736)
44	5010028	Gypsum Sales Proceeds	(1)	(110,664)	59.00%	(65,292)	91.971%	$ (60,049)
45	5010029	Gypsum handling/displ-Affiliat	(1)	44,004	59.00%	25,963	91.971%	$ 23,878
46	Incremental purchased power - Non Fuel			PSUM	PSUM			
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	(3)	$ -	-	$ -	91.971%	$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	389,275	151,507	237,768	91.971%	$ 218,678
49	5550032	PP - Mone - Non-Fuel	(3)	38,041	38,042	(1)	91.971%	$ (1)
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	(3)	-	-	-	91.971%	$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	(3)	-	-	-	91.971%	$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:OVEC bill)	(3)	3,209,349	100%	3,209,349	91.971%	$ 2,951,671
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	(1)	8,606	100%	8,606	91.971%	$ 7,915
54	5550023	PP Capacity - Non Affil.	(1)	222,105	100%	222,105	91.971%	$ 204,272
55	5550040	PJM Inadvertent - LSE (only)	(1)	(56,444)	100%	(56,444)	91.971%	$ (51,912)
56	5550003	PP - Cogeneration	(1)	164,394	100%	164,394	91.971%	$ 151,195
57	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	91.971%	$ -
58	Lawrenceburg purchased power - Non-Fuel (NA)							
59	Renewables							
60	5550047	Purchased Power - Wind	(1)	772,228	100%	$ 772,228	100.00%	$ 772,228
61	5550109	Purchased Power - Solar Energy	(1)	81,387	100%	81,387	100.00%	$ 81,387
62	5570007	Other Pwr Exp - RECs	(1)	-	100%	-	100.00%	$ -
63	5570008	Renewable Energy Credit Exp.	(1)	-	100%	-	100.00%	$ -
64	5570009	Other Pwr Exp - REC's - RETAIL	(1)	234,834	100%	234,834	100.00%	$ 234,834
65	Environmental Material & Expense							
66	5020001	Lime Expense	(1)	$ 3,510,623	59.00%	$ 2,071,268	91.971%	$ 1,904,966
67	5020002	Urea Expense	(1)	1,611,147	59.00%	950,577	91.971%	$ 874,255
68	5020003	Trona Expense	(1)	1,108,362	59.00%	653,934	91.971%	$ 601,429
69	5020004	Limestone Expense	(1)	1,148,641	59.00%	677,698	91.971%	$ 623,286
70	5020005	Polymer expense	(1)	526,662	59.00%	310,730	91.971%	$ 285,782
71	5020007	Lime Hydrate Expense	(1)	(0)	59.00%	(0)	91.971%	$ (0)
72	5020008	Activated Carbon	(1)	-	59.00%	-	91.971%	$ -
73	5020025	Steam Exp Environmental	(1)	51,730	59.00%	30,521	91.971%	$ 28,070
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
75	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -	91.971%	$ -
76	5550039	PJM Inadvertent - OSS (only)	(1)	(3,565)	0%	-	91.971%	$ -
77	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-	91.971%	$ -
78	5550099	PJM Purchases - NonECR (Auction)	(1)	2,121,708	0%	-	91.971%	$ -
79	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	259,383	0%	-	91.971%	$ -
80	5550102	PP Pool Non Fuel - OSS Aff	(1)	5,358,909	0%	-	91.971%	$ -
81	5550107	Capacity Purchases - Trading	(1)	778,300	0%	-	91.971%	$ -
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)	(1)	-	0%	-	91.971%	$ -
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
84	5550075	PJM Reactive Credit	(1)	$ (625,332)	0%	$ -	91.971%	$ -
85	5550077	PJM Black Start Credit	(1)	(7,353)	0%	-	91.971%	$ -
86	5550079	PJM Regulation Credit	(1)	(300,171)	0%	-	91.971%	$ -
87	5550084	PJM Spinning Reserve Credit	(1)	137	0%	-	91.971%	$ -
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-	91.971%	$ -
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
90	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -	91.971%	$ -
91	5550041	PJM Synchronous Cond. Charge	(1)	884	0%	-	91.971%	$ -
92	5550074	PJM Reactive Charge	(1)	602,742	0%	-	91.971%	$ -
93	5550076	PJM BlackStart Charge	(1)	7,987	0%	-	91.971%	$ -
94	5550078	PJM Regulation Charge	(1)	860,361	0%	-	91.971%	$ -
95	5550083	PJM Spinning Reserve Charge	(1)	36,162	0%	-	91.971%	$ -
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	62,958	0%	-	91.971%	$ -
97		Total Additional FAC		$ 25,196,130		$ 11,351,981		$ 10,527,922
98		TOTAL		$ 115,918,577		$ 62,076,467		$ 57,179,739
99								
100	NOTATIONS:							
101	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
102	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
103	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
104	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
105	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						
106								

		Actual CYCLE					EXH CSP-1				
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)									
		OCT 2010							Reconcile NEC to GL		
Line	A	B	C	D	E	F	G	H			Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail	ACT	Applicable	NEC Adjs for
2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel			NEC	NEC (4)						
5	5010001/5010022	Fuel Consumed	(2)	$ 13,340,515	$ 739,047	$ 12,601,468			$ 13,340,515	$ 13,585,903	$ (245,388)
6	5010009	Fuel Consumed - No Load (CV4)	(2)	719,889		719,889			719,889	651,879	68,010
7	5010013	Fuel Survey Activity	(2)	-	-	-			-	-	-
8	5010019	Fuel Oil Consumed	(2)	441,932		441,932			441,932	264,554	177,378
9	5010020/5010036	Natural Gas Consumed	(2)	799,265	-	799,265			799,265	899,108	(99,843)
10	5470001/5470003	Fuel - Gas Turbine	(2)	-	$ -	-			-	(99,843)	99,843
11		Subtotal - Generation Fuel		$ 15,301,601	$ 739,047	$ 14,562,554			15,301,601	15,301,601	0
12	Purchases Power - Fuel portion			NEC (4)	NEC (4)						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	(3)	$ 1,234,073	$ 352,074	$ 881,999			1,234,073	3,023,220	(1,789,147)
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	14,053,090	-	14,053,090			14,053,090	14,078,504	(25,414)
15	5550080	PJM Energy Purchases (Fuel)	(3)	5,449,200	3,685,035	1,764,165			5,449,200	3,843,920	1,605,280
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	1,698,611	1,571,701	126,910			1,698,611	1,578,513	120,098
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	12,110	10,668	1,442			12,110	2,504,791	(2,492,681)
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	(3)	2,469,833	29,700	2,440,133			2,469,833	-	2,469,833
19	5550032	Purchased Pwr - Mone (Fuel)	(3)	-	-	-			-	36,280	(36,280)
20		Subtotal - Purchased Power Fuel		$ 24,916,917	$ 5,649,178	$ 19,267,739			24,916,917	25,065,228	(148,311)
21		Total NEC Fuel		$ 40,218,518	$ 6,388,225	$ 33,830,293	100.000%	$ 33,830,293	40,218,518	40,366,829	(148,311)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount			(a) Report diffs. due to timing of GL recording of est./a		
24	Emission Allowance Expense				(EXH CSP 2)						
25	5090000/2	Allowance Consumption - SO2	(1)	$ 363,880	97.68%	$ 355,438					
26	5090001	Allowance Consumption - Seasonal NOx	(1)	2,565	97.68%	2,506					
27	5090005	Allowance Expenses - Annual NOx	(1)	15,601	97.68%	15,239					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)	-	97.68%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2	(1)		97.68%	$ -					
31	4118003	Comp. Allow. Gains-Seas NOx	(1)		97.68%	-					
32	4118004	Comp. Allow. Gains-Ann NOx	(1)		97.68%	-					
33	4119000	Loss Disposition of Allowances	(1)		97.68%	-					
34		Total Allowance Dollars		$ 382,046		$ 373,182	100.000%	$ 373,182			
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum				(EXH CSP 2)						
39	5010000	Fuel (Ash Handling)	(1)	$ 483,317	97.68%	$ 472,104	100.000%	$ 472,104			
40	5010003	Fuel - Procurement, Unloading & Handling	(1)	629,403	97.68%	614,801	100.000%	$ 614,801			
41	5010011	Fuel Handling - No Load (CV4)	(1)	11,830	97.68%	11,555	100.000%	$ 11,555			
42	5010012	Ash Sales Proceeds	(1)	(8,986)	97.68%	(8,777)	100.000%	$ (8,777)			
43	5010027	Gypsum handling/disposal costs	(1)	140,055	97.68%	136,806	100.000%	$ 136,806			
44	5010028	Gypsum Sales Proceeds	(1)	-	97.68%	-	100.000%	$ -			
45	5010032	Coal Procurement-Aff	(1)		97.68%	-	100.000%	$ -			
46	5010033	Coal Procurement-NA	(1)		97.68%	-	100.000%	$ -			
47	Incremental purchased power - Non Fuel			PSUM	PSUM						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	(3)	$ -	$ -	$ -	100.000%	$ -	$ -	$ -	$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	117,462	33,513	83,949	100.000%	$ 83,949	$ 117,462	$ 1,068,637	$ (971,174)
50	5550032	PP - Mone - Non-Fuel	(3)	37,499	-	37,499	100.000%	$ 37,499	$ 37,499		$ 37,499
51	5550098 INACTIVE	PP - PJM - Non-Fuel	(3)		-	-	100.000%	$ -	$ -		$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	(3)		-	-	100.000%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source OVEC bill)	(3)	1,084,422	100%	1,084,422	100.000%	$ 1,084,422	1,084,422		1,084,422
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	(1)	1,765,111	100%	1,765,111	100.000%	$ 1,765,111	1,239,384	1,068,637	150,747
55	5550004	Purchased Power - Pool Capacity	(1)	1,478,897	100%	1,478,897	100.000%	$ 1,478,897			
56	5550023	Purchase Power - Capacity	(1)	181,964	100%	181,964	100.000%	$ 181,964			
57	5550040	PJM Inadvertent - LSE (only)	(1)	21,852	100%	21,852	100.000%	$ 21,852			
58	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affil (Lawrenceburg)	(1)	$ 3,047,847	100%	$ 3,047,847	100.000%	$ 3,047,847			
61	5550104	Defd Depr & Capacity portion-Affil (Lawrenceburg)	(1)	(153,129)	100%	(153,129)	100.000%	$ (153,129)			
62	5550046 in part	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)	(3) (5)	23,217	98.69%	22,912	100.000%	$ 22,912			
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)	(1) (5)	1,388,452	98.69%	1,370,237	100.000%	$ 1,370,237			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)	(1) (5)	860,300	98.69%	849,014	100.000%	$ 849,014			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar	(1)	950,380	100%	$ 950,380	100.000%	$ 950,380	$ 950,380	$ 950,380	$ -
67	5550109	Purchased Power - Solar	(1)	57,130	100%	$ 57,130	100.000%	$ 57,130	$ 57,130	$ 57,130	$ -
68	5570007	Renewable Energy Credit Exp.	(1)	-	100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)	(1)	162,269	100%	$ 162,269	100.000%	$ 162,269			
70	Environmental Material & Expense										
71	5020001	Lime Expense	(1)	$ 471,852	97.68%	$ 460,905	100.000%	$ 460,905			
72	5020002	Urea Expense	(1)	200,835	97.68%	196,176	100.000%	$ 196,176			
73	5020003	Trona Expense	(1)	98,402	97.68%	96,119	100.000%	$ 96,119			
74	5020004	Limestone Expense	(1)	266,806	97.68%	260,616	100.000%	$ 260,616			
75	5020005	Polymer expense	(1)	166	97.68%	162	100.000%	$ 162			
76	5020007	Lime Hydrate Expense	(1)	-	97.68%	-	100.000%	$ -			
77	5020008	Activated Carbon	(1)	-	97.68%	-	100.000%	$ -			
78	5020025	Steam Exp Environmental	(1)	(78)	97.68%	(76)	100.000%	$ (76)			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)	(1)	1,278	0%	-					
82	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-					
83	5550099	PJM Purchases - NonECR (Auction)	(1)	1,505,084	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	192,077	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)	(1)	4,025,542	0%	-					
86	5550107	Capacity Purchases -Trading	(1)	669,205	0%	-					
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)	(1)	-	0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)	(1)	-	0%	-					
89	555 Purchased Power Ancillary Credits Included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit	(1)	$ (512,317)	0%	$ -					
91	5550077	PJM Black Start Credit	(1)	(6,203)	0%	-					
92	5550079	PJM Regulation Credit	(1)	(105,866)	0%	-					
93	5550084	PJM Spinning Reserve Credit	(1)	728	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -					
97	5550041	PJM Synchronous Cond. Charge	(1)	(589)	0%	-					
98	5550074	PJM Reactive Charge	(1)	598,452	0%	-					
99	5550076	PJM BlackStart Charge	(1)	1,367	0%	-					
100	5550078	PJM Regulation Charge	(1)	353,972	0%	-					
101	5550083	PJM Spinning Reserve Charge	(1)	20,866	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	6,918	0%	-					
103		Total Additional FAC		$ 20,067,810		$ 13,200,744		$ 13,200,744			
104		TOTAL		$ 60,668,374		$ 47,404,220		$ 47,404,220			
105											
106	NOTATIONS:										
107	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.							
108	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.									
109	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs									
110	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))									
111	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						PIVOT	ESTIMATE		
112								60,642,720	60,642,720		

OHIO POWER COMPANY - NET ENERGY COST (NEC)

OCTOBER 2010

Line	A	B	C	D	E	F	G	H
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC				
2					Assigned	Assigned	Retail	Retail
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 85,290,193	$ 42,876,577	$ 42,413,616		
6	5010009	*Fuel Consumed - No Load (CV4)*	(2)			-		
7	5010013	Fuel Survey Activity	(2)	-		-		
8	5010019	Fuel Oil Consumed	(2)	864,653		864,653		
9	5010020	Natural Gas Consumed	(2)			-		
10	5010022	Fuel Consumed - Sawdust	(2)	-		-		
11	5470001	Fuel - Gas Turbine	(2)			-		
12		**Subtotal - Generation Plant**		$ 86,154,846	$ 42,876,577	$ 43,278,269		
13	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	(3)	$ 4,308,834	$ 976,750	$ 3,332,084		
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	-	-	$ -		
16	5550080	PJM Energy Purchases (Fuel)	(3)	6,651,277	4,497,940	$ 2,153,337		
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	2,073,337	1,918,405	154,932		
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	14,782	13,022	1,760		
19	5550031/32	Purchased Pwr - Mone (Fuel)	(3)	-	-	-		
20		**Subtotal - Purchased Power Fuel**		$ 13,048,230	$ 7,406,117	$ 5,642,113		
21		**Total NEC Fuel**		$ 99,203,076	$ 50,282,694	$ 48,920,382	91.477%	$ 44,750,898
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt		
24	Emission Allowance Expense				EXH OPCO 2			
25	5090000	Allowance Consumption SO2	(1)	$ 543,737	50.44%	$ 274,261		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	151	50.44%	76		
27	5090005	Allowance Expenses - Annual NOx	(1)	7,154	50.44%	3,608		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)	-	50.44%	-		
29	*Allowance Gains/Losses*							
30	4118002	Comp. Allow. Gains SO2	(1)	-	50.44%	-		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)	(116,182)	50.44%	(58,602)		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)	-	50.44%	-		
33	4119000	Loss Disposition of Allowances	(1)		50.44%	-		
34	4119002	Comp. Allow. Loss - SO2	(1)	-	50.44%	-		
35		**Total Allowance Dollars**		$ 434,860		$ 219,343	91.477%	$ 200,649
36	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC				
37						Firm Load		
38	Account	Description	Notes		Allocation Factor	Allocated Amount		
39	Incremental Fuel Handling/Ash/Gypsum				EXH OPCO 2			
40	5010000	Fuel (Ash Handling)	(1)	$ 919,604	50.44%	$ 463,848	91.477%	$ 424,315
41	5010003	Fuel - Procurement, Unloading & Handling	(1)	3,046,516	50.44%	1,537,672	91.477%	$ 1,406,616
42	5010012	Ash Sales Proceeds	(1)	(102,557)	50.44%	(51,730)	91.477%	$ (47,321)
43	5010027	Gypsum handling/disposal costs	(1)	294,541	50.44%	148,566	91.477%	$ 135,904
44	5010028	*Gypsum Sales Proceeds*	(1)	26,955	50.44%	13,596	91.477%	$ 12,438
45	5010029	Gypsum handling/displ-Affiliat	(1)	38,190	50.44%	19,263	91.477%	$ 17,621
46	Incremental purchased power - Non Fuel			PSUM	PSUM			
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	(3)	$ -	-	$ -	91.477%	$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	410,127	92,971	317,156	91.477%	$ 290,125
49	5550032	PP - Mone - Non-Fuel	(3)	45,771	-	45,771	91.477%	$ 41,870
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	(3)	-	-	-	91.477%	$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	(3)	-	-	-	91.477%	$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:OVEC bill)	(3)	3,783,267	100%	3,783,267	91.477%	$ 3,460,819
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	(1)	(793)	100%	(793)	91.477%	$ (725)
54	5550023	PP Capacity - Non Affil.	(1)	222,105	100%	222,105	91.477%	$ 203,175
55	5550040	PJM Inadvertent - LSE (only)	(1)	26,672	100%	26,672	91.477%	$ 24,399
56	5550003	PP - Cogeneration	(1)	189,155	100%	189,155	91.477%	$ 173,033
57	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	91.477%	$ -
58	Lawrenceburg purchased power - Non-Fuel (NA)							
59	Renewables							
60	5550047	Purchased Power - Wind	(1)	950,380	100%	$ 950,380	100.00%	$ 950,380
61	5550109	Purchased Power - Solar Energy	(1)	72,710	100%	72,710	100.00%	$ 72,710
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010	(1)	-	100%	-	100.00%	$ -
63	5570008	Renewable Energy Credit Exp.	(1)	-	100%	-	100.00%	$ -
64	5570009	Other Pwr Exp - REC's - RETAIL	(1)	213,728	100%	213,728	100.00%	$ 213,728
65	Environmental Material & Expense							
66	5020001	Lime Expense	(1)	$ 3,322,985	50.44%	$ 1,676,114	91.477%	$ 1,533,259
67	5020002	Urea Expense	(1)	1,906,182	50.44%	961,478	91.477%	$ 879,532
68	5020003	Trona Expense	(1)	1,005,913	50.44%	507,383	91.477%	$ 464,138
69	5020004	Limestone Expense	(1)	1,288,394	50.44%	649,866	91.477%	$ 594,478
70	5020005	Polymer expense	(1)	634,642	50.44%	320,114	91.477%	$ 292,830
71	5020007	Lime Hydrate Expense	(1)	6,717	50.44%	3,388	91.477%	$ 3,099
72	5020008	Activated Carbon	(1)	-	50.44%	-	91.477%	$ -
73	5020025	Steam Exp Environmental	(1)	48,023	50.44%	24,223	91.477%	$ 22,158
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
75	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -	91.477%	$ -
76	5550039	PJM Inadvertent - OSS (only)	(1)	1,560	0%	-	91.477%	$ -
77	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-	91.477%	$ -
78	5550099	PJM Purchases - NonECR (Auction)	(1)	1,837,101	0%	-	91.477%	$ -
79	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	234,449	0%	-	91.477%	$ -
80	5550102	PP Pool Non Fuel - OSS Aff	(1)	3,892,895	0%	-	91.477%	$ -
81	5550107	Capacity Purchases - Trading	(1)	816,830	0%	-	91.477%	$ -
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)	(1)	-	0%	-	91.477%	$ -
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
84	5550075	PJM Reactive Credit	(1)	$ (625,332)	0%	$ -	91.477%	$ -
85	5550077	PJM Black Start Credit	(1)	(7,572)	0%	-	91.477%	$ -
86	5550079	PJM Regulation Credit	(1)	(129,220)	0%	-	91.477%	$ -
87	5550084	PJM Spinning Reserve Credit	(1)	888	0%	-	91.477%	$ -
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-	91.477%	$ -
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
90	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ -	0%	$ -	91.477%	$ -
91	5550041	PJM Synchronous Cond. Charge	(1)	(719)	0%	-	91.477%	$ -
92	5550074	PJM Reactive Charge	(1)	730,468	0%	-	91.477%	$ -
93	5550076	PJM BlackStart Charge	(1)	1,693	0%	-	91.477%	$ -
94	5550078	PJM Regulation Charge	(1)	432,057	0%	-	91.477%	$ -
95	5550083	*PJM Spinning Reserve Charge*	(1)	25,469	0%	-	91.477%	$ -
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	8,444	0%	-	91.477%	$ -
97		**Total Additional FAC**		$ 25,570,242		$ 12,093,933		$ 11,168,581
98		TOTAL		$ 125,208,178		$ 61,233,658		$ 56,120,127
99								
100	NOTATIONS:							
101	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
102	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
103	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
104	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
105	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						
106								

Actual Cycle — EXH CSP-1

COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)

November 2010

Line	A	B	C	D	E	F	G	H
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail
2					Assigned	Assigned	Allocation	FAC Cost
3	Account	Description	Notes	Total	Off-System	To Firm Load		
4	Generation Fuel			NEC	NEC (4)			
5	5010001/5010022	Fuel Consumed	(2)	$ 11,785,476	$ 1,608,659	$ 10,176,817		
6	5010009	Fuel Consumed - No Load (CV4)	(2)	719,889		719,889		
7	5010013	Fuel Survey Activity	(2)	2,708,718	-	2,708,718		
8	5010019	Fuel Oil Consumed	(2)	245,357		245,357		
9	5010020/5010036	Natural Gas Consumed	(2)	5,632,122	-	5,632,122		
10	5470001/5470003	Fuel - Gas Turbine	(2)	-	$ -	-		
11		Subtotal - Generation Fuel		$ 21,091,563	$ 1,608,659	$ 19,482,904		
12	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	(3)	$ 1,497,683	$ 490,826	$ 1,006,857		
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	10,695,798	-	10,695,798		
15	5550080	PJM Energy Purchases (Fuel)	(3)	6,803,121	2,495,074	4,308,047		
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	1,260,772	1,159,644	101,128		
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	7,318	3,076	4,242		
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	(3)	2,065,910	84,600	1,981,310		
19	5550032	Purchased Pwr - Mone (Fuel)	(3)	-	-	-		
20		Subtotal - Purchased Power Fuel		$ 22,330,602	$ 4,233,220	$ 18,097,382		
21		Total NEC Fuel		$ 43,422,164	$ 5,841,879	$ 37,580,285	100.000%	$ 37,580,285
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount		
24	Emission Allowance Expense				(EXH CSP 2)			
25	5090000/2	Allowance Consumption - SO2	(1)	$ 390,786	95.09%	$ 371,598		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	11,712	95.09%	11,137		
27	5090005	Allowance Expenses - Annual NOx	(1)	15,474	95.09%	14,715		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)	-	95.09%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)		95.09%	$ -		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)		95.09%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)		95.09%	-		
33	4119000	Loss Disposition of Allowances	(1)		95.09%	-		
34		Total Allowance Dollars		$ 417,972		$ 397,450	100.000%	$ 397,450
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC				
36						Firm Load		
37	Account	Description	Notes		Allocation Factor	Allocated Amount		
38	Incremental Fuel Handling/Ash/Gypsum				(EXH CSP 2)			
39	5010000	Fuel (Ash Handling)	(1)	$ 356,670	95.09%	$ 339,157	100.000%	$ 339,157
40	5010003	Fuel - Procurement, Unloading & Handling	(1)	425,181	95.09%	404,305	100.000%	$ 404,305
41	5010011	Fuel Handling - No Load (CV4)	(1)	28,304	95.09%	26,914	100.000%	$ 26,914
42	5010012	Ash Sales Proceeds	(1)	(6,874)	95.09%	(6,536)	100.000%	$ (6,536)
43	5010027	Gypsum handling/disposal costs	(1)	84,493	95.09%	80,345	100.000%	$ 80,345
44	5010028	Gypsum Sales Proceeds	(1)	-	95.09%	-	100.000%	$ -
45	5010032	Coal Procurement-Aff	(1)		95.09%	-	100.000%	$ -
46	5010033	Coal Procurement-NA	(1)		95.09%	-	100.000%	$ -
47	Incremental purchased power - Non Fuel			PSUM	PSUM			
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	(3)	$ -	$ -	$ -	100.000%	$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	179,808	58,913	120,895	100.000%	$ 120,895
50	5550032	PP - Mone - Non-Fuel	(3)	25,055	-	25,055	100.000%	$ 25,055
51	5550098 INACTIVE	PP - PJM - Non-Fuel	(3)		-	-	100.000%	$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	(3)		-	-	100.000%	$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source OVEC bill)	(3)	940,373	100%	940,373	100.000%	$ 940,373
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	(1)	1,701,239	100%	1,701,239	100.000%	$ 1,701,239
55	5550004	Purchased Power - Pool Capacity	(1)	1,457,777	100%	1,457,777	100.000%	$ 1,457,777
56	5550023	Purchase Power - Capacity	(1)	181,964	100%	181,964	100.000%	$ 181,964
57	5550040	PJM Inadvertent - LSE (only)	(1)	(24,730)	100%	(24,730)	100.000%	$ (24,730)
58	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	100.000%	$ -
59	Lawrenceburg purchased power - Non-Fuel							
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)	(1)	$ 3,047,847	100%	$ 3,047,847	100.000%	$ 3,047,847
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)	(1)	(153,129)	100%	(153,129)	100.000%	$ (153,129)
62	5550046 in part	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)	(3) (5)	17,483	95.47%	16,690	100.000%	$ 16,690
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)	(1) (5)	1,035,254	95.47%	988,320	100.000%	$ 988,320
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)	(1) (5)	978,808	95.47%	934,433	100.000%	$ 934,433
65	Renewables							
66	5550047	Purchased Power - Wind/Solar	(1)	1,169,961	100%	$ 1,169,961	100.000%	$ 1,169,961
67	5550109	Purchased Power - Solar	(1)	43,955	100%	$ 43,955	100.000%	$ 43,955
68	5570007	Renewable Energy Credit Exp.	(1)	-	100%	$ -	100.000%	$ -
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)	(1)	168,989	100%	$ 168,989	100.000%	$ 168,989
70	Environmental Material & Expense							
71	5020001	Lime Expense	(1)	$ 314,418	95.09%	$ 298,980	100.000%	$ 298,980
72	5020002	Urea Expense	(1)	206,167	95.09%	196,044	100.000%	$ 196,044
73	5020003	Trona Expense	(1)	(444)	95.09%	(422)	100.000%	$ (422)
74	5020004	Limestone Expense	(1)	124,304	95.09%	118,201	100.000%	$ 118,201
75	5020005	Polymer expense	(1)	165	95.09%	157	100.000%	$ 157
76	5020007	Lime Hydrate Expense	(1)	927	95.09%	882	100.000%	$ 882
77	5020008	Activated Carbon	(1)	-	95.09%	-	100.000%	$ -
78	5020025	Steam Exp Environmental	(1)	3,350	95.09%	3,185	100.000%	$ 3,185
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
80	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -		
81	5550039	PJM Inadvertent - OSS (only)	(1)	570	0%	-		
82	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-		
83	5550099	PJM Purchases - NonECR (Auction)	(1)	1,438,517	0%	-		
84	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	216,386	0%	-		
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)	(1)	5,163,314	0%	-		
86	5550107	Capacity Purchases -Trading	(1)	628,403	0%	-		
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)	(1)	-	0%	-		
88	5550069	PP - Monon. Power (2008 PPA only)	(1)	-	0%	-		
89	555 Purchased Power Ancillary Credits Included in Base "G" Rates (Excluded from FAC)							
90	5550075	PJM Reactive Credit	(1)	$ (494,609)	0%	$ -		
91	5550077	PJM Black Start Credit	(1)	(5,598)	0%	-		
92	5550079	PJM Regulation Credit	(1)	(109,439)	0%	-		
93	5550084	PJM Spinning Reserve Credit	(1)	(6,012)	0%	-		
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-		
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
96	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ 1	0%	$ -		
97	5550041	PJM Synchronous Cond. Charge	(1)	146	0%	-		
98	5550074	PJM Reactive Charge	(1)	91,679	0%	-		
99	5550076	PJM BlackStart Charge	(1)	8,693	0%	-		
100	5550078	PJM Regulation Charge	(1)	423,273	0%	-		
101	5550083	PJM Spinning Reserve Charge	(1)	29,056	0%	-		
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	1,055	0%	-		
103		Total Additional FAC		$ 19,692,751		$ 12,080,853		$ 12,080,853
104		TOTAL		$ 63,532,888		$ 50,058,588		$ 50,058,588
105								
106	NOTATIONS:							
107	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
108	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
109	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
110	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
111	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						PIVOT
112								62,440,644

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

NOVEMBER 2010

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					EST	Applicable	Diff. To GL
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	NEC Adjs. for
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Actual Cycle Or PPAs
4	Generation Fuel			NEC	NEC (4)						
5	5010001	Fuel Consumed	(2)	$ 78,501,624	$ 37,089,060	$ 41,412,564			$ 78,501,624	$ 78,501,624	$ 0
6	5010009	Fuel Consumed - No Load (CV4)	(2)			-			$ -	-	$ -
7	5010013	Fuel Survey Activity	(2)	-		-			$ -	-	$ -
8	5010019	Fuel Oil Consumed	(2)	1,237,753		1,237,753			$ 1,237,753	1,237,753	$ (0)
9	5010020	Natural Gas Consumed	(2)			-			$ -	-	$ -
10	5010022	Fuel Consumed - Biomass	(2)	-		-			$ -	50,041	$ (50,041)
11	5470001	Fuel - Gas Turbine	(2)			-			$ -	-	$ -
12		Subtotal - Generation Plant		$ 79,739,377	$ 37,089,060	$ 42,650,317			$ 79,739,377	$ 79,789,418	$ (50,041)
13	Purchases Power - Fuel portion			NEC (4)	NEC (4)						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	(3)	$ 5,221,884	$ 1,160,235	$ 4,061,649			$ 5,221,884	$ 11,394,221	$ (6,172,337)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	-	-	$ -			$ -	-	$ -
16	5550080	PJM Energy Purchases (Fuel)	(3)	8,303,869	3,045,483	$ 5,258,386			$ 8,303,869	2,793,103	$ 5,510,766
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	1,538,887	1,415,432	123,455			$ 1,538,887	1,416,800	$ 122,087
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	8,932	3,754	5,178			$ 8,932	9,155	$ (223)
19	5550031/32	Purchased Pwr - Mone (Fuel)	(3)	-	-	-			$ -	(93)	$ 93
20		Subtotal - Purchased Power Fuel		$ 15,073,572	$ 5,624,904	$ 9,448,668			15,073,572	15,613,186	(539,614)
21		Total NEC Fuel		$ 94,812,949	$ 42,713,964	$ 52,098,985	91.754%	$ 47,802,903	94,812,949	95,402,604	(589,655)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt			(a) Report diffs. due to timing of GL recording of est./actuals.		
24	Emission Allowance Expense				EXH OPCO 2						
25	5090000	Allowance Consumption SO2	(1)	$ 467,533	53.59%	$ 250,551					
26	5090001	Allowance Consumption - Seasonal NOx	(1)	287	53.59%	154					
27	5090005	*Allowance Expenses - Annual NOx*	(1)	6,777	53.59%	3,632					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)	-	53.59%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2	(1)	-	53.59%	-					
31	4118003	Comp. Allow. Gains-Seas NOx	(1)	(75,921)	53.59%	(40,686)					
32	4118004	*Comp. Allow. Gains-Ann NOx*	(1)	(363,021)	53.59%	(194,543)					
33	4119000	Loss Disposition of Allowances	(1)		53.59%	-					
34	4119002	Comp. Allow. Loss - SO2	(1)	-	53.59%	-					
35		Total Allowance Dollars		$ 35,655		$ 19,107	91.754%	$ 17,532			
36	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC							
37						Firm Load					
38	Account	Description	Notes		Allocation Factor	Allocated Amount					
39	Incremental Fuel Handling/Ash/Gypsum				EXH OPCO 2						
40	5010000	Fuel (Ash Handling)	(1)	$ 998,559	53.59%	$ 535,128	91.754%	$ 491,001			
41	5010003	Fuel - Procurement, Unloading & Handling	(1)	2,677,542	53.59%	1,434,895	91.754%	$ 1,316,573			
42	5010012	Ash Sales Proceeds	(1)	(148,205)	53.59%	(79,423)	91.754%	$ (72,874)			
43	5010027	Gypsum handling/disposal costs	(1)	(409,339)	53.59%	(219,365)	91.754%	$ (201,276)			
44	5010028	Gypsum Sales Proceeds	(1)	(142,490)	53.59%	(76,361)	91.754%	$ (70,064)			
45	5010029	Gypsum handling/displ-Affiliat	(1)	40,181	53.59%	21,533	91.754%	$ 19,757			
46	Incremental purchased power - Non Fuel			PSUM	PSUM						
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	(3)	$ -	-	$ -	91.754%	$ -	$ -		$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	626,925	139,236	487,689	91.754%	$ 447,474	$ 626,925	$ 3,148,177	$ (2,521,252)
49	5550032	PP - Mone - Non-Fuel	(3)	30,582	-	30,582	91.754%	$ 28,060	$ 30,582	$ 33,038	$ (2,456)
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	(3)	-	-	-	91.754%	$ -	$ -		$ -
51	5550027	*PP Affiliated-Non-Fuel Portion (from West Pool)*	(3)	-	-	-	91.754%	$ -	$ -		$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:OVEC bill)	(3)	3,280,715	100%	3,280,715	91.754%	$ 3,010,187	3,280,715		3,280,715
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	(1)	-	100%	-	91.754%	$ -	3,938,222	3,181,214	757,008
54	5550023	PP Capacity - Non Affil.	(1)	222,105	100%	222,105	91.754%	$ 203,790			
55	5550040	PJM Inadvertent - LSE (only)	(1)	(30,185)	100%	(30,185)	91.754%	$ (27,696)			
56	5550003	*PP - Cogeneration*	(1)	178,136	100%	178,136	91.754%	$ 163,447			
57	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	91.754%	$ -			
58	Lawrenceburg purchased power - Non-Fuel (NA)										
59	Renewables										
60	5550047	Purchased Power - Wind	(1)	1,169,962	100%	$ 1,169,962	100.00%	$ 1,169,962	$ 1,169,962.00	$ 1,169,961.47	$ 0.53
61	5550109	Purchased Power - Solar Energy	(1)	55,943	100%	55,943	100.00%	$ 55,943	$ 55,943.00	$ 55,943.36	$ (0.36)
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010	(1)	-	100%	-	100.00%	$ -			
63	5570008	Renewable Energy Credit Exp.	(1)	-	100%	-	100.00%	$ -			
64	5570009	Other Pwr Exp - REC's - RETAIL	(1)	212,459	100%	212,459	100.00%	$ 212,459			
65	Environmental Material & Expense										
66	5020001	Lime Expense	(1)	$ 3,948,722	53.59%	$ 2,116,120	91.754%	$ 1,941,625			
67	5020002	Urea Expense	(1)	1,800,971	53.59%	965,140	91.754%	$ 885,555			
68	5020003	Trona Expense	(1)	792,148	53.59%	424,512	91.754%	$ 389,507			
69	5020004	Limestone Expense	(1)	1,005,052	53.59%	538,607	91.754%	$ 494,194			
70	5020005	Polymer expense	(1)	298,061	53.59%	159,731	91.754%	$ 146,560			
71	5020007	Lime Hydrate Expense	(1)	9,721	53.59%	5,210	91.754%	$ 4,780			
72	5020008	Activated Carbon	(1)	-	53.59%	-	91.754%	$ -			
73	5020025	Steam Exp Environmental	(1)	36,499	53.59%	19,560	91.754%	$ 17,947			
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
75	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -	91.754%	$ -			
76	5550039	PJM Inadvertent - OSS (only)	(1)	696	0%	-	91.754%	$ -			
77	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-	91.754%	$ -			
78	5550099	PJM Purchases - NonECR (Auction)	(1)	1,755,853	0%	-	91.754%	$ -			
79	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	264,120	0%	-	91.754%	$ -			
80	5550102	PP Pool Non Fuel - OSS Aff	(1)	4,255,291	0%	-	91.754%	$ -			
81	5550107	Capacity Purchases - Trading	(1)	767,026	0%	-	91.754%	$ -			
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)	(1)	-	0%	-	91.754%	$ -			
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
84	5550075	PJM Reactive Credit	(1)	$ (603,719)	0%	$ -	91.754%	$ -			
85	5550077	*PJM Black Start Credit*	(1)	(6,833)	0%	-	91.754%	$ -			
86	5550079	PJM Regulation Credit	(1)	(133,581)	0%	-	91.754%	$ -			
87	5550084	PJM Spinning Reserve Credit	(1)	(7,338)	0%	-	91.754%	$ -			
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-	91.754%	$ -			
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
90	5550036	*PJM Emergency Purchases (Demand Response Program)*	(1)	$ 1	0%	$ -	91.754%	$ -			
91	5550041	PJM Synchronous Cond. Charge	(1)	178	0%	-	91.754%	$ -			
92	5550074	PJM Reactive Charge	(1)	111,902	0%	-	91.754%	$ -			
93	5550076	PJM BlackStart Charge	(1)	10,610	0%	-	91.754%	$ -			
94	5550078	PJM Regulation Charge	(1)	516,646	0%	-	91.754%	$ -			
95	5550083	*PJM Spinning Reserve Charge*	(1)	35,465	0%	-	91.754%	$ -			
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	1,288	0%	-	91.754%	$ -			
97		Total Additional FAC		$ 23,621,670		$ 11,452,694		$ 10,626,912			
98		TOTAL		$ 118,470,273		$ 63,570,786		$ 58,447,347			
99											
100	NOTATIONS:										
101	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.							
102	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.									
103	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs									
104	(4)	*Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys (ECR))*									
105	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.									
106											

Estimate Cycle — EXH CSP-1

COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)

December 2010

Line	A	B	C	D	E	F	G	H
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail
2					Assigned	Assigned	Allocation	FAC Cost
3	Account	Description	Notes	Total	Off-System	To Firm Load		
4	Generation Fuel			NEC	NEC (4)			
5	5010001/5010022	Fuel Consumed	(2)	$ 24,802,321	$ 2,019,815	$ 22,782,506		
6	5010009	Fuel Consumed - No Load (CV4)	(2)	-		-		
7	5010013	Fuel Survey Activity	(2)	-	-	-		
8	5010019	Fuel Oil Consumed	(2)	-		-		
9	5010020/5010036	Natural Gas Consumed	(2)	8,820,237	-	8,820,237		
10	5470001/5470003	Fuel - Gas Turbine	(2)	-	$ -	-		
11		Subtotal - Generation Fuel		$ 33,622,558	$ 2,019,815	$ 31,602,743		
12	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	(3)	$ 1,608,518	$ 184,742	$ 1,423,776		
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	5,795,366	-	5,795,366		
15	5550080	PJM Energy Purchases (Fuel)	(3)	7,869,261	6,317,274	1,551,987		
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	1,877,066	1,369,626	507,440		
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	49,645	31,629	18,016		
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	(3)	12,359,516	787,125	11,572,391		
19	5550032	Purchased Pwr - Mone (Fuel)	(3)	144,037	122,659	21,378		
20		Subtotal - Purchased Power Fuel		$ 29,703,409	$ 8,813,055	$ 20,890,354		
21		Total NEC Fuel		$ 63,325,967	$ 10,832,870	$ 52,493,097	100.000%	$ 52,493,097
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount		
24	Emission Allowance Expense				(EXH CSP 2)			
25	5090000/2	Allowance Consumption - SO2	(1)	$ 550,266	89.38%	$ 491,828		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	-	89.38%	-		
27	5090005	Allowance Expenses - Annual NOx	(1)	192,792	89.38%	172,317		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)	(1)	-	89.38%	-		
29	Allowance Gains/Losses							
30	4118002	Comp. Allow. Gains SO2	(1)	$ (3,688,616)	89.38%	$ (3,296,885)		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)		89.38%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)		89.38%	-		
33	4119000	Loss Disposition of Allowances	(1)		89.38%	-		
34		Total Allowance Dollars		$ (2,945,558)		$ (2,632,740)	100.000%	$ (2,632,740)
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC				
36						Firm Load		
37	Account	Description	Notes		Allocation Factor	Allocated Amount		
38	Incremental Fuel Handling/Ash/Gypsum				(EXH CSP 2)			
39	5010000	Fuel (Ash Handling)	(1)	$ 793,043	89.38%	$ 708,821	100.000%	$ 708,821
40	5010003	Fuel - Procurement, Unloading & Handling	(1)	817,501	89.38%	730,683	100.000%	$ 730,683
41	5010011	Fuel Handling - No Load (CV4)	(1)	301	89.38%	269	100.000%	$ 269
42	5010012	Ash Sales Proceeds	(1)	(9,936)	89.38%	(8,881)	100.000%	$ (8,881)
43	5010027	Gypsum handling/disposal costs	(1)	163,056	89.38%	145,739	100.000%	$ 145,739
44	5010028	Gypsum Sales Proceeds	(1)	(2,296)	89.38%	(2,052)	100.000%	$ (2,052)
45	5010032	Coal Procurement-Aff	(1)		89.38%	-	100.000%	$ -
46	5010033	Coal Procurement-NA	(1)		89.38%	-	100.000%	$ -
47	Incremental purchased power - Non Fuel			PSUM	PSUM			
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	(3)	$ -	$ -	$ -	100.000%	$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	117,410	13,484	103,926	100.000%	$ 103,926
50	5550032	PP - Mone - Non-Fuel	(3)	6	-	6	100.000%	$ 6
51	5550098 INACTIVE	PP - PJM - Non-Fuel	(3)		-	-	100.000%	$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	(3)		-	-	100.000%	$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source OVEC bill)	(3)	1,389,720	100%	1,389,720	100.000%	$ 1,389,720
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	(1)	841,961	100%	841,961	100.000%	$ 841,961
55	5550004	Purchased Power - Pool Capacity	(1)	1,470,980	100%	1,470,980	100.000%	$ 1,470,980
56	5550023	Purchase Power - Capacity	(1)	181,964	100%	181,964	100.000%	$ 181,964
57	5550040	PJM Inadvertent - LSE (only)	(1)	(44,390)	100%	(44,390)	100.000%	$ (44,390)
58	5550093	Peak Hour Avail Charge - LSE	(1)	-	100%	-	100.000%	$ -
59	Lawrenceburg purchased power - Non-Fuel							
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)	(1)	$ 3,047,847	100%	$ 3,047,847	100.000%	$ 3,047,847
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)	(1)	(153,129)	100%	(153,129)	100.000%	$ (153,129)
62	5550046 in part	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)	(3) (5)	267,161	93.28%	249,208	100.000%	$ 249,208
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)	(1) (5)	1,608,361	93.28%	1,500,285	100.000%	$ 1,500,285
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)	(1) (5)	931,622	93.28%	869,020	100.000%	$ 869,020
65	Renewables							
66	5550047	Purchased Power - Wind/Solar	(1)	$ 1,224,274	100%	$ 1,224,274	100.000%	$ 1,224,274
67	5550109	Purchased Power - Solar	(1)	$ 24,257	100%	$ 24,257	100.000%	$ 24,257
68	5570007	Renewable Energy Credit Exp.	(1)	-	100%	$ -	100.000%	$ -
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)	(1)	264,888	100%	$ 264,888	100.000%	$ 264,888
70	Environmental Material & Expense							
71	5020001	Lime Expense	(1)	$ 1,468,318	89.38%	$ 1,312,383	100.000%	$ 1,312,383
72	5020002	Urea Expense	(1)	195,326	89.38%	174,583	100.000%	$ 174,583
73	5020003	Trona Expense	(1)	45,407	89.38%	40,585	100.000%	$ 40,585
74	5020004	Limestone Expense	(1)	123,923	89.38%	110,762	100.000%	$ 110,762
75	5020005	Polymer expense	(1)	143	89.38%	128	100.000%	$ 128
76	5020007	Lime Hydrate Expense	(1)	-	89.38%	-	100.000%	$ -
77	5020008	Activated Carbon	(1)	6	89.38%	6	100.000%	$ 6
78	5020025	Steam Exp Environmental	(1)	11,402	89.38%	10,191	100.000%	$ 10,191
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)							
80	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -		
81	5550039	PJM Inadvertent - OSS (only)	(1)	(8,756)	0%	-		
82	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-		
83	5550099	PJM Purchases - NonECR (Auction)	(1)	1,962,168	0%	-		
84	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	207,995	0%	-		
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)	(1)	5,271,583	0%	-		
86	5550107	Capacity Purchases -Trading	(1)	441,080	0%	-		
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)	(1)	-	0%	-		
88	5550069	PP - Monon. Power (2008 PPA only)	(1)	-	0%	-		
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)							
90	5550075	PJM Reactive Credit	(1)	$ (530,024)	0%	$ -		
91	5550077	PJM Black Start Credit	(1)	(5,984)	0%	-		
92	5550079	PJM Regulation Credit	(1)	(190,002)	0%	-		
93	5550084	PJM Spinning Reserve Credit	(1)	(3,090)	0%	-		
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE	(1)	-	0%	-		
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)							
96	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ 9	0%	$ -		
97	5550041	PJM Synchronous Cond. Charge	(1)	2,659	0%	-		
98	5550074	PJM Reactive Charge	(1)	1,000,218	0%	-		
99	5550076	PJM BlackStart Charge	(1)	16,082	0%	-		
100	5550078	PJM Regulation Charge	(1)	816,011	0%	-		
101	5550083	PJM Spinning Reserve Charge	(1)	89,847	0%	-		
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE	(1)	4,145	0%	-		
103		Total Additional FAC		$ 23,853,068		$ 14,194,036		$ 14,194,036
104		TOTAL		$ 84,233,477		$ 64,054,393		$ 64,054,393
105								
106	NOTATIONS:							
107	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
108	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
109	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
110	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
111	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						PIVOT
112								83,735,802

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OHIO POWER COMPANY - NET ENERGY COST (NEC)
DECEMBER 2010

Line	A	B	C	D	E	F	G	H
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			Net Energy Cost (NEC) in EFC				
2					Assigned	Assigned	Retail	Retail
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost
4	Generation Fuel			NEC	NEC (4)			
5	5010001	Fuel Consumed	(2)	$ 85,320,062	$ 31,325,791	$ 53,994,271		
6	5010009	Fuel Consumed - No Load (CV4)	(2)			-		
7	5010013	Fuel Survey Activity	(2)	$ -		-		
8	5010019	Fuel Oil Consumed	(2)	$ -		-		
9	5010020	Natural Gas Consumed	(2)			-		
10	5010022	Fuel Consumed - Biomass	(2)	$ -		-		
11	5470001	Fuel - Gas Turbine	(2)			-		
12		Subtotal - Generation Plant		$ 85,320,062	$ 31,325,791	$ 53,994,271		
13	Purchases Power - Fuel portion			NEC (4)	NEC (4)			
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	(3)	$ 5,600,867	$ 349,648	$ 5,251,219		
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	(3)	3,404	-	$ 3,404		
16	5550080	PJM Energy Purchases (Fuel)	(3)	9,605,196	7,710,845	$ 1,894,351		
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	(3)	2,291,137	1,671,774	619,363		
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	(3)	60,596	38,606	21,990		
19	5550031/32	Purchased Pwr - Mone (Fuel)	(3)	175,811	149,718	26,093		
20		Subtotal - Purchased Power Fuel		$ 17,737,011	$ 9,920,591	$ 7,816,420		
21		Total NEC Fuel		$ 103,057,073	$ 41,246,382	$ 61,810,691	91.960%	$ 56,841,111
22						Firm Load		
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt		
24	Emission Allowance Expense				EXH OPCO 2			
25	5090000	Allowance Consumption SO2	(1)	$ 1,964,397	63.18%	$ 1,241,106		
26	5090001	Allowance Consumption - Seasonal NOx	(1)	-	63.18%			
	5090002	Allowance Expenses	(1)	(7,731)	63.18%	-		
27	5090005	Allowance Expenses - Annual NOx	(1)	15,468	63.18%	9,773		
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	63.18%	-		
29	Allowance Gains/Losses		(1)					
30	4118002	Comp. Allow. Gains SO2	(1)	(6,541,971)	63.18%	(4,133,217)		
31	4118003	Comp. Allow. Gains-Seas NOx	(1)	-	63.18%	-		
32	4118004	Comp. Allow. Gains-Ann NOx	(1)	(10,528)	63.18%	(6,651)		
33	4119000	Loss Disposition of Allowances	(1)		63.18%	-		
34	4119002	Comp. Allow. Loss - SO2		785,221	63.18%	496,103		
35		Total Allowance Dollars		$ (3,795,142)		$ (2,392,887)	91.960%	$ (2,200,499)
36	**Additional S.B. 221 FAC Accounts Forecast for 2009**			Additional Fuel and Environmental Accounts in FAC				
37			Notes			Firm Load		
38	Account	Description			Allocation Factor	Allocated Amount		
39	Incremental Fuel Handling/Ash/Gypsum		(1)		EXH OPCO 2			
40	5010000	Fuel (Ash Handling)	(1)	$ 1,369,184	63.18%	$ 865,050	91.960%	$ 795,500
41	5010003	Fuel - Procurement, Unloading & Handling	(1)	3,129,101	63.18%	1,976,966	91.960%	$ 1,818,018
42	5010012	Ash Sales Proceeds	(1)	(105,657)	63.18%	(66,754)	91.960%	$ (61,387)
43	5010027	Gypsum handling/disposal costs	(1)	472,419	63.18%	298,474	91.960%	$ 274,477
44	5010028	Gypsum Sales Proceeds	(1)	(509,139)	63.18%	(321,674)	91.960%	$ (295,811)
45	5010029	Gypsum handling/displ-Affiliat		41,353	63.18%	26,127	91.960%	$ 24,026
46	Incremental purchased power - Non Fuel		(3)	PSUM	PSUM			
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	(3)	$ -	-	$ -	91.960%	$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	(3)	408,824	25,522	383,302	91.960%	$ 352,485
49	5550032	PP - Mone - Non-Fuel	(3)	(7)	-	(7)	91.960%	$ (6)
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	(3)	-	-	-	91.960%	$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	(3)	-	-	-	91.960%	$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:OVEC bill)	(1)	4,848,370	100%	4,848,370	91.960%	$ 4,458,561
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	(1)	414	100%	414	91.960%	$ 381
54	5550023	PP Capacity - Non Affil.	(1)	222,105	100%	222,105	91.960%	$ 204,248
55	5550040	PJM Inadvertent - LSE (only)	(1)	(54,182)	100%	(54,182)	91.960%	$ (49,826)
56	5550003	PP - Cogeneration	(1)	44,397	100%	44,397	91.960%	$ 40,828
57	5550093	Peak Hour Avail Charge - LSE		-	100%	-	91.960%	$ -
58	Lawrenceburg purchased power - Non-Fuel (NA)							
59	Renewables		(1)					
60	5550047	Purchased Power - Wind	(1)	1,224,274	100%	$ 1,224,274	100.00%	$ 1,224,274
61	5550109	Purchased Power - Solar Energy	(1)	28,873	100%	28,873	100.00%	$ 28,873
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010	(1)	-	100%	-	100.00%	$ -
63	5570008	Renewable Energy Credit Exp.	(1)	-	100%	-	100.00%	$ -
64	5570009	Other Pwr Exp - REC's - RETAIL		321,929	100%	321,929	100.00%	$ 321,929
65	Environmental Material & Expense		(1)					
66	5020001	Lime Expense	(1)	$ 3,082,193	63.18%	$ 1,947,329	91.960%	$ 1,790,764
67	5020002	Urea Expense	(1)	1,788,549	63.18%	1,130,005	91.960%	$ 1,039,153
68	5020003	Trona Expense	(1)	941,454	63.18%	594,810	91.960%	$ 546,988
69	5020004	Limestone Expense	(1)	1,349,975	63.18%	852,914	91.960%	$ 784,340
70	5020005	Polymer expense	(1)	295,299	63.18%	186,570	91.960%	$ 171,570
71	5020007	Lime Hydrate Expense	(1)	6,677	63.18%	4,219	91.960%	$ 3,880
72	5020008	Activated Carbon	(1)	21	63.18%	13	91.960%	$ 12
73	5020025	Steam Exp Environmental		40,276	63.18%	25,446	91.960%	$ 23,400
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)		(1)					
75	5550035	PJM Normal Purchases (Non ECR OSS)	(1)	$ -	0%	$ -	91.960%	$ -
76	5550039	PJM Inadvertent - OSS (only)	(1)	(10,687)	0%	-	91.960%	$ -
77	5550088	PJM Capacity Charge (OSS only)	(1)	-	0%	-	91.960%	$ -
78	5550099	PJM Purchases - NonECR (Auction)	(1)	2,395,019	0%	-	91.960%	$ -
79	5550100	PJM Capacity Purchases - NonECR (Auction)	(1)	253,878	0%	-	91.960%	$ -
80	5550102	PP Pool Non Fuel - OSS Aff	(1)	6,401,078	0%	-	91.960%	$ -
81	5550107	Capacity Purchases - Trading	(1)	536,380	0%	-	91.960%	$ -
82	5550002	PP - Associated (PPA only - discontinued after Jan09)		-	0%	-	91.960%	$ -
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FA(		(1)					
84	5550075	PJM Reactive Credit	(1)	$ (646,946)	0%	$ -	91.960%	$ -
85	5550077	PJM Black Start Credit	(1)	(7,305)	0%	-	91.960%	$ -
86	5550079	PJM Regulation Credit	(1)	(231,916)	0%	-	91.960%	$ -
87	5550084	PJM Spinning Reserve Credit	(1)	(3,770)	0%	-	91.960%	$ -
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	91.960%	$ -
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)		(1)					
90	5550036	PJM Emergency Purchases (Demand Response Program)	(1)	$ 11	0%	$ -	91.960%	$ -
91	5550041	PJM Synchronous Cond. Charge	(1)	3,245	0%	-	91.960%	$ -
92	5550074	PJM Reactive Charge	(1)	1,220,863	0%	-	91.960%	$ -
93	5550076	PJM BlackStart Charge	(1)	19,630	0%	-	91.960%	$ -
94	5550078	PJM Regulation Charge	(1)	996,020	0%	-	91.960%	$ -
95	5550083	PJM Spinning Reserve Charge	(1)	109,666	0%	-	91.960%	$ -
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE		5,060	0%	-	91.960%	$ -
97		Total Additional FAC		$ 29,988,930		$ 14,538,972		$ 13,496,675
98		**TOTAL**		$ 129,250,861		$ 73,956,777		$ 68,137,288
99								
100	NOTATIONS:							
101	(1)	Total Co. amount is and agrees to GL account amount for applic. month	(a)	Report diffs. due to timing of GL recording of estimate/actuals.				
102	(2)	Total Co. amt. for fuel equals and agrees to sum of applic. GL fuel a/c amts.						
103	(3)	Actual cycle recorded amts are used for this purchased power activity - reconciled/agreed to GL account amt for applic. Month - See Recon WPs						
104	(4)	Derived amounts applic. to OSS (provided by Settlements via cost reconstr. sys.(ECR))						
105	(5)	Lawrenceburg firm load allocation derived from CSP NER schedule.						
106								

IEU-Ohio Exhibit 4

Line	A	B	C	D	E	F	G	H			
		Actual Cycle - Revised					EXH CSP-1				
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)									
		January 2011							Reconcile NEC to GL		
Line	A	B	C	D	E	F	G	H			Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail	EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel				NEC						
5	5010001/5010022	Fuel Consumed		$ 29,946,526	$ 7,397,322	$ 22,549,204			$ 29,946,526	$ 28,146,444	$ 1,800,082
6	5010009	Fuel Consumed - No Load (CV4)		719,889		719,889			$ 719,889	731,690	$ (11,801)
7	5010013	Fuel Survey Activity		-	-	-			$ -	1,841,057	$ (1,841,057)
8	5010019	Fuel Oil Consumed		1,674,002		1,674,002			$ 1,674,002	1,621,225	$ 52,776
9	5010020/5010036	Natural Gas Consumed		8,855,053	-	8,855,053			$ 8,855,053	8,854,300	$ 753
10	5470001/5470003	Fuel - Gas Turbine		-	$ -	-			$ -	753	$ (753)
11		Subtotal - Generation Fuel		$ 41,195,469	$ 7,397,322	$ 33,798,147			$ 41,195,469	$ 41,195,469	$ (0)
12	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	A	$ 1,600,002	$ 441,089	$ 1,158,913			$ 1,600,002	$ 2,254,980	$ (654,978)
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	$ 6,877,134	$ -	6,877,134			$ 6,877,134	7,879,243	$ (1,002,109)
15	5550080	PJM Energy Purchases (Fuel)	C	$ 3,215,409	$ 2,957,240	258,169			$ 3,215,409	2,995,709	$ 219,700
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	D	$ 638,577	$ 422,050	216,527			$ 638,577	419,147	$ 219,430
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	$ 36,060	$ 25,992	10,068			$ 36,060	-	$ 36,060
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	F	$ 12,114,915	$ 1,494,031	10,620,884			$ 12,114,915	12,532,248	$ (417,333)
19	5550032	Purchased Pwr - Mone (Fuel)	B	$ 16,588	$ 13,349	3,239			$ 16,588	-	$ 16,588
20		Subtotal - Purchased Power Fuel		$ 24,498,685	$ 5,353,751	$ 19,144,934			24,498,685	26,081,326	(1,582,641)
21		Total NEC Fuel		$ 65,694,155	$ 12,751,073	$ 52,943,082	100.000%	$ 52,943,082	65,694,155	67,276,796	(1,582,641)
22						Firm Load					
23	Allowance Accounts in FAC:				Allocation Factor	Allocated Amount					
24	Emission Allowance Expense										
25	5090000/2	Allowance Consumption - SO2		$ 1,008,399	81.47%	$ 821,542					
26	5090001	Allowance Consumption - Seasonal NOx		-	81.47%	-					
27	5090005	Allowance Expenses - Annual NOx		24,476	81.47%	19,941					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	81.47%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		$ (415,668)	81.47%	$ (338,645)					
31	4118003	Comp. Allow. Gains-Seas NOx			81.47%	-					
32	4118004	Comp. Allow. Gains-Ann NOx			81.47%	-					
33	4119000	Loss Disposition of Allowances			81.47%	-					
34		Total Allowance Dollars		$ 617,207		$ 502,839	100.000%	$ 502,839			
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum										
39	5010000	Fuel (Ash Handling)		$ 940,992	81.47%	$ 766,626	100.000%	$ 766,626			
40	5010003	Fuel - Procurement, Unloading & Handling		1,360,240	81.47%	1,108,187	100.000%	$ 1,108,187			
41	5010011	Fuel Handling - No Load (CV4)		21,156	81.47%	17,236	100.000%	$ 17,236			
42	5010012	Ash Sales Proceeds		(9,063)	81.47%	(7,384)	100.000%	$ (7,384)			
43	5010027	Gypsum handling/disposal costs		114,573	81.47%	93,343	100.000%	$ 93,343			
44	5010028	Gypsum Sales Proceeds		(35,417)	81.47%	(28,854)	100.000%	$ (28,854)			
45	5010032	Coal Procurement-Aff			81.47%	-	100.000%	$ -			
46	5010033	Coal Procurement-NA			81.47%	-	100.000%	$ -			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	D	$ -	$ -	$ -	100.000%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	139,880	68,562	71,318	100.000%	$ 71,318	$ 139,880	$ 791,476	$ (651,596)
50	5550032	PP - Mone - Non-Fuel	B	21,594	17,378	4,216	100.000%	$ 4,216	$ 21,594	$ 10,169	$ 11,425
51	5550098 INACTIVE	PP - PJM - Non-Fuel	C		-	-	100.000%	$ -	$ -		$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	F	(16)	-	(16)	100.000%	$ (16)	$ (16)		$ (16)
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)		829,846	100%	829,846	100.000%	$ 829,846	829,846		829,846
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	E	1,579,204	100%	1,579,204	100.000%	$ 1,579,204	991,304	801,645	189,659
55	5550004	Purchased Power - Pool Capacity		899,076	100%	899,076	100.000%	$ 899,076			
56	5550023	Purchase Power - Capacity		180,122	100%	180,122	100.000%	$ 180,122			
57	5550040	PJM Inadvertent - LSE (only)		96,185	100%	96,185	100.000%	$ 96,185			
58	5550093	Peak Hour Avail Charge - LSE		-	100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)		$ 2,943,736	100%	$ 2,943,736	100.000%	$ 2,943,736			
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)		(85,013)	100%	(85,013)	100.000%	$ (85,013)			
62	5550046	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)		382,040	86.59%	330,802	100.000%	$ 330,802			
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)		1,168,983	86.59%	1,012,202	100.000%	$ 1,012,202			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)		3,547,520	86.59%	3,071,736	100.000%	$ 3,071,736			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar		$ 1,031,383	100%	$ 1,031,383	100.000%	$ 1,031,383	$ 1,031,383	$ 1,031,383	$ -
67	5550109	Purchased Power - Solar		$ 28,481	100%	$ 28,481	100.000%	$ 28,481	$ 28,481	$ 28,481	$ -
68	5570007	Renewable Energy Credit Exp.		-	100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)		264,465	100%	$ 264,465	100.000%	$ 264,465			
70	Environmental Material & Expense										
71	5020001	Lime Expense		$ 1,882,020	81.47%	$ 1,533,281	100.000%	$ 1,533,281			
72	5020002	Urea Expense		266,288	81.47%	216,944	100.000%	$ 216,944			
73	5020003	Trona Expense		106,395	81.47%	86,680	100.000%	$ 86,680			
74	5020004	Limestone Expense		299,527	81.47%	244,024	100.000%	$ 244,024			
75	5020005	Polymer expense		104	81.47%	85	100.000%	$ 85			
76	5020007	Lime Hydrate Expense		11,842	81.47%	9,647	100.000%	$ 9,647			
77	5020008	Activated Carbon		(6)	81.47%	(5)	100.000%	$ (5)			
78	5020025	Steam Exp Environmental		6,501	81.47%	5,296	100.000%	$ 5,296			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)		2,501	0%	-					
82	5550088	PJM Capacity Charge (OSS only)		-	0%	-					
83	5550099	PJM Purchases - NonECR (Auction)		3,176,397	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)		508,540	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)		7,260,278	0%	-					
86	5550107	Capacity Purchases -Trading		437,306	0%	-					
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)		-	0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)		-	0%	-					
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit		$ (507,128)	0%	$ -					
91	5550077	PJM Black Start Credit		(5,733)	0%	-					
92	5550079	PJM Regulation Credit		(172,002)	0%	-					
93	5550084	PJM Spinning Reserve Credit		(1,034)	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)		$ (10)	0%	$ -					
97	5550041	PJM Synchronous Cond. Charge		4,296	0%	-					
98	5550074	PJM Reactive Charge		557,291	0%	-					
99	5550076	PJM BlackStart Charge		8,916	0%	-					
100	5550078	PJM Regulation Charge		761,260	0%	-					
101	5550083	PJM Spinning Reserve Charge		43,851	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE		4,192	0%	-					
103		Total Additional FAC		$ 30,071,555		$ 16,302,850		$ 16,302,850			
104		TOTAL		$ 96,382,917		$ 69,748,770		$ 69,748,770			
105											
106	NOTATIONS:										
107	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
108	B	East Pool group computes/books Mone fuel & non-fuel separately	E	IPS is source for fuel/non-fuel split for pool energy							
109	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%				PIVOT	ESTIMATE		
110								97,393,859	97,393,859		

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

JANUARY 2011 REVISED

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		Diff. To GL
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			Net Energy Cost (NEC) in EFC					EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	Generation Fuel			Mar GL	NEC						
5	5010001	Fuel Consumed		$ 92,498,752	$ 37,881,903	$ 54,616,849			$ 92,498,752	$ 92,498,752	$ (0)
6	5010009	Fuel Consumed - No Load (CV4)				-			$ -	-	$ -
7	5010013	Fuel Survey Activity		$ -		-			$ -	-	$ -
8	5010019	Fuel Oil Consumed		$ 1,538,827		1,538,827			$ 1,538,827	1,538,827	$ 0
9	5010020	Natural Gas Consumed				-			$ -	-	$ -
10	5010022	Fuel Consumed - Biomass				-			$ -	-	$ -
11	5470001	Fuel - Gas Turbine				-			$ -	-	$ -
12		**Subtotal - Generation Plant**		$ 94,037,579	$ 37,881,903	$ 56,155,676			$ 94,037,579	$ 94,037,579	$ (0)
13	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	A	$ 5,573,477	$ 1,034,664	$ 4,538,813			$ 5,573,477	$ 6,896,019	$ (1,322,542)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	-	-	$ -			$ -	(1,445)	$ 1,445
16	5550080	PJM Energy Purchases (Fuel)	C	3,857,255	3,547,552	$ 309,703			$ 3,857,255	3,656,349	$ 200,906
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	D	766,049	506,296	259,753			$ 766,049	511,578	$ 254,471
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	43,258	31,181	12,077			$ 43,258	43,076	$ 182
19	5550031/32	Purchased Pwr - Mone (Fuel)	B	19,899	16,014	3,885			$ 19,899	15,618	$ 4,281
20		**Subtotal - Purchased Power Fuel**		$ 10,259,938	$ 5,135,707	$ 5,124,231			10,259,938	11,121,194	(861,256)
21		**Total NEC Fuel**		$ 104,297,517	$ 43,017,610	$ 61,279,907	92.204%	$ 56,502,525	104,297,517	105,158,773	(861,256)
22						Firm Load					
23	***Allowance Accounts in FAC:***				Allocation Factor	Allocated Amt					
24	Emission Allowance Expense										
25	5090000	Allowance Consumption SO2		$ 3,125,715	60.21%	$ 1,881,993					
26	5090001	Allowance Consumption - Seasonal NOx		-	60.21%						
	5090002	Allowance Expenses		(6)	60.21%	-					
27	5090005	Allowance Expenses - Annual NOx		8,646	60.21%	5,206					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	60.21%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		3,379	60.21%	2,035					
31	4118003	Comp. Allow. Gains-Seas NOx		-	60.21%	-					
32	4118004	Comp. Allow. Gains-Ann NOx		(789,812)	60.21%	(475,546)					
33	4119000	Loss Disposition of Allowances		-	60.21%	-					
34	4119002	Comp. Allow. Loss - SO2		-	60.21%	-					
35		**Total Allowance Dollars**		$ 2,347,922		$ 1,413,686	92.204%	$ 1,303,477			
36	**Additional S.B. 221 FAC Accounts Forecast for 2009**			Additional Fuel and Environmental Accounts in FAC							
37						Firm Load					
38	Account	Description	Notes		Allocation Factor	Allocated Amount					
39	Incremental Fuel Handling/Ash/Gypsum										
40	5010000	Fuel (Ash Handling)		$ 1,581,923	60.21%	$ 952,476	92.204%	$ 878,221			
41	5010003	Fuel - Procurement, Unloading & Handling		3,753,749	60.21%	2,260,132	92.204%	$ 2,083,932			
42	5010012	Ash Sales Proceeds		(25,784)	60.21%	(15,525)	92.204%	$ (14,314)			
43	5010027	Gypsum handling/disposal costs		366,868	60.21%	220,891	92.204%	$ 203,670			
44	5010028	Gypsum Sales Proceeds		(78,577)	60.21%	(47,311)	92.204%	$ (43,623)			
45	5010029	Gypsum handling/displ-Affiliat		(43,492)	60.21%	(26,186)	92.204%	$ (24,145)			
46	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	D	$ -	-	$ -	92.204%	$ -	$ -		$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	487,258	90,455	396,803	92.204%	$ 365,868	$ 487,258	$ 2,761,252	$ (2,273,994)
49	5550032	PP - Mone - Non-Fuel	B	25,904	20,847	5,057	92.204%	$ 4,663	$ 25,904	$ -	$ 25,904
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	C	-	-	-	92.204%	$ -	$ -		$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	F	-	-	-	92.204%	$ -	$ -		$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:bill, Genea Taylor email)		2,895,117	100%	2,895,117	92.204%	$ 2,669,414	2,895,117		2,895,117
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	E	(37)	100%	(37)	92.204%	$ (34)	3,408,279	2,761,252	647,027
54	5550023	PP Capacity - Non Affil.		219,843	100%	219,843	92.204%	$ 202,704			
55	5550040	PJM Inadvertent - LSE (only)		117,398	100%	117,398	92.204%	$ 108,246			
56	5550003	PP - Cogeneration		84,909	100%	84,909	92.204%	$ 78,290			
57	5550093	Peak Hour Avail Charge - LSE		-	100%	-	92.204%	$ -			
58	Lawrenceburg purchased power - Non-Fuel (NA)										
59	Renewables										
60	5550047	Purchased Power - Wind		1,031,383	100%	$ 1,031,383	100.00%	$ 1,031,383	$ 1,031,383.35	$ 1,031,383.35	$ -
61	5550109	Purchased Power - Solar Energy		36,249	100%	36,249	100.00%	$ 36,249	$ 36,248.74	$ 36,248.74	$ -
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010		-	100%	-	100.00%	$ -			
63	5570008	Renewable Energy Credit Exp.		-	100%	-	100.00%	$ -			
64	5570009	Other Pwr Exp - REC's - RETAIL		334,214	100%	334,214	100.00%	$ 334,214			
65	Environmental Material & Expense										
66	5020001	Lime Expense		$ 3,940,758	60.21%	$ 2,372,731	92.204%	$ 2,187,753			
67	5020002	Urea Expense		2,117,627	60.21%	1,275,023	92.204%	$ 1,175,622			
68	5020003	Trona Expense		1,017,263	60.21%	612,494	92.204%	$ 564,744			
69	5020004	Limestone Expense		1,554,432	60.21%	935,923	92.204%	$ 862,959			
70	5020005	Polymer expense		296,099	60.21%	178,281	92.204%	$ 164,383			
71	5020007	Lime Hydrate Expense		4,821	60.21%	2,903	92.204%	$ 2,676			
72	5020008	Activated Carbon		(21)	60.21%	(12)	92.204%	$ (11)			
73	5020025	Steam Exp Environmental		48,674	60.21%	29,307	92.204%	$ 27,022			
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
75	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -	92.204%	$ -			
76	5550039	PJM Inadvertent - OSS (only)		3,052	0%	-	92.204%	$ -			
77	5550088	PJM Capacity Charge (OSS only)		-	0%	-	92.204%	$ -			
78	5550099	PJM Purchases - NonECR (Auction)		3,876,853	0%	-	92.204%	$ -			
79	5550100	PJM Capacity Purchases - NonECR (Auction)		620,686	0%	-	92.204%	$ -			
80	5550102	PP Pool Non Fuel - OSS Aff		10,115,631	0%	-	92.204%	$ -			
81	5550107	Capacity Purchases - Trading		533,742	0%	-	92.204%	$ -			
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)		-	0%	-	92.204%	$ -			
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
84	5550075	PJM Reactive Credit		$ (618,964)	0%	$ -	92.204%	$ -			
85	5550077	PJM Black Start Credit		(6,997)	0%	-	92.204%	$ -			
86	5550079	PJM Regulation Credit		(209,935)	0%	-	92.204%	$ -			
87	5550084	PJM Spinning Reserve Credit		(1,262)	0%	-	92.204%	$ -			
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	92.204%	$ -			
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
90	5550036	PJM Emergency Purchases (Demand Response Program)		$ (12)	0%	$ -	92.204%	$ -			
91	5550041	PJM Synchronous Cond. Charge		5,244	0%	-	92.204%	$ -			
92	5550074	PJM Reactive Charge		680,189	0%	-	92.204%	$ -			
93	5550076	PJM BlackStart Charge		10,882	0%	-	92.204%	$ -			
94	5550078	PJM Regulation Charge		929,147	0%	-	92.204%	$ -			
95	5550083	PJM Spinning Reserve Charge		53,521	0%	-	92.204%	$ -			
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE		5,117	0%	-	92.204%	$ -			
97		**Total Additional FAC**		$ 35,763,474		$ 13,872,063		$ 12,899,885	GL AMOUNTS	$ 142,623,142.17	
98		**TOTAL**		$ 142,408,913		$ 76,565,658		$ 70,705,887	EXCL 5010032/33	$ -	
99									TOTAL GL QUERY	$ 142,623,142.17	
100	NOTATIONS:										
101	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
102	B	East Pool group computes/books Mone fuel & non-fuel separately (80/20	E	IPS is source for fuel/non-fuel split for pool energy							
103	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%							
104											

EXH CSP-1

COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)

Actual Cycle

February 2011

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		
									EST	Applicable	Diff. To GL
1	*Fuel, Purchased Power, and Environmental Costs Included FAC*			Net Energy Cost (NEC) in EFC			Retail	Retail			NEC Adjs. for
2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel				NEC						
5	5010001/5010022	Fuel Consumed		$ 23,272,753	$ 5,831,206	$ 17,441,547			$ 23,272,753	$ 23,260,408	$ 12,346
6	5010009	Fuel Consumed - No Load (CV4)		719,889		719,889			$ 719,889	745,788	$ (25,899)
7	5010013	Fuel Survey Activity		-	-	-			$ -	-	$ -
8	5010019	Fuel Oil Consumed		505,214		505,214			$ 505,214	491,661	$ 13,554
9	5010020/5010036	Natural Gas Consumed		3,114,890	-	3,114,890			$ 3,114,890	3,106,430	$ 8,460
10	5470001/5470003	Fuel - Gas Turbine		-	$ -	-			$ -	8,460	$ (8,460)
11		Subtotal - Generation Fuel		$ 27,612,747	$ 5,831,206	$ 21,781,541			$ 27,612,747	$ 27,612,747	$ 0
12	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	A	$ 1,451,920	$ 564,840	$ 887,080			$ 1,451,920	$ 1,740,526	$ (288,606)
14	5550005	*Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)*	E	$ 8,815,212	$ -	8,815,212			$ 8,815,212	9,710,485	$ (895,273)
15	5550080	PJM Energy Purchases (Fuel)	C	$ 1,680,417	$ 1,605,792	74,625			$ 1,680,417	1,692,338	$ (11,921)
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	D	$ 514,814	$ 341,344	173,470			$ 514,814	356,402	$ 158,412
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	$ 2,001	$ 1,652	349			$ 2,001		$ 2,001
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	F	$ 6,844,673	$ 1,006,151	5,838,522			$ 6,844,673	6,871,969	$ (27,296)
19	5550032	Purchased Pwr - Mone (Fuel)	B	$ 33,522	$ 30,721	2,801			$ 33,522	46,145	$ (12,623)
20		Subtotal - Purchased Power Fuel		$ 19,342,559	$ 3,550,500	$ 15,792,059			19,342,559	20,417,865	(1,075,306)
21		Total NEC Fuel		$ 46,955,306	$ 9,381,706	$ 37,573,600	100.000%	$ 37,573,600	46,955,306	48,030,612	(1,075,306)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount					
24	Emission Allowance Expense										
25	5090000/2	Allowance Consumption - SO2		$ 406,774	84.66%	$ 344,375					
26	5090001	Allowance Consumption - Seasonal NOx		-	84.66%	-					
27	5090005	Allowance Expenses - Annual NOx		41,515	84.66%	35,147					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	84.66%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2			84.66%	$ -					
31	4118003	Comp. Allow. Gains-Seas NOx			84.66%	-					
32	4118004	Comp. Allow. Gains-Ann NOx			84.66%	-					
33	4119000	Loss Disposition of Allowances			84.66%	-					
34		*Total Allowance Dollars*		$ 448,289		$ 379,521	100.000%	$ 379,521			
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum										
39	5010000	Fuel (Ash Handling)		$ 211,668	84.66%	$ 179,199	100.000%	$ 179,199			
40	5010003	Fuel - Procurement, Unloading & Handling		926,555	84.66%	784,421	100.000%	$ 784,421			
41	5010011	Fuel Handling - No Load (CV4)		19,824	84.66%	16,783	100.000%	$ 16,783			
42	5010012	Ash Sales Proceeds		(5,568)	84.66%	(4,714)	100.000%	$ (4,714)			
43	5010027	Gypsum handling/disposal costs		223,863	84.66%	189,522	100.000%	$ 189,522			
44	5010028	Gypsum Sales Proceeds		(11,086)	84.66%	(9,385)	100.000%	$ (9,385)			
45	5010032	Coal Procurement-Aff			84.66%	-	100.000%	$ -			
46	5010033	Coal Procurement-NA			84.66%	-	100.000%	$ -			
47	*Incremental purchased power - Non Fuel*			*ECR PP SUM Rpt*	*ECR PP SUM Rpt*						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	D	$ -	$ -	$ -	100.000%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	156,861	61,023	95,837	100.000%	$ 95,837	$ 156,861	$ 907,324	$ (750,464)
50	5550032	PP - Mone - Non-Fuel	B	14,741	13,509	1,232	100.000%	$ 1,232	$ 14,741		$ 14,741
51	5550098 INACTIVE	PP - PJM - Non-Fuel	C		-	-	100.000%	$ -	$ -		$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	F		-	-	100.000%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)		967,873	100%	967,873	100.000%	$ 967,873	967,873		967,873
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	E	1,921,834	100%	1,921,834	100.000%	$ 1,921,834	1,139,475	907,324	232,150
55	5550004	Purchased Power - Pool Capacity		732,958	100%	732,958	100.000%	$ 732,958			
56	5550023	Purchase Power - Capacity		180,122	100%	180,122	100.000%	$ 180,122			
57	5550040	PJM Inadvertent - LSE (only)		56,934	100%	56,934	100.000%	$ 56,934			
58	5550093	Peak Hour Avail Charge - LSE		-	100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affil (Lawrenceburg)		$ 2,943,736	100%	$ 2,943,736	100.000%	$ 2,943,736			
61	5550104	Defd Depr & Capacity portion-Affil (Lawrenceburg)		(85,013)	100%	(85,013)	100.000%	$ (85,013)			
62	5550046	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)		24,600	84.10%	20,688	100.000%	$ 20,688			
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)		1,520,576	84.10%	1,278,744	100.000%	$ 1,278,744			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)		763,460	84.10%	642,040	100.000%	$ 642,040			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar		$ 1,322,193	100%	$ 1,322,193	100.000%	$ 1,322,193	$ 1,322,193	$ 1,322,193	$ -
67	5550109	Purchased Power - Solar		$ 33,333	100%	$ 33,333	100.000%	$ 33,333	$ 33,333	$ 33,333	$ -
68	5570007	Renewable Energy Credit Exp.			100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)		280,788	100%	$ 280,788	100.000%	$ 280,788			
70	Environmental Material & Expense										
71	5020001	Lime Expense		$ 1,283,737	84.66%	$ 1,086,812	100.000%	$ 1,086,812			
72	5020002	Urea Expense		156,215	84.66%	132,252	100.000%	$ 132,252			
73	5020003	Trona Expense		18,194	84.66%	15,403	100.000%	$ 15,403			
74	5020004	Limestone Expense		316,527	84.66%	267,971	100.000%	$ 267,971			
75	5020005	Polymer expense		124	84.66%	105	100.000%	$ 105			
76	5020007	Lime Hydrate Expense		8,937	84.66%	7,566	100.000%	$ 7,566			
77	5020008	Activated Carbon		9	84.66%	8	100.000%	$ 8			
78	5020025	Steam Exp Environmental		3,128	84.66%	2,648	100.000%	$ 2,648			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)			0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)		10,850	0%	-					
82	5550088	PJM Capacity Charge (OSS only)			0%	-					
83	5550099	PJM Purchases - NonECR (Auction)		1,752,124	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)		269,572	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)		6,251,305	0%	-					
86	5550107	Capacity Purchases -Trading		405,767	0%	-					
87	5550002	PP - Associated *(PPA only - discountinued use after Jan09)*			0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)			0%	-					
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit		$ (488,349)	0%	$ -					
91	5550077	PJM Black Start Credit		(5,733)	0%	-					
92	5550079	PJM Regulation Credit		(111,509)	0%	-					
93	5550084	PJM Spinning Reserve Credit		74	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE			0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)		$ -	0%	$ -					
97	5550041	PJM Synchronous Cond. Charge		4,837	0%	-					
98	5550074	PJM Reactive Charge		516,966	0%	-					
99	5550076	PJM BlackStart Charge		8,240	0%	-					
100	5550078	PJM Regulation Charge		476,635	0%	-					
101	5550083	PJM Spinning Reserve Charge		8,337	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE		2,225	0%	-					
103		Total Additional FAC		$ 23,088,464		$ 13,061,888		$ 13,061,888			
104		TOTAL		$ 70,492,058		$ 51,015,009		$ 51,015,009			
105											
106	NOTATIONS:										
107	A	OVEC fuel/non-fuel portions provided in billing detail	D	*3rd PP trading purchases split: 100% fuel*							
108	B	East Pool group computes/books Mone fuel & non-fuel separately	E	IPS is source for fuel/non-fuel split for pool energy							
109	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%				PIVOT	ESTIMATE		
110								71,310,614	71,310,614		

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

FEBRUARY 2011

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	Generation Fuel			Mar GL	NEC						
5	5010001	Fuel Consumed		$ 80,446,330	$ 32,970,936	$ 47,475,394			$ 80,446,330	$ 80,319,076	$ 127,254
6	5010009	Fuel Consumed - No Load (CV4)				-			$ -	-	$ -
7	5010013	Fuel Survey Activity		$ -		-			$ -	127,254	$ (127,254)
8	5010019	Fuel Oil Consumed		$ 1,566,367		1,566,367			$ 1,566,367	1,566,367	$ -
9	5010020	Natural Gas Consumed				-			$ -	-	$ -
10	5010022	Fuel Consumed - Biomass				-			$ -	3,649	$ (3,649)
11	5470001	Fuel - Gas Turbine				-			$ -	-	$ -
12		Subtotal - Generation Plant		$ 82,012,697	$ 32,970,936	$ 49,041,761			$ 82,012,697	$ 82,016,346	$ (3,649)
13	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	A	$ 5,052,785	$ 974,486	$ 4,078,299			$ 5,052,785	$ 5,762,486	$ (709,701)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	-	-	$ -			$ -	-	$ -
16	5550080	PJM Energy Purchases (Fuel)	C	2,015,855	1,926,334	$ 89,521			$ 2,015,855	2,065,543	$ (49,688)
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	D	617,586	409,482	208,104			$ 617,586	434,999	$ 182,587
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	2,401	1,981	420			$ 2,401	3,291	$ (890)
19	5550031/32	Purchased Pwr - Mone (Fuel)	B	40,214	36,853	3,361			$ 40,214	56,739	$ (16,525)
20		Subtotal - Purchased Power Fuel		$ 7,728,841	$ 3,349,136	$ 4,379,705			7,728,841	8,323,059	(594,218)
21		Total NEC Fuel		$ 89,741,538	$ 36,320,072	$ 53,421,466	92.263%	$ 49,288,247	89,741,538	90,339,405	(597,867)
22						Firm Load					
23	Allowance Accounts in FAC:				Allocation Factor	Allocated Amt					
24	Emission Allowance Expense										
25	5090000	Allowance Consumption SO2		$ 2,879,895	60.31%	$ 1,736,865					
26	5090001	Allowance Consumption - Seasonal NOx		-	60.31%						
	5090002	Allowance Expenses		-	60.31%	-					
27	5090005	Allowance Expenses - Annual NOx		8,790	60.31%	5,301					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	60.31%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		-	60.31%	-					
31	4118003	Comp. Allow. Gains-Seas NOx		-	60.31%	-					
32	4118004	Comp. Allow. Gains-Ann NOx		(767,579)	60.31%	(462,927)					
33	4119000	Loss Disposition of Allowances		-	60.31%	-					
34	4119002	Comp. Allow. Loss - SO2		-	60.31%	-					
35		Total Allowance Dollars		$ 2,121,106		$ 1,279,239	92.263%	$ 1,180,264			
36	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC							
37						Firm Load					
38	Account	Description	Notes		Allocation Factor	Allocated Amount					
39	Incremental Fuel Handling/Ash/Gypsum										
40	5010000	Fuel (Ash Handling)		$ 1,257,399	60.31%	$ 758,337	92.263%	$ 699,665			
41	5010003	Fuel - Procurement, Unloading & Handling		3,053,850	60.31%	1,841,777	92.263%	$ 1,699,279			
42	5010012	Ash Sales Proceeds		(64,502)	60.31%	(38,901)	92.263%	$ (35,891)			
43	5010027	Gypsum handling/disposal costs		154,159	60.31%	92,973	92.263%	$ 85,780			
44	5010028	Gypsum Sales Proceeds		(133,862)	60.31%	(80,732)	92.263%	$ (74,486)			
45	5010029	Gypsum handling/displ-Affiliat		24,573	60.31%	14,820	92.263%	$ 13,673			
46	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	D	$ -	-	$ -	92.263%	$ -	$ -		$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	547,021	105,499	441,522	92.263%	$ 407,361	$ 547,021	$ 3,165,418	$ (2,618,397)
49	5550032	PP - Mone - Non-Fuel	B	17,683	16,205	1,478	92.263%	$ 1,364	$ 17,683	$ -	$ 17,683
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	C	-	-	-	92.263%	$ -	$ -		$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	F	-	-	-	92.263%	$ -	$ -		$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:bill, Genea Taylor email)		3,376,657	100%	3,376,657	92.263%	$ 3,115,405	3,376,657		3,376,657
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	E	-	100%	-	92.263%	$ -	3,941,361	3,165,418	775,943
54	5550023	PP Capacity - Non Affil.		219,843	100%	219,843	92.263%	$ 202,834			
55	5550040	PJM Inadvertent - LSE (only)		69,489	100%	69,489	92.263%	$ 64,113			
56	5550003	PP - Cogeneration		111,998	100%	111,998	92.263%	$ 103,332			
57	5550093	Peak Hour Avail Charge - LSE		-	100%	-	92.263%	$ -			
58	Lawrenceburg purchased power - Non-Fuel (NA)										
59	Renewables										
60	5550047	Purchased Power - Wind		1,322,193	100%	$ 1,322,193	100.00%	$ 1,322,193	$ 1,322,193.00	$ 1,322,192.94	$ 0.06
61	5550109	Purchased Power - Solar Energy		42,423	100%	42,423	100.00%	$ 42,423	$ 42,423.27	$ 42,423.27	$ -
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010		-	100%	-	100.00%	$ -			
63	5570008	Renewable Energy Credit Exp.		-	100%	-	100.00%	$ -			
64	5570009	Other Pwr Exp - REC's - RETAIL		355,316	100%	355,316	100.00%	$ 355,316			
65	Environmental Material & Expense										
66	5020001	Lime Expense		$ 3,955,750	60.31%	$ 2,385,713	92.263%	$ 2,201,130			
67	5020002	Urea Expense		2,006,849	60.31%	1,210,331	92.263%	$ 1,116,687			
68	5020003	Trona Expense		(498,654)	60.31%	(300,738)	92.263%	$ (277,470)			
69	5020004	Limestone Expense		1,230,084	60.31%	741,864	92.263%	$ 684,466			
70	5020005	Polymer expense		384,041	60.31%	231,615	92.263%	$ 213,695			
71	5020007	Lime Hydrate Expense		7,209	60.31%	4,348	92.263%	$ 4,011			
72	5020008	Activated Carbon		30	60.31%	18	92.263%	$ 17			
73	5020025	Steam Exp Environmental		50,486	60.31%	30,448	92.263%	$ 28,093			
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
75	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -	92.263%	$ -			
76	5550039	PJM Inadvertent - OSS (only)		13,243	0%	-	92.263%	$ -			
77	5550088	PJM Capacity Charge (OSS only)		-	0%	-	92.263%	$ -			
78	5550099	PJM Purchases - NonECR (Auction)		2,138,513	0%	-	92.263%	$ -			
79	5550100	PJM Capacity Purchases - NonECR (Auction)		329,018	0%	-	92.263%	$ -			
80	5550102	PP Pool Non Fuel - OSS Aff		6,898,975	0%	-	92.263%	$ -			
81	5550107	Capacity Purchases - Trading		495,249	0%	-	92.263%	$ -			
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)		-	0%	-	92.263%	$ -			
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
84	5550075	PJM Reactive Credit		$ (596,042)	0%	$ -	92.263%	$ -			
85	5550077	PJM Black Start Credit		(6,997)	0%	-	92.263%	$ -			
86	5550079	PJM Regulation Credit		(136,100)	0%	-	92.263%	$ -			
87	5550084	PJM Spinning Reserve Credit		91	0%	-	92.263%	$ -			
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	92.263%	$ -			
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
90	5550036	PJM Emergency Purchases (Demand Response Program)		$ -	0%	$ -	92.263%	$ -			
91	5550041	PJM Synchronous Cond. Charge		5,904	0%	-	92.263%	$ -			
92	5550074	PJM Reactive Charge		630,971	0%	-	92.263%	$ -			
93	5550076	PJM BlackStart Charge		10,058	0%	-	92.263%	$ -			
94	5550078	PJM Regulation Charge		581,746	0%	-	92.263%	$ -			
95	5550083	PJM Spinning Reserve Charge		10,176	0%	-	92.263%	$ -			
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE		2,716	0%	-	92.263%	$ -			
97		Total Additional FAC		$ 27,867,556		$ 12,832,792		$ 11,972,990	GL AMOUNTS	$ 119,552,123.72	
98		TOTAL		$ 119,730,200		$ 67,533,498		$ 62,441,502	EXCL 5010032/33	$ -	
99									TOTAL GL QUERY	$ 119,552,123.72	
100	NOTATIONS:										
101	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
102	B	East Pool group computes/books Mone fuel & non-fuel separately (80/2(	E	IPS is source for fuel/non-fuel split for pool energy							
103	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%							
104											

Line	A	B	C	D	E	F	G	H			
		Actual Cycle					EXH CSP-1				
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)									
		March 2011							Reconcile NEC to GL		
Line	A	B	C	D	E	F	G	H			Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail	EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel				NEC						
5	5010001/5010022	Fuel Consumed		$ 24,065,940	$ 7,046,466	$ 17,019,474			$ 24,065,940	$ 24,666,106	$ (600,166)
6	5010009	Fuel Consumed - No Load (CV4)		719,889		719,889			$ 719,889	164,174	$ 555,715
7	5010013	Fuel Survey Activity		-	-	-			$ -		$ -
8	5010019	Fuel Oil Consumed		662,475		662,475			$ 662,475	618,024	$ 44,451
9	5010020/5010035	Natural Gas Consumed		10,186,983	-	10,186,983			$ 10,186,983	10,186,383	$ 600
10	5470001/5470003	Fuel - Gas Turbine		-	$ -	-			$ -	600	$ (600)
11		Subtotal - Generation Fuel		$ 35,635,287	$ 7,046,466	$ 28,588,821			$ 35,635,287	$ 35,635,287	$ 0
12	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	A	$ 1,488,657	$ 915,261	$ 573,396			$ 1,488,657	$ 3,252,622	$ (1,763,965)
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	$ 3,717,324	$ -	3,717,324			$ 3,717,324	2,530,234	$ 1,187,090
15	5550080	PJM Energy Purchases (Fuel)	C	$ 1,531,006	$ 1,241,610	289,396			$ 1,531,006	1,249,129	$ 281,877
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	D	$ 1,353,569	$ 1,162,842	190,727			$ 1,353,569	2,926	$ 1,350,643
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	$ 8,074	$ 8,074	-			$ 8,074	-	$ 8,074
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	F	$ 14,319,493	$ 1,870,812	12,448,681			$ 14,319,493	14,349,455	$ (29,962)
19	5550032	Purchased Pwr - Mone (Fuel)	B	$ -	$ -	-			$ -	86,257	$ (86,257)
20		Subtotal - Purchased Power Fuel		$ 22,418,123	$ 5,198,599	$ 17,219,524			22,418,123	21,470,623	947,500
21		Total NEC Fuel		$ 58,053,410	$ 12,245,065	$ 45,808,345	100.000%	$ 45,808,345	58,053,410	57,105,910	947,500
22						Firm Load					
23	Allowance Accounts in FAC:				Allocation Factor	Allocated Amount					
24	Emission Allowance Expense										
25	5090000/2	Allowance Consumption - SO2		$ 276,736	73.31%	$ 204,341					
26	5090001	Allowance Consumption - Seasonal NOx			73.31%	-					
27	5090005	Allowance Expenses - Annual NOx		32,176	73.31%	23,588					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)			73.31%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		$ (2,559)	73.31%	$ (1,876)					
31	4118003	Comp. Allow. Gains-Seas NOx			73.31%	-					
32	4118004	Comp. Allow. Gains-Ann NOx			73.31%	-					
33	4119000	Loss Disposition of Allowances			73.31%	-					
34		Total Allowance Dollars		$ 308,352		$ 226,053	100.000%	$ 226,053			
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum										
39	5010000	Fuel (Ash Handling)		$ 520,196	73.31%	$ 381,356	100.000%	$ 381,356			
40	5010003	Fuel - Procurement, Unloading & Handling		820,967	73.31%	601,851	100.000%	$ 601,851			
41	5010011	Fuel Handling - No Load (CV4)		29,190	73.31%	21,399	100.000%	$ 21,399			
42	5010012	Ash Sales Proceeds		(2,953)	73.31%	(2,165)	100.000%	$ (2,165)			
43	5010027	Gypsum handling/disposal costs		140,889	73.31%	103,286	100.000%	$ 103,286			
44	5010028	Gypsum Sales Proceeds		(3)	73.31%	(2)	100.000%	$ (2)			
45	5010032	Coal Procurement-Aff			73.31%	-	100.000%	$ -			
46	5010033	Coal Procurement-NA			73.31%	-	100.000%	$ -			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	D	$ -	$ -	$ -	100.000%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	166,641	102,176	64,465	100.000%	$ 64,465	$ 166,641	$ 1,196,755	$ (1,030,114)
50	5550032	PP - Mone - Non-Fuel	B	16,123	-	16,123	100.000%	$ 16,123	$ 16,123		$ 16,123
51	5550098 INACTIVE	PP - PJM - Non-Fuel	C		-	-	100.000%	$ -	$ -		$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	F		-	-	100.000%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)		1,196,753	100%	1,196,753	100.000%	$ 1,196,753	1,196,753		1,196,753
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	E	105,235	100%	105,235	100.000%	$ 105,235	1,379,517	1,196,755	182,762
55	5550004	Purchased Power - Pool Capacity		3,600,633	100%	3,600,633	100.000%	$ 3,600,633			
56	5550023	Purchase Power - Capacity		187,785	100%	187,785	100.000%	$ 187,785			
57	5550040	PJM Inadvertent - LSE (only)		90,991	100%	90,991	100.000%	$ 90,991			
58	5550093	Peak Hour Avail Charge - LSE		-	100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affil (Lawrenceburg)		$ 2,943,736	100%	$ 2,943,736	100.000%	$ 2,943,736			
61	5550104	Defd Depr & Capacity portion-Affil (Lawrenceburg)		(85,013)	100%	(85,013)	100.000%	$ (85,013)			
62	5550046	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)		20,890	86.24%	18,014	100.000%	$ 18,014			
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)		980,007	86.24%	845,110	100.000%	$ 845,110			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)		770,651	86.24%	664,571	100.000%	$ 664,571			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar		$ 1,127,180	100%	$ 1,127,180	100.000%	$ 1,127,180	$ 1,127,180	$ 1,127,180	$ -
67	5550109	Purchased Power - Solar		$ 50,522	100%	$ 50,522	100.000%	$ 50,522	$ 50,522	$ 50,522	$ -
68	5570007	Renewable Energy Credit Exp.			100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)		468,673	100%	$ 468,673	100.000%	$ 468,673			
70	Environmental Material & Expense										
71	5020001	Lime Expense		$ 1,893,674	73.31%	$ 1,388,252	100.000%	$ 1,388,252			
72	5020002	Urea Expense		455,961	73.31%	334,265	100.000%	$ 334,265			
73	5020003	Trona Expense		99,040	73.31%	72,606	100.000%	$ 72,606			
74	5020004	Limestone Expense		146,728	73.31%	107,567	100.000%	$ 107,567			
75	5020005	Polymer expense		135	73.31%	99	100.000%	$ 99			
76	5020007	Lime Hydrate Expense		353	73.31%	259	100.000%	$ 259			
77	5020008	Activated Carbon		27	73.31%	20	100.000%	$ 20			
78	5020025	Steam Exp Environmental		5,657	73.31%	4,147	100.000%	$ 4,147			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)			0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)		(1,399)	0%	-					
82	5550088	PJM Capacity Charge (OSS only)			0%	-					
83	5550099	PJM Purchases - NonECR (Auction)		1,712,552	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)		302,609	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)		8,059,739	0%	-					
86	5550107	Capacity Purchases -Trading		524,290	0%	-					
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)			0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)			0%	-					
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit		$ (537,978)	0%	$ -					
91	5550077	PJM Black Start Credit		(5,873)	0%	-					
92	5550079	PJM Regulation Credit		(166,289)	0%	-					
93	5550084	PJM Spinning Reserve Credit		(4,238)	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE			0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)			0%	$ -					
97	5550041	PJM Synchronous Cond. Charge		45	0%	-					
98	5550074	PJM Reactive Charge		566,340	0%	-					
99	5550076	PJM BlackStart Charge		9,048	0%	-					
100	5550078	PJM Regulation Charge		411,620	0%	-					
101	5550083	PJM Spinning Reserve Charge		53,555	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE		1,202	0%	-					
103		Total Additional FAC		$ 26,675,890		$ 14,307,717		$ 14,307,717			
104		TOTAL		$ 85,037,652		$ 60,342,115		$ 60,342,115			
105											
106	NOTATIONS:										
107	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
108	B	East Pool group computes/books Mone fuel & non-fuel separately	E	IPS is source for fuel/non-fuel split for pool energy							
109	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%				PIVOT	ESTIMATE		
110								83,886,501	83,886,500		

C:\Users\joliker\AppData\Local\Temp\Temp3_LA-2011-49 CONFIDENTIAL.zip\[LA-2011-49, Confidential CC (OPCO_BU_181_				ACTUAL		EXH OPCo-1					
OHIO POWER COMPANY - NET ENERGY COST (NEC)											
MARCH 2011									Reconcile NEC to GL		
Line	A	B	C	D	E	F	G	H			Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	Generation Fuel			Mar GL	NEC						
5	5010001	Fuel Consumed		$ 80,510,313	$ 28,766,843	$ 51,743,470			$ 80,510,313	$ 80,502,651	$ 7,662
6	5010009	Fuel Consumed - No Load (CV4)				-			$ -	-	$ -
7	5010013	Fuel Survey Activity		$ 2,078,841		2,078,841			$ 2,078,841	2,078,841	$ (0)
8	5010019	Fuel Oil Consumed		$ 3,337,605		3,337,605			$ 3,337,605	3,337,605	$ 0
9	5010020	Natural Gas Consumed				-			$ -	-	$ -
10	5010022	Fuel Consumed - Biomass				-			$ -	7,661	$ (7,661)
11	5470001	Fuel - Gas Turbine				-			$ -	-	$ -
12		Subtotal - Generation Plant		$ 85,926,759	$ 28,766,843	$ 57,159,916			$ 85,926,759	$ 85,926,759	$ 0
13	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	A	$ 5,203,823	$ 2,564,199	$ 2,639,624			$ 5,203,823	$ 7,651,799	$ (2,447,976)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	1,605	-	$ 1,605			$ 1,605	1,147	$ 458
16	5550080	PJM Energy Purchases (Fuel)	C	1,836,619	1,489,456	$ 347,163			$ 1,836,619	1,402,469	$ 434,150
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	D	1,623,762	1,394,962	228,800			$ 1,623,762	(12,633)	$ 1,636,395
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	9,686	9,686	-			$ 9,686	10,842	$ (1,156)
19	5550031/32	Purchased Pwr - Mone (Fuel)	B	-	-	-			$ -	106,599	$ (106,599)
20		Subtotal - Purchased Power Fuel		$ 8,675,495	$ 5,458,303	$ 3,217,192			8,675,495	9,160,223	(484,728)
21		Total NEC Fuel		$ 94,602,254	$ 34,225,146	$ 60,377,108	91.842%	$ 55,451,544	94,602,254	95,086,982	(484,728)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt					
24	Emission Allowance Expense										
25	5090000	Allowance Consumption SO2		$ 3,071,545	66.43%	$ 2,040,428					
26	5090001	Allowance Consumption - Seasonal NOx		-	66.43%						
	5090002	Allowance Expenses		-	66.43%	-					
27	5090005	Allowance Expenses - Annual NOx		9,713	66.43%	6,452					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	66.43%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		(9,710)	66.43%	(6,450)					
31	4118003	Comp. Allow. Gains-Seas NOx		-	66.43%	-					
32	4118004	Comp. Allow. Gains-Ann NOx		-	66.43%	-					
33	4119000	Loss Disposition of Allowances		-	66.43%	-					
34	4119002	Comp. Allow. Loss - SO2		-	66.43%	-					
35		Total Allowance Dollars		$ 3,071,548		$ 2,040,430	91.842%	$ 1,873,971			
36	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC							
37						Firm Load					
38	Account	Description	Notes		Allocation Factor	Allocated Amount					
39	Incremental Fuel Handling/Ash/Gypsum										
40	5010000	Fuel (Ash Handling)		$ 859,170	66.43%	$ 570,747	91.842%	$ 524,185			
41	5010003	Fuel - Procurement, Unloading & Handling		3,557,876	66.43%	2,363,498	91.842%	$ 2,170,684			
42	5010012	Ash Sales Proceeds		(36,948)	66.43%	(24,545)	91.842%	$ (22,542)			
43	5010027	Gypsum handling/disposal costs		191,169	66.43%	126,994	91.842%	$ 116,634			
44	5010028	Gypsum Sales Proceeds		(100,888)	66.43%	(67,020)	91.842%	$ (61,552)			
45	5010029	Gypsum handling/displ-Affiliat		21,727	66.43%	14,433	91.842%	$ 13,256			
46	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	D	$ -	-	$ -	91.842%	$ -	$ -		$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	579,792	285,695	294,097	91.842%	$ 270,105	$ 579,792	$ 4,175,166	$ (3,595,374)
49	5550032	PP - Mone - Non-Fuel	B	19,341	-	19,341	91.842%	$ 17,763	$ 19,341	$ -	$ 19,341
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	C	-	-	-	91.842%	$ -	$ -		$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	F	-	-	-	91.842%	$ -	$ -		$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:bill, Genea Taylor email)		4,175,160	100%	4,175,160	91.842%	$ 3,834,550	4,175,160		4,175,160
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	E	104	100%	104	91.842%	$ 96	4,774,293	4,175,166	599,126
54	5550023	PP Capacity - Non Affil.		217,737	100%	217,737	91.842%	$ 199,974			
55	5550040	PJM Inadvertent - LSE (only)		108,173	100%	108,173	91.842%	$ 99,348			
56	5550003	PP - Cogeneration		94,253	100%	94,253	91.842%	$ 86,564			
57	5550093	Peak Hour Avail Charge - LSE		-	100%	-	91.842%	$ -			
58	Lawrenceburg purchased power - Non-Fuel (NA)										
59	Renewables										
60	5550047	Purchased Power - Wind		1,127,180	100%	$ 1,127,180	100.00%	$ 1,127,180	$ 1,127,180.00	$ 1,127,180.14	$ (0.14)
61	5550109	Purchased Power - Solar Energy		64,300	100%	64,300	100.00%	$ 64,300	$ 64,300.00	$ 64,300.26	$ (0.26)
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010		-	100%	-	100.00%	$ -			
63	5570008	Renewable Energy Credit Exp.		-	100%	-	100.00%	$ -			
64	5570009	Other Pwr Exp - REC's - RETAIL		578,515	100%	578,515	100.00%	$ 578,515			
65	Environmental Material & Expense										
66	5020001	Lime Expense		$ 3,225,299	66.43%	$ 2,142,566	91.842%	$ 1,967,775			
67	5020002	Urea Expense		2,282,479	66.43%	1,516,251	91.842%	$ 1,392,555			
68	5020003	Trona Expense		999,571	66.43%	664,015	91.842%	$ 609,845			
69	5020004	Limestone Expense		1,167,870	66.43%	775,816	91.842%	$ 712,525			
70	5020005	Polymer expense		406,337	66.43%	269,930	91.842%	$ 247,909			
71	5020007	Lime Hydrate Expense		-	66.43%	-	91.842%	$ -			
72	5020008	Activated Carbon		90	66.43%	60	91.842%	$ 55			
73	5020025	Steam Exp Environmental		55,514	66.43%	36,878	91.842%	$ 33,870			
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
75	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -	91.842%	$ -			
76	5550039	PJM Inadvertent - OSS (only)		(1,839)	0%	-	91.842%	$ -			
77	5550088	PJM Capacity Charge (OSS only)		-	0%	-	91.842%	$ -			
78	5550099	PJM Purchases - NonECR (Auction)		1,946,385	0%	-	91.842%	$ -			
79	5550100	PJM Capacity Purchases - NonECR (Auction)		346,742	0%	-	91.842%	$ -			
80	5550102	PP Pool Non Fuel - OSS Aff		10,493,007	0%	-	91.842%	$ -			
81	5550107	Capacity Purchases - Trading		611,319	0%	-	91.842%	$ -			
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)		-	0%	-	91.842%	$ -			
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
84	5550075	PJM Reactive Credit		$ (637,379)	0%	$ -	91.842%	$ -			
85	5550077	PJM Black Start Credit		(6,945)	0%	-	91.842%	$ -			
86	5550079	PJM Regulation Credit		(198,040)	0%	-	91.842%	$ -			
87	5550084	PJM Spinning Reserve Credit		(5,086)	0%	-	91.842%	$ -			
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	91.842%	$ -			
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
90	5550036	PJM Emergency Purchases (Demand Response Program)		$ -	0%	$ -	91.842%	$ -			
91	5550041	PJM Synchronous Cond. Charge		(52)	0%	-	91.842%	$ -			
92	5550074	PJM Reactive Charge		670,272	0%	-	91.842%	$ -			
93	5550076	PJM BlackStart Charge		10,711	0%	-	91.842%	$ -			
94	5550078	PJM Regulation Charge		486,937	0%	-	91.842%	$ -			
95	5550083	PJM Spinning Reserve Charge		64,398	0%	-	91.842%	$ -			
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE		1,417	0%	-	91.842%	$ -			
97		Total Additional FAC		$ 33,375,669		$ 15,068,483		$ 13,983,592	GL AMOUNTS	$ 130,935,073.44	
98		TOTAL		$ 131,049,472		$ 77,486,020		$ 71,309,107	EXCL 5010032/33	$ -	
99									TOTAL GL QUERY	$ 130,935,073.44	
100	NOTATIONS:										
101	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
102	B	East Pool group computes/books Mone fuel & non-fuel separately (80/2(	E	IPS is source for fuel/non-fuel split for pool energy							
103	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%							
104											

Actual Cycle | EXH CSP-1

COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)

April 2011

Reconcile NEC to GL

Line	A	B	C	D	E	F	G	H			Diff. To GL
1	*Fuel, Purchased Power, and Environmental Costs Included FAC*			*Net Energy Cost (NEC) in EFC*			*Retail*	*Retail*	EST	Applicable	NEC Adjs. for
-2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel				NEC						
5	5010001/5010022	Fuel Consumed		$ 23,747,626	$ 8,413,624	$ 15,334,002			$ 23,747,626	$ 24,032,458	$ (284,832)
6	5010009	Fuel Consumed - No Load (CV4)		719,889		719,889			$ 719,889	485,235	$ 234,654
7	5010013	Fuel Survey Activity		-	-	-			$ -		$ -
8	5010019	Fuel Oil Consumed		788,281		788,281			$ 788,281	738,104	$ 50,177
9	5010020/5010036	Natural Gas Consumed		65,009	-	65,009			$ 65,009	46,622	$ 18,387
10	5470001/5470003	Fuel - Gas Turbine		-	$ -	-			$ -	18,387	$ (18,387)
11		Subtotal - Generation Fuel		$ 25,320,805	$ 8,413,624	$ 16,907,181			$ 25,320,805	$ 25,320,805	$ 0
12	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	A	$ 1,418,586	$ 1,230,108	$ 188,478			$ 1,418,586	$ 3,406,573	$ (1,987,987)
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	$ 8,016,317	$ -	8,016,317			$ 8,016,317	7,178,649	$ 837,668
15	5550080	PJM Energy Purchases (Fuel)	C	$ 1,077,219	$ 1,059,234	17,985			$ 1,077,219	1,039,599	$ 37,620
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	D	$ 2,083,157	$ 2,005,152	78,005			$ 2,083,157	349,251	$ 1,733,906
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	$ 7,382	$ 7,382	-			$ 7,382		$ 7,382
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	F	$ 9,118,724	$ 1,850,143	7,268,581			$ 9,118,724	9,151,745	$ (33,021)
19	5550032	Purchased Pwr - Mone (Fuel)	B	$ -	$ -	-			$ -	33,466	$ (33,466)
20		Subtotal - Purchased Power Fuel		$ 21,721,385	$ 6,152,019	$ 15,569,366			21,721,385	21,159,282	562,102
21		Total NEC Fuel		$ 47,042,190	$ 14,565,643	$ 32,476,547	100.000%	$ 32,476,547	47,042,190	46,480,088	562,102
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount					
24	Emission Allowance Expense										
25	5090000/2	Allowance Consumption - SO2		$ 448,811	75.67%	$ 339,615					
26	5090001	Allowance Consumption - Seasonal NOx			75.67%	-					
27	5090005	Allowance Expenses - Annual NOx		31,120	75.67%	23,548					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)			75.67%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		$ -	75.67%	$ -					
31	4118003	Comp. Allow. Gains-Seas NOx			75.67%	-					
32	4118004	Comp. Allow. Gains-Ann NOx			75.67%	-					
33	4119000	*Loss Disposition of Allowances*			75.67%	-					
34		Total Allowance Dollars		$ 479,930		$ 363,163	100.000%	$ 363,163			
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum										
39	5010000	Fuel (Ash Handling)		$ 617,943	75.67%	$ 467,597	100.000%	$ 467,597			
40	5010003	Fuel - Procurement, Unloading & Handling		994,450	75.67%	752,500	100.000%	$ 752,500			
41	5010011	Fuel Handling - No Load (CV4)		8,141	75.67%	6,160	100.000%	$ 6,160			
42	5010012	Ash Sales Proceeds		(22,061)	75.67%	(16,693)	100.000%	$ (16,693)			
43	5010027	Gypsum handling/disposal costs		82,488	75.67%	62,418	100.000%	$ 62,418			
44	5010028	Gypsum Sales Proceeds		-	75.67%	-	100.000%	$ -			
45	5010032	Coal Procurement-Aff			75.67%	-	100.000%	$ -			
46	5010033	Coal Procurement-NA			75.67%	-	100.000%	$ -			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	D	$ -	$ -	$ -	100.000%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	157,615	136,681	20,934	100.000%	$ 20,934	$ 157,615	$ 1,440,953	$ (1,283,338)
50	5550032	PP - Mone - Non-Fuel	B	33,959	-	33,959	100.000%	$ 33,959	$ 33,959		$ 33,959
51	5550098 INACTIVE	PP - PJM - Non-Fuel	C	-	-	-	100.000%	$ -	$ -		$ -
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	F	156	-	156	100.000%	$ 156	$ 156		$ 156
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)		1,469,195	100%	1,469,195	100.000%	$ 1,469,195	1,469,195		1,469,195
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	E	1,444,651	100%	1,444,651	100.000%	$ 1,444,651	1,660,925	1,440,953	219,971
55	5550004	Purchased Power - Pool Capacity		2,085,931	100%	2,085,931	100.000%	$ 2,085,931			
56	5550023	Purchase Power - Capacity		183,339	100%	183,339	100.000%	$ 183,339			
57	5550040	PJM Inadvertent - LSE (only)		1,347	100%	1,347	100.000%	$ 1,347			
58	5550093	Peak Hour Avail Charge - LSE		-	100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)		$ 2,943,736	100%	$ 2,943,736	100.000%	$ 2,943,736			
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)		(85,013)	100%	(85,013)	100.000%	$ (85,013)			
62	5550046	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)		26,890	79.06%	21,259	100.000%	$ 21,259			
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)		1,207,370	79.06%	954,543	100.000%	$ 954,543			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)		799,829	79.06%	632,342	100.000%	$ 632,342			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar		$ 1,220,662	100%	$ 1,220,662	100.000%	$ 1,220,662	$ 1,220,662	$ -	$ 1,220,662
67	5550109	Purchased Power - Solar		$ 45,712	100%	$ 45,712	100.000%	$ 45,712	$ 45,712	$ -	$ 45,712
68	5570007	Renewable Energy Credit Exp.			100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)		226,809	100%	$ 226,809	100.000%	$ 226,809			
70	Environmental Material & Expense										
71	5020001	Lime Expense		$ 1,952,022	75.67%	$ 1,477,095	100.000%	$ 1,477,095			
72	5020002	Urea Expense		213,498	75.67%	161,554	100.000%	$ 161,554			
73	5020003	Trona Expense		76,197	75.67%	57,658	100.000%	$ 57,658			
74	5020004	Limestone Expense		231,298	75.67%	175,023	100.000%	$ 175,023			
75	5020005	Polymer expense		109	75.67%	82	100.000%	$ 82			
76	5020007	Lime Hydrate Expense		2,179	75.67%	1,649	100.000%	$ 1,649			
77	5020008	Activated Carbon		28	75.67%	21	100.000%	$ 21			
78	5020025	Steam Exp Environmental		(172)	75.67%	(130)	100.000%	$ (130)			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)			0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)		(577)	0%	-					
82	5550088	PJM Capacity Charge (OSS only)			0%	-					
83	5550099	PJM Purchases - NonECR (Auction)		1,234,575	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)		263,613	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)		10,006,616	0%	-					
86	5550107	Capacity Purchases -Trading		506,957	0%	-					
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)			0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)			0%	-					
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit		$ (516,191)	0%	$ -					
91	5550077	PJM Black Start Credit		(5,835)	0%	-					
92	5550079	PJM Regulation Credit		(182,552)	0%	-					
93	5550084	PJM Spinning Reserve Credit		-	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE			0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)			0%	$ -					
97	5550041	PJM Synchronous Cond. Charge		1,615	0%	-					
98	5550074	PJM Reactive Charge		543,153	0%	-					
99	5550076	PJM BlackStart Charge		8,653	0%	-					
100	5550078	PJM Regulation Charge		473,369	0%	-					
101	5550083	PJM Spinning Reserve Charge		29,127	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE		1,101	0%	-					
103		Total Additional FAC		$ 28,261,948		$ 14,344,497		$ 14,344,497			
104		TOTAL		$ 75,804,068		$ 47,184,207		$ 47,184,207			
105											
106	NOTATIONS:										
107	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
108	B	East Pool group computes/books Mone fuel & non-fuel separately	E	IPS is source for fuel/non-fuel split for pool energy							
109	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%				PIVOT	ESTIMATE		
110								74,995,104	74,995,104		

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

APRIL 2011

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					EST	Applicable	Diff. To GL NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	Generation Fuel			Mar GL	NEC						
5	5010001	Fuel Consumed		$ 74,890,319	$ 27,496,903	$ 47,393,416			$ 74,890,319	$ 74,890,319	$ 0
6	5010009	Fuel Consumed - No Load (CV4)				-			$ -	-	$ -
7	5010013	Fuel Survey Activity		$ -		-			$ -	-	$ -
8	5010019	Fuel Oil Consumed		$ 835,731		835,731			$ 835,731	835,731	$ (0)
9	5010020	Natural Gas Consumed				-			$ -	-	$ -
10	5010022	Fuel Consumed - Biomass				-			$ -	-	$ -
11	5470001	Fuel - Gas Turbine				-			$ -	-	$ -
12		Subtotal - Generation Plant		$ 75,726,050	$ 27,496,903	$ 48,229,147			$ 75,726,050	$ 75,726,050	$ 0
13	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	A	$ 4,942,279	$ 3,690,156	$ 1,252,123			$ 4,942,279	$ 7,718,223	$ (2,775,944)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	8,517	-	$ 8,517			$ 8,517	4,216	$ 4,301
16	5550080	PJM Energy Purchases (Fuel)	C	1,291,472	1,269,910	$ 21,562			$ 1,291,472	1,246,344	$ 45,128
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	D	2,498,530	2,405,012	93,518			$ 2,498,530	418,724	$ 2,079,806
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	8,851	8,851	-			$ 8,851	7,351	$ 1,500
19	5550031/32	Purchased Pwr - Mone (Fuel)	B	-		-			$ -	42,469	$ (42,469)
20		Subtotal - Purchased Power Fuel		$ 8,749,649	$ 7,373,929	$ 1,375,720			8,749,649	9,437,326	(687,677)
21		Total NEC Fuel		$ 84,475,699	$ 34,870,832	$ 49,604,867	92.394%	$ 45,831,921	84,475,699	85,163,376	(687,677)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt					
24	Emission Allowance Expense										
25	5090000	Allowance Consumption SO2		$ 2,722,079	64.38%	$ 1,752,474					
26	5090001	Allowance Consumption - Seasonal NOx		-	64.38%						
	5090002	Allowance Expenses		-	64.38%	-					
27	5090005	Allowance Expenses - Annual NOx		6,553	64.38%	4,219					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	64.38%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		-	64.38%	-					
31	4118003	Comp. Allow. Gains-Seas NOx		-	64.38%	-					
32	4118004	Comp. Allow. Gains-Ann NOx		-	64.38%	-					
33	4119000	Loss Disposition of Allowances		-	64.38%	-					
34	4119002	Comp. Allow. Loss - SO2		-	64.38%	-					
35		Total Allowance Dollars		$ 2,728,631		$ 1,756,693	92.394%	$ 1,623,079			
36	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC							
37						Firm Load					
38	Account	Description	Notes		Allocation Factor	Allocated Amount					
39	Incremental Fuel Handling/Ash/Gypsum										
40	5010000	Fuel (Ash Handling)		$ 1,292,066	64.38%	$ 831,845	92.394%	$ 768,575			
41	5010003	Fuel - Procurement, Unloading & Handling		3,011,980	64.38%	1,939,113	92.394%	$ 1,791,624			
42	5010012	Ash Sales Proceeds		(137,742)	64.38%	(88,678)	92.394%	$ (81,934)			
43	5010027	Gypsum handling/disposal costs		183,534	64.38%	118,160	92.394%	$ 109,172			
44	5010028	Gypsum Sales Proceeds		(110,838)	64.38%	(71,358)	92.394%	$ (65,930)			
45	5010029	Gypsum handling/displ-Affiliat		23,358	64.38%	15,038	92.394%	$ 13,894			
46	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	D	$ -	-	$ -	92.394%	$ -	$ -		$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	550,627	411,125	139,502	92.394%	$ 128,891	$ 550,627	$ 5,027,110	$ (4,476,483)
49	5550032	PP - Mone - Non-Fuel	B	40,713	-	40,713	92.394%	$ 37,616	$ 40,713	$ -	$ 40,713
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	C	-	-	-	92.394%	$ -	$ -		$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	F	-	-	-	92.394%	$ -	$ -		$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:bill, Genea Taylor email)		5,125,636	100%	5,125,636	92.394%	$ 4,735,780	5,125,636		5,125,636
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	E	1,136	100%	1,136	92.394%	$ 1,050	5,716,976	5,027,110	689,866
54	5550023	PP Capacity - Non Affil.		219,804	100%	219,804	92.394%	$ 203,086			
55	5550040	PJM Inadvertent - LSE (only)		1,616	100%	1,616	92.394%	$ 1,493			
56	5550003	PP - Cogeneration		72,200	100%	72,200	92.394%	$ 66,708			
57	5550093	Peak Hour Avail Charge - LSE		-	100%	-	92.394%	$ -			
58	Lawrenceburg purchased power - Non-Fuel (NA)										
59	Renewables										
60	5550047	Purchased Power - Wind		1,220,662	100%	$ 1,220,662	100.00%	$ 1,220,662	$ 1,220,662.21	$ 1,220,662.21	$ -
61	5550109	Purchased Power - Solar Energy		58,179	100%	58,179	100.00%	$ 58,179	$ 58,178.96	$ 58,178.96	$ -
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010		-	100%	-	100.00%	$ -			
63	5570008	Renewable Energy Credit Exp.		-	100%	-	100.00%	$ -			
64	5570009	Other Pwr Exp - REC's - RETAIL		291,767	100%	291,767	100.00%	$ 291,767			
65	Environmental Material & Expense										
66	5020001	Lime Expense		$ 3,136,243	64.38%	$ 2,019,113	92.394%	$ 1,865,539			
67	5020002	Urea Expense		2,019,039	64.38%	1,299,857	92.394%	$ 1,200,990			
68	5020003	Trona Expense		904,068	64.38%	582,052	92.394%	$ 537,781			
69	5020004	Limestone Expense		1,153,395	64.38%	742,556	92.394%	$ 686,077			
70	5020005	Polymer expense		302,691	64.38%	194,872	92.394%	$ 180,050			
71	5020007	Lime Hydrate Expense		4,505	64.38%	2,900	92.394%	$ 2,680			
72	5020008	Activated Carbon		94	64.38%	60	92.394%	$ 56			
73	5020025	Steam Exp Environmental		60,225	64.38%	38,773	92.394%	$ 35,824			
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
75	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -	92.394%	$ -			
76	5550039	PJM Inadvertent - OSS (only)		(693)	0%	-	92.394%	$ -			
77	5550088	PJM Capacity Charge (OSS only)		-	0%	-	92.394%	$ -			
78	5550099	PJM Purchases - NonECR (Auction)		1,480,121	0%	-	92.394%	$ -			
79	5550100	PJM Capacity Purchases - NonECR (Auction)		316,041	0%	-	92.394%	$ -			
80	5550102	PP Pool Non Fuel - OSS Aff		11,121,368	0%	-	92.394%	$ -			
81	5550107	Capacity Purchases - Trading		607,790	0%	-	92.394%	$ -			
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)		-	0%	-	92.394%	$ -			
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
84	5550075	PJM Reactive Credit		$ (618,854)	0%	$ -	92.394%	$ -			
85	5550077	PJM Black Start Credit		(6,996)	0%	-	92.394%	$ -			
86	5550079	PJM Regulation Credit		(218,867)	0%	-	92.394%	$ -			
87	5550084	PJM Spinning Reserve Credit		-	0%	-	92.394%	$ -			
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	92.394%	$ -			
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
90	5550036	PJM Emergency Purchases (Demand Response Program)		$ -	0%	$ -	92.394%	$ -			
91	5550041	PJM Synchronous Cond. Charge		1,936	0%	-	92.394%	$ -			
92	5550074	PJM Reactive Charge		651,179	0%	-	92.394%	$ -			
93	5550076	PJM BlackStart Charge		10,374	0%	-	92.394%	$ -			
94	5550078	PJM Regulation Charge		567,575	0%	-	92.394%	$ -			
95	5550083	PJM Spinning Reserve Charge		34,941	0%	-	92.394%	$ -			
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE		1,320	0%	-	92.394%	$ -			
97		Total Additional FAC		$ 33,372,234		$ 14,795,518		$ 13,789,631	GL AMOUNTS	$ 120,574,375.14	
98		TOTAL		$ 120,576,564		$ 66,157,077		$ 61,244,631	EXCL 5010032/33	$ -	
99									TOTAL GL QUERY	$ 120,574,375.14	
100	NOTATIONS:										
101	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
102	B	East Pool group computes/books Mone fuel & non-fuel separately (80/2(	E	IPS is source for fuel/non-fuel split for pool energy							
103	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%							
104											

Line	A	B	C	D	E	F	G	H			
		Actual Cycle					EXH CSP-1				
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)									
		May 2011							Reconcile NEC to GL		
Line	A	B	C	D	E	F	G	H			Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail	EST	Applicable	NEC Adjs. for
-2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel				NEC						
5	5010001/5010022/23	Fuel Consumed		$ 23,942,160	$ 4,925,298	$ 19,016,862			$ 23,942,160	$ 24,266,244	$ (324,084)
6	5010009	Fuel Consumed - No Load (CV4)		719,889		719,889			$ 719,889	332,554	$ 387,335
7	5010013	Fuel Survey Activity		-	-	-			$ -		$ -
8	5010019	Fuel Oil Consumed		477,640		477,640			$ 477,640	540,890	$ (63,251)
9	5010020/5010036	Natural Gas Consumed		1,548,882	-	1,548,882			$ 1,548,882	900,548	$ 648,335
10	5470001/5470003	Fuel - Gas Turbine		-	$ -	-			$ -	648,335	$ (648,335)
11		Subtotal - Generation Fuel		$ 26,688,571	$ 4,925,298	$ 21,763,273			$ 26,688,571	$ 26,688,571	$ 0
12	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	A	$ 1,341,500	$ 402,289	$ 939,211			$ 1,341,500	$ 4,850,233	$ (3,508,733)
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	$ 6,356,184	$ -	6,356,184			$ 6,356,184	6,553,526	$ (197,342)
15	5550080	PJM Energy Purchases (Fuel)	C	$ 5,308,465	$ 3,576,642	1,731,823			$ 5,308,465	3,535,032	$ 1,773,433
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	D	$ 1,597,777	$ 856,960	740,817			$ 1,597,777	227,302	$ 1,370,475
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	$ 7,571	$ 1,335	6,236			$ 7,571		$ 7,571
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	F	$ 9,034,885	$ 623,152	8,411,733			$ 9,034,885	9,067,743	$ (32,858)
19	5550032	Purchased Pwr - Mone (Fuel)	B	$ 24,189	$ 1,015	23,174			$ 24,189	45,697	$ (21,508)
20		Subtotal - Purchased Power Fuel		$ 23,670,571	$ 5,461,393	$ 18,209,178			23,670,571	24,279,534	(608,963)
21		Total NEC Fuel		$ 50,359,142	$ 10,386,691	$ 39,972,451	100.000%	$ 39,972,451	50,359,142	50,968,105	(608,963)
22						Firm Load					
23	Allowance Accounts in FAC:				Allocation Factor	Allocated Amount					
24	Emission Allowance Expense										
25	5090000/2	Allowance Consumption - SO2		$ 543,934	84.02%	$ 457,014					
26	5090001	Allowance Consumption - Seasonal NOx		63,897	84.02%	53,686					
27	5090005	Allowance Expenses - Annual NOx		26,693	84.02%	22,427					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)			84.02%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2			84.02%	$ -					
31	4118003	Comp. Allow. Gains-Seas NOx			84.02%	-					
32	4118004	Comp. Allow. Gains-Ann NOx			84.02%	-					
33	4119000	Loss Disposition of Allowances			84.02%	-					
34		Total Allowance Dollars		$ 634,524		$ 533,127	100.000%	$ 533,127			
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum										
39	5010000	Fuel (Ash Handling)		$ 725,492	84.02%	$ 609,558	100.000%	$ 609,558			
40	5010003	Fuel - Procurement, Unloading & Handling		815,197	84.02%	684,929	100.000%	$ 684,929			
41	5010011	Fuel Handling - No Load (CV4)		15,201	84.02%	12,772	100.000%	$ 12,772			
42	5010012	Ash Sales Proceeds		(3,660)	84.02%	(3,075)	100.000%	$ (3,075)			
43	5010027	Gypsum handling/disposal costs		146,062	84.02%	122,721	100.000%	$ 122,721			
44	5010028	Gypsum Sales Proceeds		(13,218)	84.02%	(11,106)	100.000%	$ (11,106)			
45	5010032	Coal Procurement-Aff			84.02%	-	100.000%	$ -			
46	5010033	Coal Procurement-NA			84.02%	-	100.000%	$ -			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	D	$ -	$ -	$ -	100.000%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	167,537	50,252	117,285	100.000%	$ 117,285	$ 167,537	$ 985,235	$ (817,697)
50	5550032	PP - Mone - Non-Fuel	B	22,017	924	21,093	100.000%	$ 21,093	$ 22,017		$ 22,017
51	5550098 INACTIVE	PP - PJM - Non-Fuel	C	0	-	0	100.000%	$ 0	$ 0		$ 0
52	5550027	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	F	102	-	102	100.000%	$ 102	$ 102		$ 102
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)		960,143	100%	960,143	100.000%	$ 960,143	960,143		960,143
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	E	1,374,031	100%	1,374,031	100.000%	$ 1,374,031	1,149,799	985,235	164,564
55	5550004	Purchased Power - Pool Capacity		1,987,703	100%	1,987,703	100.000%	$ 1,987,703			
56	5550023	Purchase Power - Capacity		183,339	100%	183,339	100.000%	$ 183,339			
57	5550040	PJM Inadvertent - LSE (only)		131,005	100%	131,005	100.000%	$ 131,005			
58	5550093	Peak Hour Avail Charge - LSE			100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)		$ 2,943,736	100%	$ 2,943,736	100.000%	$ 2,943,736			
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)		(85,013)	100%	(85,013)	100.000%	$ (85,013)			
62	5550046	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)		24,271	92.52%	22,457	100.000%	$ 22,457			
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)		1,203,416	92.52%	1,113,451	100.000%	$ 1,113,451			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)		542,942	92.52%	502,353	100.000%	$ 502,353			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar		$ 859,224	100%	$ 859,224	100.000%	$ 859,224	$ 859,224	$ 859,224	$ -
67	5550109	Purchased Power - Solar		$ 59,472	100%	$ 59,472	100.000%	$ 59,472	$ 59,472	$ 59,472	$ -
68	5570007	Renewable Energy Credit Exp.			100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)		234,966	100%	$ 234,966	100.000%	$ 234,966			
70	Environmental Material & Expense										
71	5020001	Lime Expense		$ 1,804,135	84.02%	$ 1,515,834	100.000%	$ 1,515,834			
72	5020002	Urea Expense		162,432	84.02%	136,476	100.000%	$ 136,476			
73	5020003	Trona Expense		48,542	84.02%	40,785	100.000%	$ 40,785			
74	5020004	Limestone Expense		215,340	84.02%	180,929	100.000%	$ 180,929			
75	5020005	Polymer expense		127	84.02%	107	100.000%	$ 107			
76	5020007	Lime Hydrate Expense		-	84.02%	-	100.000%	$ -			
77	5020008	Activated Carbon		52	84.02%	44	100.000%	$ 44			
78	5020025	Steam Exp Environmental		4,551	84.02%	3,824	100.000%	$ 3,824			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)			0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)		(4,925)	0%	-					
82	5550088	PJM Capacity Charge (OSS only)			0%	-					
83	5550099	PJM Purchases - NonECR (Auction)		1,282,878	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)		262,899	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)		5,934,899	0%	-					
86	5550107	Capacity Purchases -Trading		522,852	0%	-					
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)			0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)			0%	-					
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit		$ (516,187)	0%	$ -					
91	5550077	PJM Black Start Credit		(5,835)	0%	-					
92	5550079	PJM Regulation Credit		(153,938)	0%	-					
93	5550084	PJM Spinning Reserve Credit		(1,942)	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE			0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)			0%	$ -					
97	5550041	PJM Synchronous Cond. Charge		(265)	0%	-					
98	5550074	PJM Reactive Charge		536,787	0%	-					
99	5550076	PJM BlackStart Charge		8,588	0%	-					
100	5550078	PJM Regulation Charge		490,420	0%	-					
101	5550083	PJM Spinning Reserve Charge		38,873	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE		514	0%	-					
103		Total Additional FAC		$ 22,924,764		$ 13,719,145		$ 13,719,145			
104		TOTAL		$ 73,918,430		$ 54,224,723		$ 54,224,723			
105											
106	NOTATIONS:										
107	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
108	B	East Pool group computes/books Mone fuel & non-fuel separately	E	IPS is source for fuel/non-fuel split for pool energy							
109	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%				PIVOT	ESTIMATE		
110								74,338,557	74,338,557		

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

MAY 2011

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL: EST NEC Rpt Costs	Applicable GL Recorded Amounts	Diff. To GL NEC Adjs. for Actual Cycle Or PPAs
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					EST	Applicable	Diff. To GL NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	Generation Fuel			Mar GL	NEC						
5	5010001	Fuel Consumed		$ 57,106,162	$ 10,054,677	$ 47,051,485			$ 57,106,162	$ 56,916,145	$ 190,017
6	5010009	Fuel Consumed - No Load (CV4)				-			$ -	-	$ -
7	5010013	Fuel Survey Activity		$ -		-			$ -	-	$ -
8	5010019	Fuel Oil Consumed		$ 2,036,956		2,036,956			$ 2,036,956	2,036,956	$ (0)
9	5010020	Natural Gas Consumed				-			$ -	-	$ -
10	5010023	Fuel Consumed - Biomass				-			$ -	190,016	$ (190,016)
11	5470001	Fuel - Gas Turbine				-			$ -	-	$ -
12		Subtotal - Generation Plant		$ 59,143,118	$ 10,054,677	$ 49,088,441			$ 59,143,118	$ 59,143,118	$ 0
13	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	A	$ 4,675,916	$ 1,175,583	$ 3,500,333			$ 4,675,916	$ 9,246,128	$ (4,570,212)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	2,782,024	-	$ 2,782,024			$ 2,782,024	2,698,621	$ 83,403
16	5550080	PJM Energy Purchases (Fuel)	C	6,364,286	4,288,014	$ 2,076,272			$ 6,364,286	4,238,129	$ 2,126,157
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	D	1,915,566	1,027,408	888,158			$ 1,915,566	272,514	$ 1,643,052
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	9,077	1,600	7,477			$ 9,077	10,295	$ (1,218)
19	5550031/32	Purchased Pwr - Mone (Fuel)	B	29,000	1,216	27,784			$ 29,000	55,745	$ (26,745)
20		Subtotal - Purchased Power Fuel		$ 15,775,869	$ 6,493,821	$ 9,282,048			15,775,869	16,521,431	(745,562)
21		Total NEC Fuel		$ 74,918,987	$ 16,548,498	$ 58,370,489	92.137%	$ 53,780,817	74,918,987	75,664,549	(745,562)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt					
24	Emission Allowance Expense										
25	5090000	Allowance Consumption SO2		$ 2,312,206	83.90%	$ 1,939,941					
26	5090001	Allowance Consumption - Seasonal NOx		5,317	83.90%						
	5090002	Allowance Expenses		-	83.90%	4,461					
27	5090005	Allowance Expenses - Annual NOx		5,108	83.90%	4,286					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	83.90%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		-	83.90%	-					
31	4118003	Comp. Allow. Gains-Seas NOx		-	83.90%	-					
32	4118004	Comp. Allow. Gains-Ann NOx		(45,415)	83.90%	(38,103)					
33	4119000	Loss Disposition of Allowances		-	83.90%	-					
34	4119002	Comp. Allow. Loss - SO2		-	83.90%	-					
35		Total Allowance Dollars		$ 2,277,217		$ 1,910,585	92.137%	$ 1,760,355			
36	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC							
37						Firm Load					
38	Account	Description	Notes		Allocation Factor	Allocated Amount					
39	Incremental Fuel Handling/Ash/Gypsum										
40	5010000	Fuel (Ash Handling)		$ 1,282,320	83.90%	$ 1,075,866	92.137%	$ 991,271			
41	5010003	Fuel - Procurement, Unloading & Handling		2,054,204	83.90%	1,723,477	92.137%	$ 1,587,960			
42	5010012	Ash Sales Proceeds		(44,560)	83.90%	(37,386)	92.137%	$ (34,447)			
43	5010027	Gypsum handling/disposal costs		(105,585)	83.90%	(88,586)	92.137%	$ (81,621)			
44	5010028	Gypsum Sales Proceeds		(186,552)	83.90%	(156,517)	92.137%	$ (144,210)			
45	5010029	Gypsum handling/displ-Affiliat		20,648	83.90%	17,324	92.137%	$ 15,962			
46	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	D	$ -	-	$ -	92.137%	$ -	$ -		$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	583,970	146,792	437,178	92.137%	$ 402,803	$ 583,970	$ 3,437,226	$ (2,853,256)
49	5550032	PP - Mone - Non-Fuel	B	26,396	1,107	25,289	92.137%	$ 23,301	$ 26,396	$ -	$ 26,396
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	C	-	-	-	92.137%	$ -	$ -		$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	F	-	-	-	92.137%	$ -	$ -		$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:bill, Genea Taylor email)		3,349,687	100%	3,349,687	92.137%	$ 3,086,301	3,349,687		3,349,687
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	E	481,108	100%	481,108	92.137%	$ 443,278	3,960,053	3,437,226	522,827
54	5550023	PP Capacity - Non Affil.		219,804	100%	219,804	92.137%	$ 202,521			
55	5550040	PJM Inadvertent - LSE (only)		157,061	100%	157,061	92.137%	$ 144,711			
56	5550003	PP - Cogeneration		127,235	100%	127,235	92.137%	$ 117,230			
57	5550093	Peak Hour Avail Charge - LSE		-	100%	-	92.137%	$ -			
58	Lawrenceburg purchased power - Non-Fuel (NA)										
59	Renewables										
60	5550047	Purchased Power - Wind		859,224	100%	$ 859,224	100.00%	$ 859,224	$ 859,224.07	$ 859,224.07	$ -
61	5550109	Purchased Power - Solar Energy		75,691	100%	75,691	100.00%	$ 75,691	$ 75,691.20	$ 75,691.20	$ -
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010		-	100%	-	100.00%	$ -			
63	5570008	Renewable Energy Credit Exp.		-	100%	-	100.00%	$ -			
64	5570009	Other Pwr Exp - REC's - RETAIL		293,708	100%	293,708	100.00%	$ 293,708			
65	Environmental Material & Expense										
66	5020001	Lime Expense		$ 1,823,030	83.90%	$ 1,529,522	92.137%	$ 1,409,256			
67	5020002	Urea Expense		1,421,424	83.90%	1,192,575	92.137%	$ 1,098,802			
68	5020003	Trona Expense		510,146	83.90%	428,012	92.137%	$ 394,358			
69	5020004	Limestone Expense		741,502	83.90%	622,120	92.137%	$ 573,203			
70	5020005	Polymer expense		297,645	83.90%	249,724	92.137%	$ 230,089			
71	5020007	Lime Hydrate Expense		0	83.90%	0	92.137%	$ 0			
72	5020008	Activated Carbon		174	83.90%	146	92.137%	$ 135			
73	5020025	Steam Exp Environmental		60,810	83.90%	51,020	92.137%	$ 47,008			
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
75	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -	92.137%	$ -			
76	5550039	PJM inadvertent - OSS (only)		(5,905)	0%	-	92.137%	$ -			
77	5550088	PJM Capacity Charge (OSS only)		-	0%	-	92.137%	$ -			
78	5550099	PJM Purchases - NonECR (Auction)		1,538,036	0%	-	92.137%	$ -			
79	5550100	PJM Capacity Purchases - NonECR (Auction)		315,188	0%	-	92.137%	$ -			
80	5550102	PP Pool Non Fuel - OSS Aff		7,455,943	0%	-	92.137%	$ -			
81	5550107	Capacity Purchases - Trading		626,845	0%	-	92.137%	$ -			
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)		-	0%	-	92.137%	$ -			
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
84	5550075	PJM Reactive Credit		$ (618,854)	0%	$ -	92.137%	$ -			
85	5550077	PJM Black Start Credit		(6,995)	0%	-	92.137%	$ -			
86	5550079	PJM Regulation Credit		(184,555)	0%	-	92.137%	$ -			
87	5550084	PJM Spinning Reserve Credit		(2,328)	0%	-	92.137%	$ -			
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	92.137%	$ -			
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
90	5550036	PJM Emergency Purchases (Demand Response Program)		$ -	0%	$ -	92.137%	$ -			
91	5550041	PJM Synchronous Cond. Charge		(317)	0%	-	92.137%	$ -			
92	5550074	PJM Reactive Charge		643,551	0%	-	92.137%	$ -			
93	5550076	PJM BlackStart Charge		10,296	0%	-	92.137%	$ -			
94	5550078	PJM Regulation Charge		587,962	0%	-	92.137%	$ -			
95	5550083	PJM Spinning Reserve Charge		46,605	0%	-	92.137%	$ -			
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE		616	0%	-	92.137%	$ -			
97		Total Additional FAC		$ 24,455,178		$ 12,633,284		$ 11,736,535	GL AMOUNTS	$ 101,874,116.24	
98		TOTAL		$ 101,651,381		$ 72,914,357		$ 67,277,708	EXCL 5010032/33	$ -	
99									TOTAL GL QUERY	$ 101,874,116.24	
100	NOTATIONS:										
101	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
102	B	East Pool group computes/books Mone fuel & non-fuel separately (80/2(	E	IPS is source for fuel/non-fuel split for pool energy							
103	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%							
104											

		Actual					EXH CSP-1				
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)									
		June 2011							Reconcile NEC to GL		
Line	A	B	C	D	E	F	G	H			Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail	EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel				NEC						
5	5010001/5010022/23	Fuel Consumed		$ 26,077,654	$ 9,283,412	$ 16,794,242			$ 26,077,654	$ 25,768,625	$ 309,029
6	5010009	Fuel Consumed - No Load (CV4)		719,889		719,889			$ 719,889	781,967	$ (62,078)
7	5010013	Fuel Survey Activity		713,140	-	713,140			$ 713,140	984,025	$ (270,885)
8	5010019	Fuel Oil Consumed		1,057,362		1,057,362			$ 1,057,362	1,033,429	$ 23,933
9	5010020/5010036	Natural Gas Consumed		6,437,883	-	6,437,883			$ 6,437,883	5,713,669	$ 724,214
10	5470001/5470003	Fuel - Gas Turbine		-	$ -	-			$ -	724,214	$ (724,214)
11		Subtotal - Generation Fuel		$ 35,005,929	$ 9,283,412	$ 25,722,517			$ 35,005,929	$ 35,005,929	$ (0)
12	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	A	$ 1,513,044	$ 1,201,790	$ 311,254			$ 1,513,044	$ 3,524,049	$ (2,011,005)
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	$ 10,767,261	$ -	10,767,261			$ 10,767,261	11,056,657	$ (289,396)
15	5550080	PJM Energy Purchases (Fuel)	C	$ 3,609,985	$ 3,059,251	550,734			$ 3,609,985	3,118,156	$ 491,829
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	D	$ 1,601,594	$ 1,350,969	250,625			$ 1,601,594	63,267	$ 1,538,327
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	$ 8,261	$ 8,261	-			$ 8,261		$ 8,261
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	F	$ 8,469,264	$ 1,605,598	6,863,666			$ 8,469,264	8,502,064	$ (32,799)
19	5550032	Purchased Pwr - Mone (Fuel)	B	$ 88,705	$ 60,091	28,614			$ 88,705	40,632	$ 48,073
20		Subtotal - Purchased Power Fuel		$ 26,058,114	$ 7,285,960	$ 18,772,154			26,058,114	26,304,824	(246,709)
21		Total NEC Fuel		$ 61,064,043	$ 16,569,372	$ 44,494,671	100.000%	$ 44,494,671	61,064,043	61,310,752	(246,709)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount					
24	Emission Allowance Expense										
25	5090000/2	Allowance Consumption - SO2		$ 31,263	76.89%	$ 24,038					
26	5090001	Allowance Consumption - Seasonal NOx		78,988	76.89%	60,734					
27	5090005	Allowance Expenses - Annual NOx		25,748	76.89%	19,797					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)			76.89%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2			76.89%	$ -					
31	4118003	Comp. Allow. Gains-Seas NOx			76.89%	-					
32	4118004	Comp. Allow. Gains-Ann NOx			76.89%	-					
33	4119000	Loss Disposition of Allowances			76.89%	-					
34		Total Allowance Dollars		$ 135,999		$ 104,569	100.000%	$ 104,569			
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum										
39	5010000	Fuel (Ash Handling)		$ 648,924	76.89%	$ 498,957	100.000%	$ 498,957			
40	5010003	Fuel - Procurement, Unloading & Handling		922,909	76.89%	709,625	100.000%	$ 709,625			
41	5010011	Fuel Handling - No Load (CV4)		23,913	76.89%	18,386	100.000%	$ 18,386			
42	5010012	Ash Sales Proceeds		(6,076)	76.89%	(4,672)	100.000%	$ (4,672)			
43	5010027	Gypsum handling/disposal costs		155,482	76.89%	119,550	100.000%	$ 119,550			
44	5010028	Gypsum Sales Proceeds		(32,228)	76.89%	(24,780)	100.000%	$ (24,780)			
45	5010032	Coal Procurement-Aff			76.89%	-	100.000%	$ -			
46	5010033	Coal Procurement-NA			76.89%	-	100.000%	$ -			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	D	$ -	$ -	$ -	100.000%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	139,784	108,659	31,125	100.000%	$ 31,125	$ 139,784	$ 955,703	$ (815,918)
50	5550032	PP - Mone - Non-Fuel	B	15,853	10,743	5,110	100.000%	$ 5,110	$ 15,853		$ 15,853
51	5550098 INACTIVE	PP - PJM - Non-Fuel	C		-	-	100.000%	$ -	$ -		$ -
52	5550046	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	F	(3)	-	(3)	100.000%	$ (3)	$ (3)		$ (3)
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)		963,975	100%	963,975	100.000%	$ 963,975	963,975		963,975
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	E	1,519,464	100%	1,519,464	100.000%	$ 1,519,464	1,119,609	955,703	163,907
55	5550004	Purchased Power - Pool Capacity		1,955,064	100%	1,955,064	100.000%	$ 1,955,064			
56	5550023	Purchase Power - Capacity		183,339	100%	183,339	100.000%	$ 183,339			
57	5550040	PJM Inadvertent - LSE (only)		54,284	100%	54,284	100.000%	$ 54,284			
58	5550093	Peak Hour Avail Charge - LSE			100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affil (Lawrenceburg)		$ 2,943,736	100%	$ 2,943,736	100.000%	$ 2,943,736			
61	5550104	Defd Depr & Capacity portion-Affil (Lawrenceburg)		(85,013)	100%	(85,013)	100.000%	$ (85,013)			
62	5550046	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)		24,934	80.06%	19,963	100.000%	$ 19,963			
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)		1,148,291	80.06%	919,375	100.000%	$ 919,375			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)		805,641	80.06%	645,034	100.000%	$ 645,034			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar		$ 544,907	100%	$ 544,907	100.000%	$ 544,907	$ 544,907	$ -	$ 544,907
67	5550109	Purchased Power - Solar		$ 72,353	100%	$ 72,353	100.000%	$ 72,353	$ 72,353	$ -	$ 72,353
68	5570007	Renewable Energy Credit Exp.			100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)		236,689	100%	$ 236,689	100.000%	$ 236,689			
70	Environmental Material & Expense										
71	5020001	Lime Expense		$ 1,932,569	76.89%	$ 1,485,952	100.000%	$ 1,485,952			
72	5020002	Urea Expense		103,170	76.89%	79,328	100.000%	$ 79,328			
73	5020003	Trona Expense		89,314	76.89%	68,674	100.000%	$ 68,674			
74	5020004	Limestone Expense		179,860	76.89%	138,295	100.000%	$ 138,295			
75	5020005	Polymer expense		126	76.89%	97	100.000%	$ 97			
76	5020007	Lime Hydrate Expense		-	76.89%	-	100.000%	$ -			
77	5020008	Activated Carbon		36	76.89%	27	100.000%	$ 27			
78	5020025	Steam Exp Environmental		1,222	76.89%	939	100.000%	$ 939			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)			0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)		15,132	0%	-					
82	5550088	PJM Capacity Charge (OSS only)			0%	-					
83	5550099	PJM Purchases - NonECR (Auction)		3,787,751	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)		93,199	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)		13,266,133	0%	-					
86	5550107	Capacity Purchases -Trading		370,763	0%	-					
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)			0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)			0%	-					
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit		$ (516,187)	0%	$ -					
91	5550077	PJM Black Start Credit		(5,706)	0%	-					
92	5550079	PJM Regulation Credit		(373,488)	0%	-					
93	5550084	PJM Spinning Reserve Credit		(2,948)	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE			0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)			0%	$ -					
97	5550041	PJM Synchronous Cond. Charge		1,613	0%	-					
98	5550074	PJM Reactive Charge		539,183	0%	-					
99	5550076	PJM BlackStart Charge		8,346	0%	-					
100	5550078	PJM Regulation Charge		1,056,791	0%	-					
101	5550083	PJM Spinning Reserve Charge		48,682	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE		273,572	0%	-					
103		Total Additional FAC		$ 33,105,456		$ 13,099,782		$ 13,099,782			
104		TOTAL		$ 94,305,498		$ 57,699,023		$ 57,699,023			
105											
106	NOTATIONS:										
107	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
108	B	East Pool group computes/books Mone fuel & non-fuel separately	E	IPS is source for fuel/non-fuel split for pool energy							
109	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%				PIVOT	ESTIMATE		
110								94,363,366	94,363,366		

C:\Users\joliker\AppData\Local\Temp\Temp3_LA-2011-49 CONFIDENTIAL.zip\[LA-2011-49, Confidential FF (OPCO_BU_181_F				ACTUAL			EXH OPCo-1				
		OHIO POWER COMPANY - NET ENERGY COST (NEC)									
		JUNE 2011							Reconcile NEC to GL		
Line	A	B	C	D	E	F	G	H			Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	Generation Fuel			Mar GL	NEC						
5	5010001	Fuel Consumed		$ 90,691,901	$ 39,146,478	$ 51,545,423			$ 90,691,901	$ 90,472,377	$ 219,524
6	5010009	Fuel Consumed - No Load (CV4)				-			$ -	-	$ -
7	5010013	Fuel Survey Activity		$ (799,810)		(799,810)			$ (799,810)	(799,810)	$ 0
8	5010019	Fuel Oil Consumed		$ 2,479,192		2,479,192			$ 2,479,192	2,479,192	$ (0)
9	5010020	Natural Gas Consumed				-			$ -	-	$ -
10	5010023	Fuel Consumed - Biomass				-			$ -	219,525	$ (219,525)
11	5470001	Fuel - Gas Turbine				-			$ -	-	$ -
12		Subtotal - Generation Plant		$ 92,371,283	$ 39,146,478	$ 53,224,805			$ 92,371,283	$ 92,371,284	$ (1)
13	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	A	$ 5,277,105	$ 4,045,871	$ 1,231,234			$ 5,277,105	$ 8,027,816	$ (2,750,711)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	1,765,773	-	$ 1,765,773			$ 1,765,773	1,721,570	$ 44,203
16	5550080	PJM Energy Purchases (Fuel)	C	4,327,989	3,667,718	$ 660,271			$ 4,327,989	3,738,338	$ 589,651
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	D	1,920,139	1,619,666	300,473			$ 1,920,139	75,845	$ 1,844,294
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	9,904	9,904	-			$ 9,904	9,429	$ 475
19	5550031/32	Purchased Pwr - Mone (Fuel)	B	106,348	72,043	34,305			$ 106,348	47,419	$ 58,929
20		Subtotal - Purchased Power Fuel		$ 13,407,258	$ 9,415,202	$ 3,992,056			13,407,258	13,620,418	(213,160)
21		Total NEC Fuel		$ 105,778,541	$ 48,561,680	$ 57,216,861	92.292%	$ 52,806,585	105,778,541	105,991,702	(213,161)
22						Firm Load					
23	Allowance Accounts in FAC:				Allocation Factor	Allocated Amt					
24	Emission Allowance Expense										
25	5090000	Allowance Consumption SO2		$ 3,502,163	57.85%	$ 2,026,001					
26	5090001	Allowance Consumption - Seasonal NOx		6,731	57.85%						
	5090002	Allowance Expenses		-	57.85%	5,051					
27	5090005	Allowance Expenses - Annual NOx		8,518	57.85%	4,926					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	57.85%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		-	57.85%	-					
31	4118003	Comp. Allow. Gains-Seas NOx		(7,847)	57.85%	(4,539)					
32	4118004	Comp. Allow. Gains-Ann NOx		(463,428)	57.85%	(268,093)					
33	4119000	Loss Disposition of Allowances		-	57.85%	-					
34	4119002	Comp. Allow. Loss - SO2		-	57.85%	-					
35		Total Allowance Dollars		$ 3,048,137		$ 1,763,347	92.292%	$ 1,627,428			
36	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC							
37						Firm Load					
38	Account	Description	Notes		Allocation Factor	Allocated Amount					
39	Incremental Fuel Handling/Ash/Gypsum										
40	5010000	Fuel (Ash Handling)		$ 250,909	57.85%	$ 145,151	92.292%	$ 133,963			
41	5010003	Fuel - Procurement, Unloading & Handling		3,420,556	57.85%	1,978,792	92.292%	$ 1,826,267			
42	5010012	Ash Sales Proceeds		(31,947)	57.85%	(18,481)	92.292%	$ (17,057)			
43	5010027	Gypsum handling/disposal costs		372,174	57.85%	215,303	92.292%	$ 198,707			
44	5010028	Gypsum Sales Proceeds		(53,490)	57.85%	(30,944)	92.292%	$ (28,559)			
45	5010029	Gypsum handling/displ-Affiliat		22,045	57.85%	12,753	92.292%	$ 11,770			
46	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	D	$ -	-	$ -	92.292%	$ -	$ -		$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	477,337	365,804	111,533	92.292%	$ 102,936	$ 477,337	$ 3,334,197	$ (2,856,860)
49	5550032	PP - Mone - Non-Fuel	B	19,006	12,880	6,126	92.292%	$ 5,654	$ 19,006	$ -	$ 19,006
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	C	-	-	-	92.292%	$ -	$ -		$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	F	-	-	-	92.292%	$ -	$ -		$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:bill, Genea Taylor email)		3,363,058	100%	3,363,058	92.292%	$ 3,103,834	3,363,058		3,363,058
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	E	204,169	100%	204,169	92.292%	$ 188,432	3,859,401	3,334,197	525,204
54	5550023	PP Capacity - Non Affil.		219,804	100%	219,804	92.292%	$ 202,862			
55	5550040	PJM Inadvertent - LSE (only)		65,080	100%	65,080	92.292%	$ 60,064			
56	5550003	PP - Cogeneration		120,747	100%	120,747	92.292%	$ 111,440			
57	5550093	Peak Hour Avail Charge - LSE		-	100%	-	92.292%	$ -			
58	Lawrenceburg purchased power - Non-Fuel (NA)										
59	Renewables										
60	5550047	Purchased Power - Wind		544,907	100%	$ 544,907	100.00%	$ 544,907	$ 544,906.89	$ 544,906.89	$ -
61	5550109	Purchased Power - Solar Energy		92,086	100%	92,086	100.00%	$ 92,086	$ 92,085.64	$ 92,085.64	$ -
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010		-	100%	-	100.00%	$ -			
63	5570008	Renewable Energy Credit Exp.		-	100%	-	100.00%	$ -			
64	5570009	Other Pwr Exp - REC's - RETAIL		305,111	100%	305,111	100.00%	$ 305,111			
65	Environmental Material & Expense										
66	5020001	Lime Expense		$ 3,412,348	57.85%	$ 1,974,043	92.292%	$ 1,821,884			
67	5020002	Urea Expense		2,179,208	57.85%	1,260,672	92.292%	$ 1,163,499			
68	5020003	Trona Expense		796,163	57.85%	460,580	92.292%	$ 425,079			
69	5020004	Limestone Expense		1,868,711	57.85%	1,081,049	92.292%	$ 997,722			
70	5020005	Polymer expense		167,317	57.85%	96,793	92.292%	$ 89,332			
71	5020007	Lime Hydrate Expense		4,838	57.85%	2,799	92.292%	$ 2,583			
72	5020008	Activated Carbon		119	57.85%	69	92.292%	$ 63			
73	5020025	Steam Exp Environmental		81,686	57.85%	47,255	92.292%	$ 43,613			
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
75	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -	92.292%	$ -			
76	5550039	PJM Inadvertent - OSS (only)		18,142	0%	-	92.292%	$ -			
77	5550088	PJM Capacity Charge (OSS only)		-	0%	-	92.292%	$ -			
78	5550099	PJM Purchases - NonECR (Auction)		4,541,111	0%	-	92.292%	$ -			
79	5550100	PJM Capacity Purchases - NonECR (Auction)		111,736	0%	-	92.292%	$ -			
80	5550102	PP Pool Non Fuel - OSS Aff		14,195,362	0%	-	92.292%	$ -			
81	5550107	Capacity Purchases - Trading		444,506	0%	-	92.292%	$ -			
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)		-	0%	-	92.292%	$ -			
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
84	5550075	PJM Reactive Credit		$ (618,854)	0%	$ -	92.292%	$ -			
85	5550077	PJM Black Start Credit		(6,841)	0%	-	92.292%	$ -			
86	5550079	PJM Regulation Credit		(447,773)	0%	-	92.292%	$ -			
87	5550084	PJM Spinning Reserve Credit		(3,535)	0%	-	92.292%	$ -			
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	92.292%	$ -			
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
90	5550036	PJM Emergency Purchases (Demand Response Program)		$ -	0%	$ -	92.292%	$ -			
91	5550041	PJM Synchronous Cond. Charge		1,934	0%	-	92.292%	$ -			
92	5550074	PJM Reactive Charge		646,424	0%	-	92.292%	$ -			
93	5550076	PJM BlackStart Charge		10,006	0%	-	92.292%	$ -			
94	5550078	PJM Regulation Charge		1,266,980	0%	-	92.292%	$ -			
95	5550083	PJM Spinning Reserve Charge		58,364	0%	-	92.292%	$ -			
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE		328,103	0%	-	92.292%	$ -			
97		Total Additional FAC		$ 38,447,609		$ 12,258,455		$ 11,386,191	GL AMOUNTS	$ 146,962,243.52	
98		TOTAL		$ 147,274,287		$ 71,238,663		$ 65,820,205	EXCL 5010032/33	$ -	
99									TOTAL GL QUERY	$ 146,962,243.52	
100	NOTATIONS:										
101	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
102	B	East Pool group computes/books Mone fuel & non-fuel separately (80/20	E	IPS is source for fuel/non-fuel split for pool energy							
103	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%							
104											

Actual | EXH CSP-1

COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)

July 2011

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail	EST	Applicable	Diff. To GL NEC Adjs. for
-2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel				NEC						
5	5010001/5010022/23	Fuel Consumed		$ 31,789,160	$ 12,987,362	$ 18,801,798			$ 31,789,160	$ 31,888,137	$ (98,977)
6	5010009	Fuel Consumed - No Load (CV4)		719,889		719,889			$ 719,889	917,406	$ (197,517)
7	5010013	Fuel Survey Activity		-	-	-			$ -	(270,884)	$ 270,884
8	5010019	Fuel Oil Consumed		623,282		623,282			$ 623,282	597,673	$ 25,609
9	5010020/5010036	Natural Gas Consumed		12,194,865	-	12,194,865			$ 12,194,865	11,431,485	$ 763,379
10	5470001/5470003	Fuel - Gas Turbine		-	$ -	-			$ -	763,380	$ (763,380)
11		Subtotal - Generation Fuel		$ 45,327,195	$ 12,987,362	$ 32,339,834			$ 45,327,195	$ 45,327,196	$ (1)
12	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	A	$ 1,568,930	$ 1,373,176	$ 195,754			$ 1,568,930	$ 1,787,431	$ (218,501)
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	$ 10,334,580	$ -	10,334,580			$ 10,334,580	9,861,246	$ 473,334
15	5550080	PJM Energy Purchases (Fuel)	C	$ 3,727,163	$ 3,719,940	7,223			$ 3,727,163	3,145,925	$ 581,238
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	D	$ 859,570	$ 851,876	7,694			$ 859,570	857,979	$ 1,592
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	$ 2,656	$ 2,656	-			$ 2,656		$ 2,656
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	F	$ 15,723,467	$ 2,678,216	13,045,251			$ 15,723,467	15,771,171	$ (47,704)
19	5550032	Purchased Pwr - Mone (Fuel)	B	$ 310,887	$ 310,887	0			$ 310,887	376,107	$ (65,220)
20		Subtotal - Purchased Power Fuel		$ 32,527,253	$ 8,936,751	$ 23,590,502			32,527,253	31,799,858	727,396
21		Total NEC Fuel		$ 77,854,449	$ 21,924,113	$ 55,930,336	100.000%	$ 55,930,336	77,854,449	77,127,054	727,395
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount					
24	Emission Allowance Expense										
25	5090000/2	Allowance Consumption - SO2		$ 478,244	73.84%	$ 353,135					
26	5090001	Allowance Consumption - Seasonal NOx		89,008	73.84%	65,724					
27	5090005	Allowance Expenses - Annual NOx		30,022	73.84%	22,168					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)			73.84%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2			73.84%	$ -					
31	4118003	Comp. Allow. Gains-Seas NOx			73.84%	-					
32	4118004	Comp. Allow. Gains-Ann NOx			73.84%	-					
33	4119000	Loss Disposition of Allowances			73.84%	-					
34		Total Allowance Dollars		$ 597,273		$ 441,027	100.000%	$ 441,027			
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum										
39	5010000	Fuel (Ash Handling)		$ 688,275	73.84%	$ 508,222	100.000%	$ 508,222			
40	5010003	Fuel - Procurement, Unloading & Handling		920,586	73.84%	679,761	100.000%	$ 679,761			
41	5010011	Fuel Handling - No Load (CV4)		25,910	73.84%	19,132	100.000%	$ 19,132			
42	5010012	Ash Sales Proceeds		(11,530)	73.84%	(8,514)	100.000%	$ (8,514)			
43	5010027	Gypsum handling/disposal costs		159,688	73.84%	117,913	100.000%	$ 117,913			
44	5010028	Gypsum Sales Proceeds		(55,038)	73.84%	(40,640)	100.000%	$ (40,640)			
45	5010032	Coal Procurement-Aff			73.84%	-	100.000%	$ -			
46	5010033	Coal Procurement-NA			73.84%	-	100.000%	$ -			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	D	$ -	$ -	$ -	100.000%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	137,245	120,123	17,122	100.000%	$ 17,122	$ 137,245	$ 999,495	$ (862,250)
50	5550032	PP - Mone - Non-Fuel	B			-	100.000%	$ -	$ -		$ -
51	5550098 INACTIVE	PP - PJM - Non-Fuel	C			-	100.000%	$ -	$ -		$ -
52	5550046	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	F			-	100.000%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)		981,672	100%	981,672	100.000%	$ 981,672	981,672		981,672
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	E	1,025,247	100%	1,025,247	100.000%	$ 1,025,247	1,118,917	999,495	119,422
55	5550004	Purchased Power - Pool Capacity		1,917,813	100%	1,917,813	100.000%	$ 1,917,813			
56	5550023	Purchase Power - Capacity		183,339	100%	183,339	100.000%	$ 183,339			
57	5550040	PJM Inadvertent - LSE (only)		103,635	100%	103,635	100.000%	$ 103,635			
58	5550093	Peak Hour Avail Charge - LSE			100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affil (Lawrenceburg)		$ 2,943,736	100%	$ 2,943,736	100.000%	$ 2,943,736			
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)		(85,013)	100%	(85,013)	100.000%	$ (85,013)			
62	5550046	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)		$45,118.64	76.33%	34,440	100.000%	$ 34,440			
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)		1,394,405	76.33%	1,064,363	100.000%	$ 1,064,363			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)		608,577	76.33%	464,532	100.000%	$ 464,532			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar		$ 347,894	100%	$ 347,894	100.000%	$ 347,894	$ 347,894	$ -	$ 347,894
67	5550109	Purchased Power - Solar		$ 81,219	100%	$ 81,219	100.000%	$ 81,219	$ 81,219	$ -	$ 81,219
68	5570007	Renewable Energy Credit Exp.			100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)		223,178	100%	$ 223,178	100.000%	$ 223,178			
70	Environmental Material & Expense										
71	5020001	Lime Expense		$ 1,912,242	73.84%	$ 1,412,000	100.000%	$ 1,412,000			
72	5020002	Urea Expense		302,313	73.84%	223,228	100.000%	$ 223,228			
73	5020003	Trona Expense		99,228	73.84%	73,270	100.000%	$ 73,270			
74	5020004	Limestone Expense		279,715	73.84%	206,541	100.000%	$ 206,541			
75	5020005	Polymer expense		54	73.84%	40	100.000%	$ 40			
76	5020007	Lime Hydrate Expense		1,045	73.84%	772	100.000%	$ 772			
77	5020008	Activated Carbon		(102)	73.84%	(75)	100.000%	$ (75)			
78	5020025	Steam Exp Environmental		7,063	73.84%	5,216	100.000%	$ 5,216			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)			0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)		47,064	0%	-					
82	5550088	PJM Capacity Charge (OSS only)			0%	-					
83	5550099	PJM Purchases - NonECR (Auction)		3,718,358	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)		94,610	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)		17,302,385	0%	-					
86	5550107	Capacity Purchases -Trading		383,286	0%	-					
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)			0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)			0%	-					
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit		$ 19,041	0%	$ -					
91	5550077	PJM Black Start Credit		(6,172)	0%	-					
92	5550079	PJM Regulation Credit		(352,032)	0%	-					
93	5550084	PJM Spinning Reserve Credit		(1,320)	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE			0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)			0%	$ -					
97	5550041	PJM Synchronous Cond. Charge		10,859	0%	-					
98	5550074	PJM Reactive Charge		(2,304)	0%	-					
99	5550076	PJM BlackStart Charge		8,746	0%	-					
100	5550078	PJM Regulation Charge		891,515	0%	-					
101	5550083	PJM Spinning Reserve Charge		30,272	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE		543,761	0%	-					
103		Total Additional FAC		$ 36,925,583		$ 12,500,042		$ 12,500,042			
104		TOTAL		$ 115,377,305		$ 68,871,404		$ 68,871,404			
105											
106	NOTATIONS:										
107	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
108	B	East Pool group computes/books Mone fuel & non-fuel separately	E	IPS is source for fuel/non-fuel split for pool energy							
109	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%				PIVOT	ESTIMATE		
110								114,485,370	114,485,369		

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

JULY 2011

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		
											Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	Generation Fuel			Mar GL	NEC						
5	5010001	Fuel Consumed		$ 108,393,460	$ 44,640,818	$ 63,752,642			$ 108,393,460	$ 108,236,614	$ 156,846
6	5010009	Fuel Consumed - No Load (CV4)				-			$ -	-	$ -
7	5010013	Fuel Survey Activity		$ -		-			$ -	-	$ -
8	5010019	Fuel Oil Consumed		$ 1,470,019		1,470,019			$ 1,470,019	1,470,019	$ (0)
9	5010020	Natural Gas Consumed				-			$ -	-	$ -
10	5010023	Fuel Consumed - Biomass				-			$ -	156,846	$ (156,846)
11	5470001	Fuel - Gas Turbine				-			$ -	-	$ -
12		Subtotal - Generation Plant		$ 109,863,479	$ 44,640,818	$ 65,222,661			$ 109,863,479	$ 109,863,479	$ 0
13	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	A	$ 5,473,572	$ 4,906,518	$ 567,054			$ 5,473,572	$ 6,083,044	$ (609,471)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	2,025	-	$ 2,025			$ 2,025	133,107	$ (131,082)
16	5550080	PJM Energy Purchases (Fuel)	C	4,468,473	4,459,814	$ 8,659			$ 4,468,473	3,771,631	$ 696,842
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	D	1,030,534	1,021,309	9,225			$ 1,030,534	1,028,626	$ 1,907
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	3,184	3,184	-			$ 3,184	3,099	$ 85
19	5550031/32	Purchased Pwr - Mone (Fuel)	B	372,721	372,721	-			$ 372,721	441,989	$ (69,268)
20		Subtotal - Purchased Power Fuel		$ 11,350,509	$ 10,763,546	$ 586,963			11,350,509	11,461,496	(110,987)
21		Total NEC Fuel		$ 121,213,988	$ 55,404,364	$ 65,809,624	92.717%	$ 61,016,709	121,213,988	121,324,975	(110,987)
22						Firm Load					
23	Allowance Accounts in FAC:				Allocation Factor	Allocated Amt					
24	Emission Allowance Expense										
25	5090000	Allowance Consumption SO2		$ 573,372	59.23%	$ 339,608					
26	5090001	Allowance Consumption - Seasonal NOx		10,719	59.23%						
	5090002	Allowance Expenses		-	59.23%	6,349					
27	5090005	Allowance Expenses - Annual NOx		10,695	59.23%	6,335					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	59.23%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		-	59.23%	-					
31	4118003	Comp. Allow. Gains-Seas NOx		-	59.23%	-					
32	4118004	Comp. Allow. Gains-Ann NOx		(57,397)	59.23%	(33,996)					
33	4119000	Loss Disposition of Allowances		-	59.23%	-					
34	4119002	Comp. Allow. Loss - SO2		-	59.23%	-					
35		Total Allowance Dollars		$ 537,390		$ 318,296	92.717%	$ 295,114			
36	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC							
37						Firm Load					
38	Account	Description	Notes		Allocation Factor	Allocated Amount					
39	Incremental Fuel Handling/Ash/Gypsum										
40	5010000	Fuel (Ash Handling)		$ 2,040,965	59.23%	$ 1,208,864	92.717%	$ 1,120,822			
41	5010003	Fuel - Procurement, Unloading & Handling		4,289,948	59.23%	2,540,936	92.717%	$ 2,355,880			
42	5010012	Ash Sales Proceeds		(124,029)	59.23%	(73,462)	92.717%	$ (68,112)			
43	5010027	Gypsum handling/disposal costs		276,718	59.23%	163,900	92.717%	$ 151,963			
44	5010028	Gypsum Sales Proceeds		(9,449)	59.23%	(5,596)	92.717%	$ (5,189)			
45	5010029	Gypsum handling/displ-Affiliat		22,398	59.23%	13,266	92.717%	$ 12,300			
46	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	D	$ -	-	$ -	92.717%	$ -	$ -		$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	521,532	461,761	59,771	92.717%	$ 55,418	$ 521,532	$ 3,486,978	$ (2,965,446)
49	5550032	PP - Mone - Non-Fuel	B	-	-	-	92.717%	$ -	$ -	$ -	$ -
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	C	-	-	-	92.717%	$ -	$ -		$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	F	-	-	-	92.717%	$ -	$ -		$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:bill, Genea Taylor email)		3,424,796	100%	3,424,796	92.717%	$ 3,175,368	3,424,796		3,424,796
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	E	430	100%	430	92.717%	$ 399	3,946,328	3,486,978	459,350
54	5550023	PP Capacity - Non Affil.		219,804	100%	219,804	92.717%	$ 203,796			
55	5550040	PJM Inadvertent - LSE (only)		124,248	100%	124,248	92.717%	$ 115,199			
56	5550003	PP - Cogeneration		195,877	100%	195,877	92.717%	$ 181,611			
57	5550093	Peak Hour Avail Charge - LSE		-	100%	-	92.717%	$ -			
58	Lawrenceburg purchased power - Non-Fuel (NA)										
59	Renewables										
60	5550047	Purchased Power - Wind		347,894	100%	$ 347,894	100.00%	$ 347,894	$ 347,893.85	$ 347,893.85	$ -
61	5550109	Purchased Power - Solar Energy		103,370	100%	103,370	100.00%	$ 103,370	$ 103,370.12	$ 103,370.12	$ -
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010		-	100%	-	100.00%	$ -			
63	5570008	Renewable Energy Credit Exp.		-	100%	-	100.00%	$ -			
64	5570009	Other Pwr Exp - REC's - RETAIL		280,227	100%	280,227	100.00%	$ 280,227			
65	Environmental Material & Expense										
66	5020001	Lime Expense		$ 3,838,414	59.23%	$ 2,273,493	92.717%	$ 2,107,914			
67	5020002	Urea Expense		2,512,923	59.23%	1,488,405	92.717%	$ 1,380,004			
68	5020003	Trona Expense		1,002,018	59.23%	593,495	92.717%	$ 550,271			
69	5020004	Limestone Expense		1,654,804	59.23%	980,141	92.717%	$ 908,757			
70	5020005	Polymer expense		280,651	59.23%	166,230	92.717%	$ 154,123			
71	5020007	Lime Hydrate Expense		5,028	59.23%	2,978	92.717%	$ 2,761			
72	5020008	Activated Carbon		(341)	59.23%	(202)	92.717%	$ (187)			
73	5020025	Steam Exp Environmental		56,554	59.23%	33,497	92.717%	$ 31,057			
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
75	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -	92.717%	$ -			
76	5550039	PJM Inadvertent - OSS (only)		56,425	0%	-	92.717%	$ -			
77	5550088	PJM Capacity Charge (OSS only)		-	0%	-	92.717%	$ -			
78	5550099	PJM Purchases - NonECR (Auction)		4,457,917	0%	-	92.717%	$ -			
79	5550100	PJM Capacity Purchases - NonECR (Auction)		113,428	0%	-	92.717%	$ -			
80	5550102	PP Pool Non Fuel - OSS Aff		17,713,471	0%	-	92.717%	$ -			
81	5550107	Capacity Purchases - Trading		459,519	0%	-	92.717%	$ -			
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)		-	0%	-	92.717%	$ -			
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
84	5550075	PJM Reactive Credit		$ 22,828	0%	$ -	92.717%	$ -			
85	5550077	PJM Black Start Credit		(7,400)	0%	-	92.717%	$ -			
86	5550079	PJM Regulation Credit		(422,049)	0%	-	92.717%	$ -			
87	5550084	PJM Spinning Reserve Credit		(1,583)	0%	-	92.717%	$ -			
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	92.717%	$ -			
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
90	5550036	PJM Emergency Purchases (Demand Response Program)		$ -	0%	$ -	92.717%	$ -			
91	5550041	PJM Synchronous Cond. Charge		13,018	0%	-	92.717%	$ -			
92	5550074	PJM Reactive Charge		(2,763)	0%	-	92.717%	$ -			
93	5550076	PJM BlackStart Charge		10,485	0%	-	92.717%	$ -			
94	5550078	PJM Regulation Charge		1,068,832	0%	-	92.717%	$ -			
95	5550083	PJM Spinning Reserve Charge		36,292	0%	-	92.717%	$ -			
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE		651,912	0%	-	92.717%	$ -			
97		Total Additional FAC		$ 45,235,114		$ 14,142,360		$ 13,165,646	GL AMOUNTS	$ 166,638,129.34	
98		TOTAL		$ 166,986,492		$ 80,270,280		$ 74,477,470	EXCL 5010032/33	$ -	
99									TOTAL GL QUERY	$ 166,638,129.34	
100	NOTATIONS:										
101	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
102	B	East Pool group computes/books Mone fuel & non-fuel separately (80/2(	E	IPS is source for fuel/non-fuel split for pool energy							
103	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%							
104											

Line	A	B	C	D	E	F	G	H			
		Actual					EXH CSP-1				
*		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)									
		August 2011							Reconcile NEC to GL		
Line	A	B	C	D	E	F	G	H			Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail	EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel				NEC						
5	5010001/5010022/23	Fuel Consumed		$ 30,869,392	$ 11,074,953	$ 19,794,439			$ 30,869,392	$ 30,520,381	$ 349,012
6	5010009	Fuel Consumed - No Load (CV4)		719,889		719,889			$ 719,889	1,055,123	$ (335,234)
7	5010013	Fuel Survey Activity		-	-	-			$ -	-	$ -
8	5010019	Fuel Oil Consumed		525,777		525,777			$ 525,777	539,555	$ (13,778)
9	5010020/5010036	Natural Gas Consumed		9,538,439	-	9,538,439			$ 9,538,439	9,243,282	$ 295,157
10	5470001/5470003	Fuel - Gas Turbine		-	$ -	-			$ -	295,157	$ (295,157)
11		Subtotal - Generation Fuel		$ 41,653,498	$ 11,074,953	$ 30,578,544			$ 41,653,498	$ 41,653,498	$ (0)
12	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	A	$ 1,606,156	$ 1,527,804	$ 78,352			$ 1,606,156	$ 1,741,840	$ (135,684)
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	$ 9,247,150	$ -	9,247,150			$ 9,247,150	9,312,342	$ (65,192)
15	5550080	PJM Energy Purchases (Fuel)	C	$ 2,622,033	$ 2,613,395	8,638			$ 2,622,033	3,133,072	$ (511,040)
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	D	$ 439,856	$ 432,659	7,196			$ 439,856	429,239	$ 10,616
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	$ -	$ -	-			$ -		$ -
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	F	$ 9,744,448	$ 1,364,035	8,380,412			$ 9,744,448	9,772,015	$ (27,568)
19	5550032	Purchased Pwr - Mone (Fuel)	B	$ 105,676	$ 105,676	-			$ 105,676	104,087	$ 1,589
20		Subtotal - Purchased Power Fuel		$ 23,765,318	$ 6,043,570	$ 17,721,747			23,765,318	24,492,596	(727,279)
21		Total NEC Fuel		$ 65,418,815	$ 17,118,523	$ 48,300,292	100.000%	$ 48,300,292	65,418,815	66,146,094	(727,279)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount					
24	Emission Allowance Expense										
25	5090000/2	Allowance Consumption - SO2		$ 481,039	77.60%	$ 373,286					
26	5090001	Allowance Consumption - Seasonal NOx		78,025	77.60%	60,547					
27	5090005	Allowance Expenses - Annual NOx		23,360	77.60%	18,128					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)			77.60%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2			77.60%	$ -					
31	4118003	Comp. Allow. Gains-Seas NOx			77.60%	-					
32	4118004	Comp. Allow. Gains-Ann NOx			77.60%	-					
33	4119000	Loss Disposition of Allowances			77.60%	-					
34		Total Allowance Dollars		$ 582,424		$ 451,961	100.000%	$ 451,961			
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum										
39	5010000	Fuel (Ash Handling)		$ 705,792	77.60%	$ 547,695	100.000%	$ 547,695			
40	5010003	Fuel - Procurement, Unloading & Handling		851,137	77.60%	660,482	100.000%	$ 660,482			
41	5010011	Fuel Handling - No Load (CV4)		32,957	77.60%	25,575	100.000%	$ 25,575			
42	5010012	Ash Sales Proceeds		(8,535)	77.60%	(6,623)	100.000%	$ (6,623)			
43	5010027	Gypsum handling/disposal costs		271,169	77.60%	210,442	100.000%	$ 210,442			
44	5010028	Gypsum Sales Proceeds		(2)	77.60%	(2)	100.000%	$ (2)			
45	5010032	Coal Procurement-Aff			77.60%	-	100.000%	$ -			
46	5010033	Coal Procurement-NA			77.60%	-	100.000%	$ -			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	D	$ -	$ -	$ -	100.000%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	163,890	155,897	7,993	100.000%	$ 7,993	$ 163,890	$ 1,008,312	$ (844,422)
50	5550032	PP - Mone - Non-Fuel	B			-	100.000%	$ -	$ -		$ -
51	5550098 INACTIVE	PP - PJM - Non-Fuel	C			-	100.000%	$ -	$ -		$ -
52	5550046	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	F			-	100.000%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)		1,007,904	100%	1,007,904	100.000%	$ 1,007,904	1,007,904		1,007,904
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	E	1,167,179	100%	1,167,179	100.000%	$ 1,167,179	1,171,793	1,008,312	163,482
55	5550004	Purchased Power - Pool Capacity		3,708,551	100%	3,708,551	100.000%	$ 3,708,551			
56	5550023	Purchase Power - Capacity		188,204	100%	188,204	100.000%	$ 188,204			
57	5550040	PJM Inadvertent - LSE (only)		122,639	100%	122,639	100.000%	$ 122,639			
58	5550093	Peak Hour Avail Charge - LSE			100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affil (Lawrenceburg)		$ 2,943,736	100%	$ 2,943,736	100.000%	$ 2,943,736			
61	5550104	Defd Depr & Capacity portion-Affil (Lawrenceburg)		(85,013)	100%	(85,013)	100.000%	$ (85,013)			
62	5550046	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)		$27,536	85.31%	23,492	100.000%	$ 23,492			
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)		1,430,069	85.31%	1,220,035	100.000%	$ 1,220,035			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)		776,209	85.31%	662,207	100.000%	$ 662,207			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar		$ 363,036	100%	$ 363,036	100.000%	$ 363,036	$ 363,036	$ 363,036	$ -
67	5550109	Purchased Power - Solar		$ 74,899	100%	$ 74,899	100.000%	$ 74,899	$ 74,899	$ 74,899	$ -
68	5570007	Renewable Energy Credit Exp.			100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)		232,458	100%	$ 232,458	100.000%	$ 232,458			
70	Environmental Material & Expense										
71	5020001	Lime Expense		$ 1,714,500	77.60%	$ 1,330,452	100.000%	$ 1,330,452			
72	5020002	Urea Expense		263,554	77.60%	204,518	100.000%	$ 204,518			
73	5020003	Trona Expense		89,370	77.60%	69,351	100.000%	$ 69,351			
74	5020004	Limestone Expense		332,977	77.60%	258,390	100.000%	$ 258,390			
75	5020005	Polymer expense		77	77.60%	60	100.000%	$ 60			
76	5020007	Lime Hydrate Expense		1,139	77.60%	884	100.000%	$ 884			
77	5020008	Activated Carbon		28	77.60%	22	100.000%	$ 22			
78	5020025	Steam Exp Environmental		15,337	77.60%	11,901	100.000%	$ 11,901			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)			0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)		41,930	0%	-					
82	5550088	PJM Capacity Charge (OSS only)			0%	-					
83	5550099	PJM Purchases - NonECR (Auction)		2,280,292	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)		94,988	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)		14,034,631	0%	-					
86	5550107	Capacity Purchases -Trading		392,968	0%	-					
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)			0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)			0%	-					
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit		$ (529,885)	0%	$ -					
91	5550077	PJM Black Start Credit		(6,130)	0%	-					
92	5550079	PJM Regulation Credit		(286,088)	0%	-					
93	5550084	PJM Spinning Reserve Credit		(1,868)	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE			0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)			0%	$ -					
97	5550041	PJM Synchronous Cond. Charge		387	0%	-					
98	5550074	PJM Reactive Charge		552,601	0%	-					
99	5550076	PJM BlackStart Charge		8,764	0%	-					
100	5550078	PJM Regulation Charge		839,506	0%	-					
101	5550083	PJM Spinning Reserve Charge		25,723	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE		128,181	0%	-					
103		Total Additional FAC		$ 33,966,816		$ 14,950,466		$ 14,950,466			
104		TOTAL		$ 99,968,056		$ 63,702,719		$ 63,702,719			
105											
106	NOTATIONS:										
107	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
108	B	East Pool group computes/books Mone fuel & non-fuel separately	E	IPS is source for fuel/non-fuel split for pool energy							
109	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%				PIVOT	ESTIMATE		
110								100,504,317	100,504,317		

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

AUGUST 2011

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		
											Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	Generation Fuel			Mar GL	NEC						
5	5010001	Fuel Consumed		$ 96,016,972	$ 35,467,221	$ 60,549,751			$ 96,016,972	$ 95,884,321	$ 132,651
6	5010009	Fuel Consumed - No Load (CV4)				-			$ -		$ -
7	5010013	Fuel Survey Activity		$ (760,423)		(760,423)			$ (760,423)	(760,423)	$ (0)
8	5010019	Fuel Oil Consumed		$ 1,673,712		1,673,712			$ 1,673,712	1,673,712	$ 0
9	5010020	Natural Gas Consumed				-			$ -	-	$ -
10	5010023	Fuel Consumed - Biomass				-			$ -	132,652	$ (132,652)
11	5470001	Fuel - Gas Turbine				-			$ -	-	$ -
12		Subtotal - Generation Plant		$ 96,930,261	$ 35,467,221	$ 61,463,040			$ 96,930,261	$ 96,930,261	$ (0)
13	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	A	$ 5,603,444	$ 5,233,128	$ 370,315			$ 5,603,444	$ 6,534,386	$ (930,942)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	21,466	-	$ 21,466			$ 21,466	13,670	$ 7,796
16	5550080	PJM Energy Purchases (Fuel)	C	3,113,343	3,103,093	$ 10,249			$ 3,113,343	3,726,371	$ (613,028)
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	D	522,276	513,731	8,545			$ 522,276	-	$ 522,276
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	-	-	-			$ -	38	$ (38)
19	5550031/32	Purchased Pwr - Mone (Fuel)	B	125,478	125,478	-			$ 125,478	128,728	$ (3,250)
20		Subtotal - Purchased Power Fuel		$ 9,386,006	$ 8,975,430	$ 410,576			9,386,006	10,403,194	(1,017,187)
21		Total NEC Fuel		$ 106,316,267	$ 44,442,651	$ 61,873,616	92.271%	$ 57,091,404	106,316,267	107,333,455	(1,017,188)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt					
24	Emission Allowance Expense										
25	5090000	Allowance Consumption SO2		$ 474,221	63.60%	$ 301,605					
26	5090001	Allowance Consumption - Seasonal NOx		9,817	63.60%						
	5090002	Allowance Expenses		-	63.60%	6,244					
27	5090005	Allowance Expenses - Annual NOx		8,242	63.60%	5,242					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	63.60%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		-	63.60%	-					
31	4118003	Comp. Allow. Gains-Seas NOx		(2,276)	63.60%	(1,447)					
32	4118004	Comp. Allow. Gains-Ann NOx		(35,661)	63.60%	(22,680)					
33	4119000	Loss Disposition of Allowances		-	63.60%	-					
34	4119002	Comp. Allow. Loss - SO2		-	63.60%	-					
35		Total Allowance Dollars		$ 454,344		$ 288,963	92.271%	$ 266,629			
36	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC							
37						Firm Load					
38	Account	Description	Notes		Allocation Factor	Allocated Amount					
39	Incremental Fuel Handling/Ash/Gypsum										
40	5010000	Fuel (Ash Handling)		$ 1,521,041	63.60%	$ 967,382	92.271%	$ 892,613			
41	5010003	Fuel - Procurement, Unloading & Handling		3,574,479	63.60%	2,273,369	92.271%	$ 2,097,660			
42	5010012	Ash Sales Proceeds		(177,107)	63.60%	(112,640)	92.271%	$ (103,934)			
43	5010027	Gypsum handling/disposal costs		444,997	63.60%	283,018	92.271%	$ 261,143			
44	5010028	Gypsum Sales Proceeds		(357,656)	63.60%	(227,469)	92.271%	$ (209,888)			
45	5010029	Gypsum handling/displ-Affiliat		20,332	63.60%	12,931	92.271%	$ 11,932			
46	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	D	$ -	-	$ -	92.271%	$ -	$ -		$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	533,583	498,333	35,250	92.271%	$ 32,525	$ 533,583	$ 3,517,736	$ (2,984,154)
49	5550032	PP - Mone - Non-Fuel	B	-	-	-	92.271%	$ -	$ -	$ -	$ -
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	C	-	-	-	92.271%	$ -	$ -		$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	F	-	-	-	92.271%	$ -	$ -		$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:bill, Genea Taylor email)		3,516,313	100%	3,516,313	92.271%	$ 3,244,537	3,516,313		3,516,313
53	5550101	*PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)*	E	1,778	100%	1,778	92.271%	$ 1,641	4,049,895	3,517,736	532,159
54	5550023	PP Capacity - Non Affil.		223,470	100%	223,470	92.271%	$ 206,198			
55	5550040	PJM Inadvertent - LSE (only)		145,846	100%	145,846	92.271%	$ 134,574			
56	5550003	PP - Cogeneration		192,033	100%	192,033	92.271%	$ 177,191			
57	5550093	Peak Hour Avail Charge - LSE		-	100%	-	92.271%	$ -			
58	Lawrenceburg purchased power - Non-Fuel (NA)										
59	Renewables										
60	5550047	Purchased Power - Wind		363,036	100%	$ 363,036	100.00%	$ 363,036	$ 363,035.94	$ 363,035.94	$ -
61	5550109	Purchased Power - Solar Energy		95,326	100%	95,326	100.00%	$ 95,326	$ 95,325.59	$ 95,325.59	$ -
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010		-	100%	-	100.00%	$ -			
63	5570008	Renewable Energy Credit Exp.		-	100%	-	100.00%	$ -			
64	5570009	Other Pwr Exp - REC's - RETAIL		301,504	100%	301,504	100.00%	$ 301,504			
65	Environmental Material & Expense										
66	5020001	Lime Expense		$ 4,028,634	63.60%	$ 2,562,211	92.271%	$ 2,364,178			
67	5020002	Urea Expense		2,491,362	63.60%	1,584,506	92.271%	$ 1,462,040			
68	5020003	Trona Expense		1,047,162	63.60%	665,995	92.271%	$ 614,520			
69	5020004	Limestone Expense		1,443,910	63.60%	918,326	92.271%	$ 847,349			
70	5020005	Polymer expense		338,541	63.60%	215,312	92.271%	$ 198,671			
71	5020007	Lime Hydrate Expense		1,085	63.60%	690	92.271%	$ 636			
72	5020008	Activated Carbon		93	63.60%	59	92.271%	$ 55			
73	5020025	Steam Exp Environmental		25,489	63.60%	16,211	92.271%	$ 14,958			
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
75	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -	92.271%	$ -			
76	5550039	PJM Inadvertent - OSS (only)		49,835	0%	-	92.271%	$ -			
77	5550088	PJM Capacity Charge (OSS only)		-	0%	-	92.271%	$ -			
78	5550099	PJM Purchases - NonECR (Auction)		2,706,949	0%	-	92.271%	$ -			
79	5550100	PJM Capacity Purchases - NonECR (Auction)		112,787	0%	-	92.271%	$ -			
80	5550102	PP Pool Non Fuel - OSS Aff		14,751,911	0%	-	92.271%	$ -			
81	5550107	Capacity Purchases - Trading		466,602	0%	-	92.271%	$ -			
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)		-	0%	-	92.271%	$ -			
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
84	5550075	PJM Reactive Credit		$ (629,175)	0%	$ -	92.271%	$ -			
85	5550077	PJM Black Start Credit		(7,278)	0%	-	92.271%	$ -			
86	5550079	PJM Regulation Credit		(340,211)	0%	-	92.271%	$ -			
87	5550084	PJM Spinning Reserve Credit		(2,240)	0%	-	92.271%	$ -			
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	92.271%	$ -			
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
90	5550036	*PJM Emergency Purchases (Demand Response Program)*		$ -	0%	$ -	92.271%	$ -			
91	5550041	PJM Synchronous Cond. Charge		401	0%	-	92.271%	$ -			
92	5550074	PJM Reactive Charge		656,148	0%	-	92.271%	$ -			
93	5550076	PJM BlackStart Charge		10,407	0%	-	92.271%	$ -			
94	5550078	PJM Regulation Charge		998,322	0%	-	92.271%	$ -			
95	5550083	PJM Spinning Reserve Charge		30,592	0%	-	92.271%	$ -			
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE		152,576	0%	-	92.271%	$ -			
97		Total Additional FAC		$ 38,732,876		$ 14,034,457		$ 13,008,464	GL AMOUNTS	$ 145,988,514.94	
98		TOTAL		$ 145,503,487		$ 76,197,036		$ 70,366,497	EXCL 5010032/33	$ -	
99									TOTAL GL QUERY	$ 145,988,514.94	
100	NOTATIONS:										
101	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
102	B	East Pool group computes/books Mone fuel & non-fuel separately (80/2(	E	IPS is source for fuel/non-fuel split for pool energy							
103	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%							
104											

Actual | EXH CSP-1

COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)

September 2011

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		Diff. To GL
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			Net Energy Cost (NEC) in EFC			Retail	Retail	EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel				NEC						
5	5010001/5010022/23	Fuel Consumed		$ 24,968,042	$ 7,323,945	$ 17,644,097			$ 24,968,042	$ 25,581,896	$ (613,854)
6	5010009	Fuel Consumed - No Load (CV4)		719,889		719,889			$ 719,889	106,035	$ 613,854
7	5010013	Fuel Survey Activity		-	-	-			$ -	-	$ -
8	5010019	Fuel Oil Consumed		246,424		246,424			$ 246,424	246,424	$ -
9	5010020/5010036	Natural Gas Consumed		3,218,690	-	3,218,690			$ 3,218,690	3,134,459	$ 84,230
10	5470001/5470003	Fuel - Gas Turbine		-	$ -	-			$ -	84,230	$ (84,230)
11		Subtotal - Generation Fuel		$ 29,153,045	$ 7,323,945	$ 21,829,099			$ 29,153,045	$ 29,153,045	$ 0
12	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	A	$ 1,331,693	$ 1,118,924	$ 212,769			$ 1,331,693	$ 3,553,344	$ (2,221,651)
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	$ 8,030,923	$ -	8,030,923			$ 8,030,923	8,532,691	$ (501,768)
15	5550080	PJM Energy Purchases (Fuel)	C	$ 3,451,963	$ 3,170,300	281,663			$ 3,451,963	3,221,082	$ 230,881
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	D	$ 1,241,470	$ 1,130,141	111,329			$ 1,241,470	(628,987)	$ 1,870,456
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	$ 2,338	$ 1,226	1,112			$ 2,338		$ 2,338
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	F	$ 5,714,130	$ 600,147	5,113,983			$ 5,714,130	5,743,414	$ (29,283)
19	5550032	Purchased Pwr - Mone (Fuel)	B	$ -	$ -	-			$ -	56,845	$ (56,845)
20		Subtotal - Purchased Power Fuel		$ 19,772,518	$ 6,020,739	$ 13,751,779			19,772,518	20,478,389	(705,872)
21		Total NEC Fuel		$ 48,925,562	$ 13,344,684	$ 35,580,878	100.000%	$ 35,580,878	48,925,562	49,631,434	(705,872)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount					
24	Emission Allowance Expense										
25	5090000/2	Allowance Consumption - SO2		$ 220,637	79.37%	$ 175,120					
26	5090001	Allowance Consumption - Seasonal NOx		61,399	79.37%	48,732					
27	5090005	Allowance Expenses - Annual NOx		20,945	79.37%	16,624					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)			79.37%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2			79.37%	$ -					
31	4118003	Comp. Allow. Gains-Seas NOx			79.37%	-					
32	4118004	Comp. Allow. Gains-Ann NOx			79.37%	-					
33	4119000	Loss Disposition of Allowances			79.37%	-					
34		Total Allowance Dollars		$ 302,981		$ 240,476	100.000%	$ 240,476			
35	**Additional S.B. 221 FAC Accounts for 2009**			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum										
39	5010000	Fuel (Ash Handling)		$ 767,995	79.37%	$ 609,558	100.000%	$ 609,558			
40	5010003	Fuel - Procurement, Unloading & Handling		1,265,265	79.37%	1,004,241	100.000%	$ 1,004,241			
41	5010011	Fuel Handling - No Load (CV4)		30,443	79.37%	24,163	100.000%	$ 24,163			
42	5010012	Ash Sales Proceeds		(5,674)	79.37%	(4,503)	100.000%	$ (4,503)			
43	5010027	Gypsum handling/disposal costs		130,183	79.37%	103,327	100.000%	$ 103,327			
44	5010028	Gypsum Sales Proceeds		(30,762)	79.37%	(24,415)	100.000%	$ (24,415)			
45	5010032	Coal Procurement-Aff			79.37%	-	100.000%	$ -			
46	5470004	Fuel - Gas Turbine - Purchasing / Handling Costs - this is cumulative 2011 YTD		167,912	79.37%	133,272	100.000%	$ 133,272			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	D	$ -	$ -	$ -	100.000%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	139,362	117,094	22,267	100.000%	$ 22,267	$ 139,362	$ 1,118,904	$ (979,542)
50	5550032	PP - Mone - Non-Fuel	B			-	100.000%	$ -	$ -		$ -
51	5550098 INACTIVE	PP - PJM - Non-Fuel	C			-	100.000%	$ -	$ -		$ -
52	5550046	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	F			-	100.000%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)		1,136,769	100%	1,136,769	100.000%	$ 1,136,769	1,136,769		1,136,769
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	E	1,219,474	100%	1,219,474	100.000%	$ 1,219,474	1,276,131	1,118,904	157,227
55	5550004	Purchased Power - Pool Capacity		2,681,180	100%	2,681,180	100.000%	$ 2,681,180			
56	5550023	Purchase Power - Capacity		188,204	100%	188,204	100.000%	$ 188,204			
57	5550040	PJM Inadvertent - LSE (only)		29,738	100%	29,738	100.000%	$ 29,738			
58	5550093	Peak Hour Avail Charge - LSE			100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affil (Lawrenceburg)		$ 2,943,736	100%	$ 2,943,736	100.000%	$ 2,943,736			
61	5550104	Defd Depr & Capacity portion-Affil (Lawrenceburg)		(85,013)	100%	(85,013)	100.000%	$ (85,013)			
62	5550046	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)		$26,945.38	88.79%	23,925	100.000%	$ 23,925			
63	5550066	PurchPwr-O&M portion-Affiliate (Lawrenceburg)		1,432,925	88.79%	1,272,285	100.000%	$ 1,272,285			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)		2,212,487	88.79%	1,964,453	100.000%	$ 1,964,453			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar		$ 641,336	100%	$ 641,336	100.000%	$ 641,336	$ 641,336	$ 641,336	$ -
67	5550109	Purchased Power - Solar		$ 45,625	100%	$ 45,625	100.000%	$ 45,625	$ 45,625	$ 45,625	$ -
68	5570007	Renewable Energy Credit Exp.			100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)		228,256	100%	$ 228,256	100.000%	$ 228,256			
70	Environmental Material & Expense										
71	5020001	Lime Expense		$ 1,984,589	79.37%	$ 1,575,169	100.000%	$ 1,575,169			
72	5020002	Urea Expense		291,954	79.37%	231,724	100.000%	$ 231,724			
73	5020003	Trona Expense		27,181	79.37%	21,574	100.000%	$ 21,574			
74	5020004	Limestone Expense		156,066	79.37%	123,870	100.000%	$ 123,870			
75	5020005	Polymer expense		121	79.37%	96	100.000%	$ 96			
76	5020007	Lime Hydrate Expense		1,085	79.37%	861	100.000%	$ 861			
77	5020008	Activated Carbon		52	79.37%	41	100.000%	$ 41			
78	5020025	Steam Exp Environmental		9,492	79.37%	7,534	100.000%	$ 7,534			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)			0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)		13,074	0%	-					
82	5550088	PJM Capacity Charge (OSS only)			0%	-					
83	5550099	PJM Purchases - NonECR (Auction)		2,219,798	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)		87,248	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)		10,834,770	0%	-					
86	5550107	Capacity Purchases -Trading		225,872	0%	-					
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)			0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)			0%	-					
89	555 Purchased Power Ancillary Credits Included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit		$ 19,546	0%	$ -					
91	5550077	PJM Black Start Credit		(6,063)	0%	-					
92	5550079	PJM Regulation Credit		(187,352)	0%	-					
93	5550084	PJM Spinning Reserve Credit		(4,183)	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE			0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)		$ 2,337	0%	$ -					
97	5550041	PJM Synchronous Cond. Charge		(745)	0%	-					
98	5550074	PJM Reactive Charge		3,196	0%	-					
99	5550076	PJM BlackStart Charge		8,748	0%	-					
100	5550078	PJM Regulation Charge		490,425	0%	-					
101	5550083	PJM Spinning Reserve Charge		26,427	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE		8,696	0%	-					
103		Total Additional FAC		$ 31,378,723		$ 16,118,745		$ 16,118,745			
104		TOTAL		$ 80,607,266		$ 51,940,099		$ 51,940,099			
105											
106	NOTATIONS:										
107	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
108	B	East Pool group computes/books Mone fuel & non-fuel separately	E	IPS is source for fuel/non-fuel split for pool energy							
109	C	East Pool group; PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%				PIVOT	ESTIMATE		
110								81,128,965	81,128,965		

C:\Users\jolker\AppData\Local\Temp\Temp3_LA-2011-49 CONFIDENTIAL.zip\[LA-2011-49, Confidnential II (OPCO_BU_181_F				ACTUAL		EXH OPCo-1					
OHIO POWER COMPANY - NET ENERGY COST (NEC)											
SEPTEMBER 2011									Reconcile NEC to GL		
Line	A	B	C	D	E	F	G	H			Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	Generation Fuel			Mar GL	NEC						
5	5010001	Fuel Consumed		$ 86,166,383	$ 35,698,469	$ 50,467,914			$ 86,166,383	$ 86,073,394	$ 92,989
6	5010009	Fuel Consumed - No Load (CV4)				-			$ -	-	$ -
7	5010013	Fuel Survey Activity		$ (180,386)		(180,386)			$ (180,386)	(180,386)	$ 0
8	5010019	Fuel Oil Consumed		$ 732,291		732,291			$ 732,291	732,291	$ 0
9	5010020	Natural Gas Consumed				-			$ -	-	$ -
10	5010023	Fuel Consumed - Biomass				-			$ -	92,989	$ (92,989)
11	5470001	Fuel - Gas Turbine				-			$ -	-	$ -
12		Subtotal - Generation Plant		$ 86,718,288	$ 35,698,469	$ 51,019,819			$ 86,718,288	$ 86,718,287	$ 1
13	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	A	$ 4,645,922	$ 3,903,629	$ 742,293			$ 4,645,922	$ 7,678,616	$ (3,032,693)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	9,740	-	$ 9,740			$ 9,740	16,467	$ (6,727)
16	5550080	PJM Energy Purchases (Fuel)	C	4,098,793	3,764,351	$ 334,441			$ 4,098,793	3,824,649	$ 274,144
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	D	1,474,097	1,341,906	132,190			$ 1,474,097	(754,611)	$ 2,228,708
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	2,776	1,456	1,320			$ 2,776	2,776	$ -
19	5550031/32	Purchased Pwr - Mone (Fuel)	B	-	-	-			$ -	69,538	$ (69,538)
20		Subtotal - Purchased Power Fuel		$ 10,231,328	$ 9,011,343	$ 1,219,985			10,231,328	10,837,435	(606,107)
21		Total NEC Fuel		$ 96,949,616	$ 44,709,812	$ 52,239,804	91.746%	$ 47,927,931	96,949,616	97,555,722	(606,106)
22						Firm Load					
23	Allowance Accounts in FAC:				Allocation Factor	Allocated Amt					
24	Emission Allowance Expense										
25	5090000	Allowance Consumption SO2		$ 397,753	58.51%	$ 232,725					
26	5090001	Allowance Consumption - Seasonal NOx		11,436	58.51%						
	5090002	Allowance Expenses		-	58.51%	6,691					
27	5090005	Allowance Expenses - Annual NOx		8,054	58.51%	4,713					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	58.51%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		-	58.51%	-					
31	4118003	Comp. Allow. Gains-Seas NOx		(9,790)	58.51%	(5,728)					
32	4118004	Comp. Allow. Gains-Ann NOx		(452,842)	58.51%	(264,958)					
33	4119000	Loss Disposition of Allowances		-	58.51%	-					
34	4119002	Comp. Allow. Loss - SO2		-	58.51%	-					
35		Total Allowance Dollars		$ (45,389)		$ (26,557)	91.746%	$ (24,365)			
36	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC							
37						Firm Load					
38	Account	Description	Notes		Allocation Factor	Allocated Amount					
39	Incremental Fuel Handling/Ash/Gypsum										
40	5010000	Fuel (Ash Handling)		$ 1,581,022	58.51%	$ 925,056	91.746%	$ 848,702			
41	5010003	Fuel - Procurement, Unloading & Handling		3,449,215	58.51%	2,018,136	91.746%	$ 1,851,559			
42	5010012	Ash Sales Proceeds		(207,747)	58.51%	(121,553)	91.746%	$ (111,520)			
43	5010027	Gypsum handling/disposal costs		195,243	58.51%	114,237	91.746%	$ 104,807			
44	5010028	Gypsum Sales Proceeds		101,769	58.51%	59,545	91.746%	$ 54,630			
45	5010029	Gypsum handling/displ-Affiliat		22,911	58.51%	13,405	91.746%	$ 12,299			
46	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
47	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	D	$ -	-	$ -	91.746%	$ -	$ -		$ -
48	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	486,196	408,511	77,685	91.746%	$ 71,273	$ 486,196	$ -	$ 486,196
49	5550032	PP - Mone - Non-Fuel	B	-	-	-	91.746%	$ -	$ -	$ -	$ -
50	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	C	-	-	-	91.746%	$ -	$ -		$ -
51	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	F	-	-	-	91.746%	$ -	$ -		$ -
52	5550096 - in part	PP - OVEC Demand-Actual only (source:bill, Genea Taylor email)		3,965,890	100%	3,965,890	91.746%	$ 3,638,546	3,965,890	3,903,563	62,327
53	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	E	1,837	100%	1,837	91.746%	$ 1,685	4,452,086	3,903,563	548,523
54	5550023	PP Capacity - Non Affil.		223,470	100%	223,470	91.746%	$ 205,025			
55	5550040	PJM Inadvertent - LSE (only)		35,310	100%	35,310	91.746%	$ 32,396			
56	5550003	PP - Cogeneration		197,909	100%	197,909	91.746%	$ 181,574			
57	5550093	Peak Hour Avail Charge - LSE		-	100%	-	91.746%	$ -			
58	Lawrenceburg purchased power - Non-Fuel (NA)										
59	Renewables										
60	5550047	Purchased Power - Wind		641,336	100%	$ 641,336	100.00%	$ 641,336	$ 641,336.00	$ 641,336.00	$ -
61	5550109	Purchased Power - Solar Energy		58,068	100%	58,068	100.00%	$ 58,068	$ 58,068.24	$ 58,068.24	$ -
62	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010		-	100%	-	100.00%	$ -			
63	5570008	Renewable Energy Credit Exp.		-	100%	-	100.00%	$ -			
64	5570009	Other Pwr Exp - REC's - RETAIL		319,636	100%	319,636	100.00%	$ 319,636			
65	Environmental Material & Expense										
66	5020001	Lime Expense		$ 4,334,411	58.51%	$ 2,536,064	91.746%	$ 2,326,737			
67	5020002	Urea Expense		2,266,391	58.51%	1,326,065	91.746%	$ 1,216,612			
68	5020003	Trona Expense		842,679	58.51%	493,052	91.746%	$ 452,355			
69	5020004	Limestone Expense		1,341,009	58.51%	784,624	91.746%	$ 719,862			
70	5020005	Polymer expense		321,244	58.51%	187,960	91.746%	$ 172,445			
71	5020007	Lime Hydrate Expense		5,193	58.51%	3,038	91.746%	$ 2,788			
72	5020008	Activated Carbon		165	58.51%	96	91.746%	$ 88			
73	5020025	Steam Exp Environmental		45,631	58.51%	26,699	91.746%	$ 24,495			
74	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
75	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -	91.746%	$ -			
76	5550039	PJM Inadvertent - OSS (only)		15,524	0%	-	91.746%	$ -			
77	5550088	PJM Capacity Charge (OSS only)		-	0%	-	91.746%	$ -			
78	5550099	PJM Purchases - NonECR (Auction)		2,635,754	0%	-	91.746%	$ -			
79	5550100	PJM Capacity Purchases - NonECR (Auction)		103,596	0%	-	91.746%	$ -			
80	5550102	PP Pool Non Fuel - OSS Aff		11,037,975	0%	-	91.746%	$ -			
81	5550107	Capacity Purchases - Trading		268,196	0%	-	91.746%	$ -			
82	5550002	PP - Assocated (PPA only - discontinued after Jan09)		-	0%	-	91.746%	$ -			
83	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
84	5550075	PJM Reactive Credit		$ 23,209	0%	$ -	91.746%	$ -			
85	5550077	PJM Black Start Credit		(7,200)	0%	-	91.746%	$ -			
86	5550079	PJM Regulation Credit		(222,458)	0%	-	91.746%	$ -			
87	5550084	PJM Spinning Reserve Credit		(4,967)	0%	-	91.746%	$ -			
88	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	91.746%	$ -			
89	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
90	5550036	PJM Emergency Purchases (Demand Response Program)		$ 2,775	0%	$ -	91.746%	$ -			
91	5550041	PJM Synchronous Cond. Charge		(884)	0%	-	91.746%	$ -			
92	5550074	PJM Reactive Charge		3,795	0%	-	91.746%	$ -			
93	5550076	PJM BlackStart Charge		10,387	0%	-	91.746%	$ -			
94	5550078	PJM Regulation Charge		582,321	0%	-	91.746%	$ -			
95	5550083	PJM Spinning Reserve Charge		31,378	0%	-	91.746%	$ -			
96	5550090	PJM 30 min Suppl. Reserve Charge - LSE		10,325	0%	-	91.746%	$ -			
97		Total Additional FAC		$ 34,718,513		$ 13,887,565		$ 12,825,397	GL AMOUNTS	$ 131,680,322.44	
98		TOTAL		$ 131,622,740		$ 66,100,812		$ 60,728,963	EXCL 5010032/33	$ -	
99									TOTAL GL QUERY	$ 131,680,322.44	
100	NOTATIONS:										
101	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
102	B	East Pool group computes/books Mone fuel & non-fuel separately (80/20	E	IPS is source for fuel/non-fuel split for pool energy							
103	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%							
104											

Line	A	B	C	D	E	F	G	H			
		Actual					EXH CSP-1				
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)									
		October 2011							Reconcile NEC to GL		
Line	A	B	C	D	E	F	G	H			Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail	EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel				NEC						
5	5010001/5010022/23	Fuel Consumed		$ 24,023,727	$ 5,852,872	$ 18,170,855			$ 24,023,727	$ 23,828,285	$ 195,442
6	5010009	Fuel Consumed - No Load (CV4)		719,889		719,889			$ 719,889	962,879	$ (242,990)
7	5010013	Fuel Survey Activity		-	-	-			$ -	-	$ -
8	5010019	Fuel Oil Consumed		381,819		381,819			$ 381,819	334,271	$ 47,547
9	5010020/5010036	Natural Gas Consumed		12,358,210	-	12,358,210			$ 12,358,210	12,293,081	$ 65,130
10	5470001/5470003	Fuel - Gas Turbine		-	$ -	-			$ -	65,130	$ (65,130)
11		Subtotal - Generation Fuel		$ 37,483,645	$ 5,852,872	$ 31,630,773			$ 37,483,645	$ 37,483,645	$ (0)
12	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	A	$ 1,072,035	$ 659,512	$ 412,523			$ 1,072,035	$ 4,868,889	$ (3,796,855)
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	$ 1,554,251	$ -	1,554,251			$ 1,554,251	850,084	$ 704,167
15	5550080	PJM Energy Purchases (Fuel)	C	$ 5,428,751	$ 2,597,197	2,831,554			$ 5,428,751	2,663,410	$ 2,765,340
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	D	$ 901,249	$ 768,038	133,211			$ 901,249	99,739	$ 801,510
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	$ 11,638	$ 9,211	2,427			$ 11,638		$ 11,638
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	F	$ 6,576,441	$ 244,057	6,332,384			$ 6,576,441	6,621,686	$ (45,245)
19	5550032	Purchased Pwr - Mone (Fuel)	B	$ 24,261	$ -	24,261			$ 24,261	23,761	$ 500
20		Subtotal - Purchased Power Fuel		$ 15,568,626	$ 4,278,014	$ 11,290,611			15,568,626	15,127,570	441,056
21		Total NEC Fuel		$ 53,052,271	$ 10,130,887	$ 42,921,384	100.000%	$ 42,921,384	53,052,271	52,611,215	441,056
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount					
24	Emission Allowance Expense										
25	5090000/2	Allowance Consumption - SO2		$ 317,666	72.20%	$ 229,355					
26	5090001	Allowance Consumption - Seasonal NOx		1,188	72.20%	857					
27	5090005	Allowance Expenses - Annual NOx		186,676	72.20%	134,780					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)			72.20%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2			72.20%	$ -					
31	4118003	Comp. Allow. Gains-Seas NOx			72.20%	-					
32	4118004	Comp. Allow. Gains-Ann NOx			72.20%	-					
33	4119000	Loss Disposition of Allowances			72.20%	-					
34		Total Allowance Dollars		$ 505,530		$ 364,993	100.000%	$ 364,993			
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum										
39	5010000	Fuel (Ash Handling)		$ 633,917	72.20%	$ 457,688	100.000%	$ 457,688			
40	5010003	Fuel - Procurement, Unloading & Handling		703,885	72.20%	508,205	100.000%	$ 508,205			
41	5010011	Fuel Handling - No Load (CV4)		1,379	72.20%	996	100.000%	$ 996			
42	5010012	Ash Sales Proceeds		(4,779)	72.20%	(3,450)	100.000%	$ (3,450)			
43	5010027	Gypsum handling/disposal costs		72,911	72.20%	52,642	100.000%	$ 52,642			
44	5010028	Gypsum Sales Proceeds		(30,764)	72.20%	(22,211)	100.000%	$ (22,211)			
45	5010032	Coal Procurement-Aff			72.20%	-	100.000%	$ -			
46	5470004	Fuel - Gas Turbine - Purchasing / Handling Costs - this is cumulative 2011 YTD		34,430	72.20%	24,859	100.000%	$ 24,859			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	D	$ -	$ -	$ -	100.000%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	126,230	77,657	48,573	100.000%	$ 48,573	$ 126,230	$ 1,406,144	$ (1,279,914)
50	5550032	PP - Mone - Non-Fuel	B			-	100.000%	$ -	$ -		$ -
51	5550098 INACTIVE	PP - PJM - Non-Fuel	C			-	100.000%	$ -	$ -		$ -
52	5550046	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	F			-	100.000%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)		1,411,864	100%	1,411,864	100.000%	$ 1,411,864	1,411,864		1,411,864
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	E	192,969	100%	192,969	100.000%	$ 192,969	1,538,094	1,406,144	131,950
55	5550004	Purchased Power - Pool Capacity		4,693,789	100%	4,693,789	100.000%	$ 4,693,789			
56	5550023	Purchase Power - Capacity		188,204	100%	188,204	100.000%	$ 188,204			
57	5550040	PJM Inadvertent - LSE (only)		7,276	100%	7,276	100.000%	$ 7,276			
58	5550093	Peak Hour Avail Charge - LSE			100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)		$ 2,943,736	100%	$ 2,943,736	100.000%	$ 2,943,736			
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)		(85,013)	100%	(85,013)	100.000%	$ (85,013)			
62	5550046	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)		$33,409.90	96.20%	32,140	100.000%	$ 32,140			
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)		2,176,215	96.20%	2,093,508	100.000%	$ 2,093,508			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)		1,320,958	96.20%	1,270,755	100.000%	$ 1,270,755			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar		$ 712,101	100%	$ 712,101	100.000%	$ 712,101	$ 712,101	$ -	$ 712,101
67	5550109	Purchased Power - Solar		$ 45,123	100%	$ 45,123	100.000%	$ 45,123	$ 45,123	$ -	$ 45,123
68	5570007	Renewable Energy Credit Exp.			100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)		(231,367)	100%	$ (231,367)	100.000%	$ (231,367)			
70	Environmental Material & Expense										
71	5020001	Lime Expense		$ 1,642,995	72.20%	$ 1,186,243	100.000%	$ 1,186,243			
72	5020002	Urea Expense		370,750	72.20%	267,682	100.000%	$ 267,682			
73	5020003	Trona Expense		88,440	72.20%	63,854	100.000%	$ 63,854			
74	5020004	Limestone Expense		315,839	72.20%	228,036	100.000%	$ 228,036			
75	5020005	Polymer expense		157	72.20%	114	100.000%	$ 114			
76	5020007	Lime Hydrate Expense		32	72.20%	23	100.000%	$ 23			
77	5020008	Activated Carbon		18	72.20%	13	100.000%	$ 13			
78	5020025	Steam Exp Environmental		1,977	72.20%	1,428	100.000%	$ 1,428			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)			0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)		1,499	0%	-					
82	5550088	PJM Capacity Charge (OSS only)			0%	-					
83	5550099	PJM Purchases - NonECR (Auction)		2,457,443	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)		150,778	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)		5,854,716	0%	-					
86	5550107	Capacity Purchases -Trading		166,978	0%	-					
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)			0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)			0%	-					
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit		$ 19,546	0%	$ -					
91	5550077	PJM Black Start Credit		(6,096)	0%	-					
92	5550079	PJM Regulation Credit		(149,962)	0%	-					
93	5550084	PJM Spinning Reserve Credit		(499)	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE			0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)		$ 924	0%	$ -					
97	5550041	PJM Synchronous Cond. Charge		(654)	0%	-					
98	5550074	PJM Reactive Charge		2,031	0%	-					
99	5550076	PJM BlackStart Charge		8,722	0%	-					
100	5550078	PJM Regulation Charge		309,607	0%	-					
101	5550083	PJM Spinning Reserve Charge		615	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE		(760)	0%	-					
103		Total Additional FAC		$ 26,181,372		$ 16,089,777		$ 16,089,777			
104		TOTAL		$ 79,739,173		$ 59,376,154		$ 59,376,154			
105											
106	NOTATIONS:										
107	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
108	B	East Pool group computes/books Mone fuel & non-fuel separately	E	IPS is source for fuel/non-fuel split for pool energy							
109	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%				PIVOT	ESTIMATE		
110								79,132,757	79,132,757		

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

OCTOBER 2011

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					EST	Applicable	Diff. To GL NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	Generation Fuel			Mar GL	NEC						
5	5010001	Fuel Consumed		$ 60,458,098	$ 18,570,112	$ 41,887,986			$ 60,458,098	$ 60,298,001	$ 160,097
6	5010009	Fuel Consumed - No Load (CV4)				-			$ -	-	$ -
7	5010013	Fuel Survey Activity		$ (36,004)		(36,004)			$ (36,004)	(36,004)	$ 0
8	5010019	Fuel Oil Consumed		$ 792,541		792,541			$ 792,541	792,541	$ 0
9	5010020	Natural Gas Consumed				-			$ -	-	$ -
10	5010023	Fuel Consumed - Biomass				-			$ -	160,097	$ (160,097)
11	5470001	Fuel - Gas Turbine				-			$ -	-	$ -
12		Subtotal - Generation Plant		$ 61,214,635	$ 18,570,112	$ 42,644,623			$ 61,214,635	$ 61,214,634	$ 1
13	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	A	$ 3,740,035	$ 2,300,851	$ 1,439,184			$ 3,740,035	$ 8,571,525	$ (4,831,490)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	2,385,712	-	$ 2,385,712			$ 2,385,712	2,510,125	$ (124,413)
16	5550080	PJM Energy Purchases (Fuel)	C	6,445,991	3,083,860	$ 3,362,131			$ 6,445,991	3,162,481	$ 3,283,510
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	D	1,070,125	911,953	158,173			$ 1,070,125	118,428	$ 951,697
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	13,819	10,937	2,882			$ 13,819	14,053	$ (234)
19	5550031/32	Purchased Pwr - Mone (Fuel)	B	28,807	-	28,807			$ 28,807	30,632	$ (1,825)
20		Subtotal - Purchased Power Fuel		$ 13,684,489	$ 6,307,600	$ 7,376,889			13,684,489	14,407,243	(722,754)
21		Total NEC Fuel		$ 74,899,124	$ 24,877,712	$ 50,021,412	92.051%	$ 46,045,210	74,899,124	75,621,878	(722,754)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt					
24	Emission Allowance Expense										
25	5090000	Allowance Consumption SO2		$ 213,945	71.62%	$ 153,227					
26	5090001	Allowance Consumption - Seasonal NOx		-	71.62%						
	5090002	Allowance Expenses		-	71.62%	-					
27	5090005	Allowance Expenses - Annual NOx		40,448	71.62%	28,969					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	71.62%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		-	71.62%	-					
31	4118003	Comp. Allow. Gains-Seas NOx		-	71.62%	-					
32	4118004	Comp. Allow. Gains-Ann NOx		(120,246)	71.62%	(86,120)					
33	4119000	Loss Disposition of Allowances		-	71.62%	-					
34	4119002	Comp. Allow. Loss - SO2		-	71.62%	-					
35	4119003	Comp. Allow. Loss-Seas Nox		164,435	71.62%	117,769					
36		Total Allowance Dollars		$ 298,583		$ 213,845	92.051%	$ 196,847			
37	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC							
38						Firm Load					
39	Account	Description	Notes		Allocation Factor	Allocated Amount					
40	Incremental Fuel Handling/Ash/Gypsum										
41	5010000	Fuel (Ash Handling)		$ 717,274	71.62%	$ 513,712	92.051%	$ 472,877			
42	5010003	Fuel - Procurement, Unloading & Handling		2,541,240	71.62%	1,820,036	92.051%	$ 1,675,361			
43	5010012	Ash Sales Proceeds		(172,327)	71.62%	(123,421)	92.051%	$ (113,610)			
44	5010027	Gypsum handling/disposal costs		128,378	71.62%	91,944	92.051%	$ 84,635			
45	5010028	Gypsum Sales Proceeds		(233,414)	71.62%	(167,171)	92.051%	$ (153,883)			
46	5010029	Gypsum handling/displ-Affiliat		21,141	71.62%	15,141	92.051%	$ 13,937			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	D	$ -	-	$ -	92.051%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	440,382	270,923	169,459	92.051%	$ 155,989	$ 440,382	$ 4,905,668	$ (4,465,286)
50	5550032	PP - Mone - Non-Fuel	B	-	-	-	92.051%	$ -	$ -	$ -	$ -
51	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	C	-	-	-	92.051%	$ -	$ -		$ -
52	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	F	-	-	-	92.051%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source:bill, Genea Taylor email)		4,925,626	100%	4,925,626	92.051%	$ 4,534,088	4,925,626	-	4,925,626
54	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	E	430,608	100%	430,608	92.051%	$ 396,379	5,366,008	4,905,668	460,340
55	5550023	PP Capacity - Non Affil.		223,470	100%	223,470	92.051%	$ 205,706			
56	5550040	PJM Inadvertent - LSE (only)		8,639	100%	8,639	92.051%	$ 7,952			
57	5550003	PP - Cogeneration		193,772	100%	193,772	92.051%	$ 178,369			
58	5550093	Peak Hour Avail Charge - LSE		-	100%	-	92.051%	$ -			
59	Lawrenceburg purchased power - Non-Fuel (NA)										
60	Renewables										
61	5550047	Purchased Power - Wind		712,101	100%	$ 712,101	100.00%	$ 712,101	$ 712,101.32	$ 712,101.32	$ -
62	5550109	Purchased Power - Solar Energy		57,430	100%	57,430	100.00%	$ 57,430	$ 57,429.54	$ 57,429.54	$ -
63	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010		-	100%	-	100.00%	$ -			
64	5570008	Renewable Energy Credit Exp.		-	100%	-	100.00%	$ -			
65	5570009	Other Pwr Exp - REC's - RETAIL		(289,511)	100%	(289,511)	100.00%	$ (289,511)			
66	Environmental Material & Expense										
67	5020001	Lime Expense		$ 3,001,716	71.62%	$ 2,149,831	92.051%	$ 1,978,941			
68	5020002	Urea Expense		1,753,712	71.62%	1,256,008	92.051%	$ 1,156,168			
69	5020003	Trona Expense		750,217	71.62%	537,306	92.051%	$ 494,595			
70	5020004	Limestone Expense		539,941	71.62%	386,706	92.051%	$ 355,966			
71	5020005	Polymer expense		357,973	71.62%	256,381	92.051%	$ 236,001			
72	5020007	Lime Hydrate Expense		5,455	71.62%	3,907	92.051%	$ 3,596			
73	5020008	Activated Carbon		56	71.62%	40	92.051%	$ 37			
74	5020025	Steam Exp Environmental		70,182	71.62%	50,264	92.051%	$ 46,269			
75	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
76	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -	92.051%	$ -			
77	5550039	PJM Inadvertent - OSS (only)		1,779	0%	-	92.051%	$ -			
78	5550088	PJM Capacity Charge (OSS only)		-	0%	-	92.051%	$ -			
79	5550099	PJM Purchases - NonECR (Auction)		2,917,919	0%	-	92.051%	$ -			
80	5550100	PJM Capacity Purchases - NonECR (Auction)		179,031	0%	-	92.051%	$ -			
81	5550102	PP Pool Non Fuel - OSS Aff		7,318,914	0%	-	92.051%	$ -			
82	5550107	Capacity Purchases - Trading		198,266	0%	-	92.051%	$ -			
83	5550002	PP - Assocated (PPA only - discontinued after Jan09)		-	0%	-	92.051%	$ -			
84	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
85	5550075	PJM Reactive Credit		$ 23,209	0%	$ -	92.051%	$ -			
86	5550077	PJM Black Start Credit		(7,239)	0%	-	92.051%	$ -			
87	5550079	PJM Regulation Credit		(176,062)	0%	-	92.051%	$ -			
88	5550084	PJM Spinning Reserve Credit		(593)	0%	-	92.051%	$ -			
89	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	92.051%	$ -			
90	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
91	5550036	PJM Emergency Purchases (Demand Response Program)		$ 1,097	0%	$ -	92.051%	$ -			
92	5550041	PJM Synchronous Cond. Charge		(1,014)	0%	-	92.051%	$ -			
93	5550074	PJM Reactive Charge		2,411	0%	-	92.051%	$ -			
94	5550076	PJM BlackStart Charge		10,357	0%	-	92.051%	$ -			
95	5550078	PJM Regulation Charge		367,621	0%	-	92.051%	$ -			
96	5550083	PJM Spinning Reserve Charge		730	0%	-	92.051%	$ -			
97	5550090	PJM 30 min Suppl. Reserve Charge - LSE		(902)	0%	-	92.051%	$ -			
98		Total Additional FAC		$ 27,017,587		$ 13,222,277		$ 12,209,395	GL AMOUNTS	$ 102,477,708.02	
99		TOTAL		$ 102,215,294		$ 63,457,534		$ 58,461,452	EXCL 5010032/33	$ -	
100									TOTAL GL QUERY	$ 102,477,708.02	
101	NOTATIONS:										
102	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
103	B	East Pool group computes/books Mone fuel & non-fuel separately (80/2(	E	IPS is source for fuel/non-fuel split for pool energy							
104	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%							
105											

		Actuals					EXH CSP-1				
	COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)										
		November 2011							Reconcile NEC to GL		
Line	A	B	C	D	E	F	G	H			Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC			Retail	Retail	EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel				NEC						
5	5010001/5010022/23	Fuel Consumed		$ 15,042,495	$ 1,804,912	$ 13,237,584			$ 15,042,495	$ 15,217,874	$ (175,378)
6	5010009	Fuel Consumed - No Load (CV4)		719,889		719,889			$ 719,889	544,510	$ 175,378
7	5010013	Fuel Survey Activity		(976,222)	-	(976,222)			$ (976,222)	(976,222)	$ -
8	5010019	Fuel Oil Consumed		1,051,347		1,051,347			$ 1,051,347	1,051,347	$ -
9	5010020/5010036	Natural Gas Consumed		3,400,111	-	3,400,111			$ 3,400,111	3,399,877	$ 234
10	5470001/5470003	Fuel - Gas Turbine		-	$ -	-			$ -	234	$ (234)
11		Subtotal - Generation Fuel		$ 19,237,620	$ 1,804,912	$ 17,432,708			$ 19,237,620	$ 19,237,620	$ (0)
12	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	A	$ 1,114,447	$ 350,359	$ 764,088			$ 1,114,447	$ 5,324,779	$ (4,210,332)
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	$ 3,319,701	$ -	3,319,701			$ 3,319,701	3,566,726	$ (247,025)
15	5550080	PJM Energy Purchases (Fuel)	C	$ 7,266,503	$ 3,388,223	3,878,280			$ 7,266,503	3,973,516	$ 3,292,987
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	D	$ 979,947	$ 520,739	459,209			$ 979,947	108,675	$ 871,272
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	$ 46,090	$ 27,512	18,578			$ 46,090		$ 46,090
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	F	$ 8,310,521	$ 80,609	8,229,912			$ 8,310,521	8,430,429	$ (119,908)
19	5550032	Purchased Pwr - Mone (Fuel)	B	$ 31,428	$ -	31,428			$ 31,428	31,892	$ (464)
20		Subtotal - Purchased Power Fuel		$ 21,068,636	$ 4,367,442	$ 16,701,194			21,068,636	21,436,016	(367,380)
21		Total NEC Fuel		$ 40,306,256	$ 6,172,354	$ 34,133,901	100.000%	$ 34,133,901	40,306,256	40,673,636	(367,380)
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount					
24	Emission Allowance Expense										
25	5090000/2	Allowance Consumption - SO2		$ 241,990	91.03%	$ 220,284					
26	5090001	Allowance Consumption - Seasonal NOx		5,641	91.03%	5,135					
27	5090005	Allowance Expenses - Annual NOx		165,023	91.03%	150,220					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)			91.03%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2			91.03%	$ -					
31	4118003	Comp. Allow. Gains-Seas NOx			91.03%	-					
32	4118004	Comp. Allow. Gains-Ann NOx			91.03%	-					
33	4119000	Loss Disposition of Allowances			91.03%	-					
34		Total Allowance Dollars		$ 412,654		$ 375,639	100.000%	$ 375,639			
35	Additional S.B. 221 FAC Accounts for 2009			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum										
39	5010000	Fuel (Ash Handling)		$ 448,785	91.03%	$ 408,529	100.000%	$ 408,529			
40	5010003	Fuel - Procurement, Unloading & Handling		799,021	91.03%	727,349	100.000%	$ 727,349			
41	5010011	Fuel Handling - No Load (CV4)		56,338	91.03%	51,284	100.000%	$ 51,284			
42	5010012	Ash Sales Proceeds		(4,603)	91.03%	(4,190)	100.000%	$ (4,190)			
43	5010027	Gypsum handling/disposal costs		350,613	91.03%	319,163	100.000%	$ 319,163			
44	5010028	Gypsum Sales Proceeds		(563)	91.03%	(513)	100.000%	$ (513)			
45	5010032	Coal Procurement-Aff			91.03%	-	100.000%	$ -			
46	5470004	Fuel - Gas Turbine - Purchasing / Handling Costs - this is cumulative 2011 YTD		97,944	91.03%	89,158	100.000%	$ 89,158			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	D	$ -	$ -	$ -	100.000%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	154,620	48,609	106,011	100.000%	$ 106,011	$ 154,620	$ 1,368,929	$ (1,214,309)
50	5550032	PP - Mone - Non-Fuel	B			-	100.000%	$ -	$ -		$ -
51	5550098 INACTIVE	PP - PJM - Non-Fuel	C			-	100.000%	$ -	$ -		$ -
52	5550046	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	F			-	100.000%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)		1,314,557	100%	1,314,557	100.000%	$ 1,314,557	1,314,557		1,314,557
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	E	650,844	100%	650,844	100.000%	$ 650,844	1,469,177	1,368,929	100,248
55	5550004	Purchased Power - Pool Capacity		2,714,740	100%	2,714,740	100.000%	$ 2,714,740			
56	5550023	Purchase Power - Capacity		188,204	100%	188,204	100.000%	$ 188,204			
57	5550040	PJM Inadvertent - LSE (only)		19,703	100%	19,703	100.000%	$ 19,703			
58	5550093	Peak Hour Avail Charge - LSE			100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affili (Lawrenceburg)		$ 2,943,736	100%	$ 2,943,736	100.000%	$ 2,943,736			
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)		(85,013)	100%	(85,013)	100.000%	$ (85,013)			
62	5550046	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)		$74,203.31	98.95%	73,426	100.000%	$ 73,426			
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)		1,904,577	98.95%	1,884,617	100.000%	$ 1,884,617			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)		(2,155,592)	98.95%	(2,133,001)	100.000%	$ (2,133,001)			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar		$ 1,335,047	100%	$ 1,335,047	100.000%	$ 1,335,047	$ 1,335,047	$ 1,335,047	$ -
67	5550109	Purchased Power - Solar		$ 35,379	100%	$ 35,379	100.000%	$ 35,379	$ 35,379	$ 35,379	$ -
68	5570007	Renewable Energy Credit Exp.			100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)		250,460	100%	$ 250,460	100.000%	$ 250,460			
70	Environmental Material & Expense										
71	5020001	Lime Expense		$ 228,479	91.03%	$ 207,985	100.000%	$ 207,985			
72	5020002	Urea Expense		76,497	91.03%	69,635	100.000%	$ 69,635			
73	5020003	Trona Expense		61,229	91.03%	55,737	100.000%	$ 55,737			
74	5020004	Limestone Expense		241,357	91.03%	219,707	100.000%	$ 219,707			
75	5020005	Polymer expense		190	91.03%	173	100.000%	$ 173			
76	5020007	Lime Hydrate Expense		1,111	91.03%	1,012	100.000%	$ 1,012			
77	5020008	Activated Carbon		28	91.03%	25	100.000%	$ 25			
78	5020025	Steam Exp Environmental		12,133	91.03%	11,045	100.000%	$ 11,045			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)			0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)		3,692	0%	-					
82	5550088	PJM Capacity Charge (OSS only)			0%	-					
83	5550099	PJM Purchases - NonECR (Auction)		2,212,202	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)		112,326	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)		3,756,947	0%	-					
86	5550107	Capacity Purchases -Trading		193,634	0%	-					
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)			0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)			0%	-					
89	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit		$ 568,978	0%	$ -					
91	5550077	PJM Black Start Credit		(6,097)	0%	-					
92	5550079	PJM Regulation Credit		(228,843)	0%	-					
93	5550084	PJM Spinning Reserve Credit		-	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE			0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)		$ -	0%	$ -					
97	5550041	PJM Synchronous Cond. Charge		(5)	0%	-					
98	5550074	PJM Reactive Charge		(550,318)	0%	-					
99	5550076	PJM BlackStart Charge		8,593	0%	-					
100	5550078	PJM Regulation Charge		445,039	0%	-					
101	5550083	PJM Spinning Reserve Charge		18	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE		24	0%	-					
103		Total Additional FAC		$ 18,230,217		$ 11,454,809		$ 11,454,809			
104		TOTAL		$ 56,949,127		$ 45,964,350		$ 45,964,350			
105											
106	NOTATIONS:										
107	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
108	B	East Pool group computes/books Mone fuel & non-fuel separately	E	IPS is source for fuel/non-fuel split for pool energy							
109	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%				PIVOT	ESTIMATE		
110								59,142,056	59,142,056		

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

NOVEMBER 2011

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		Diff. To GL
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	Generation Fuel			Mar GL	NEC						
5	5010001	Fuel Consumed		$ 50,236,672	$ 15,907,941	$ 34,328,731			$ 50,236,672	$ 50,147,739	$ 88,933
6	5010009	Fuel Consumed - No Load (CV4)				-			$ -		$ -
7	5010013	Fuel Survey Activity		$ -		-			$ -	-	$ -
8	5010019	Fuel Oil Consumed		$ 1,990,894		1,990,894			$ 1,990,894	1,990,894	$ 0
9	5010020	Natural Gas Consumed				-			$ -	-	$ -
10	5010023	Fuel Consumed - Biomass				-			$ -	88,933	$ (88,933)
11	5470001	Fuel - Gas Turbine				-			$ -	-	$ -
12		Subtotal - Generation Plant		$ 52,227,566	$ 15,907,941	$ 36,319,625			$ 52,227,566	$ 52,227,566	$ 0
13	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	A	$ 3,888,008	$ 1,222,311	$ 2,665,697			$ 3,888,008	$ 9,129,901	$ (5,241,892)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	8,500,766	-	$ 8,500,766			$ 8,500,766	9,046,648	$ (545,882)
16	5550080	PJM Energy Purchases (Fuel)	C	8,628,102	4,023,109	$ 4,604,992			$ 8,628,102	4,718,074	$ 3,910,028
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	D	1,163,570	618,315	545,255			$ 1,163,570	129,038	$ 1,034,532
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	54,726	32,667	22,059			$ 54,726	54,269	$ 457
19	5550031/32	Purchased Pwr - Mone (Fuel)	B	37,316	-	37,316			$ 37,316	35,468	$ 1,848
20		Subtotal - Purchased Power Fuel		$ 22,272,488	$ 5,896,402	$ 16,376,086			22,272,488	23,113,398	(840,910)
21		Total NEC Fuel		$ 74,500,054	$ 21,804,343	$ 52,695,711	91.429%	$ 48,179,161	74,500,054	75,340,964	(840,910)
22						Firm Load					
23	Allowance Accounts in FAC:				Allocation Factor	Allocated Amt					
24	Emission Allowance Expense										
25	5090000	Allowance Consumption SO2		$ 221,977	73.84%	$ 163,907					
26	5090001	Allowance Consumption - Seasonal NOx		84	73.84%						
	5090002	Allowance Expenses		-	73.84%	62					
27	5090005	Allowance Expenses - Annual NOx		37,727	73.84%	27,858					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	73.84%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		-	73.84%	-					
31	4118003	Comp. Allow. Gains-Seas NOx		-	73.84%	-					
32	4118004	Comp. Allow. Gains-Ann NOx		(8,803)	73.84%	(6,500)					
33	4119000	Loss Disposition of Allowances		-	73.84%	-					
34	4119002	Comp. Allow. Loss - SO2		-	73.84%	-					
35	4119003	Comp. Allow. Loss-Seas Nox		27,041	73.84%	19,967					
36		Total Allowance Dollars		$ 278,026		$ 205,293	91.429%	$ 187,698			
37	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC							
38						Firm Load					
39	Account	Description	Notes		Allocation Factor	Allocated Amount					
40	Incremental Fuel Handling/Ash/Gypsum										
41	5010000	Fuel (Ash Handling)		$ 1,250,313	73.84%	$ 923,231	91.429%	$ 844,101			
42	5010003	Fuel - Procurement, Unloading & Handling		2,154,518	73.84%	1,590,896	91.429%	$ 1,454,540			
43	5010012	Ash Sales Proceeds		(76,935)	73.84%	(56,809)	91.429%	$ (51,940)			
44	5010027	Gypsum handling/disposal costs		259,079	73.84%	191,304	91.429%	$ 174,907			
45	5010028	Gypsum Sales Proceeds		(161,891)	73.84%	(119,540)	91.429%	$ (109,295)			
46	5010029	Gypsum handling/displ-Affiliat		20,969	73.84%	15,483	91.429%	$ 14,156			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	D	$ -	-	$ -	91.429%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	539,428	169,585	369,843	91.429%	$ 338,143	$ 539,428	$ 4,775,838	$ (4,236,410)
50	5550032	PP - Mone - Non-Fuel	B	-	-	-	91.429%	$ -	$ -	$ -	$ -
51	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	C	-	-	-	91.429%	$ -	$ -		$ -
52	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	F	-	-	-	91.429%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source:bill, Genea Taylor email)		4,586,146	100%	4,586,146	91.429%	$ 4,193,068	4,586,146	-	4,586,146
54	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	E	1,611,302	100%	1,611,302	91.429%	$ 1,473,197	5,125,574	4,775,838	349,737
55	5550023	PP Capacity - Non Affil.		223,470	100%	223,470	91.429%	$ 204,316			
56	5550040	PJM Inadvertent - LSE (only)		23,395	100%	23,395	91.429%	$ 21,390			
57	5550003	PP - Cogeneration		170,797	100%	170,797	91.429%	$ 156,158			
58	5550093	Peak Hour Avail Charge - LSE		-	100%	-	91.429%	$ -			
59	Lawrenceburg purchased power - Non-Fuel (NA)										
60	Renewables										
61	5550047	Purchased Power - Wind		1,335,047	100%	$ 1,335,047	100.00%	$ 1,335,047	$ 1,335,046.75	$ 1,335,046.75	$ -
62	5550109	Purchased Power - Solar Energy		45,028	100%	45,028	100.00%	$ 45,028	$ 45,028.17	$ 45,028.17	$ -
63	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010		-	100%	-	100.00%	$ -			
64	5570008	Renewable Energy Credit Exp.		-	100%	-	100.00%	$ -			
65	5570009	Other Pwr Exp - REC's - RETAIL		328,713	100%	328,713	100.00%	$ 328,713			
66	Environmental Material & Expense										
67	5020001	Lime Expense		$ 3,416,932	73.84%	$ 2,523,062	91.429%	$ 2,306,811			
68	5020002	Urea Expense		1,540,389	73.84%	1,137,423	91.429%	$ 1,039,934			
69	5020003	Trona Expense		602,037	73.84%	444,544	91.429%	$ 406,442			
70	5020004	Limestone Expense		587,191	73.84%	433,582	91.429%	$ 396,420			
71	5020005	Polymer expense		415,078	73.84%	306,493	91.429%	$ 280,224			
72	5020007	Lime Hydrate Expense		4,606	73.84%	3,401	91.429%	$ 3,110			
73	5020008	Activated Carbon		74	73.84%	54	91.429%	$ 50			
74	5020025	Steam Exp Environmental		42,128	73.84%	31,107	91.429%	$ 28,441			
75	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
76	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -	91.429%	$ -			
77	5550039	PJM Inadvertent - OSS (only)		4,384	0%	-	91.429%	$ -			
78	5550088	PJM Capacity Charge (OSS only)		-	0%	-	91.429%	$ -			
79	5550099	PJM Purchases - NonECR (Auction)		2,626,726	0%	-	91.429%	$ -			
80	5550100	PJM Capacity Purchases - NonECR (Auction)		133,374	0%	-	91.429%	$ -			
81	5550102	PP Pool Non Fuel - OSS Aff		4,494,236	0%	-	91.429%	$ -			
82	5550107	Capacity Purchases - Trading		229,916	0%	-	91.429%	$ -			
83	5550002	PP - Assocated (PPA only - discontinued after Jan09)		-	0%	-	91.429%	$ -			
84	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
85	5550075	PJM Reactive Credit		$ 675,593	0%	$ -	91.429%	$ -			
86	5550077	PJM Black Start Credit		(7,239)	0%	-	91.429%	$ -			
87	5550079	PJM Regulation Credit		(271,724)	0%	-	91.429%	$ -			
88	5550084	PJM Spinning Reserve Credit		-	0%	-	91.429%	$ -			
89	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	91.429%	$ -			
90	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
91	5550036	PJM Emergency Purchases (Demand Response Program)		$ -	0%	$ -	91.429%	$ -			
92	5550041	PJM Synchronous Cond. Charge		(6)	0%	-	91.429%	$ -			
93	5550074	PJM Reactive Charge		(653,437)	0%	-	91.429%	$ -			
94	5550076	PJM BlackStart Charge		10,204	0%	-	91.429%	$ -			
95	5550078	PJM Regulation Charge		528,431	0%	-	91.429%	$ -			
96	5550083	PJM Spinning Reserve Charge		21	0%	-	91.429%	$ -			
97	5550090	PJM 30 min Suppl. Reserve Charge - LSE		29	0%	-	91.429%	$ -			
98		Total Additional FAC		$ 26,688,321		$ 16,117,973		$ 14,882,962	GL AMOUNTS	$ 101,957,572.69	
99		TOTAL		$ 101,466,400		$ 69,018,977		$ 63,249,821	EXCL 5010032/33	$ -	
100									TOTAL GL QUERY	$ 101,957,572.69	
101	NOTATIONS:										
102	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
103	B	East Pool group computes/books Mone fuel & non-fuel separately (80/2(	E	IPS is source for fuel/non-fuel split for pool energy							
104	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%							
105											

Line	A	B	C	D	E	F	G	H			
		Estimate					EXH CSP-1				
		COLUMBUS SOUTHERN POWER COMPANY - NET ENERGY COST (NEC)									
		December							Reconcile NEC to GL		
Line	A	B	C	D	E	F	G	H			Diff. To GL
1	**Fuel, Purchased Power, and Environmental Costs Included FAC**			Net Energy Cost (NEC) in EFC			Retail	Retail	EST	Applicable	NEC Adjs. for
2					Assigned	Assigned	Allocation	FAC Cost	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load			Costs	Amounts	Or PPAs
4	Generation Fuel				NEC						
5	5010001/5010022/23	Fuel Consumed		$ 19,625,614	$ 2,075,139	$ 17,550,475			$ 19,625,614	$ 17,752,389	$ 1,873,225
6	5010009	Fuel Consumed - No Load (CV4)		-		-			$ -	2,629	$ (2,629)
7	5010013	Fuel Survey Activity		-	-	-			$ -	(257,484)	$ 257,484
8	5010019	Fuel Oil Consumed		-		-			$ -	769,748	$ (769,748)
9	5010020/5010036	Natural Gas Consumed		6,119,196	-	6,119,196			$ 6,119,196	6,118,887	$ 309
10	5470001/5470003	Fuel - Gas Turbine		-	$ -	-			$ -	450	$ (450)
11		Subtotal - Generation Fuel		$ 25,744,810	$ 2,075,139	$ 23,669,672			$ 25,744,810	$ 24,386,620	$ 1,358,191
12	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
13	5550001	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)	A	$ 1,336,366	$ 767,991	$ 568,375			$ 1,336,366	$ 4,641,913	$ (3,305,547)
14	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	$ 931,828	$ -	931,828			$ 931,828	618,996	$ 312,832
15	5550080	PJM Energy Purchases (Fuel)	C	$ 4,568,920	$ 3,094,905	1,474,015			$ 4,568,920	2,413,452	$ 2,155,468
16	5550094	Purch Pwr-Trading-Nonassoc (Fuel)	D	$ 1,181,970	$ 1,073,171	108,798			$ 1,181,970	168,574	$ 1,013,396
17	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	$ 9,291	$ 4,885	4,406			$ 9,291		$ 9,291
18	5550046	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg)	F	$ 17,513,201	$ 702,520	16,810,681			$ 17,513,201	17,562,030	$ (48,830)
19	5550032	Purchased Pwr - Mone (Fuel)	B	$ 45,943	$ 45,460	483			$ 45,943	46,362	$ (419)
20		Subtotal - Purchased Power Fuel		$ 25,587,518	$ 5,688,932	$ 19,898,586			25,587,518	25,451,328	136,191
21		Total NEC Fuel		$ 51,332,329	$ 7,764,071	$ 43,568,258	100.000%	$ 43,568,258	51,332,329	49,837,946	1,494,381
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amount					
24	Emission Allowance Expense										
25	5090000/2	Allowance Consumption - SO2		$ 331,228	81.84%	$ 271,077					
26	5090001	Allowance Consumption - Seasonal NOx			81.84%	-					
27	5090005	Allowance Expenses - Annual NOx		294,390	81.84%	240,929					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)			81.84%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		$ (10,684,110)	81.84%	$ (8,743,876)					
31	4118003	Comp. Allow. Gains-Seas NOx			81.84%	-					
32	4118004	Comp. Allow. Gains-Ann NOx			81.84%	-					
33	4119000	Loss Disposition of Allowances			81.84%	-					
34		Total Allowance Dollars		$ (10,058,493)		$ (8,231,870)	100.000%	$ (8,231,870)			
35	**Additional S.B. 221 FAC Accounts for 2009**			Additional Fuel and Environmental Accounts in FAC							
36						Firm Load					
37	Account	Description	Notes		Allocation Factor	Allocated Amount					
38	Incremental Fuel Handling/Ash/Gypsum										
39	5010000	Fuel (Ash Handling)		$ 498,111	81.84%	$ 407,654	100.000%	$ 407,654			
40	5010003	Fuel - Procurement, Unloading & Handling		890,867	81.84%	729,085	100.000%	$ 729,085			
41	5010011	Fuel Handling - No Load (CV4)		-	81.84%	-	100.000%	$ -			
42	5010012	Ash Sales Proceeds		(46,987)	81.84%	(38,454)	100.000%	$ (38,454)			
43	5010027	Gypsum handling/disposal costs		165,179	81.84%	135,183	100.000%	$ 135,183			
44	5010028	Gypsum Sales Proceeds		34,012	81.84%	27,835	100.000%	$ 27,835			
45	5010032	Coal Procurement-Aff			81.84%	-	100.000%	$ -			
46	5470004	Fuel - Gas Turbine - Purchasing / Handling Costs - this is cumulative 2011 YTD		31,023	81.84%	25,389	100.000%	$ 25,389			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095 INACTIVE	Purch Pwr-Trading-Nonassoc (Non-Fuel)	D	$ -	$ -	$ -	100.000%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	102,330	58,807	43,523	100.000%	$ 43,523	$ 102,330	$ 1,488,250	$ (1,385,920)
50	5550032	PP - Mone - Non-Fuel	B			-	100.000%	$ -	$ -		$ -
51	5550098 INACTIVE	PP - PJM - Non-Fuel	C			-	100.000%	$ -	$ -		$ -
52	5550046	Purch Pwr-Non-Fuel Portion - Affiliated (PP from West Pool)	F			-	100.000%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source bill, Jcaskie)		1,603,373	100%	1,603,373	100.000%	$ 1,603,373	1,603,373		1,603,373
54	5550101	PP Pool Non Fuel -Aff (primary/econ. purchases from East Pool)	E	270,689	100%	270,689	100.000%	$ 270,689	1,705,703	1,488,250	217,453
55	5550004	Purchased Power - Pool Capacity		2,784,601	100%	2,784,601	100.000%	$ 2,784,601			
56	5550023	Purchase Power - Capacity		188,204	100%	188,204	100.000%	$ 188,204			
57	5550040	PJM Inadvertent - LSE (only)		19,927	100%	19,927	100.000%	$ 19,927			
58	5550093	Peak Hour Avail Charge - LSE			100%	-	100.000%	$ -			
59	Lawrenceburg purchased power - Non-Fuel										
60	5550105	Depr & Capacity portion-Affil (Lawrenceburg)		$ 2,943,736	100%	$ 2,943,736	100.000%	$ 2,943,736			
61	5550104	Defd Depr & Capacity portion-Affili (Lawrenceburg)		(85,013)	100%	(85,013)	100.000%	$ (85,013)			
62	5550046	PP - Fuel Portion - Affil (PP - Lawrenceburg fuel handling)		$48,829.57	95.40%	46,584	100.000%	$ 46,584			
63	5550086	PurchPwr-O&M portion-Affiliate (Lawrenceburg)		2,094,401	95.40%	1,998,067	100.000%	$ 1,998,067			
64	5550087	PurchPwr-Tax portion-Affiliate (Lawrenceburg)		(451,537)	95.40%	(430,768)	100.000%	$ (430,768)			
65	Renewables										
66	5550047	Purchased Power - Wind/Solar		$ 1,036,371	100%	$ 1,036,371	100.000%	$ 1,036,371	$ 1,036,371	$ -	$ 1,036,371
67	5550109	Purchased Power - Solar		$ 21,788	100%	$ 21,788	100.000%	$ 21,788	$ 21,788	$ -	$ 21,788
68	5570007	Renewable Energy Credit Exp.			100%	$ -	100.000%	$ -			
69	5570008/0009	Renewable Energy Credit Exp. (Green Power)		224,636	100%	$ 224,636	100.000%	$ 224,636			
70	Environmental Material & Expense										
71	5020001	Lime Expense		$ 1,064,210	81.84%	$ 870,949	100.000%	$ 870,949			
72	5020002	Urea Expense		242,985	81.84%	198,859	100.000%	$ 198,859			
73	5020003	Trona Expense		15,923	81.84%	13,032	100.000%	$ 13,032			
74	5020004	Limestone Expense		49,899	81.84%	40,838	100.000%	$ 40,838			
75	5020005	Polymer expense		53	81.84%	43	100.000%	$ 43			
76	5020007	Lime Hydrate Expense		32	81.84%	27	100.000%	$ 27			
77	5020008	Activated Carbon		(131)	81.84%	(107)	100.000%	$ (107)			
78	5020025	Steam Exp Environmental		327	81.84%	268	100.000%	$ 268			
79	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
80	5550035	PJM Normal Purchases (Non ECR OSS)			0%	$ -					
81	5550039	PJM Inadvertent - OSS (only)		4,352	0%	-					
82	5550088	PJM Capacity Charge (OSS only)			0%	-					
83	5550099	PJM Purchases - NonECR (Auction)		2,404,757	0%	-					
84	5550100	PJM Capacity Purchases - NonECR (Auction)		71,097	0%	-					
85	5550102	PP Pool Non Fuel - OSS Aff (ARB-14)		6,655,849	0%	-					
86	5550107	Capacity Purchases -Trading		217,639	0%	-					
87	5550002	PP - Associated (PPA only - discountinued use after Jan09)			0%	-					
88	5550069	PP - Monon. Power (2008 PPA only)			0%	-					
89	555 Purchased Power Ancillary Credits Included in Base "G" Rates (Excluded from FAC)										
90	5550075	PJM Reactive Credit		$ 19,546	0%	$ -					
91	5550077	PJM Black Start Credit		(6,096)	0%	-					
92	5550079	PJM Regulation Credit		(151,385)	0%	-					
93	5550084	PJM Spinning Reserve Credit		26	0%	-					
94	5550089	PJM 30 min Suppl. Reserve Credit - LSE			0%	-					
95	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
96	5550036	PJM Emergency Purchases (Demand Response Program)		$ -	0%	$ -					
97	5550041	PJM Synchronous Cond. Charge		(2)	0%	-					
98	5550074	PJM Reactive Charge		1,659	0%	-					
99	5550076	PJM BlackStart Charge		8,499	0%	-					
100	5550078	PJM Regulation Charge		373,572	0%	-					
101	5550083	PJM Spinning Reserve Charge		300	0%	-					
102	5550090	PJM 30 min Suppl. Reserve Charge - LSE		147	0%	-					
103		Total Additional FAC		$ 23,348,000		$ 13,076,317		$ 13,076,317			
104		TOTAL		$ 64,621,837		$ 48,412,704		$ 48,412,704			
105											
106	NOTATIONS:										
107	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
108	B	East Pool group computes/books Mone fuel & non-fuel separately	E	IPS is source for fuel/non-fuel split for pool energy							
109	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%				PIVOT	ESTIMATE		
110								62,861,173	62,861,173		

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OHIO POWER COMPANY - NET ENERGY COST (NEC)

DECEMBER 2011

Line	A	B	C	D	E	F	G	H	Reconcile NEC to GL		
1	Fuel, Purchased Power, and Environmental Costs Included FAC			Net Energy Cost (NEC) in EFC					EST	Applicable	Diff. To GL NEC Adjs. for
2					Assigned	Assigned	Retail	Retail	NEC Rpt	GL Recorded	Actual Cycle
3	Account	Description	Notes	Total	Off-System	To Firm Load	Allocation	FAC Cost	Costs	Amounts	Or PPAs
4	Generation Fuel			Mar GL	NEC						
5	5010001	Fuel Consumed		$ 70,445,997	$ 23,189,585	$ 47,256,412			$ 70,445,997	$ 70,636,284	$ (190,287)
6	5010009	Fuel Consumed - No Load (CV4)				-			$ -	-	$ -
7	5010013	Fuel Survey Activity		$ -		-			$ -	(2,267,996)	$ 2,267,996
8	5010019	*Fuel Oil Consumed*		$ -		-			$ -	2,103,951	$ (2,103,951)
9	5010020	Natural Gas Consumed				-			$ -	-	$ -
10	5010023	Fuel Consumed - Biomass				-			$ -	139,508	$ (139,508)
11	5470001	Fuel - Gas Turbine				-			$ -	-	$ -
12		Subtotal - Generation Plant		$ 70,445,997	$ 23,189,585	$ 47,256,412			$ 70,445,997	$ 70,611,748	$ (165,751)
13	Purchases Power - Fuel portion			NEC/ECR PP	NEC/ECR PP						
14	5550001/0094	Purch Pwr-NonTrading (OVEC-Fuel & Trash plant)	A	$ 4,662,221	$ 2,679,315	$ 1,982,907			$ 4,662,221	$ 8,918,348	$ (4,256,127)
15	5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)	E	4,086,353	-	$ 4,086,353			$ 4,086,353	3,416,866	$ 669,487
16	5550080	PJM Energy Purchases (Fuel)	C	5,425,045	3,674,829	$ 1,750,216			$ 5,425,045	2,865,686	$ 2,559,360
17	5550094/0001	Purch Pwr-Trading-Nonassoc (Fuel)	D	1,403,447	1,274,262	129,185			$ 1,403,447	201,872	$ 1,201,575
18	5550046	PP - Fuel Portion - Affil (PP from West Pool)	F	11,031	5,800	5,231			$ 11,031	11,255	$ (223)
19	5550031/32	Purchased Pwr - Mone (Fuel)	B	54,551	53,978	573			$ 54,551	46,349	$ 8,202
20		Subtotal - Purchased Power Fuel		$ 15,642,649	$ 7,688,184	$ 7,954,465			15,642,649	15,460,376	182,273
21		Total NEC Fuel		$ 86,088,646	$ 30,877,769	$ 55,210,877	91.544%	$ 50,542,245	86,088,646	86,072,124	16,522
22						Firm Load					
23	*Allowance Accounts in FAC:*				Allocation Factor	Allocated Amt					
24	Emission Allowance Expense										
25	5090000	Allowance Consumption SO2		$ 1,375,566	68.99%	$ 949,003					
26	5090001	Allowance Consumption - Seasonal NOx		-	68.99%						
	5090002	Allowance Expenses		-	68.99%	-					
27	5090005	Allowance Expenses - Annual NOx		48,561	68.99%	33,502					
28	5090003	CO2 Allowance Consumption (none in this a/c currently)		-	68.99%	-					
29	Allowance Gains/Losses										
30	4118002	Comp. Allow. Gains SO2		-	68.99%	-					
31	4118003	Comp. Allow. Gains-Seas NOx		-	68.99%	-					
32	4118004	Comp. Allow. Gains-Ann NOx		(109,452)	68.99%	(75,511)					
33	4119000	Loss Disposition of Allowances		-	68.99%	-					
34	4119002	Comp. Allow. Loss - SO2		5,777,796	68.99%	3,986,101					
35	4119003	Comp. Allow. Loss-Seas Nox		-	68.99%	-					
36		Total Allowance Dollars		$ 7,092,471		$ 4,893,096	91.544%	$ 4,479,336			
37	Additional S.B. 221 FAC Accounts Forecast for 2009			Additional Fuel and Environmental Accounts in FAC							
38						Firm Load					
39	Account	Description	Notes		Allocation Factor	Allocated Amount					
40	Incremental Fuel Handling/Ash/Gypsum										
41	5010000	Fuel (Ash Handling)		$ 805,022	68.99%	$ 555,385	91.544%	$ 508,421			
42	5010003	Fuel - Procurement, Unloading & Handling		2,699,589	68.99%	1,862,447	91.544%	$ 1,704,958			
43	5010012	Ash Sales Proceeds		(37,385)	68.99%	(25,792)	91.544%	$ (23,611)			
44	5010027	Gypsum handling/disposal costs		218,523	68.99%	150,759	91.544%	$ 138,011			
45	5010028	Gypsum Sales Proceeds		(120,791)	68.99%	(83,334)	91.544%	$ (76,287)			
46	5010029	Gypsum handling/displ-Affiliat		19,631	68.99%	13,543	91.544%	$ 12,398			
47	Incremental purchased power - Non Fuel			ECR PP SUM Rpt	ECR PP SUM Rpt						
48	5550095	Purch Pwr-Trading-Nonassoc (Non-Fuel) - INACTIVATED 11/09	D	$ -	-	$ -	91.544%	$ -	$ -		$ -
49	5550096 - in part	PP - Non Trade - Non-Fuel (OVEC, 3rd party)	A	357,001	205,163	151,838	91.544%	$ 138,998	$ 357,001	$ 5,192,115	$ (4,835,114)
50	5550032	PP - Mone - Non-Fuel	B	-	-	-	91.544%	$ -	$ -	$ -	$ -
51	5550098	PP - PJM - Non-Fuel - INACTIVATED 11/09	C	-	-	-	91.544%	$ -	$ -		$ -
52	5550027	PP Affiliated-Non-Fuel Portion (from West Pool)	F	-	-	-	91.544%	$ -	$ -		$ -
53	5550096 - in part	PP - OVEC Demand-Actual only (source:bill, Genea Taylor email)		5,593,749	100%	5,593,749	91.544%	$ 5,120,742	5,593,749	-	5,593,749
54	5550101	PP Affil. Pool- Non Fuel (primary/econ. purchases from East Pool)	E	951,844	100%	951,844	91.544%	$ 871,356	5,950,750	5,192,115	758,635
55	5550023	PP Capacity - Non Affil.		223,470	100%	223,470	91.544%	$ 204,573			
56	5550040	PJM Inadvertent - LSE (only)		23,661	100%	23,661	91.544%	$ 21,660			
57	5550003	PP - Cogeneration		165,578	100%	165,578	91.544%	$ 151,576			
58	5550093	Peak Hour Avail Charge - LSE		-	100%	-	91.544%	$ -			
59	Lawrenceburg purchased power - Non-Fuel (NA)										
60	Renewables										
61	5550047	Purchased Power - Wind		1,036,371	100%	$ 1,036,371	100.00%	$ 1,036,371	$ 1,036,370.96	$ 1,036,370.96	$ -
62	5550109	Purchased Power - Solar Energy		27,730	100%	27,730	100.00%	$ 27,730	$ 27,730.11	$ 27,730.11	$ -
63	5570007	Other Pwr Exp - RECs - Do not include beginning 3/1/2010		-	100%	-	100.00%	$ -			
64	5570008	Renewable Energy Credit Exp.		-	100%	-	100.00%	$ -			
65	5570009	Other Pwr Exp - REC's - RETAIL		287,958	100%	287,958	100.00%	$ 287,958			
66	Environmental Material & Expense										
67	5020001	Lime Expense		$ 3,633,177	68.99%	$ 2,506,529	91.544%	$ 2,294,577			
68	5020002	Urea Expense		2,010,059	68.99%	1,386,740	91.544%	$ 1,269,477			
69	5020003	Trona Expense		790,527	68.99%	545,385	91.544%	$ 499,267			
70	5020004	Limestone Expense		1,087,901	68.99%	750,543	91.544%	$ 687,077			
71	5020005	Polymer expense		300,068	68.99%	207,017	91.544%	$ 189,512			
72	5020007	Lime Hydrate Expense		-	68.99%	-	91.544%	$ -			
73	5020008	Activated Carbon		(402)	68.99%	(278)	91.544%	$ (254)			
74	5020025	Steam Exp Environmental		60,961	68.99%	42,057	91.544%	$ 38,500			
75	555 Purchased Power Accounts only for OSS (Excluded from FAC)										
76	5550035	PJM Normal Purchases (Non ECR OSS)		$ -	0%	$ -	91.544%	$ -			
77	5550039	PJM Inadvertent - OSS (only)		5,167	0%	-	91.544%	$ -			
78	5550088	PJM Capacity Charge (OSS only)		-	0%	-	91.544%	$ -			
79	5550099	PJM Purchases - NonECR (Auction)		2,855,361	0%	-	91.544%	$ -			
80	5550100	PJM Capacity Purchases - NonECR (Auction)		84,419	0%	-	91.544%	$ -			
81	5550102	PP Pool Non Fuel - OSS Aff		7,384,325	0%	-	91.544%	$ -			
82	5550107	Capacity Purchases - Trading		258,420	0%	-	91.544%	$ -			
83	5550002	PP - Assocated (PPA only - discontinued after Jan09)		-	0%	-	91.544%	$ -			
84	555 Purchased Power Ancillary Credits included in Base "G" Rates (Excluded from FAC)										
85	5550075	PJM Reactive Credit		$ 23,209	0%	$ -	91.544%	$ -			
86	5550077	PJM Black Start Credit		(7,239)	0%	-	91.544%	$ -			
87	5550079	PJM Regulation Credit		(179,751)	0%	-	91.544%	$ -			
88	5550084	PJM Spinning Reserve Credit		31	0%	-	91.544%	$ -			
89	5550089	PJM 30 min Suppl. Reserve Credit - LSE		-	0%	-	91.544%	$ -			
90	555 Purchased Power Accounts included in ETCRR (Excluded from FAC)										
91	5550036	PJM Emergency Purchases (Demand Response Program)		$ -	0%	$ -	91.544%	$ -			
92	5550041	PJM Synchronous Cond. Charge		(2)	0%	-	91.544%	$ -			
93	5550074	PJM Reactive Charge		2,208	0%	-	91.544%	$ -			
94	5550076	PJM BlackStart Charge		10,092	0%	-	91.544%	$ -			
95	5550078	PJM Regulation Charge		443,572	0%	-	91.544%	$ -			
96	5550083	PJM Spinning Reserve Charge		357	0%	-	91.544%	$ -			
97	5550090	PJM 30 min Suppl. Reserve Charge - LSE		174	0%	-	91.544%	$ -			
98		Total Additional FAC		$ 31,014,584		$ 16,373,198		$ 15,103,011	GL AMOUNTS	$ 123,420,543.76	
99		TOTAL		$ 124,195,701		$ 76,477,171		$ 70,124,591	EXCL 5010032/33	$ -	
100									TOTAL GL QUERY	$ 123,420,543.76	
101	NOTATIONS:										
102	A	OVEC fuel/non-fuel portions provided in billing detail	D	3rd PP trading purchases split: 100% fuel							
103	B	East Pool group computes/books Mone fuel & non-fuel separately (80/2(	E	IPS is source for fuel/non-fuel split for pool energy							
104	C	East Pool group: PJM PP 100% fuel	F	PP fuel/nonfuel from West Pool split fuel 100%							
105											

5

IEU-Ohio Exhibit 8

Ohio Power

	555 Purch. Power OVEC Demand in Power Bill	Ohio Retail Perc.	OVEC Demand Allocated to Ohio Retail & FAC	(a) 555 Purch. Power OVEC Energy Recorded
January-10	$2,939,917	92.085%	$2,707,223	$5,816,711
February-10	$3,413,859	92.087%	$3,143,720	$4,857,635
March-10	$4,439,898	91.840%	$4,077,603	$5,303,853
April-10	$5,029,038	90.784%	$4,565,562	$3,958,267
May-10	$4,234,480	91.922%	$3,892,418	$4,912,441
June-10	$4,115,976	92.581%	$3,810,611	$5,420,962
July-10	$3,337,415	92.220%	$3,077,764	$3,957,638
August-10	$3,751,971	92.636%	$3,475,676	$4,814,179
September-10	$3,209,349	91.971%	$2,951,671	$4,628,266
October-10	$3,783,267	91.477%	$3,460,819	$4,715,282
November-10	$3,280,715	91.754%	$3,010,187	$5,639,857
December-10	$4,848,370	91.960%	$4,458,561	$5,778,065

Columbus Southern Power

	555 Purch. Power OVEC Demand in Power Bill	Ohio Retail Perc.	OVEC Demand Allocated to Ohio Retail & FAC	(a) 555 Purch. Power OVEC Energy Recorded
January-10	$842,688	100%	$842,688	$1,994,863
February-10	$978,537	100%	$978,537	$1,687,716
March-10	$1,272,637	100%	$1,272,637	$1,667,801
April-10	$1,441,506	100%	$1,441,506	$1,317,947
May-10	$1,213,757	100%	$1,213,757	$1,625,304
June-10	$1,179,789	100%	$1,179,789	$1,703,436
July-10	$956,625	100%	$956,625	$1,106,467
August-10	$1,075,452	100%	$1,075,452	$1,382,155
September-10	$919,917	100%	$919,917	$1,327,913
October-10	$1,084,422	100%	$1,084,422	$1,348,939
November-10	$940,373	100%	$940,373	$1,615,736
December-10	$1,389,720	100%	$1,389,720	$1,657,226

(a) OVEC energy allocated to Ohio Retail & FAC are not readily available.

IEU-Ohio Exhibit 6

Ohio Power

	555 Purch. Power OVEC Demand in Power Bill	Ohio Retail Perc.	OVEC Demand Allocated to Ohio Retail & FAC	(a) 555 Purch. Power OVEC Energy Recorded
January-11	$2,895,117	92.204%	$2,669,414	$6,245,982
February-11	$3,376,657	92.263%	$3,115,405	$5,389,168
March-11	$4,175,160	91.842%	$3,834,550	$7,438,698
April-11	$5,125,636	92.394%	$4,735,780	$8,233,765
May-11	$3,349,687	92.137%	$3,086,301	$7,721,777
June-11	$3,363,058	92.292%	$3,103,834	$7,247,601
July-11	$3,424,796	92.717%	$3,175,368	$5,998,911
August-11	$3,516,313	92.271%	$3,244,537	$6,043,541
September-11	$3,965,890	91.746%	$3,638,546	$6,747,767
October-11	$4,925,626	92.051%	$4,534,088	$5,848,177
November-11	$4,586,146	91.429%	$4,193,068	$6,038,124
December-11	$5,593,749	91.544%	$5,120,742	$6,599,103

Columbus Southern Power

	555 Purch. Power OVEC Demand in Power Bill	Ohio Retail Perc.	OVEC Demand Allocated to Ohio Retail & FAC	(a) 555 Purch. Power OVEC Energy Recorded
January-11	$829,846	100%	$829,846	$1,793,693
February-11	$967,873	100%	$967,873	$1,547,185
March-11	$1,196,753	100%	$1,196,753	$3,064,207
April-11	$1,469,195	100%	$1,469,195	$3,890,600
May-11	$960,143	100%	$960,143	$3,530,842
June-11	$963,975	100%	$963,975	$2,889,071
July-11	$981,672	100%	$981,672	$1,683,212
August-11	$1,007,904	100%	$1,007,904	$1,756,607
September-11	$1,136,769	100%	$1,136,769	$2,810,558
October-11	$1,411,864	100%	$1,411,864	$2,586,400
November-11	$1,314,557	100%	$1,314,557	$2,615,531
December-11	$1,603,373	100%	$1,603,373	$2,910,356

(a) OVEC energy allocated to Ohio Retail & FAC are not readily available.

IEU-OHIO EX. 7

EXHIBIT NO. _____

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company	))))	Case No. 10-2929 -EL-UNC

DIRECT TESTIMONY OF
KELLY D. PEARCE
ON BEHALF OF
OHIO POWER COMPANY

Filed: March 23, 2012

B-2
DETERMINATION OF RATES APPLICABLE TO
CSP'S CAPACITY REQUIREMENTS
12 Months Ending 12/31/2010 (actuals)

1. Capacity Daily Rates

$$\$/MW = \frac{\text{Annual Production Fixed Cost}}{\text{(CSP 5 CP Demand/365) (Note A)}}$$

$$\frac{477,093,822}{4,126.2 \quad /365} = \$316.76211$$

Where: Annual Production Fixed Cost, P.4

Note A: Average of demand at time of PJM five highest daily peaks.

		Reference	
1.	GSU & Associated Investment	Note A	13,680,915
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	658,515,757
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	2.08%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	13,952,264
5.	GSU Related Depreciation Expense	L.3 x L.4	289,864
6.	Station Equipment Acct. 353 Investment	FF1, P.207, L.50, Col.g	335,003,384
7.	Percent (GSU to Acct. 353)	L.1 / L.6	4.08%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L 93, Col.b, and L.107, Col.b	2,640,539
9.	GSU & Associated Investment O&M	L.7 x L.8	107,835

Note A: Workpapers -- tab WP-16

B-4
ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/2010 (actuals)

		Reference	PRODUCTION Amount
1.	Return on Rate Base	P.5, L.19, Col.(2)	$129,071,540
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$217,843,953
3.	Depreciation Expense	P.16, L.11, Col.(2)	$59,590,261
4.	Taxes Other Than Income Taxes	P.17, L.5, Col.(2)	$55,511,568
5.	Income Tax	P.18, L.5, Col.(2)	$45,891,012
6.	Sales for Resale	Note A	$30,785,441
7.	Ancillary Service Revenue	Note B	$29,070
8.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6 + L.7)	$477,093,822

Note A: Capacity related revenues associated with sales as reported in Account 447(includes pool capacity payments).
Note B: Workpapers -- tab WP-2

B-14 Exhibit KDP-3
Page 14

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/2010 (actuals)

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)
1. Coal Handling	501.xx	8,699,618		8,699,618
2. Lignite Handling	501.xx	0		0
3. Sale of Fly Ash (Revenue & Expense)	501.xx	(155,717)		(155,717)
4. Rents	507	0		
5. Hydro O & M Expenses	535-545	0		
6. Other Production Expenses	557	9,086,718	9,086,718	
7. System Control of Load Dispatching	Note C	8,645,979	8,645,979	
8. Other Steam Expenses	Note A	134,255,442	73,747,250	60,508,192
9. Combustion Turbine	Note A	0		0
10. Nuclear Power Expense-Other	Note A	0		
11. Purchased Power	555	591,825,260	106,281,091	485,544,169
12. Total Production Expense Excluding Fuel Used In Electric Generation above		752,357,301	197,761,039	554,596,263
13. A & G Expense P.10, L.17		27,254,303	19,975,079	7,279,224
14. Generator Step Up related O&M	Note B	107,835	107,835	0
15. Total O & M		779,719,439	217,843,953	561,875,487

NOTE A: Amounts recorded in Accounts 500, 502-509, 510-514, 546, 548-550 and 551-554 classified into Fixed and Variable Components in accordance with P.15 and WP-14

NOTE B: FF1, P.321, L.93 & L.107 (ACCTS. 562 & 570) times GSU Investment to Account 353 ratio (See P.3, L.9)

NOTE C: Pursuant to FERC Order 668, expenses were booked in Account 556 are now being recorded in the following accounts: 561.4, 561.8 and 575.7

EXHIBIT KDP-4

B-1 Exhibit KDP-4

CAPACITY (FIXED) CHARGE CALCULATION Page 1

OPCO

12 Months Ending 12/31/2010 (actuals)

	RATE $/MW/Day (1)	Loss Factor (2)	Final FRR Rate (1) x (2) (Note A) (3)
Capacity Daily Charge:			
1. Reference	P.2		Col (1) x (2)
2. Amount	$366.71683	1.034126	$379.23

Note A: Final Rate that will be applied to CRES providers demand that will be metered at or adjusted to transmission level.

DETERMINATION OF RATES APPLICABLE TO
OPC'S CAPACITY REQUIREMENTS
12 Months Ending 12/31/2010 (actuals)

1. Capacity Daily Rates

$$\$/MW = \frac{\text{Annual Production Fixed Cost}}{\text{(OPC 5 CP Demand/365) (Note A)}}$$

$$\frac{660{,}504{,}310}{4{,}934.6 \quad /365} = \$366.71683$$

Where: Annual Production Fixed Cost, P.4

Note A: Average of demand at time of PJM five highest daily peaks.

B-3
Generator Step Up Transformer Workpaper
12 Months Ending 12/31/2010 (actuals)

		Reference	
1.	GSU & Associated Investment	Note A	46,501,375
2.	Total Transmission Investment	FF1, P.207, L.58, Col.g	1,232,468,069
3.	Percent (GSU to Total Trans. Investment)	L.1 / L.2	3.77%
4.	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	26,883,115
5.	GSU Related Depreciation Expense	L.3 x L.4	1,014,308
6.	Station Equipment Acct. 353 Investment	FF1, P.207, L.50, Col.g	672,249,191
7.	Percent (GSU to Acct. 353)	L.1 / L.6	6.92%
8.	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	5,697,368
9.	GSU & Associated Investment O&M	L.7 x L.8	394,103

Note A: Workpapers -- tab WP-16

B-4
ANNUAL PRODUCTION FIXED COST
12 Months Ending 12/31/2010 (actuals)

		Reference	PRODUCTION Amount
1.	Return on Rate Base	P.5, L.19, Col.(2)	$311,327,830
2.	Operation & Maintenance Expense	P.14, L.15, Col.(2)	$338,666,260
3.	Depreciation Expense	P.16, L.11, Col.(2)	$256,957,852
4.	Taxes Other Than Income Taxes	P.17, L.6, Col.(2)	$89,767,677
5.	Income Tax	P.18, L.5, Col.(2)	$123,339,938
6.	Sales for Resale	Note A	$459,510,726
7.	Ancillary Service Revenue	Note B	$34,520
8.	Annual Production Fixed Cost	Sum (L.1 : L.5) - (L.6 + L.7)	$660,504,310

Note A: Capacity related revenues associated with sales as reported in Account 447 (includes pool capacity demand).

Note B: Workpapers -- tab WP-2

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
12 Months Ending 12/31/2010 (actuals)

	Account No.	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)
1. Coal Handling	501.xx	35,107,375		35,107,375
2. Lignite Handling	501.xx	0		0
3. Sale of Fly Ash (Revenue & Expense)	501.xx	(1,361,098)		(1,361,098)
4. Rents	507	0		
5. Hydro O & M Expenses	535-545	0		
6. Other Production Expenses	557	10,771,997	10,771,997	
7. System Control of Load Dispatching	Note C	12,098,923	12,098,923	
8. Other Steam Expenses	Note A	366,453,080	213,250,909	153,202,170
9. Combustion Turbine	Note A	0		0
10. Nuclear Power Expense-Other	Note A	0		
11. Purchased Power	555	362,926,322	59,290,595	303,635,727
12. Total Production Expense Excluding Fuel Used In Electric Generation above		785,996,598	295,412,424	490,584,174
13. A & G Expense P.10, L.17		68,081,627	42,849,733	25,231,894
14. Generator Step Up related O&M	Note B	394,103	394,103	0
15. Total O & M		854,472,328	338,656,260	515,816,069

NOTE A: Amounts recorded in Accounts 500, 502-509, 510-514, 546, 548-550 and 551-554 classified into Fixed and Variable Components in accordance with P.15 and WP-14

NOTE B: FF1, P.321, L.93 & L.107 (ACCTS. 562 & 570) times GSU investment to Account 353 ratio (See P.3, L.9)

NOTE C: Pursuant to FERC Order 668, expenses were booked in Account 556 are now being recorded in the following accounts: 561.4, 561.8 and 575.7

IEU-OHIO EX. 8

THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Ohio Power Company	End of 2010/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. *Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use* acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	AEP Service Corporation	OS	20			
2	AEP Service Corporation	OS	23			
3	ALLETE, Inc. dba Minnesota Pwr	OS				
4	Ameren Energy Marketing	OS				
5	Associated Elect Cooperative	OS				
6	Barclays Bank PLC	OS				
7	Beech Ridge Energy LLC	OS				
8	Big Rivers Electric Corp	OS				
9	BP AMOCO	OS				
10	Buckeye Rural Electric Admin	OS				
11	Carolina Power & Light	OS				
12	Citigroup Energy Inc.	OS				
13	Conectiv Energy Supply Inc.	OS				
14	Constellation Engy Commodities	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Cook Inlet Energy Supply LP	OS				
2	DTE Energy Trading Inc.	OS				
3	Duke Energy Carolinas, LLC	OS				
4	Duke Power Company	OS				
5	Dynegy Power Marketing Inc.	OS				
6	EDF Trading North America LLC	OS				
7	Edison Mission Mktg & Trading	OS				
8	Endure Energy, LLC	OS				
9	Entergy Power Serv	OS				
10	Exelon Generation - Power Team	OS				
11	FirstEnergy Trading Services	OS				
12	Fowler Ridge II Wind Farm LLC	OS				
13	Hoosier Power Market	OS				
14	Integrys Energy Services, Inc	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	J ARON & Company	OS				
2	JP Morgan Ventures Energy Corp	OS				
3	Kansas City Power & Light Co	OS				
4	LG&E Utilities Power Sales	OS				
5	Madison Gas and Electric Co	OS				
6	Midwest ISO	OS				
7	Mingo Junction Energy Center	OS				
8	Mizuho Securities USA Inc	OS				
9	National Power Cooperative Inc	OS				
10	NC Electric Membership Corp.	OS				
11	NextEra Energy Power Mktg LLC	OS				
12	No Carolina Muni Pwr Agency #1	OS				
13	NRG Power Marketing Inc.	OS				
14	Ohio Economic Development Rider	OS				
	Total					

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Old Dominion Elec.	OS				
2	OVEC Power Scheduling	OS				
3	PJM Interconnection	OS				
4	PP&L Energy Plus Co.	OS				
5	PSEG Energy Resources & Trade	OS				
6	Sempra Energy Solutions, LLC	OS				
7	Sempra Energy Trading	OS				
8	South Carolina Electric & Gas	OS				
9	Southeastern Pub Serv Auth -VA	OS				
10	Southern Company	OS				
11	Southern Illinois Power Co-Op	OS				
12	The Energy Authority	OS				
13	Titlon Energy, LLC	OS				
14	Town of Front Royal	OS				
	Total					

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	TVA Bulk Power Trading	OS				
2	UBS Securities LLC	OS				
3	Union Electric Company	OS				
4	Wabash Valley Power Assn Inc.	OS				
5	Westar Energy Inc.	OS				
6	Wisconsin Electric Power Co	OS				
7	Wyandot Solar LLC	OS				
8	Adjustment					
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
13,785				538,472		538,472	1
2,486,531				90,575,709		90,575,709	2
			58,593	74,429		133,022	3
			1,789	2,023		3,812	4
6,086				196,069		196,069	5
				1,883		1,883	6
				-6,263		-6,263	7
828				28,742		28,742	8
				6,614		6,614	9
19				437,663		437,663	10
485				14,260		14,260	11
				-778		-778	12
			45,429			45,429	13
45,305			2,584,013	2,428,095		5,012,108	14
8,010,064			59,290,595	305,322,046	-1,686,319	362,926,322	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				2,247		2,247	1
2,120				136,363		136,363	2
89				4,746		4,746	3
99				5,489		5,489	4
			107,868	-2		107,866	5
			109,991	701		110,692	6
4,224				102,285		102,285	7
				10,022		10,022	8
3,375				126,160		126,160	9
61,943			49,135	2,245,756		2,294,891	10
				2,612		2,612	11
131,780				10,080,727		10,080,727	12
				7		7	13
2,232				113,979		113,979	14
8,010,064			59,290,595	305,322,046	-1,686,319	362,926,322	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
51,491				2,163,105		2,163,105	1
3,826			6,446	262,277		268,723	2
2,872				84,467		84,467	3
9,345				384,225		384,225	4
			23,711			23,711	5
490,763			359	19,963,629		19,963,988	6
86,065				1,502,522		1,502,522	7
				258,387		258,387	8
11,998			54,763	948,927		1,003,690	9
114				2,682		2,682	10
			50,327	129		50,456	11
147				7,905		7,905	12
51				1,905		1,905	13
					-1,686,319	-1,686,319	14
8,010,064			59,290,595	305,322,046	-1,686,319	362,926,322	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
18,844				698,151		698,151	1
2,363,475			46,149,435	62,101,296		108,250,731	2
1,398,110			9,375,150	70,905,912		80,281,062	3
212,547				10,411,078		10,411,078	4
573,687				28,129,317		28,129,317	5
				3,909		3,909	6
456				15,916		15,916	7
284				17,743		17,743	8
9,310				303,074		303,074	9
277				14,765		14,765	10
				1		1	11
3,900				191,494		191,494	12
			23,639			23,639	13
			259,060			259,060	14
8,010,064			59,290,595	305,322,046	-1,686,319	362,926,322	

Name of Respondent Chio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
7,477				340,329		340,329	1
				2,654,702		2,654,702	2
			22,561	8,107		30,668	3
			250,130	-1,364		248,766	4
				8,468		8,468	5
			118,196			118,196	6
6,122				558,610		558,610	7
				-3,747,632		-3,747,632	8
							9
							10
							11
							12
							13
							14
8,010,064			59,290,595	305,322,046	-1,686,319	362,926,322	

IEU-OHIO EX. 9

THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. *Failure to report may result in criminal fines, civil penalties and* other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Columbus Southern Power Company	**End of** 2010/Q4

FERC FORM No.1/3-Q (REV. 02-04)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	AEP Generating	RQ	AEG 3			
2	AEP Service Corporation	OS	20			
3	AEP Service Corporation	OS	30			
4	ALLETE, Inc. dba Minnesota Pwr	OS				
5	Ameren Energy Marketing	OS				
6	Associated Elect Cooperative	OS				
7	Barclays Bank PLC	OS				
8	Beech Ridge Energy LLC	OS				
9	Big Rivers Electric Corp	OS				
10	BP AMOCO	OS				
11	Buckeye Rural Electric Admin	OS				
12	Carolina Power & Light	OS				
13	Citigroup Energy Inc.	OS				
14	Conectiv Energy Supply Inc.	OS				
	Total					

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Constellation Engy Commodities	OS				
2	Cook Inlet Energy Supply LP	OS				
3	DTE Energy Trading Inc.	OS				
4	Duke Energy Carolinas, LLC	OS				
5	Duke Power Company	OS				
6	Dynegy Power Marketing Inc.	OS				
7	EDF Trading North America LLC	OS				
8	Edison Mission Mktg & Trading	OS				
9	Endure Energy, LLC	OS				
10	Entergy Power Serv	OS				
11	Exelon Generation - Power Team	OS				
12	FirstEnergy Trading Services	OS				
13	Fowler Ridge II Wind Farm LLC	OS				
14	Hoosier Power Market	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Integrys Energy Services, Inc	OS				
2	J ARON & Company	OS				
3	JP Morgan Ventures Energy Corp	OS				
4	Kansas City Power & Light Co	OS				
5	LG&E Utilities Power Sales	OS				
6	Madison Gas and Electric Co	OS				
7	Midwest ISO	OS				
8	Mizuho Securities USA Inc	OS				
9	National Power Cooperative Inc	OS				
10	NC Electric Membership Corp.	OS				
11	NextEra Energy Power Mktg LLC	OS				
12	No Carolina Muni Pwr Agency #1	OS				
13	NRG Power Marketing Inc.	OS				
14	Ohio Economic Development Rider	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

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IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Old Dominion Elec.	OS				
2	OVEC Power Scheduling	OS				
3	PJM Interconnection	OS				
4	PP&L Energy Plus Co.	OS				
5	PSEG Energy Resources & Trade	OS				
6	Sempra Energy Solutions, LLC	OS				
7	Sempra Energy Trading	OS				
8	South Carolina Electric & Gas	OS				
9	Southeastern Pub Serv Auth -VA	OS				
10	Southen Maryland Elec Coop Inc	OS				
11	Southern Company	OS				
12	Southern Illinois Power Co-Op	OS				
13	The Energy Authority	OS				
14	Tillon Energy, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Town of Front Royal	OS				
2	TVA Bulk Power Trading	OS				
3	UBS Securities LLC	OS				
4	Union Electric Company	OS				
5	Wabash Valley Power Assn Inc.	OS				
6	Westar Energy Inc.	OS				
7	Wisconsin Electric Power Co	OS				
8	Wyandot Solar LLC	OS				
9	Adjustment	OS				
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,547,862			60,734,136	53,066,404		113,800,540	1
11,749				458,157		458,157	2
10,732,648			19,380,410	275,458,228		294,838,638	3
			50,798	64,527		115,325	4
			1,466	1,779		3,245	5
5,122				166,620		166,620	6
				1,617		1,617	7
				-5,230		-5,230	8
642				23,548		23,548	9
				4,916		4,916	10
16				370,433		370,433	11
403				11,853		11,853	12
				-676		-676	13
			39,383			39,383	14
15,631,380			104,443,543	485,544,169		589,987,712	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
38,224			2,185,950	2,043,719		4,229,669	1
				1,922		1,922	2
1,640				115,248		115,248	3
73				3,980		3,980	4
85				4,770		4,770	5
			92,201	-2		92,199	6
			92,063	604		92,667	7
3,376				83,835		83,835	8
				8,709		8,709	9
2,846				106,856		106,856	10
51,877			42,596	1,919,699		1,962,295	11
				2,270		2,270	12
131,780				10,080,727		10,080,727	13
				6		6	14
15,631,380			104,443,543	485,544,169		589,987,712	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
1,864				93,380		93,380	1
43,517				1,829,618		1,829,618	2
3,325			5,588	227,867		233,455	3
2,323				69,697		69,697	4
7,791				323,940		323,940	5
			19,940			19,940	6
415,571			303	16,925,378		16,925,681	7
				210,576		210,576	8
10,007			47,586	799,615		847,201	9
83				2,198		2,198	10
			42,208	111		42,319	11
121				6,697		6,697	12
41				1,593		1,593	13
				7,485,164		7,485,164	14
15,631,380			104,443,543	485,544,169		589,987,712	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2010/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
14,425				572,209		572,209	1
757,709			13,228,114	20,296,195		33,524,309	2
1,172,916			7,907,198	59,548,107		67,455,305	3
179,117				8,898,619		8,898,619	4
471,367				23,990,770		23,990,770	5
				3,397		3,397	6
360				13,448		13,448	7
240				14,975		14,975	8
7,724				262,643		262,643	9
							10
235				12,594		12,594	11
				1		1	12
3,271				163,045		163,045	13
			19,659			19,659	14
15,631,380			104,443,543	485,544,169		589,987,712	

Name of Respondent Columbus Southern Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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			224,581			224,581	1
6,220				283,959		283,959	2
				2,248,483		2,248,483	3
			19,559	6,975		26,534	4
			211,508	-1,186		210,322	5
				7,272		7,272	6
			98,296			98,296	7
4,810				440,479		440,479	8
				-3,188,169		-3,188,169	9
							10
							11
							12
							13
							14
15,631,380			104,443,543	485,544,169		589,987,712	

IEU-OHIO EX. 10

EXHIBIT NO. ____________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company	))))	Case No. 10-2929-EL-UNC

REBUTTAL TESTIMONY OF
WILLIAM A. ALLEN
ON BEHALF OF
OHIO POWER COMPANY

Filed: May 11, 2012

INDEX TO REBUTTAL TESTIMONY OF
WILLIAM A. ALLEN

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
REBUTTAL TESTIMONY OF
WILLIAM A. ALLEN
ON BEHALF OF
OHIO POWER COMPANY

PERSONAL DATA

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William A. Allen, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. DID YOU PRESENT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my rebuttal testimony is to 1) address certain adjustments to the Company's capacity cost calculation proposed by Staff witnesses Smith, Harter and Medine; 2) address FES witness Lesser's comparison of AEP Ohio's base generation rates to AEP Ohio's requested capacity cost rates; 3) refute the assumption in Staff's analysis that shopping load remains constant at 26%; and 4) present an estimate of earnings for 2013 under the assumption that the Company recovers its full cost of capacity from CRES providers ($355.72/MW-day).

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring the following exhibits:

Exhibit WAA-R1	Impact of Understated Fuel Cost on Staff's Energy Credit
Exhibit WAA-R2	Comparison of Staff's Heat Rate to 2011 Actual

Exhibit WAA-R3	Impact of Incorrect Heat Rates on Staff's Energy Credit
Exhibit WAA-R4	Impact of Overstated Market Prices on Staff's Energy Credit
Exhibit WAA-R5	Impact of Excluding WPCo Load from Energy Credit Calculation
Exhibit WAA-R6	Cross Impact of Fuel and Market
Exhibit WAA-R7	Cost of Service Adjustments
Exhibit WAA-R8	Estimate of AEP Ohio's Earnings

<u>**ENERGY CREDIT ADJUSTMENTS**</u>

Q. HAVE YOU REVIEWED THE ENERGY CREDIT CALCULATIONS PRESENTED BY STAFF WITNESSES HARTER AND MEDINE IN THE CASE?

A. Yes. I have reviewed their energy credit calculations as well as the supporting work papers.

Q. DID YOU MAKE ANY OBSERVATIONS AS A RESULT OF YOUR REVIEW OF STAFF WITNESSES HARTER AND MEDINE'S ENERGY CREDIT CALCULATIONS AND WORK PAPERS?

A. Yes. My observations are as follows: 1) the analysis fails to reflect the impact of the AEP Interconnection Agreement (AEP Pool); 2) the fuel cost data used in the analysis is not reasonable; 3) the heat rate data for the generation resources of AEP Ohio are not accurate; 4) the market prices used in the analysis are overstated; 5) the generation resources included in the analysis are not consistent with the actual generation resources of AEP Ohio[1]; 6) the full requirements obligation of AEP Ohio to serve Wheeling Power Company is not reflected in the analysis; and 7) the natural gas price forecast presented in the analysis significantly exceeds the current forward prices. Each of these errors significantly inflates the energy margins attributed to AEP Ohio by Staff witnesses Harter and Medine. Consequently, Staff's proposed energy credit is significantly overstated.

Throughout this section of my testimony I will address individual elements of the analysis that was presented by Staff witnesses Harter and Medine. While I present and quantify the impact of correcting specific errors in their analysis, this should not be construed as agreement with the overall methodology presented by these Staff witnesses. Company witness Meehan presents an independent analysis of the gross margins that AEP Ohio could realistically expect to achieve during the period from June 2012 through May 2015. Throughout my analysis I will be using actual 2011 values while Company witness Meehan uses projected values in his analysis. Therefore, the results presented in my testimony will necessarily differ from those presented by Company witness Meehan.

During the course of the hearing Staff witnesses presented three different versions of their calculation of an energy credit to apply in determining an appropriate capacity charge rate as well as three different sets of work papers. The initial calculation was revised twice to address errors that were identified

[1] This error in the work papers of Staff witness Harter was largely, but not completely, corrected by Staff witness Medine as discussed later in my testimony.

prior to and during the hearing. The results of the three analyses are presented in the table below. For clarity, my analysis uses the Medine Revised Calculation and associated work papers as a starting point.

Version	Result
Harter Initial Calculation	$154.24/MW-day
Harter Revised Calculation	$127.38/MW-day
Medine Revised Calculation	$152.41/MW-day

Q. YOU INDICATED THAT STAFF'S ANALYSIS FAILS TO REFLECT THE IMPACT OF THE AEP INTERCONNECTION AGREEMENT. PLEASE EXPLAIN.

A. Staff witnesses Harter and Medine's analysis fails to reflect several elements of the AEP Interconnection Agreement even though Staff witness Smith includes credits associated with capacity equalization payments under the AEP Pool in his analysis. These elements include appropriate sharing of off-system sales (OSS) margins and recognition of primary energy provided to other members of the AEP Interconnection Agreement. Thus Staff's calculation of an energy credit without properly reflecting the AEP Pool Agreement's treatment of OSS margins and primary energy results in an energy credit that is overstated and a capacity charge rate that is too low. Company witness Nelson discusses this topic in greater detail.

Q. YOU INDICATED THAT THE FUEL COST DATA USED IN THE ANALYSIS IS NOT REASONABLE. PLEASE EXPLAIN.

A. In reviewing the work papers of Staff witnesses Harter and Medine, I observed that the fuel cost data appeared to be very low for certain of AEP Ohio generation resources. Most notably, the fuel cost that Staff witnesses Harter and Medine included for Gavin units 1 and 2 was between $13/MWh and $15/MWh which is well below the level that I would expect. On cross examination, Staff witness Medine admitted that the projected costs for the Gavin units used in Staff's analysis were "certainly aggressive." Gavin units 1 and 2, with a capacity of approximately 1,300 MW each, are the largest generation resources of AEP Ohio. A review of actual and forecasted fuel cost data for the Gavin units showed that the values used by Staff witnesses Harter and Medine were understated by over $5/MWh. This is a gross understatement of fuel costs. Based upon the Staff witnesses projected generation for the Gavin units this resulted in a understatement of fuel cost in excess of $390 million.

In addition to reviewing the fuel cost data that Staff witnesses Harter and Medine used for the Gavin units, I also reviewed the fuel cost data that was used for the other generation resources that were included in their analysis. I observed that the analysis included similar understatements of fuel costs for the other coal units listed in the final work papers of Staff witness Medine.

Q: ON CROSS EXAMINATION STAFF WITNESS MEDINE TESTIFIED THAT "ANOMALOUS EVENTS" AT THE GAVIN PLANT SUCH AS ONE-TIME PAYMENTS TO SUPPLIERS IN 2008 IS THE REASON WHY GAVIN'S ACTUAL FUEL COSTS ARE SIGNIFICANTLY HIGHER THAN THE ROUGHLY $14/MWH EVA USED FOR GAVIN IN ITS AURORA MODEL RUNS. DO YOU AGREE WITH THIS EXPLANATION?

A. No. The one-time payment Ms. Medine was referring to was booked directly to fuel expense in 2008. It had no bearing on the $21/MWh actual fuel costs of Gavin reported in the FERC Form 1 for 2011 that were used as a comparison to her projected $13/MWh AURORA fuel cost. A review of historic and projected fuel cost data for the Gavin units confirms that the 2011 actual fuel costs as reported in FERC Form 1 are representative (if not conservative) of fuel costs that can be expected during the 2012-2015 period.

Q. HAVE YOU QUANTIFIED THE IMPACT OF THESE FUEL COST ERRORS ON THE ENERGY CREDIT CALCULATED BY STAFF WITNESSES HARTER AND MEDINE?

A. Yes. I have conservatively estimated that the use of more reasonable fuel costs would have reduced Staff's credit by $70/MW-day. This analysis is included in Exhibit WAA-R1. In preparing this analysis I calculated the difference in total fuel costs that results from replacing Staff witness Harter and Medine's fuel costs (on a dollar per megawatt hour basis) with the actual fuel costs from 2011 for each coal unit included in the final work papers of Staff witness Medine (on a dollar per megawatt hour basis) and multiplying that difference by the projected generation for each of these units. This difference in fuel costs is then subtracted from Staff's projected margins to determine the impact on their energy credit.

Q. YOU INDICATED THAT THE HEAT RATE DATA USED BY STAFF WITNESSES HARTER AND MEDINE FOR THE GENERATION RESOURCES OF AEP OHIO WAS NOT ACCURATE. PLEASE EXPLAIN.

A. A comparison of the heat rates presented in Staff witnesses Harter and Medine's work papers to the actual heat rates for those plants/units indicated that they significantly understated the heat rates of the plants/units. A comparison of the heat rates used by Staff witnesses Harter and Medine to the actual heat rates for 2011 is presented in Exhibit WAA-R2.

Q. IS IT DIFFICULT TO OBTAIN HEAT RATE DATA FOR THE PLANTS INCLUDED IN STAFF WITNESS HARTER AND MEDINE'S WORK PAPERS?

A. No, it is not. Actual heat rate data for these plants is publically and readily available in the annually filed FERC Form 1 of AEP Ohio and AEP Generating Company (AEG) on pages 402 and 403 in the line entitled "Average BTU per kWh Net Generation."

Q. DO YOU RECALL THE CROSS EXAMINATION OF STAFF WITNESS MEDINE RELATED TO THE HEAT RATE OF THE DARBY UNITS?

A. Yes. Staff witness Medine was not able to determine whether the heat rates included in her analysis were reflective of the optimal heat rate that could be achieved by the Darby units. The Darby units are powered with GE 7EA gas turbines. The optimal heat rate for these units is 10,430 Btu/kWh versus the 9,000 Btu/kWh that Staff has used in their analysis. This is a significant and obvious error that should have been identified and corrected by the Staff witnesses as part of their quality control of the data used in their model.

Q. HAVE YOU QUANTIFIED THE IMPACT OF THESE HEAT RATE ERRORS ON THE ENERGY CREDIT CALCULATED BY STAFF WITNESSES HARTER AND MEDINE?

A. Yes. I have estimated that the use of correct actual heat rates for the gas fired generation resources would have reduced Staff's energy credit by $1.87/MW-day. This analysis is included in Exhibit WAA-R3. The impact of these heat rate errors on the coal units is included in the fuel cost analysis I previously discussed so I have not separately calculated the impact here. The understated heat rates that Staff witnesses Harter and Medine used for the gas fired generation resources of AEP Ohio results in overstated margins. To estimate the impact of correcting the heat rates for the gas fired generation resources of AEP Ohio on Staff witness Harter's margins, I have calculated the difference in fuel cost for each plant (on a dollar per megawatt hour basis) that results from applying the actual heat rates for 2011 to the delivered gas cost (on a dollar per BTU basis) used in his analysis. I then multiplied this difference by the projected generation for each of these plants/units to determine the dollar impact on fuel costs of these errors. This difference in fuel costs is then subtracted from Staff's projected margins to determine the impact on the energy credit.

Q. YOU INDICATED THAT THE MARKET PRICES USED BY STAFF WITNESSES HARTER AND MEDINE IN THEIR ANALYSIS ARE OVERSTATED. PLEASE EXPLAIN.

A. A comparison of the market prices used in Staff witnesses Harter and Medine's analysis to publically available forward market prices for the AEP Zone shows that their market prices are overstated by over $4/MWh over the three-year forecast period. Overstated market prices will have the impact of overstating the margins produced by the generating resources of AEP Ohio and, as a result, will overstate the energy credit calculated by Staff.

Q. **DO YOU RECALL THE CROSS EXAMINATION OF STAFF WITNESS MEDINE RELATED TO THE FORWARD MARKET PRICES THAT WERE TAKEN FROM THE SNL WEBSITE?**

A. Yes. Staff witness Medine questioned the accuracy of the data because the forward prices for 2014 and 2015 did not vary by month. The values presented by SNL for 2014 and 2015 are annual average values. Q. **HAVE YOU QUANTIFIED THE IMPACT OF THE OVERSTATED MARKET PRICES ON THE ENERGY CREDIT CALCULATED BY STAFF WITNESS HARTER?**

A. Yes. I have estimated that the use of current forward market prices for the AEP Zone would have reduced Staff witness Harter's energy credit by $50.42/MW-day. This analysis is included in Exhibit WAA- R4. To estimate the impact of using current forward market prices to determine the margins from the coal fired and hydro generation resources of AEP Ohio I have calculated the difference in annual market prices (on a dollar per megawatt hour basis) and then multiplied this difference by the projected generation for each of these plants/units to determine the annual dollar impact on Staff witness Harter's margins. This difference in margins is then subtracted from Staff's projected margins to determine the impact on their energy credit.

I have not calculated the impact on Staff's energy credit related to margins from the gas-fired resources of AEP Ohio since the difference in market prices is correlated to the gas costs included in Staff's analysis. This is a conservative approach to making corrections to Staff's energy credit calculation.

Q. WERE THE GENERATION RESOURCES INCLUDED IN STAFF'S ANALYSIS CONSISTENT WITH THE ACTUAL GENERATION RESOURCES OF AEP OHIO?

A. No. While Staff witnesses Medine and Harter made several corrections to the generation resources of AEP Ohio that they included in their analyses they never fully reflected the actual generation resources of AEP Ohio. In Staff witness Medine's final analysis, Amos unit 1 is listed as 100% owned by AEP Ohio while the unit is actually owned entirely by Appalachian Power Company. AEP Ohio actually has a 66.6% ownership share in Amos unit 3. Staff witness Medine also failed to recognize AEP Ohio's OVEC entitlement.

Q. YOU INDICATED THAT THE FULL REQUIREMENTS OBLIGATION OF AEP OHIO TO SERVE WHEELING POWER COMPANY IS NOT REFLECTED IN STAFF WITNESS HARTER'S ANALYSIS. PLEASE EXPLAIN.

A. Staff witness Harter's calculation of off-system sales (OSS) margins produced by the generation resources of AEP Ohio first compares the non-shopping retail sales of AEP Ohio to the generation of AEP Ohio. He then calculates a margin for the generation in excess of the non-shopping retail sales. He fails to account for the full requirements contract between AEP Ohio and Wheeling Power Company.

The sales to Wheeling Power Company reduce the quantity of generation available for off-system sales.

Q. ON CROSS EXAMINATION, STAFF WITNESS HARTER INDICATED THAT THE HE BELIEVED THE WHEELING POWER CONTRACT WAS MARKET BASED. IS THAT CORRECT?

A. No. The contract between Ohio Power Company and Wheeling Power Company is a cost-based full requirement contract and has been in place for over 50 years.

Q. HAVE YOU QUANTIFIED THE IMPACT OF NEGLECTING TO ACCOUNT FOR THE FULL REQUIREMENTS CONTRACT WITH WHEELING POWER COMPANY ON THE ENERGY CREDIT CALCULATED BY STAFF WITNESSES HARTER AND MEDINE?

A. Yes. I have estimated that recognizing the full requirements contract between Ohio Power Company and Wheeling Power Company would have reduced Staff witnesses Harter and Medine's energy credit by $5.00/MW-day. This analysis is included in Exhibit WAA- R5. To estimate the impact of recognizing this full requirements contract I have calculated the hourly average margins from Staff witness Medine's final work papers and then multiplied this value by the projected hourly load for Wheeling Power Company. This value is then subtracted from Staff witness Harter and Medine's projected margins to determine the impact on their energy credit. The Wheeling Power impact on the peak demands must also be addressed as shown in Exhibit WAA-R5.

Q. YOU INDICATED THAT THE NATURAL GAS PRICE FORECAST PRESENTED IN STAFF'S ANALYSIS SIGNIFICANTLY EXCEEDS THE CURRENT FORWARD PRICES. PLEASE EXPLAIN.

A. As I reviewed Staff's work papers I determined that the delivered natural gas prices that Staff witnesses Harter and Medine used for AEP Ohio's gas units was in excess of $4/MMBTU. On cross examination both Staff witnesses Harter and Medine acknowledged that the projected natural gas prices used in their analysis exceeded $4/MMBTU at the Henry hub. Current natural gas price forecasts indicate significantly lower prices. On cross examination Staff witness Medine admitted that EVA's current price projections for natural gas have been reduced since the time they performed their analysis. A reduction in natural gas price forecasts will reduce the projected market prices for electricity and as a result reduce the energy credit proposed by the Staff witnesses.

Q. YOU HAVE TESTIFIED THAT THE STAFF WITNESSES' UNDERESTIMATED COAL COSTS AND OVERESTIMATED MARKET PRICES AND ULTIMATELY CALCULATED REVISIONS TO THEIR ENERGY CREDIT TO REFLECT MORE APPROPRIATE ASSUMPTIONS. WOULD EITHER OF THESE CORRECTIONS IMPACT THE UNIT DISPATCH THAT THE STAFF WITNESSES PROJECTED?

A. Yes. Because the Staff witnesses' projected coal costs and market prices diverged from reasonable levels in significant and opposite directions the unit dispatch will be significantly impacted.

Q. IN YOUR ANALYSIS DID YOU ATTEMPT TO ADDRESS THE CHANGE IN UNIT DISPATCH THAT WOULD OCCUR AS A RESULT OF REPLACING THE STAFF WITNESSES' COAL COST ASSUMPTIONS AND MARKET PRICE ASSUMPTIONS?

A. Yes. As projected market prices decline and projected coal costs increase there is a potential that margins for certain generating units may change from positive to negative. In that case, the unit would not have been dispatched in the manner that the Staff witnesses had projected. When margins are negative for a unit over a long time horizon the unit will not run. To account for this change, I have calculated (consistent with the methodology described by Staff witness Medine) which units would have negative margins on an annual basis and removed those negative margins from my calculations. I have provided this calculation in Exhibit WAA-R6 and will refer to this impact as the "Cross Impact of Fuel and Market." This item ensures that the reduction in the energy credit that I have calculated is not overstated.

Q. CAN YOU SUMMARIZE THE IMPACT ON STAFF WITNESS HARTER AND MEDINE'S ENERGY CREDIT RELATED TO THE ERRORS THAT YOU HAVE PREVIOUSLY DISCUSSED?

A. Yes. The table below provides a summary of the estimated impact of each of the errors in Staff witness Harter's analysis that I have previously discussed. After incorporating the corrections I have discussed, Staff witness Medine's final energy credit is reduced to $47.46/MW-day.

	(\$/MW-day)
Medine's Energy Credit	**152.41**
Understated Fuel Cost for Coal Units	(70.10)
Understated Heat Rate for Gas Units	(1.87)
Overstated Market Prices	(50.42)
Failure to Recognize Wheeling Power Contract	(5.00)
Cross Impact of Fuel and Market	22.44
Energy Credit after Adjustments	**47.46**

<u>COST OF SERVICE ADJUSTMENTS</u>

Q. DO YOU AGREE WITH STAFF WITNESS SMITH'S RECOMMENDATION THAT CONSTRUCTION WORK IN PROGRESS (CWIP) SHOULD BE EXCLUDED FROM THE RATE BASE USED TO DETERMINE THE COMPANY'S COST OF CAPACITY?

A. No. Although Staff witness Smith makes several claims regarding the exclusion of CWIP from rate base he fails to recognize that the Company has recovered carrying costs on environmental CWIP through the Environmental Investment Carrying Cost Rider (EICCR). The EICCR is collected through current standard service offer (SSO) rates. Including, at a minimum, CWIP on environmental investments in rate base would ensure that all customers utilizing the Company's capacity resources, SSO customers and CRES providers, are treated similarly.

Q. HOW WOULD INCLUSION OF CWIP IN RATE BASE IMPACT THE CAPACITY COST CALCULATION PERFORMED BY STAFF WITNESS SMITH?

A. Including the environmental CWIP of \$33.862 million in rate base would increase the capacity charge rate by \$1.11/MW-day and inclusion of non-environmental

CWIP of $49.422 million in rate base would increase the capacity charge rate by an additional $1.64/MW-day. These calculations are provided in Exhibit WAA-R7.

Q. DO YOU AGREE WITH STAFF WITNESS SMITH'S RECOMMENDATION THAT THE PREPAID PENSION ASSET SHOULD BE EXCLUDED FROM THE RATE BASE USED TO DETERMINE THE COMPANY'S COST OF CAPACITY?

A. No. Prepaid pension assets are appropriate to include in the determination of rate base.

Q. HOW DID THE PUCO STAFF ADDRESS THE PREPAID PENSION ASSET IN AEP OHIO'S MOST RECENT DISTRIBUTION RATE CASES?

A. In AEP Ohio's most recent distribution rate cases (11-0351-EL-AIR & 11-0352-EL-AIR) the Staff "increased rated base to recognize a prepaid pension asset." The *Report by the Staff of the Public Utilities Commission of Ohio* in the 11-351-EL-AIR case goes on to state the following:

> The Staff increased rate base to recognize a prepaid pension asset. The Applicant recorded a prepaid asset of $86,403,823 for additional pension cash contributions as of the date certain, August 31, 2010. The additional contributions represent cash investments above the amount of the pension cost included in the cost of service or the income statement. The additional contributions benefit customers by reducing future pension costs through increased earnings. In accordance with generally accepted accounting principles under FASB No. 87 Employers' Accounting for Pensions, the cumulative difference between the pension cost and pension cash contributions is to be recorded on the balance sheet as an asset or liability. A prepaid asset is recorded if pension contributions are greater than the pension cost. A liability is recorded if pension contributions are less than the pension cost.

> The prepaid pension asset is entirely supported by cash contributions in excess of pension cost. None of the additional pension contributions serve to prefund the pension obligation in advance. The Staff agrees with the Applicant's adjustment. Including the additional cash contributions in rate base, that will be expensed in the future, allows for ratemaking recognition of the cost of funds for the prepaid contributions.

Q. HOW WOULD INCLUSION OF THE PREPAID PENSION ASSET IN RATE BASE IMPACT THE CAPACITY COST CALCULATION PERFORMED BY STAFF WITNESS SMITH?

A. Including the prepaid pension asset (net of ADIT) of $96.116 million in rate base would increase the capacity charge rate by $3.20/MW-day.

Q. DO YOU AGREE WITH STAFF WITNESS SMITH'S RECOMMENDATION THAT SEVERANCE COSTS SHOULD BE EXCLUDED FROM THE O&M EXPENSE ALLOCATED TO THE GENERATION DEMAND FUNCTION?

A. No. The severance costs were properly recorded as O&M expenses in 2010 and the benefits associated with the severance program will be reflected in future annual updates to the formula based capacity cost calculation presented by Company witness Pearce.

Q. HOW DID THE PUCO STAFF ADDRESS SEVERANCE COSTS IN AEP OHIO'S MOST RECENT DISTRIBUTION RATE CASES?

A. In AEP Ohio's most recent distribution rate cases (11-0351-EL-AIR & 11-0352-EL-AIR) the Staff recommended that 50% of the cost of the severance program be amortized over a period of three years. Staff reduced the amount of the amortization by 50% to reflect their position that the severance program benefited both shareholders and ratepayers. In this case, the benefits of the severance program are flowing through 100% to CRES providers through reduced capacity charges and therefore no such reduction should be made.

Q. **HOW WOULD INCLUSION OF A THREE-YEAR AMORTIZATION OF THE COST OF THE SEVERANCE PROGRAM IMPACT THE CAPACITY COST CALCULATION PERFORMED BY STAFF WITNESS SMITH?**

A. Amortizing the $39.004 million in severance costs[2] (that Staff witness Smith removed from O&M expense) over three years would increase the capacity charge rate by $4.07/MW-day[3].

Q. **DO YOU AGREE WITH STAFF WITNESS SMITH'S RECOMMENDATION TO SIMPLY USE THE ROEs STIPULATED TO IN THE COMPANY'S MOST RECENT DISTRIBUTION RATE CASE?**

A. No. The risk profiles of the generation and distribution functions are not the same. The Commission has most recently recognized an ROE of 10.5% for certain generating assets of AEP Ohio.

Q. **HOW WOULD INCLUSION OF THE 11.15% ROE AS PROPOSED BY AEP OHIO IMPACT THE CAPACITY COST CALCULATION PERFORMED BY STAFF WITNESS SMITH?**

A. Including an 11.15% ROE versus the ROEs used by Staff witness Smith would increase the capacity charge rate by $10.09/MW-day.

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[2] Page 51 lines 17-21 of the Direct Testimony of Staff witness Smith

[3] ($39.004M/3)÷9,061MW÷365days x 1.034126 = $4.07/MW-day

Q. HOW WOULD INCLUSION OF A 10.5% ROE IMPACT THE CAPACITY COST CALCULATION PERFORMED BY STAFF WITNESS SMITH?

A. Including a 10.5% ROE versus the ROEs used by Staff witness Smith would increase the capacity charge rate by $2.95/MW-day. Every 0.1% change in ROE changes the capacity charge rate an additional $1.08/MW-day.

Q. HAVE YOU PREPARED A SUMMARY OF THE ISSUES YOU HAVE DISCUSSED REGARDING THE TESTIMONY AND RECOMMENDATIONS OF STAFF WITNESS SMITH?

A. Yes. The table below provides a summary of impact on the capacity cost rate of each of the items I have described related to the testimony of Staff witness Smith.

Issue	Impact ($/MW-day)
Smith's Merged Capacity Rate	**$305.48**
Include Environmental CWIP	$1.11
Include Non-Environmental CWIP	$1.64
Include Pre-Paid Pension Asset	$3.20
Include Amortization of Severance Expense	$4.07
Revise ROE to 11.15%	$10.09
Merged Capacity Rate After Adjustments	**$325.59**

Q. HAVE YOU CALCULATED WHAT STAFF'S CAPACITY RATE WOULD BE IF YOU INCLUDED THE ADJUSTMENTS YOU HAVE RECOMMENDED FOR THE ENERGY CREDIT AND COST OF SERVICE ISSUES?

A. Yes. If you start with a capacity cost of $325.59/MW-day and subtract an energy credit of $47.46/MW-day and ancillary service revenues of $6.66/MW-day, the resultant capacity rate would be $271.47/MW-day.

REVENUE COMPARISON

Q. DO YOU RECALL TESTIMONY BY FES WITNESS LESSER IN WHICH HE COMPARED THE COMPANY'S BASE GENERATION RATES TO THE COMPANY'S FULL COST CAPACITY RATE?

A. Yes, he provides a table (Lesser Table 1 at page 21) in his testimony showing his comparison of the company's base generation rates to the company's full cost capacity rate.

Q. HAVE YOU REVIEWED THAT COMPARISON?

A. Yes, I have. My first observation is that he did not update his table to reflect the current data presented by Company witnesses Roush and Thomas in the Modified ESP 2 case. My second observation is that he incorrectly included ancillary services in his analysis. Ancillary service costs are recovered through the Transmission Cost Recovery Rider (TCRR). My third observation is that if you convert his "un-updated" rates into revenues (by simply multiplying the rates by the projected usage for each customer class) you see that the base generation revenues and full cost capacity plus ancillary service revenues are very close as shown in Table 1 below:

Table 1: Lesser Analysis Converted into Dollars

		Base Generation		
	R	C	I	Total
($/MWh)	22.15	26.27	17.07	21.34
(GWh)	14,616	14,317	19,262	48,195
($MM)	$ 324	$ 376	$ 329	$ 1,029
		Capacity and Ancillary Service		
	R	C	I	Total
($/MWh)	28.77	23.37	16.69	22.34
(GWh)	14,616	14,317	19,262	48,195
($MM)	$ 421	$ 335	$ 321	$ 1,077
		Difference		
($MM)				$ 48
(%)				4.7%

If you prepare the same analysis that FES witness Lesser presented in his testimony and update his data for current rates and exclude ancillary service revenues you see that the base generation rate are essentially equivalent to the full cost capacity rates. See Table 2 below:

Table 2: Lesser Analysis Corrected and Converted into Dollars

		Base Generation		
	R	C	I	Total
($/MWh)	23.82	28.1	18.25	22.87
(GWh)	14,616	14,317	19,262	48,195
($MM)	$ 348	$ 402	$ 352	$ 1,102
		Capacity		
	R	C	I	Total
($/MWh)	30.01	23.01	17.29	22.85
(GWh)	14,616	14,317	19,262	48,195
($MM)	$ 439	$ 329	$ 333	$ 1,101
		Difference		
($MM)				$ (1)
(%)				-0.1%

CURRENT SHOPPING LEVELS

Q. STAFF WITNESS MEDINE TESTIFIED THAT THE CURRENT LEVEL OF SHOPPED LOAD IN AEP OHIO IS 26%. IS THAT A CORRECT AND CURRENT VALUE?

A. No. In my direct testimony I presented data showing that the level of shopped load as of March 1, 2012 was 26%. Since that time the level of shopped load has continued to increase. As of April 30, 2012, the level of shopped load has increased to 30%. The table below provides a summary of the changes in shopped load by customer class that have occurred over that period.

Class	March 1, 2012	April 30, 2012	Change
Residential	8.43%	12.74%	4.31%
Commercial	41.44%	46.65%	5.21%
Industrial	28.10%	31.16%	3.06%
Total	26.08%	30.19%	4.11%

ESTIMATE OF AEP OHIO'S EARNINGS

Q. DO YOU RECALL A QUESTION FROM COMMISSIONER PORTER REGARDING THE PROJECTED EARNINGS OF AEP OHIO IF THE COMPANY COLLECTED A CAPACITY CHARGE RATE OF $355.72/MW-DAY FROM CRES PROVIDERS?

A. Yes. I have updated the analysis that I presented as Exhibit WAA-1 in my direct testimony to reflect recovery of a $355.72/MW-day capacity charge from CRES providers. I have held all other assumptions constant and simply removed the capacity revenues that would have been recovered under an RPM-based pricing mechanism and replaced those revenues with the revenues that would be recovered based upon the Company's proposed cost-based mechanism. This estimate is provided in Exhibit WAA-R8 and demonstrates that the Company's return on equity (ROE) would be a reasonable 12.2% in 2013.

CONCLUSIONS

Q. DOES THIS COMPLETE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes, it does.

Impact of Understated Fuel Cost on Staff's Energy Credit

Plant	Staff Projected Fuel Cost	Fuel Cost Based on Actual 2011	Understatement of Fuel Cost	Reduction in Staff Energy Credit*
Conesville	$ 528,232,158	$ 649,004,656	$ 120,772,498	$ 11.20
Gavin	*$ 866,338,192*	*$ 1,258,537,270*	$ 392,199,078	$ 36.37
Cardinal	$ 210,336,405	$ 276,853,743	$ 66,517,338	$ 6.17
Zimmer	$ 128,904,363	$ 207,646,353	$ 78,741,990	$ 7.30
Kammer	$ 44,289,699	$ 58,082,843	$ 13,793,144	$ 1.28
Muskingum River	$ 137,009,410	$ 145,310,812	$ 8,301,402	$ 0.77
Stuart	$ 298,051,215	$ 359,547,905	$ 61,496,690	$ 5.70
Other	$ 37,024,661	$ 51,192,272	$ 14,167,611	$ 1.31
Total	$ 2,250,186,102	$ 3,006,175,854	$ 755,989,752	$ 70.10

*(Understated Fuel Cost / 5CP / 365 days per year / 3 years) * % of Margins Retained

5 CP = 9061
% Margins Retained = 92%

Comparison of Staff's Heat Rate to 2011 Actual

Heatrate (BTU/kWh)				
Utility	Name	ID	Staff	2011 Actual*
Columbus Southern Power Co	AEP Waterford Facility	55503-CTG1	7,000	
Columbus Southern Power Co	AEP Waterford Facility	55503-CTG2	7,000	7,308
Columbus Southern Power Co	AEP Waterford Facility	55503-CTG3	7,000	
Columbus Southern Power Co	AEP Waterford Facility	55503-ST1	7,000	
Columbus Southern Power Co	Conesville	2840-3	10,319	
Columbus Southern Power Co	Conesville	2840-5	10,073	10,982
Columbus Southern Power Co	Conesville	2840-6	10,339	
Columbus Southern Power Co	Conesville	2840-4	9,429	10,551
Columbus Southern Power Co	Darby Electric Generating Station	55247-GT1	9,000	
Columbus Southern Power Co	Darby Electric Generating Station	55247-GT2	9,000	
Columbus Southern Power Co	Darby Electric Generating Station	55247-GT3	9,000	12,429
Columbus Southern Power Co	Darby Electric Generating Station	55247-GT4	9,000	
Columbus Southern Power Co	Darby Electric Generating Station	55247-GT5	9,000	
Columbus Southern Power Co	Darby Electric Generating Station	55247-GT6	9,000	
Columbus Southern Power Co	Picway	2843-5	11,079	16,149
Ohio Power Co	General James M Gavin	8102-1	9,635	
Ohio Power Co	General James M Gavin	8102-2	9,461	9,709
Ohio Power Co	Kammer	3947-1	9,128	
Ohio Power Co	Kammer	3947-2	9,186	10,711
Ohio Power Co	Kammer	3947-3	9,189	
Ohio Power Co	Muskingum River	2872-1	9,448	
Ohio Power Co	Muskingum River	2872-2	9,403	
Ohio Power Co	Muskingum River	2872-3	9,634	10,169
Ohio Power Co	Muskingum River	2872-4	9,140	
Ohio Power Co	Muskingum River	2872-5	9,073	
Ohio Power Co	Cardinal	2828-1	9,000	9,459
Columbus Southern Power Co	Lawrenceburg Energy Facility	55502-100	7,000	
Columbus Southern Power Co	Lawrenceburg Energy Facility	55502-1100	7,000	
Columbus Southern Power Co	Lawrenceburg Energy Facility	55502-1200	7,000	7,190
Columbus Southern Power Co	Lawrenceburg Energy Facility	55502-200	7,000	
Columbus Southern Power Co	Lawrenceburg Energy Facility	55502-2100	7,000	
Columbus Southern Power Co	Lawrenceburg Energy Facility	55502-2200	7,000	
Columbus Southern Power Co	J M Stuart	2850-1	9,381	
Columbus Southern Power Co	J M Stuart	2850-2	9,162	
Columbus Southern Power Co	J M Stuart	2850-3	9,370	
Columbus Southern Power Co	J M Stuart	2850-4	9,289	9,818
Columbus Southern Power Co	J M Stuart	2850-D1	10,850	
Columbus Southern Power Co	J M Stuart	2850-D2	10,850	
Columbus Southern Power Co	J M Stuart	2850-D3	10,850	
Columbus Southern Power Co	J M Stuart	2850-D4	10,850	
Columbus Southern Power Co	W H Zimmer	6019-ST1	9,522	10,024
Ohio Power Co	Philip Sporn	3938-2	9,442	
Ohio Power Co	Philip Sporn	3938-4	9,417	11,807
Ohio Power Co	Philip Sporn	3938-5	8,924	
Columbus Southern Power Co	Walter C Beckjord	2830-6	9,680	9,217

* Source - 2011 FERC Form 1

Impact of Incorrect Heat Rates on Staff's Energy Credit

		EVA Fuel Cost ($/MWh)				EVA Heat Rate (BTU/kW)
Plant	Unit	2012	2013	2014	2015	All Years
AEP Waterford Facility	55503-CTG1	30.53	32.97	34.97	38.91	7,000
AEP Waterford Facility	55503-CTG2	30.55	32.99	35.00	38.90	7,000
AEP Waterford Facility	55503-CTG3	30.54	32.98	34.99	38.90	7,000
AEP Waterford Facility	55503-ST1	30.78	32.88	34.85	38.98	7,000
Darby Electric Generating Station	55247-GT1	39.11	40.88	43.87	49.21	9,000
Darby Electric Generating Station	55247-GT2	39.10	40.88	43.93	49.22	9,000
Darby Electric Generating Station	55247-GT3	39.08	40.91	43.67	49.11	9,000
Darby Electric Generating Station	55247-GT4	38.91	40.79	43.74	49.11	9,000
Darby Electric Generating Station	55247-GT5	39.11	40.86	43.95	49.00	9,000
Darby Electric Generating Station	55247-GT6	38.99	40.67	43.53	49.38	9,000
Lawrenceburg Energy Facility	55502-100	30.12	32.51	34.69	38.65	7,000
Lawrenceburg Energy Facility	55502-1100	30.10	32.44	34.70	38.58	7,000
Lawrenceburg Energy Facility	55502-1200	30.10	32.44	34.73	38.58	7,000
Lawrenceburg Energy Facility	55502-200	30.14	32.47	34.63	38.61	7,000
Lawrenceburg Energy Facility	55502-2100	30.08	32.44	34.72	38.58	7,000
Lawrenceburg Energy Facility	55502-2200	30.07	32.45	34.72	38.62	7,000

Impact of Incorrect Heat Rates on Staff's Energy Credit

		Fuel Cost $/MMBTU				Actual 2011 Heat Rate (BTU/kW)
Plant	Unit	2012	2013	2014	2015	All Years
AEP Waterford Facility	55503-CTG1	4.36	4.71	5.00	5.56	7,308
AEP Waterford Facility	55503-CTG2	4.36	4.71	5.00	5.56	7,308
AEP Waterford Facility	55503-CTG3	4.36	4.71	5.00	5.56	7,308
AEP Waterford Facility	55503-ST1	4.40	4.70	4.98	5.57	7,308
Darby Electric Generating Station	55247-GT1	4.35	4.54	4.87	5.47	12,429
Darby Electric Generating Station	55247-GT2	4.34	4.54	4.88	5.47	12,429
Darby Electric Generating Station	55247-GT3	4.34	4.55	4.85	5.46	12,429
Darby Electric Generating Station	55247-GT4	4.32	4.53	4.86	5.46	12,429
Darby Electric Generating Station	55247-GT5	4.35	4.54	4.88	5.44	12,429
Darby Electric Generating Station	55247-GT6	4.33	4.52	4.84	5.49	12,429
Lawrenceburg Energy Facility	55502-100	4.30	4.64	4.96	5.52	7,190
Lawrenceburg Energy Facility	55502-1100	4.30	4.63	4.96	5.51	7,190
Lawrenceburg Energy Facility	55502-1200	4.30	4.63	4.96	5.51	7,190
Lawrenceburg Energy Facility	55502-200	4.31	4.64	4.95	5.52	7,190
Lawrenceburg Energy Facility	55502-2100	4.30	4.63	4.96	5.51	7,190
Lawrenceburg Energy Facility	55502-2200	4.30	4.64	4.96	5.52	7,190

Impact of Incorrect Heat Rates on Staff's Energy Credit

		Corrected Fuel Cost ($/MWh)				Generation (MWh)			
Plant	Unit	2012	2013	2014	2015	2012	2013	2014	2015
AEP Waterford Facility	55503-CTG1	31.88	34.42	36.51	40.62	94,483	385,767	240,755	4,179
AEP Waterford Facility	55503-CTG2	31.89	34.45	36.54	40.61	93,422	393,878	244,953	4,185
AEP Waterford Facility	55503-CTG3	31.88	34.43	36.53	40.61	93,496	392,395	243,849	4,023
AEP Waterford Facility	55503-ST1	32.14	34.33	36.38	40.70	160,806	682,752	386,838	0
Darby Electric Generating Station	55247-GT1	54.01	56.45	60.59	67.95	15,218	78,594	32,676	1,330
Darby Electric Generating Station	55247-GT2	54.00	56.45	60.67	67.97	15,600	75,801	34,489	1,299
Darby Electric Generating Station	55247-GT3	53.96	56.49	60.30	67.82	10,960	62,563	22,050	628
Darby Electric Generating Station	55247-GT4	53.74	56.33	60.40	67.83	10,543	52,273	22,411	635
Darby Electric Generating Station	55247-GT5	54.01	56.43	60.69	67.67	10,069	59,026	20,970	255
Darby Electric Generating Station	55247-GT6	53.84	56.17	60.11	68.20	8,518	50,142	21,604	972
Lawrenceburg Energy Facility	55502-100	30.94	33.39	35.63	39.70	155,275	698,529	433,328	16,423
Lawrenceburg Energy Facility	55502-1100	30.91	33.33	35.64	39.63	108,239	472,448	302,803	12,161
Lawrenceburg Energy Facility	55502-1200	30.91	33.32	35.67	39.63	105,908	468,839	296,887	13,910
Lawrenceburg Energy Facility	55502-200	30.95	33.35	35.57	39.66	155,740	694,091	414,489	13,472
Lawrenceburg Energy Facility	55502-2100	30.90	33.32	35.66	39.62	105,542	470,171	302,686	13,401
Lawrenceburg Energy Facility	55502-2200	30.88	33.33	35.66	39.67	102,601	470,473	303,238	15,541

Impact of Incorrect Heat Rates on Staff's Energy Credit

		Change in Margin				
Plant	Unit	2012	2013	2014	2015	Total
AEP Waterford Facility	55503-CTG1	$ (126,940)	$ (559,691)	$ (370,466)	$ (7,154)	
AEP Waterford Facility	55503-CTG2	$ (125,570)	$ (571,824)	$ (377,240)	$ (7,163)	
AEP Waterford Facility	55503-CTG3	$ (125,629)	$ (569,378)	$ (375,384)	$ (6,884)	
AEP Waterford Facility	55503-ST1	$ (217,816)	$ (987,871)	$ (593,102)	$ -	
Darby Electric Generating Station	55247-GT1	$ (226,745)	$ (1,224,011)	$ (546,178)	$ (24,929)	
Darby Electric Generating Station	55247-GT2	$ (232,415)	$ (1,180,492)	$ (577,266)	$ (24,366)	
Darby Electric Generating Station	55247-GT3	$ (163,174)	$ (975,082)	$ (366,835)	$ (11,744)	
Darby Electric Generating Station	55247-GT4	$ (156,304)	$ (812,324)	$ (373,469)	$ (11,883)	
Darby Electric Generating Station	55247-GT5	$ (150,025)	$ (918,878)	$ (351,135)	$ (4,769)	
Darby Electric Generating Station	55247-GT6	$ (126,528)	$ (777,050)	$ (358,295)	$ (18,289)	
Lawrenceburg Energy Facility	55502-100	$ (126,964)	$ (616,307)	$ (407,974)	$ (17,227)	
Lawrenceburg Energy Facility	55502-1100	$ (88,419)	$ (416,057)	$ (285,203)	$ (12,736)	
Lawrenceburg Energy Facility	55502-1200	$ (86,515)	$ (412,818)	$ (279,855)	$ (14,568)	
Lawrenceburg Energy Facility	55502-200	$ (127,395)	$ (611,746)	$ (389,598)	$ (14,119)	
Lawrenceburg Energy Facility	55502-2100	$ (86,184)	$ (413,976)	$ (285,232)	$ (14,032)	
Lawrenceburg Energy Facility	55502-2200	$ (83,734)	$ (414,351)	$ (285,745)	$ (16,292)	
Total		$ (2,250,359)	$ (11,461,854)	$ (6,222,977)	$ (206,155)	$ (20,141,345)
Reduction in Staff Energy Credit		$ 1.07	$ 3.19	$ 1.73	$ 0.14	$ 1.87

Exhibit WAA-R4
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Impact of Overstated Market Prices on Staff's Energy Credit

	Time Period	EVA AEP Zone Price (2012 $/MWh)	AEP-DAYTON HUB ATC $/MWh *	AEP Gen Hub ($/MWh)**	Variance ($/MWh)
	2012_06	$33.32	$29.26	$28.38	$4.94
	2012_07	$35.81	$32.72	$31.74	$4.07
	2012_08	$35.72	$32.72	$31.74	$3.98
	2012_09	$32.16	$28.00	$27.16	$5.00
	2012_10	$30.95	$29.31	$28.43	$2.52
	2012_11	$32.30	$29.31	$28.43	$3.87
	2012_12	$32.11	$29.31	$28.43	$3.68
2012 Average Price		$33.19	$29.77	$28.88	$4.32
	2013_01	$40.55	$33.56	$32.55	$8.00
	2013_02	$40.83	$33.56	$32.55	$8.28
	2013_03	$37.89	$32.56	$31.58	$6.31
	2013_04	$35.12	$32.56	$31.58	$3.53
	2013_05	$35.78	$32.73	$31.75	$4.03
	2013_06	$38.21	$34.55	$33.51	$4.70
	2013_07	$41.00	$37.56	$36.43	$4.56
	2013_08	$41.64	$37.56	$36.43	$5.21
	2013_09	$37.55	$33.30	$32.30	$5.25
	2013_10	$36.25	$32.76	$31.78	$4.47
	2013_11	$37.29	$32.76	$31.78	$5.51
	2013_12	$38.91	$32.76	$31.78	$7.13
2013 Average Price		$38.42	$33.85	$32.83	$5.58
	2014_01	$42.57	$36.37	$35.28	$7.29
	2014_02	$42.20	$36.37	$35.28	$6.92
	2014_03	$37.89	$36.37	$35.28	$2.61
	2014_04	$35.51	$36.37	$35.28	$0.23
	2014_05	$36.87	$36.37	$35.28	$1.59
	2014_06	$39.03	$36.37	$35.28	$3.75
	2014_07	$42.23	$36.37	$35.28	$6.95
	2014_08	$42.22	$36.37	$35.28	$6.94
	2014_09	$38.26	$36.37	$35.28	$2.98
	2014_10	$37.24	$36.37	$35.28	$1.96
	2014_11	$37.97	$36.37	$35.28	$2.69
	2014_12	$40.57	$36.37	$35.28	$5.30
2014 Average Price		$39.38	$36.37	$35.28	$4.10
	2015_01	$43.25	$38.53	$37.37	$5.88
	2015_02	$43.89	$38.53	$37.37	$6.51
	2015_03	$38.35	$38.53	$37.37	$0.97
	2015_04	$35.75	$38.53	$37.37	($1.63)
	2015_05	$36.58	$38.53	$37.37	($0.80)
2015 Average Price		$39.56	$38.53	$37.37	$2.19
Total Period Average		$37.88	$34.61	$33.57	$4.31

	2012	2013	2014	2015	Total
Generation (MWh)	29,860,815	39,172,824	38,934,213	16,695,375	124,663,226
Variance ($/MWh)	4.32	5.58	4.10	2.19	4.36
Impact ($)	$128,921,806	$218,752,540	$159,608,014	$36,524,339	$543,806,699
Impact ($/MW-day)	$61.17	$103.79	$75.73	$17.33	$50.42

*AEP Dayton Hub ATC Price Source: SNL Energy (www.SNL.com) as of 4-25-2012
** AEP Gen Hub generally trades at a 3% discount to AD Hub

Impact of Excluding WPCo Load from Energy Credit Calculation

Energy Credits

	CSP	Year	Total Generation (MWh)	Off System Sales (MWh)	Gross Margin (2012 $)	MLR[1]	Retained Margin (2012 $)	Energy Credit ($/MWd)[2]
(1)	June-Dec	2012	9,238,414	822,462	57,483,325	19%	50,921,910	$57.67
(2)		2013	19,051,169	3,609,324	121,142,148	19%	58,376,727	$65.32
(3)		2014	16,603,470	2,041,381	119,843,987	19%	105,812,482	$70.26
(4)	Jan-May	2015	5,515,974	59,094	52,957,091	19%	52,411,263	$84.12
(5)		Total						$68.07

	OPCo	Year	Total Generation (MWh)	Off System Sales (MWh)	Gross Margin (2012 $)	MLR[1]	Retained Margin[1] (2012 $)	Energy Credit ($/MWd)2
(6)	June-Dec	2012	21,868,821	9,152,981	250,626,361	22%	170,178,962	$161.14
(7)		2013	25,629,397	3,857,070	426,080,707	22%	385,838,009	$214.20
(8)		2014	25,654,769	3,970,787	432,393,371	22%	391,453,715	$217.32
(9)	Jan-May	2015	11,281,816	2,296,000	188,181,389	22%	162,069,500	$217.49
(10)		Total						$205.32

	Merged	Year	Total Generation (MWh)	Off System Sales (MWh)	Gross Margin (2012 $)	MLR[1]	Retained Margin[1] (2012 $)	Energy Credit ($/MWd)2	% Retained
(11)	June-Dec	2012	31,107,235	8,373,663	308,109,685	40%	254,734,719	$131.37	83%
(12)		2013	44,680,567	5,987,661	547,222,855	40%	504,342,136	$152.50	92%
(13)		2014	42,258,239	4,016,475	552,237,359	40%	521,922,064	$157.81	95%
(14)	Jan-May	2015	16,797,789	1,155,836	241,138,475	40%	231,196,780	$168.98	96%
(15)		Total	134,843,830		1,648,708,378		1,512,195,699	$152.41	92%

(16)	Average Margins in $/MW-day	$166.17		$152.41
(17)	Margins Associated with WPCO Load	110,968,863	x 92%	102,091,354
(18)	Margins Exluding WPCo Load	1,537,739,515		1,410,104,345
(19)	Average Margins Excl WPCo in $/MW-day	$160.75		$147.41
(20)	Impact of Excluding WPCo	$5.42		$5.00
(21)	WPCo Sales over Period in MWh	9,367,077		

1: The MLR is applied only to off system sales.
2: This calculation uses the 5 CP Demand numbers presented in KDP-5 and reprinted below.

		CSP	OPCO	Merged	WPCO	Excl WPCo
(22)	CP-5 (MW)	4126	4935	9061	325	8736

Cross Impact of Fuel and Market

		Unit Cost (Fuel + Emissions + VOM)				Avg Market Price				Generation			
Plant	Unit ID	2012	2013	2014	2015	2012	2013	2014	2015	2012	2013	2014	2015
Conesville	2840-3	33.80	28.24	28.24	28.24	28.88	32.83	35.28	37.37	444,031	0	0	0
Conesville	2840-4	44.89	46.30	46.24	45.70	28.88	32.83	35.28	37.37	1,376,981	2,575,123	2,512,688	997,476
Conesville	2840-5	33.70	37.00	36.93	35.44	28.88	32.83	35.28	37.37	1,170,893	2,126,457	2,091,505	852,113
Conesville	2840-6	33.70	36.92	36.85	35.39	28.88	32.83	35.28	37.37	1,066,426	1,993,266	1,955,637	820,312
Picway	2843-5	67.66	62.08	62.08	62.08	28.88	32.83	35.28	37.37	23,388	0	0	0
General James M Gavin	8102-1	25.48	28.22	28.08	27.05	28.88	32.83	35.28	37.37	6,101,568	10,406,813	10,403,928	4,301,187
General James M Gavin	8102-2	25.48	28.21	28.07	27.04	28.88	32.83	35.28	37.37	6,101,568	10,406,880	10,406,132	4,304,370
Kammer	3947-1	41.11	58.80	57.86	51.31	28.88	32.83	35.28	37.37	598,899	42,895	59,515	136,135
Kammer	3947-2	41.12	59.01	58.09	51.41	28.88	32.83	35.28	37.37	294,288	17,795	23,523	58,152
Kammer	3947-3	41.11	58.99	58.02	51.39	28.88	32.83	35.28	37.37	295,068	18,731	26,083	60,902
Muskingum River	2872-1	32.30	26.69	26.69	26.69	28.88	32.83	35.28	37.37	723,672	0	0	0
Muskingum River	2872-2	32.30	26.69	26.69	26.69	28.88	32.83	35.28	37.37	720,723	0	0	0
Muskingum River	2872-3	32.31	78.66	26.69	26.69	28.88	32.83	35.28	37.37	617,241	55	0	0
Muskingum River	2872-4	32.29	26.69	26.69	26.69	28.88	32.83	35.28	37.37	827,059	0	0	0
Muskingum River	2872-5	32.02	46.65	26.69	40.43	28.88	32.83	35.28	37.37	2,170,555	13,003	0	371,106
Racine	6006-1	3.88	3.88	3.88	3.88	28.88	32.83	35.28	37.37	9,544	17,504	17,504	7,960
Racine	6006-2	3.88	3.88	3.88	3.88	28.88	32.83	35.28	37.37	9,544	17,504	17,504	7,960
Cardinal	2828-1	25.49	27.40	27.30	26.59	28.88	32.83	35.28	37.37	2,680,992	4,572,720	4,572,720	1,891,519
J M Stuart	2850-1	34.45	36.49	36.38	35.58	28.88	32.83	35.28	37.37	490,143	905,398	937,452	360,154
J M Stuart	2850-2	34.45	36.37	36.31	35.52	28.88	32.83	35.28	37.37	607,974	1,125,612	1,087,054	438,639
J M Stuart	2850-3	34.45	35.67	35.65	35.10	28.88	32.83	35.28	37.37	580,821	1,121,429	1,085,715	431,685
J M Stuart	2850-4	34.45	36.15	36.10	35.39	28.88	32.83	35.28	37.37	590,286	1,103,652	1,059,314	426,818
J M Stuart	2850-D1	29.11	35.68	35.68	35.57	28.88	32.83	35.28	37.37	0	71	12	0
J M Stuart	2850-D2	29.11	35.68	35.68	35.57	28.88	32.83	35.28	37.37	0	73	12	0
J M Stuart	2850-D3	29.11	35.68	35.68	35.57	28.88	32.83	35.28	37.37	0	72	12	0
J M Stuart	2850-D4	29.11	35.68	35.68	35.57	28.88	32.83	35.28	37.37	0	72	12	0
W H Zimmer	6019-ST1	32.27	36.81	36.62	34.82	28.88	32.83	35.28	37.37	1,525,307	2,590,260	2,542,364	1,066,146
Philip Sporn	3938-2	47.31	60.42	59.71	54.87	28.88	32.83	35.28	37.37	355,947	54,890	61,749	65,216
Philip Sporn	3938-4	47.31	60.35	59.64	54.80	28.88	32.83	35.28	37.37	362,151	60,607	66,110	77,310
Philip Sporn	3938-5	0.00	0.00	0.00	0.00	28.88	32.83	35.28	37.37	0	0	0	0
Walter C Beckjord	2830-6	29.73	44.41	43.68	38.39	28.88	32.83	35.28	37.37	115,745	1,942	7,670	20,216

Cross Impact of Fuel and Market

		Unit Margins			
Plant	Unit ID	2012	2013	2014	2015
Conesville	2840-3	$ (2,186,196)	$ -	$ -	$ -
Conesville	2840-4	$ (22,052,823)	$ (34,685,866)	$ (27,553,370)	$ (8,305,988)
Conesville	2840-5	$ (5,643,218)	$ (8,860,738)	$ (3,451,269)	$ 1,647,278
Conesville	2840-6	$ (5,143,364)	$ (8,146,387)	$ (3,078,951)	$ 1,628,215
Picway	2843-5	$ (907,177)	$ -	$ -	$ -
General James M Gavin	8102-1	$ 20,705,992	$ 47,988,074	$ 74,852,763	$ 44,420,496
General James M Gavin	8102-2	$ 20,705,870	$ 48,112,548	$ 74,985,669	$ 44,484,141
Kammer	3947-1	$ (7,327,745)	$ (1,113,642)	$ (1,344,175)	$ (1,896,998)
Kammer	3947-2	$ (3,602,242)	$ (465,858)	$ (536,657)	$ (816,446)
Kammer	3947-3	$ (3,609,035)	$ (489,974)	$ (593,150)	$ (853,302)
Muskingum River	2872-1	$ (2,477,214)	$ -	$ -	$ -
Muskingum River	2872-2	$ (2,466,242)	$ -	$ -	$ -
Muskingum River	2872-3	$ (2,117,467)	$ (2,536)	$ -	$ -
Muskingum River	2872-4	$ (2,820,449)	$ -	$ -	$ -
Muskingum River	2872-5	$ (6,831,760)	$ (179,678)	$ -	$ (1,134,466)
Racine	6006-1	$ 238,578	$ 506,824	$ 549,611	$ 266,608
Racine	6006-2	$ 238,578	$ 506,824	$ 549,611	$ 266,608
Cardinal	2828-1	$ 9,093,197	$ 24,844,296	$ 36,498,367	$ 20,402,066
J M Stuart	2850-1	$ (2,730,108)	$ (3,308,726)	$ (1,028,424)	$ 647,177
J M Stuart	2850-2	$ (3,390,769)	$ (3,984,520)	$ (1,121,765)	$ 813,809
J M Stuart	2850-3	$ (3,237,396)	$ (3,181,094)	$ (402,208)	$ 980,607
J M Stuart	2850-4	$ (3,290,558)	$ (3,656,947)	$ (866,952)	$ 848,923
J M Stuart	2850-D1	$ -	$ (203)	$ (5)	$ -
J M Stuart	2850-D2	$ -	$ (207)	$ (5)	$ -
J M Stuart	2850-D3	$ -	$ (205)	$ (5)	$ -
J M Stuart	2850-D4	$ -	$ (204)	$ (5)	$ -
W H Zimmer	6019-ST1	$ (5,173,586)	$ (10,291,452)	$ (3,410,517)	$ 2,721,398
Philip Sporn	3938-2	$ (6,560,256)	$ (1,514,242)	$ (1,508,509)	$ (1,140,828)
Philip Sporn	3938-4	$ (6,674,342)	$ (1,667,497)	$ (1,610,548)	$ (1,347,072)
Philip Sporn	3938-5	$ -	$ -	$ -	$ -
Walter C Beckjord	2830-6	$ (98,936)	$ (22,475)	$ (64,447)	$ (20,439)

Sum of Negative Margins	$ (98,340,883)	$ (81,572,451)	$ (46,570,959)	$ (15,515,538)	$ (241,999,832)
Reduction in Staff Energy Credit					22.44

Cost of Service Adjustments

Prepaid Pension Asset

	CSP	OPCo	AEP Ohio	Source
Prepaid Pension Asset	$ 39,795,915	$ 73,652,528	$ 113,448,443	Exhibit RCS-1/2 Schedule 8 pg 5 & pg 22
Associated ADIT	$ (3,627,511)	$ (13,705,181)	$ (17,332,692)	Exhibit RCS-1/2 Schedule 8-1
	$ 36,168,404	$ 59,947,347	$ 96,115,751	
Weighted Cost of Capital	7.78%	7.97%	7.90%	Exhibit RCS-1/2 Schedule 8 pg 1
Return on Rate Base	$ 2,813,902	$ 4,777,804	$ 7,591,705	
Income Tax @ 35%	$ 984,866	$ 1,672,231	$ 2,657,097	
Revenue Requirement	$ 3,798,767	$ 6,450,035	$ 10,248,802	
5 CP Demand			9061	
Days per Year			365	
Impact on Capacity Charge Rate			$ 3.10	
Loss Factor			1.034126	
Final Impact on Capacity Charge Rate			$ 3.20	

Cost of Service Adjustments

Pollution Control CWIP

	CSP	OPCo	AEP Ohio	Source
Pollution Control CWIP	$ 22,821,421	$ 10,860,321	$ 33,681,742	Exhibit RCS-1/2 Schedule B pg 1
Weighted Cost of Capital	7.78%	7.97%	7.84%	Exhibit RCS-1/2 Schedule B pg 1
Return on Rate Base	$ 1,775,507	$ 865,568	$ 2,641,074	
Income Tax @ 35%	$ 621,427	$ 302,949	$ 924,376	
Revenue Requirement	$ 2,396,934	$ 1,168,516	$ 3,565,450	
5 CP Demand			9061	
Days per Year			365	
Impact on Capacity Charge Rate			$ 1.08	
Loss Factor			1.034126	
Final Impact on Capacity Charge Rate			$ 1.11	

Cost of Service Adjustments

Non-Pollution Control CWIP

	CSP	OPCo	AEP Ohio	Source
Non-Pollution Control CWIP	$ 27,563,093	$ 21,859,033	$ 49,422,126	Exhibit RCS-1/2 Schedule B pg 1
Weighted Cost of Capital	7.78%	7.97%	7.86%	Exhibit RCS-1/2 Schedule B pg 1
Return on Rate Base	$ 2,144,409	$ 1,742,165	$ 3,886,574	
Income Tax @ 35%	$ 750,543	$ 609,758	$ 1,360,301	
Revenue Requirement	$ 2,894,952	$ 2,351,923	$ 5,246,874	
5 CP Demand			9061	
Days per Year			365	
Impact on Capacity Charge Rate			$ 1.59	
Loss Factor			1.034126	
Final Impact on Capacity Charge Rate			$ 1.64	

Cost of Service Adjustments

Impact of Change in ROE - Ohio Power

Per Staff - Ohio Power

		Total Company Capitalization	Weighted Cost Ratio	Cost of Capital	Weighted Cost of Capital
Long-Term Debt	$	2,734,580,000	45.93%	5.27%	2.42%
Preferred Stock	$	16,626,000	0.28%	3.87%	0.01%
Common Stock	$	3,202,486,000	53.79%	10.30%	5.54%
Total	$	5,953,692,000	100.00%		7.97%

At 11.15% - Ohio Power

		Total Company Capitalization	Weighted Cost Ratio	Cost of Capital	Weighted Cost of Capital
Long-Term Debt	$	2,734,580,000	45.93%	5.27%	2.42%
Preferred Stock	$	16,626,000	0.28%	3.87%	0.01%
Common Stock	$	3,202,486,000	53.79%	11.15%	6.00%
Total	$	5,953,692,000	100.00%		8.43%

Change		0.46%
Rate Base	$	3,475,504,866
Return on Rate Base	$	15,890,505
Income Tax @ 35%	$	5,561,677
Revenue Requirement	$	21,452,182
5 CP Demand		9,061
Days per Year		365
Impact on Capacity Charge Rate	$	6.49
Loss Factor		1.034126
Final Impact on Capacity Charge Rate	$	6.71

Cost of Service Adjustments

Impact of Change in ROE - CSP

Per Staff - CSP

		Total Company Capitalization	Weighted Cost Ratio	Cost of Capital	Weighted Cost of Capital
Long-Term Debt	$	1,442,745,000	49.36%	5.50%	2.71%
Preferred Stock	$	-	0.00%	0.00%	0.00%
Common Stock	$	1,480,405,000	50.64%	10.00%	5.06%
Total	$	2,923,150,000	100.00%		7.78%

At 11.15% - CSP

		Total Company Capitalization	Weighted Cost Ratio	Cost of Capital	Weighted Cost of Capital
Long-Term Debt	$	1,442,745,000	49.36%	5.50%	2.71%
Preferred Stock	$	-	0.00%	0.00%	0.00%
Common Stock	$	1,480,405,000	50.64%	11.15%	5.65%
Total	$	2,923,150,000	100.00%		8.36%

Change		0.58%
Rate Base	$	1,375,724,666
Return on Rate Base	$	8,012,330
Income Tax @ 35%	$	2,804,315
Revenue Requirement	$	10,816,645
5 CP Demand		9,061
Days per Year		365
Impact on Capacity Charge Rate	$	3.27
Loss Factor		1.034126
Final Impact on Capacity Charge Rate	$	3.38

Exhibit WAA-R8

Estimate of Ohio Power's Earnings

	Ohio Power Company					
	2012			2013		
	$ millions	$ millions	ROE	$ millions	$ millions	ROE
Projected Earnings (Two Tiered Capacity Pricing)		471	10.4%		331	7.3%
Estimate of February 23, 2012 Ruling:						
Additional Switching net of OSS Margins and Capacity Revenues	(194)			(341)		
Income Taxes	68			119		
Total adjustment (after-Tax)		(126)			(222)	
Projected Earnings (all capacity at RPM)		344	7.6%		109	2.4%
Remove RPM Capacity Revenue				(70)		
Add Capacity Revenue @ 356/MW-day				753		
Income Taxes				(239)		
Total adjustment (after-Tax)					444	
Projected Earnings (all capacity $356/MW-day)					553	12.2%

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of Ohio Power Company's Pre-filed Rebuttal Testimony of William A. Allen have been served upon the below-named counsel and Attorney Examiners by electronic mail to all Parties this 11th day of May, 2012.

/s/ Steven T. Nourse
Steven T. Nourse

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BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

\- - -

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company. : Case No. 10-2929-EL-UNC

\- - -

PROCEEDINGS

before Ms. Greta See and Ms. Sarah Parrot, Attorney Examiners, and Commissioner Andre Porter, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 9:00 a.m. on Thursday, April 19, 2012.

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VOLUME III

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\- - -

just talked about it here on the commercial class, there's a lot of headroom, okay. At 355 a CRES provider has a gross margin of 13.7 percent on an average class basis. That's a pretty significant margin. That's about $8 a megawatt hour.

I think there's plenty of opportunity for different prices. We're not debating whether or not CRES providers can earn large profits or small profits. What we need to look at is AEP being fairly compensated for the use of its capacity. We shouldn't just transfer profits from AEP to CRES providers.

Q. But aren't those two distinct questions; what is the financial -- what is the revenue that -- the amount of revenue that AEP needs to receive from its capacity charge in order to be financially whole or at least not to have its profit confiscated and then the economic relative equity of what each customer should pay?

A. So to answer your first question on the level of revenues that AEP should receive, you know, we've talked about the $355 a megawatt day price and questions have come out through the hearing to talk about what -- about the SSO rates.

If you do a comparison of our SSO rates

to the capacity rates, we've talked about are they close. There has been a lot of discussion about that with various witnesses and, in fact, you know, that's been kind of passed off to me to answer what we -- is that our base G revenue to serve all of our load would be $1 billion 102 million dollars.

If we were to price all of our capacity at $355.72, price that out for all of our load, the revenues of the company would be 1 billion 101 million dollars, a $1 million difference. If you -- and that's based upon my analysis.

If you do the same analysis looking at the testimony of FES Witness Lesser, Table 1, he presents a comparison of the prices that AEP charges SSO customers and the capacity rates.

He's got a few errors in his table, but if you just take for granted that his table is accurate, it shows there is a $48 million difference in those revenues. The point at which the capacity rate would equal the SSO rate from a revenue perspective based on his analysis shows it $340 a megawatt day.

So the revenue the company should be receiving is in line with the $355 a megawatt day price that the company has presented, so that's the answer to your first question about revenues.

And what we've seen is that level of revenue produced a return for the company on a per-books basis in 2011 of about 10-1/2 percent, on an ongoing basis 12 percent. Those are very reasonable returns.

And your second question was about how much margin should CRES providers receive.

Q. That was not my question.

A. I'm sorry, what was the second part of your question?

Q. Was -- I was asking you should we be setting the -- should we be considering equity for the individual charge of that rate besides the company's financial?

But let me withdraw that part of the question now because I want to focus down so we have a record here that's fairly clear and fairly concise on what is the fair revenue requirement for the company.

And with that look at your testimony on -- on page 3, lines 3 to 5.

A. Kind of got papers everywhere. Give me just a second.

What was that reference again?

IEU-Ohio Exhibit 12

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company	))))	Case No. 10-2929-EL-UNC

DIRECT TESTIMONY

OF

JONATHAN A. LESSER

ON BEHALF OF

FIRSTENERGY SOLUTIONS CORP.

April 4, 2012

words, the price difference cannot be justified based on different costs to serve the two groups.

For example, suppose we look at the cost to provide electric service to two residential apartments, A and B, located in the same building. The average cost (per kWh) to serve those two apartments is the same. There is no difference in the cost of reading each apartment's electric meter or sending out a bill. There is no difference in the cost of maintaining the distribution line that serves the entire apartment building. If both apartments take SSO service, then clearly there is no difference in the costs to provide service to each apartment and, as such, AEP Ohio cannot charge each a different price for capacity and energy.

Suppose, however, that apartment A is an SSO customer but that apartment B purchases electricity, including capacity, from a CRES provider. In this case, AEP Ohio sells energy to apartment A, whereas the CRES provider sells energy to apartment B. However, because AEP Ohio is an FRR entity, it provides the physical capacity associated with the energy sales to both apartments. The <u>only</u> difference is that, for apartment B, AEP Ohio first sells that capacity to a CRES provider, who then sells it, along with energy, to apartment B.

Clearly, there is no physical difference whatsoever in the cost AEP Ohio incurs to provide capacity to both apartments. Thus, there is no economic basis for AEP Ohio to charge a different capacity price for each apartment, and charging apartment B a higher price for capacity than apartment A is clearly discriminatory.

Q. HAVE YOU COMPARED AEP OHIO'S EMBEDDED COST OF CAPACITY RATES WITH ITS BGR RATES?

A. Yes. Table 1 compares the BGR rates under ESP I, which is currently in effect, and AEP Ohio's embedded capacity and ancillary service costs. As Table 1 shows, AEP Ohio's embedded capacity costs, when converted to a per-MWh basis, plus its estimated ancillary service costs, are significantly greater than what it charges residential customers of CSP and OPC, and are greater than what CSP industrial customers are charged.

The capacity rates in Table 1 are based on the $355.72/MW-day value of AEP Ohio witness Pearce, which was converted to a per-MWh value for each customer class by ESP II witness Thomas.[24] Similarly, the ancillary services cost of $0.60/MWh is taken directly from Ms. Thomas's testimony in the ESP II Stipulation case.

[24] AEP Ohio witness Horton wrongly estimates capacity charges on a per-MWh basis in his testimony. as he simply divides the per 2012/13 RPM delivered price of $20/MW-day by 24 to derive a per-MWh price of $0.83. Mr. Horton's calculation fails to account for the load factor of different customers, as Ms. Thomas did in her Stipulation testimony.

Table 1: Comparison of BGR and Capacity/Ancillary Services Rates

	BGR Rates - ESP I ($/MWh)		
Company	R	C	I
CSP	$20.13	$25.98	$14.43
OP	$24.21	$26.54	$18.05
AEP Ohio	$22.15	$26.27	$17.07

Source: Roush Workpapers, ESP II

	Capacity Rates ($/MWh)		
Company	R	C	I
CSP	$28.17	$22.77	$16.09
OP	$28.17	$22.77	$16.09
AEP Ohio	$28.17	$22.77	$16.09

Source: Thomas - ESP II, Exhibit UT-1

	Ancillary Service Rates ($/MWh)		
Company	R	C	I
CSP	$0.60	$0.60	$0.60
OP	$0.60	$0.60	$0.60
AEP Ohio	$0.60	$0.60	$0.60

Source: Thomas - ESP II, Exhibit UT-1

	Capacity + Ancillary Service Rates ($/MWh)		
Company	R	C	I
CSP	$28.77	$23.37	$16.69
OP	$28.77	$23.37	$16.69
AEP Ohio	$28.77	$23.37	$16.69

	Difference from BGR Rates ($/MWh)		
Company	R	C	I
CSP	($8.64)	$2.61	($2.26)
OP	($4.56)	$3.17	$1.36
AEP Ohio	($6.62)	$2.90	$0.38

Q. **WHY IS THIS SIGNIFICANT?**

A. AEP Ohio cannot charge a lower price for capacity to its SSO customers than it charges CRES providers, because doing so violates comparability and is price discriminatory. However, because some of the BGR rates, which include energy, capacity, and ancillary service charges, are below AEP Ohio's own estimates of embedded capacity and ancillary service costs, AEP Ohio's BGR charged to SSO

IEU-Ohio Exhibit 13

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-01 Section 2-1 of the 2010 Report of the Management/Performance and Financial Audits of the FAC ("Audit Report") of CSP and OPCo states that "[i]n March 2007, CSP and AEG entered into a 10-year agreement for the entire output of Lawrenceburg and pays for capacity, depreciation, fuel, and other operating costs." For each month in 2010, identify the amount of capacity, depreciation, and other operating costs associated with the Lawrenceburg Generating Station ("Lawrenceburg") that CSP recovered through the fuel adjustment clause ("FAC").

RESPONSE

Please refer to Question No. IEU-RPD-1-02 document "LA-2010-2-130 attachment 1".

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-02 Identify the total kilowatt hours of electricity output produced by the Lawrenceburg unit in 2010.

RESPONSE

The total kilowatt hours of electricity output produced by the Lawrenceburg units in 2010 is 1,547,862,000.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-03 CSP and OPCo are required to allocate least cost generating resources to serve standard service offer ("SSO") load. Identify the total kilowatt hours of electricity output produced by the Lawrenceburg unit in 2010 that CSP allocated to serve SSO customers.

RESPONSE

The Company does not have a readily available means of tracking the kilowatt hours that are allocated to serve SSO customers specifically. However, the total kilowatt hours of electricity output produced by the Lawrenceburg units in 2010 that CSP allocated to internal load customers was 1,341,643,000.

OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST PUCO CASE NOS. 11-281-EL-FAC FIRST SET

INTERROGATORY

INT-1-04 Identify the total kilowatt hours of electricity output produced by the Lawrenceburg unit in 2011.

RESPONSE

The total kilowatt hours of electricity output produced by the Lawrenceburg units in 2011 is 4,027,173,000

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-05 Identify the total kilowatt hours of electricity output produced by the Lawrenceburg unit in 2011 that CSP allocated to serve SSO customers.

RESPONSE

The Company does not have a readily available means of tracking the kilowatt hours that are allocated to serve SSO customers specifically. However, the total kilowatt hours of electricity output produced by the Lawrenceburg units in 2011 that CSP allocated to serve internal load customers was 3,541,911,000

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-06 Identify whether CSP or OPCo recovered non-fuel expenses associated with the Ohio Valley Electric Corporation ("OVEC") generating units through the FAC in 2010 and 2011.

RESPONSE

Yes, CSP and OPCo recovered non-fuel expenses associated with the OVEC generating units through the FAC in 2010 and 2011.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-07 For each month in 2010, identify each non-fuel expense and the total amount of expenses associated with OVEC generating units that CSP and OPCo recovered through the FAC. Identify these costs separately for CSP and OPCo.

RESPONSE

See IEU-INT-1-7 Attachment 1.

**OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET**

INTERROGATORY

INT-1-08 Identify the total kilowatt hours of electricity output produced by the OVEC generating units in 2010.

RESPONSE

The total kilowatt hours of electricity output produced by the OVEC units in 2010 was 14,634,079,000.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-09 CSP and OPCo are required to allocate least cost generating resources to serve SSO load. For each company, identify the total kilowatt hours of electricity output produced by the OVEC generating units in 2010 that CSP and OPCo allocated to serve SSO customers.

RESPONSE

The total kilowatt hours of electricity output produced by the OVEC units in 2010 that CSP and OPCo allocated to serve SSO customers was 455,124,000 and 1,729,184,000, respectively.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-010 For each month in 2011, identify each non-fuel expense and the total amount of expenses associated with OVEC generating units that CSP and OPCo recovered through the FAC. Identify these costs separately for CSP and OPCo.

RESPONSE

See IEU-INT-1-10 Attachment 1.

**OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET**

INTERROGATORY

INT-1-011 Identify the total kilowatt hours of electricity output produced by the OVEC generating units in 2011.

RESPONSE

The total kilowatt hours of electricity output produced by the OVEC units in 2011 was 14,468,168,000.

OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST PUCO CASE NOS. 11-281-EL-FAC FIRST SET

INTERROGATORY

INT-1-012 For each company, identify the total kilowatt hours of electricity output produced by the OVEC generating units in 2011 that CSP and OPCo allocated to serve SSO customers.

RESPONSE

The total kilowatt hours of electricity output produced by the OVEC units in 2011 that CSP and OPCo allocated to serve SSO customers was 245,771,000 and 980,836,000, respectively.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-018 In 1953, AEP-Ohio entered into an Intercompany Power Agreement ("ICPA") with other sponsoring companies of OVEC, correct?

RESPONSE

Correct.

OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST PUCO CASE NOS. 11-281-EL-FAC FIRST SET

INTERROGATORY

INT-1-019 AEP-Ohio and the parties to the ICPA amended and restated the ICPA on August 11, 2011, correct?

RESPONSE

No, there was no amended and restated ICPA on August 11, 2011. An Amended and Restated Inter-Company Power Agreement was filed April 27, 2011. FERC issued an order approving the ICPA on May 23, 2011.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-020 The August amendment to the ICPA extended the duration of the ICPA until June 30, 2040, correct?

RESPONSE

Correct. The April 27, 2011 Filing extended the ICPA until June 30, 2040.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-021 Identify when the ICPA would have terminated if AEP-Ohio had not amended the ICPA on August 11, 2011.

RESPONSE

If FERC denied the April 27, 2011 amended ICPA, then the previous ICPA would terminate March 13, 2026.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-01 Section 7-71 of the 2010 Audit Report states "The non-fuel purchased power costs associated with Lawrenceburg are included in the FAC for CSP as shown on the EXH CSP-1 workpaper, which was included in the FAC workbooks provided in LA-2010-43." Produce a copy of LA-2010-43.

RESPONSE

Please see the LA-2010-43 CONFIDENTIAL zip file on the enclosed CD. This response provides Accounting's summary schedules and monthly workbooks of actual cycle computations of under/over-recovery along with carrying charge computations.

**OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-02 Section 7-71 of the 2010 Audit Report states, "In data request LA-2010-2-130, Larkin asked for a summary of the non-energy components related to Lawrenceburg that were included in the FAC during 2010 and to also show how the capacity factor associated with Lawrenceburg was derived. In response, AEP Ohio provided a schedule which showed a breakout (by amount and account) of the Lawrenceburg related costs included in the FAC for each month of 2010." Produce a copy of the schedule that shows the "Lawrenceburg related costs included in the FAC for each month of 2010."

RESPONSE

See LA-2010-2-130 on the enclosed CD.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

<u>REQUEST FOR PRODUCTION OF DOCUMENTS</u>

RPD-1-03 Section 7-73 of the 2011 Audit Report states, "The non-fuel purchased power costs associated with Lawrenceburg are included in the FAC for CSP as shown on the EXH CSP-1 workpaper, which was included in the FAC workbooks provided in LA-2011-49. In data request LA-2011-57, Larkin asked for a summary of the non-energy components related to Lawrenceburg that were included in the FAC during 2011. In its confidential response, AEP Ohio provided a schedule which showed a breakout (by amount and account) of the Lawrenceburg related costs included in the FAC for each month of 2011." Produce copies of the FAC workbooks provided in LA-2011-49 and the schedule "of Lawrenceburg related costs included in the FAC for each month of 2011."

<u>RESPONSE</u>

This response, in the LA 2011-49 CONFIDENTIAL zip file on the enclosed CD, provides Accounting's summary schedules and monthly workbooks of actual cycle computations of under/over-recovery along with carrying charge computations.

In addition, please see LA-2011-1-57 Confidential Attachment 1.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-04 Produce a copy of the amended and restated ICPA that AEP-Ohio executed on August 11, 2011.

RESPONSE

See IEU-RPD-1-4 Attachment 1 for the amended and restated ICPA that AEP Ohio executed on April 27, 2011.

In addition, see IEU-RPD-1-4 Attachment 2 for the order approving the amendment.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-05 Produce a copy of the ICPA that existed before AEP-Ohio amended and restated the ICPA on August 11, 2011.

RESPONSE

See IEU-RPD-1-5 Attachment 1 for the ICPA that existed before AEP-Ohio amended and restated the ICPA on April 27, 2011.

OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST PUCO CASE NOS. 11-281-EL-FAC FIRST SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-06 Produce of a copy of the contract between CSP and AEP Generating Company identified on Section 2-1 of the 2010 Audit Report.

RESPONSE

See IEU-RPD-1-6 Confidential Attachment 1.

IEU-Ohio Exhibit 13

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-01 Section 2-1 of the 2010 Report of the Management/Performance and Financial Audits of the FAC ("Audit Report") of CSP and OPCo states that "[i]n March 2007, CSP and AEG entered into a 10-year agreement for the entire output of Lawrenceburg and pays for capacity, depreciation, fuel, and other operating costs." For each month in 2010, identify the amount of capacity, depreciation, and other operating costs associated with the Lawrenceburg Generating Station ("Lawrenceburg") that CSP recovered through the fuel adjustment clause ("FAC").

RESPONSE

Please refer to Question No. IEU-RPD-1-02 document "LA-2010-2-130 attachment 1".

OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST PUCO CASE NOS. 11-281-EL-FAC FIRST SET

INTERROGATORY

INT-1-02 Identify the total kilowatt hours of electricity output produced by the Lawrenceburg unit in 2010.

RESPONSE

The total kilowatt hours of electricity output produced by the Lawrenceburg units in 2010 is 1,547,862,000.

**OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET**

INTERROGATORY

INT-1-03 CSP and OPCo are required to allocate least cost generating resources to serve standard service offer ("SSO") load. Identify the total kilowatt hours of electricity output produced by the Lawrenceburg unit in 2010 that CSP allocated to serve SSO customers.

RESPONSE

The Company does not have a readily available means of tracking the kilowatt hours that are allocated to serve SSO customers specifically. However, the total kilowatt hours of electricity output produced by the Lawrenceburg units in 2010 that CSP allocated to internal load customers was 1,341,643,000.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-04 Identify the total kilowatt hours of electricity output produced by the Lawrenceburg unit in 2011.

RESPONSE

The total kilowatt hours of electricity output produced by the Lawrenceburg units in 2011 is 4,027,173,000

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-05 Identify the total kilowatt hours of electricity output produced by the Lawrenceburg unit in 2011 that CSP allocated to serve SSO customers.

RESPONSE

The Company does not have a readily available means of tracking the kilowatt hours that are allocated to serve SSO customers specifically. However, the total kilowatt hours of electricity output produced by the Lawrenceburg units in 2011 that CSP allocated to serve internal load customers was 3,541,911,000

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-06 Identify whether CSP or OPCo recovered non-fuel expenses associated with the Ohio Valley Electric Corporation ("OVEC") generating units through the FAC in 2010 and 2011.

RESPONSE

Yes, CSP and OPCo recovered non-fuel expenses associated with the OVEC generating units through the FAC in 2010 and 2011.

**OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET**

INTERROGATORY

INT-1-07 For each month in 2010, identify each non-fuel expense and the total amount of expenses associated with OVEC generating units that CSP and OPCo recovered through the FAC. Identify these costs separately for CSP and OPCo.

RESPONSE

See IEU-INT-1-7 Attachment 1.

**OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET**

INTERROGATORY

INT-1-08 Identify the total kilowatt hours of electricity output produced by the OVEC generating units in 2010.

RESPONSE

The total kilowatt hours of electricity output produced by the OVEC units in 2010 was 14,634,079,000.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-09 CSP and OPCo are required to allocate least cost generating resources to serve SSO load. For each company, identify the total kilowatt hours of electricity output produced by the OVEC generating units in 2010 that CSP and OPCo allocated to serve SSO customers.

RESPONSE

The total kilowatt hours of electricity output produced by the OVEC units in 2010 that CSP and OPCo allocated to serve SSO customers was 455,124,000 and 1,729,184,000, respectively.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-010 For each month in 2011, identify each non-fuel expense and the total amount of expenses associated with OVEC generating units that CSP and OPCo recovered through the FAC. Identify these costs separately for CSP and OPCo.

RESPONSE

See IEU-INT-1-10 Attachment 1.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-011 Identify the total kilowatt hours of electricity output produced by the OVEC generating units in 2011.

RESPONSE

The total kilowatt hours of electricity output produced by the OVEC units in 2011 was 14,468,168,000.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-012 For each company, identify the total kilowatt hours of electricity output produced by the OVEC generating units in 2011 that CSP and OPCo allocated to serve SSO customers.

RESPONSE

The total kilowatt hours of electricity output produced by the OVEC units in 2011 that CSP and OPCo allocated to serve SSO customers was 245,771,000 and 980,836,000, respectively.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-018 In 1953, AEP-Ohio entered into an Intercompany Power Agreement ("ICPA") with other sponsoring companies of OVEC, correct?

RESPONSE

Correct.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-019 AEP-Ohio and the parties to the ICPA amended and restated the ICPA on August 11, 2011, correct?

RESPONSE

No, there was no amended and restated ICPA on August 11, 2011. An Amended and Restated Inter-Company Power Agreement was filed April 27, 2011. FERC issued an order approving the ICPA on May 23, 2011.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

INTERROGATORY

INT-1-020 The August amendment to the ICPA extended the duration of the ICPA until June 30, 2040, correct?

RESPONSE

Correct. The April 27, 2011 Filing extended the ICPA until June 30, 2040.

**OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET**

INTERROGATORY

INT-1-021 Identify when the ICPA would have terminated if AEP-Ohio had not amended the ICPA on August 11, 2011.

RESPONSE

If FERC denied the April 27, 2011 amended ICPA, then the previous ICPA would terminate March 13, 2026.

**OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-01 Section 7-71 of the 2010 Audit Report states "The non-fuel purchased power costs associated with Lawrenceburg are included in the FAC for CSP as shown on the EXH CSP-1 workpaper, which was included in the FAC workbooks provided in LA-2010-43." Produce a copy of LA-2010-43.

RESPONSE

Please see the LA-2010-43 CONFIDENTIAL zip file on the enclosed CD. This response provides Accounting's summary schedules and monthly workbooks of actual cycle computations of under/over-recovery along with carrying charge computations.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-02 Section 7-71 of the 2010 Audit Report states, "In data request LA-2010-2-130, Larkin asked for a summary of the non-energy components related to Lawrenceburg that were included in the FAC during 2010 and to also show how the capacity factor associated with Lawrenceburg was derived. In response, AEP Ohio provided a schedule which showed a breakout (by amount and account) of the Lawrenceburg related costs included in the FAC for each month of 2010." Produce a copy of the schedule that shows the "Lawrenceburg related costs included in the FAC for each month of 2010."

RESPONSE

See LA-2010-2-130 on the enclosed CD.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-03 Section 7-73 of the 2011 Audit Report states, "The non-fuel purchased power costs associated with Lawrenceburg are included in the FAC for CSP as shown on the EXH CSP-1 workpaper, which was included in the FAC workbooks provided in LA-2011-49. In data request LA-2011-57, Larkin asked for a summary of the non-energy components related to Lawrenceburg that were included in the FAC during 2011. In its confidential response, AEP Ohio provided a schedule which showed a breakout (by amount and account) of the Lawrenceburg related costs included in the FAC for each month of 2011." Produce copies of the FAC workbooks provided in LA-2011-49 and the schedule "of Lawrenceburg related costs included in the FAC for each month of 2011."

RESPONSE

This response, in the LA 2011-49 CONFIDENTIAL zip file on the enclosed CD, provides Accounting's summary schedules and monthly workbooks of actual cycle computations of under/over-recovery along with carrying charge computations.

In addition, please see LA-2011-1-57 Confidential Attachment 1.

**OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-04 Produce a copy of the amended and restated ICPA that AEP-Ohio executed on August 11, 2011.

RESPONSE

See IEU-RPD-1-4 Attachment 1 for the amended and restated ICPA that AEP Ohio executed on April 27, 2011.

In addition, see IEU-RPD-1-4 Attachment 2 for the order approving the amendment.

**OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-05 Produce a copy of the ICPA that existed before AEP-Ohio amended and restated the ICPA on August 11, 2011.

RESPONSE

See IEU-RPD-1-5 Attachment 1 for the ICPA that existed before AEP-Ohio amended and restated the ICPA on April 27, 2011.

OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
PUCO CASE NOS. 11-281-EL-FAC
FIRST SET

REQUEST FOR PRODUCTION OF DOCUMENTS

RPD-1-06 Produce of a copy of the contract between CSP and AEP Generating Company identified on Section 2-1 of the 2010 Audit Report.

RESPONSE

See IEU-RPD-1-6 Confidential Attachment 1.

IEU-Ohio Exhibit 14

SIMPSON THACHER & BARTLETT LLP

425 LEXINGTON AVENUE
NEW YORK, N.Y. 10017-3954
(212) 455-2000

FACSIMILE (212) 455-2502

DIRECT DIAL NUMBER
212-455-3075

E-MAIL ADDRESS
BCHISLING@STBLAW.COM

VIA ELECTRONIC FILING

April 27, 2011

Re: Re-Filing of Amended and Restated Inter-Company Power Agreement and Amended and Restated OVEC-IKEC Power Agreement
Docket No. ER11-

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act and Section 35.13 of the Commission's regulations, Ohio Valley Electric Corporation, together with its wholly owned subsidiary, Indiana-Kentucky Electric Corporation ("IKEC", and Ohio Valley Electric Corporation, together with IKEC, herein referred to as "OVEC") hereby re-submits its March 23, 2011 filing made in Docket No. ER11-3181 due to inadvertent use of an incorrect Filing Type. This re-submission, as before, includes:

(1) An Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010 ("Amended ICPA") among OVEC and other parties thereto (referred to as the "Sponsoring Companies"),[1] which amends and

[1] The "Sponsoring Companies" are: Allegheny Energy Supply Company, LLC, Appalachian Power Company ("Appalachian"), Buckeye Power Generating, LLC ("Buckeye"), Columbus Southern Power Company ("CSP"), The Dayton Power and Light Company ("Dayton Power"), Duke Energy Ohio, Inc. ("Duke Ohio"), FirstEnergy Generation Corp. ("FirstEnergy Generation"), Indiana Michigan Power Company ("I&M"), Kentucky Utilities Company ("KU"), Louisville Gas and Electric Company ("LG&E"), Monongahela Power Company ("Mon Power"), Ohio Power Company ("OPCo"), Peninsula Generation Cooperative ("Peninsula") and Southern Indiana Gas and Electric Company ("SIGECO").

restates in its entirety the current Amended and Restated Inter-Company Power Agreement, dated as of March 13, 2006, as amended by Modification No. 1, dated as of March 13, 2006 (the "Current ICPA").

(2) An Amended and Restated Power Agreement, dated as of September 10, 2010 ("Amended OVEC-IKEC Agreement") between OVEC and IKEC, which amends and restates in its entirety the current Amended and Restated Power Agreement, dated as of March 13, 2006 (the "Current OVEC-IKEC Agreement").

In accordance with the Commission's Order No. 714, OVEC hereby submits the above agreements in eTariff format and, as discussed below, respectfully requests a shortened notice period of fourteen (14) days and waiver of the Commission's 60-day notice requirements pursuant to Section 35.11 of its regulations to the extent necessary to grant an effective date as soon as possible, but in any event on or before May 23, 2011, which is sixty (60) days after the date of OVEC's original March 23, 2011 filing.

I. Resubmittal

OVEC previously filed the Amended ICPA and the Amended OVEC-IKEC Agreement in Docket No. ER11-3181 on March 23, 2011. In that filing, OVEC erroneously used Filing Type 370 (Refile Tariff (Baseline Filing)) instead of Filing Type 390 (New Company's Tariff (Initial Tariff Baseline)). In accordance with direction from the Commission's Staff, OVEC filed a cancellation request for the March 23, 2011 filing in Docket No. ER11-3181 and is hereby re-submitting the Amended ICPA and Amended OVEC-IKEC Agreement to correct the Filing Type. In addition, OVEC corrects an error in two of the attachments to the March 23rd filing (Amended ICPA Clean Tariff and Marked

Tariff) and the XML file.[2] However, the substance of the March 23, 2011 filing, contained in the attached Transmittal Letter, remains accurate and is hereby incorporated by reference.

II. Effective Date

As further explained in the attached March 23, 2011 filing letter, OVEC requested an effective date of May 23, 2011. OVEC originally filed and served the Amended ICPA and Amended OVEC-IKEC Agreement on March 23, 2011 in Docket No. ER11-3181. The Commission published a notice of filing in the Federal Register on March 31, 2011, establishing a comment period ending at 5 p.m. Eastern Time on April 13, 2011.[3] No comments, protests, or interventions were filed. Because the cancellation request for the March 23, 2011 filing and this re-submission of the Amended ICPA and Amended OVEC-IKEC Agreement merely correct ministerial mistakes, OVEC respectfully requests a shortened notice period of fourteen (14) days and that the Commission waive its 60-day notice requirements pursuant to Section 35.11 of its regulations to the extent necessary to grant an effective date as soon as possible, but in any event on or before May 23, 2011, which is sixty (60) days after the date of OVEC's original March 23, 2011 filing. Such waiver will permit OVEC to timely refinance its current long-term debt and take other actions to ensure its continued operations consistent with the Amended ICPA and will not prejudice any interested parties, who have been on notice of the Amended ICPA and Amended OVEC-IKEC Agreement since March 23, 2011 and to date have filed no comments, protests, or interventions.

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2 In the March 23rd filing, OVEC erroneously included clean and marked tariff attachments and XML text that omitted a final change to the underlying contract. In particular, the previously filed attachments and XML text did not include Peninsula as a Sponsoring Company (Peninsula acquired a 6.65% interest in the Current ICPA from FirstEnergy Generation and became a signatory to the Amended ICPA prior to the submission of OVEC's initial application). The attachments filed herewith correct this error. The other attachments included in the previous filing, including the executed version of the Amended ICPA appended to the Transmittal Letter and all versions of the Amended OVEC-IKEC Agreement, were correct and complete.

3 Combined Notice of Filings, 76 Fed. Reg. 17,850 (Mar. 31, 2011).

III. Documents submitted

Submitted with this resubmittal letter are:

(a) The March 23, 2011 transmittal letter, including execution copies of the Amended ICPA, Amended OVEC-IKEC Agreement, and Certificates of Concurrence of each of the Sponsoring Companies as to the Amended ICPA;[4]

(b) Copies of the Amended ICPA and Amended OVEC-IKEC Agreement (in eTariff format);

(c) A blacklined copy of the Amended ICPA, showing changes from the composite copy of the Current ICPA (including Mod. No. 1) (in eTariff format); and

(d) A blacklined copy of the Amended OVEC-IKEC Agreement, showing changes from the Current OVEC-IKEC Agreement (in eTariff format).

4 OVEC filed Certificates of Concurrence from each of the Sponsoring Companies with respect to the Amended ICPA out of an abundance of caution since the Current ICPA contained certain ECAR emergency energy provisions permitting the Sponsoring Companies to sell emergency energy to OVEC. Since these ECAR requirements are no longer applicable, they have been removed in the Amended ICPA and thus the Amended ICPA as filed is not a "joint tariff filing" within the meaning of Order No. 714.

IV. Addresses for Correspondence

Correspondence relating to this filing should be addressed to:

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Simpson Thacher & Bartlett LLP
425 Lexington Ave.
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(212) 455-3075
(212) 455-2502 (fax)
bchisling@stblaw.com

and

Scott N. Smith
Ohio Valley Electric Corporation
1 Riverside Plaza
Columbus, Ohio 43215
(614) 716-2860
(614) 716-1094 (Fax)
snsmith@aep.com

Respectfully submitted,

OHIO VALLEY ELECTRIC CORPORATION
INDIANA-KENTUCKY ELECTRIC CORPORATION

By /s/ Brian E. Chisling
Brian E. Chisling
Simpson Thacher & Bartlett LLP
Counsel for Ohio Valley Electric Corporation and Indiana-Kentucky Electric Corporation

Attachments: (1) March 23, 2011 Transmittal Letter, including execution copies of the Amended ICPA, Amended OVEC-IKEC Agreement, and Certificates of Concurrence of each of the Sponsoring Companies as to the Amended ICPA.

Enclosures: (1) Clean Copies of the Amended ICPA and Amended OVEC-IKEC Agreement;

(2) Blacklined Copies of the Amended ICPA, showing changes from the composite copy of the Current ICPA (including Mod. No. 1) and the Amended OVEC-IKEC Agreement, showing changes from the Current OVEC-IKEC Agreement.

cc: Allegheny Energy Supply Company, LLC
Appalachian Power Company
Buckeye Power Generating, LLC
Columbus Southern Power Company
The Dayton Power and Light Company
Duke Energy Ohio, Inc.
FirstEnergy Generation Corp.
Indiana Michigan Power Company
Kentucky Utilities Company
Louisville Gas and Electric Company
Monongahela Power Company
Ohio Power Company
Peninsula Generation Cooperative
Southern Indiana Gas and Electric Company
The Utility Regulatory Commission of Indiana
The Public Service Commission of Kentucky
The Public Service Commission of Michigan
The Public Utilities Commission of Ohio
Tennessee Regulatory Authority
The State Corporation Commission of Virginia
The Public Service Commission of West Virginia

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing application of Ohio Valley Electric Corporation upon each person designated on the official service list compiled by the Secretary in Docket Nos. ER04-1026 and ER11-3181 and each person listed in the cc list above.

/s/ Brian E. Chisling
Brian E. Chisling

Dated this 27th day of April, 2011.

SIMPSON THACHER & BARTLETT LLP

425 LEXINGTON AVENUE
NEW YORK, N.Y. 10017-3954
(212) 455-2000

FACSIMILE (212) 455-2502

DIRECT DIAL NUMBER
212-455-3075

E-MAIL ADDRESS
BCHISLING@STBLAW.COM

VIA ELECTRONIC FILING

March 23, 2011

Re: Amended and Restated Inter-Company Power Agreement and Amended and Restated OVEC-IKEC Power Agreement
Docket No. ER11-__________

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act and Section 35.13 of the Commission's regulations, Ohio Valley Electric Corporation, together with its wholly owned subsidiary, Indiana-Kentucky Electric Corporation ("IKEC", and Ohio Valley Electric Corporation, together with IKEC, herein referred to as "OVEC") submits for filing:

(1) An Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010 ("Amended ICPA") among OVEC and other parties thereto (referred to as the "Sponsoring Companies"),[1] which amends and restates in its entirety the current Amended and Restated Inter-Company Power Agreement, dated as of March 13,

---

1 The "Sponsoring Companies" are: Allegheny Energy Supply Company, LLC, Appalachian Power Company ("Appalachian"), Buckeye Power Generating, LLC ("Buckeye"), Columbus Southern Power Company ("CSP"), The Dayton Power and Light Company ("Dayton Power"), Duke Energy Ohio, Inc. ("Duke Ohio"), FirstEnergy Generation Corp. ("FirstEnergy Generation"), Indiana Michigan Power Company ("I&M"), Kentucky Utilities Company ("KU"), Louisville Gas and Electric Company ("LG&E"), Monongahela Power Company ("Mon Power"), Ohio Power Company ("OPCo"), Peninsula Generation Cooperative ("Peninsula") and Southern Indiana Gas and Electric Company ("SIGECO").

2006, as amended by Modification No. 1, dated as of March 13, 2006 (the "Current ICPA").

(2) An Amended and Restated Power Agreement, dated as of September 10, 2010 ("Amended OVEC-IKEC Agreement") between OVEC and IKEC, which amends and restates in its entirety the current Amended and Restated Power Agreement, dated as of March 13, 2006 (the "Current OVEC-IKEC Agreement").

In accordance with the Commission's Order No. 714, OVEC hereby submits the above agreements in eTariff format.[2]

I. Introduction

OVEC hereby requests that the Commission accept for filing and grant any other relief necessary to permit the Amended ICPA to become effective as soon as possible after the date hereof, but in any event by the sixtieth (60th) day after the date hereof. The Amended ICPA is the result of a unanimous agreement among OVEC and the Sponsoring Companies to extend the term of the Current ICPA. In addition, the Amended ICPA contains non-substantive administrative changes, including as necessary to reflect the current parties based on assignments since 2004 and the transfer of responsibilities from East Central Area Reliability Group ("ECAR") to Reliability*First* Corporation ("RFC"). In connection with the filing of the Amended ICPA, OVEC also requests that the Commission accept the filing of the Amended OVEC-IKEC Agreement, which extends the term of that agreement to coincide with the term of the Amended ICPA. The Commission's acceptance for filing of the agreements in this application will permit the Sponsoring Companies to continue to receive the relatively low-cost electricity generated by OVEC (and its

[2] Please note, that while both the Amended ICPA and Amended OVEC-IKEC Agreement were dated as of September 10, 2010, they were not fully executed until sometime in February 2011 and their effectiveness is subject to the receipt of all necessary regulatory approvals, including from the Commission in the instant proceeding.

subsidiary, IKEC) under the basic cost-based formula rates charged by OVEC for over 50 years.

II. Background of the Current ICPA and Related Agreements

Each of the Sponsoring Companies is a public utility or a subsidiary of an electric cooperative operating in the Ohio Valley region and either owns, or is an affiliate of a company that owns, capital stock issued by OVEC.[3] During the early 1950s, these stockholders (or their predecessors) formed OVEC in response to the request of the United States Atomic Energy Commission ("AEC") to supply the electric power and energy necessary to meet the needs of a uranium enrichment plant being built by the AEC in Pike County, Ohio. To provide that electric service, OVEC built two coal-fired generating stations: (1) the Kyger Creek Plant in Cheshire, Ohio, which has a generating capacity of 1,075 megawatts, and (2) the Clifty Creek Plant in Madison, Indiana, which has a generating capacity of 1,290 megawatts and is owned by OVEC's wholly-owned subsidiary, IKEC.

These two generating stations, both of which began operation in 1955, are connected by a network of 776 circuit miles of 345,000-volt transmission lines in Ohio, Indiana and northern Kentucky. These lines were designed and built to provide for the delivery of power and energy from OVEC's generating facilities to the United States of America, currently acting by and through the AEC's successor, the Secretary of Energy, the statutory head of the United States Department of Energy (the "DOE"), as well as to permit DOE to obtain supplementary power and energy from the Sponsoring Companies to the extent that OVEC's generation output was either unavailable or insufficient to meet the

3 In particular, OVEC's stock is owned by the following companies: Allegheny Energy, Inc. ("Allegheny") (3.5%); American Electric Power Company, Inc. ("AEP") (39.17%); Buckeye (18%); CSP (4.3%); Dayton Power (4.9%); Duke Ohio (9.0%); KU (2.5%); LG&E (5.63%); Ohio Edison Company (0.85%); Peninsula (6.65%), SIGECO (1.5%); and The Toledo Edison Company (4.0%).

DOE's needs. To permit these deliveries of power and energy between OVEC, the Sponsoring Companies and DOE, OVEC's transmission facilities interconnect with the facilities of certain neighboring Sponsoring Companies.

Upon its formation, OVEC entered into two principal power sales agreements: (i) the DOE Power Agreement, which was between OVEC and the DOE, and (ii) the predecessor to the Current ICPA. At the same time, OVEC also entered into the predecessor to the Current OVEC-IKEC Agreement, which permits OVEC to purchase the entire output of IKEC's generating station at cost.

As a result of the DOE's termination of the DOE Power Agreement as of April 30, 2003, each of the Sponsoring Companies currently is entitled to its specified share of all net power and energy produced by OVEC's two generating stations.[4] In return, the Current ICPA (as amended in 2004) requires the Sponsoring Companies to pay their share of all of OVEC's costs resulting from the ownership, operation and maintenance of its generation and transmission facilities, except those costs that were paid by the DOE.

The term of each of the Current ICPA and the Current OVEC-IKEC Agreement is set to expire on March 13, 2026. OVEC wants the flexibility to refinance all or part of its long-term debt with maturities expiring after the current March 13, 2026 term. Without the Commission's acceptance for filing of the Amended ICPA and the related agreements in sufficient time to permit such refinancing during 2011, OVEC may not be able to take advantage of favorable interest rates that would allow OVEC to provide lower-cost power and energy to the Sponsoring Companies.

4 By letter dated September 29, 2000, the DOE notified OVEC of the DOE's election to terminate the DOE Power Agreement as of April 30, 2003. OVEC currently provides retail service to DOE through an "arranged power" agreement under which OVEC procures power and energy for DOE at cost from third parties (based on bids directed by DOE and spot purchases required to manage changes in load).

II. Description of Amended ICPA

The Amended ICPA is the result of a unanimous agreement among OVEC and the Sponsoring Companies. The only substantive change to the Current ICPA is the extension of its term from the current expiration date of March 13, 2026 to June 30, 2040. (See Amended ICPA § 9.07.) The other changes contained in the Amended ICPA are "clean up" changes necessary to reflect the current parties to the Amended ICPA (based on assignments since 2004) and to eliminate references to ECAR and insert (where applicable) references to current RFC obligations. OVEC's rates will not be affected by these changes.

III. Description of Amended OVEC-IKEC Agreement

The Amended OVEC-IKEC Agreement extends the term of the Current OVEC-IKEC Agreement to permit IKEC to continue to sell OVEC its entire electric output at cost during the term of the Amended ICPA. As with the Amended ICPA, IKEC's overall rates will not be affected by these changes.

IV. *Mountainview* Analysis

In OVEC's July 16, 2004 filing of the Current ICPA and the Current OVEC-IKEC Agreement and its November 18, 2004 filing of Modification No. 1 to the Current ICPA, OVEC submitted information and commitments in support of the participation in the Amended ICPA of the Sponsoring Companies that might be deemed to be "affiliates" of OVEC.[5] On December 13, 2004, the Commission accepted the Current ICPA (including Modification No. 1) and the Current OVEC-IKEC Agreement for filing.[6]

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5 Amended and Restated Inter-Company Power Agreement, Amended and Restated OVEC-IKEC Power Agreement, and Termination of First Supplementary Transmission Agreement, Docket No. ER04-1026-000, filed July 16, 2004; Modification No. 1 to the Amended and Restated Inter-Company Power Agreement and Supplemental Filing, Docket No. ER04-1026-001, filed Nov. 18, 2004.

6 Ohio Valley Electric Corporation, Amended and Restated Inter-Company Power Agreement and

As explained below (and in OVEC's July 16, 2004 and November 18, 2004 filings), OVEC submits that the Amended ICPA and the Amended OVEC-IKEC Agreement should not be subject to the scrutiny applicable to affiliate agreements entered into at market-based rates, as set forth in *Southern California Edison Co.*, 106 FERC ¶ 61,183 (2004) ("*Mountainview*") because OVEC is not controlled in the same manner as those affiliate relationships described in *Mountainview* and related cases, and because the Amended ICPA represents the continuation of a 50-plus year arrangement that does not raise affiliate abuse or competitive concerns. Nevertheless, as it provided the Commission in its November 18, 2004 filing, OVEC also provides an analysis and underlying study to demonstrate that the Amended ICPA satisfies any applicable requirements under *Mountainview*. OVEC hereby requests that the Commission accept the Amended ICPA and Amended OVEC-IKEC Agreement for filing on the same basis as it did in its 2004 order based on the arguments below and updated analysis.

A. Applicability of *Mountainview*

OVEC notes that the Amended ICPA and the Amended OVEC-IKEC Agreement are substantively nearly identical to the Current ICPA and the Current OVEC-IKEC Agreement, and other relevant facts such as ownership interests also are nearly identical to those in 2004. OVEC is owned (directly or indirectly) by nine independent holding company systems, none of which owns 50% or more of OVEC's stock (indeed, ownership is even more dispersed than at the time of OVEC's July 16, 2004 filing due to Allegheny's sale of 9% of the OVEC equity to Buckeye and Ohio Edison Company's sale of

Modification No. 1 dated as of March 13, 2006; an Amended and Restated Power Agreement and a Termination Agreement both dated March 13, 2006, Docket Nos. ER04-1026-000 and ER04-1026-001, issued Dec. 13, 2004.

6.65% to Peninsula).[7] Because of the dispersion of voting power, none of OVEC's owners can direct the management or operations of OVEC. OVEC continues to have its own employees and is solely responsible for the operation and management of its generation facilities. Furthermore, unlike in the cases of transactions between wholly owned subsidiaries with a common parent, none of OVEC's owners has the incentive to grant "undue influence" or otherwise cross-subsidize OVEC's operations through the Amended ICPA because between 55.8% and 98.5% (depending on the holding company system) of the benefits of such activities would flow to the other holding company systems, each of which is a competitor in the wholesale market. As a result, OVEC does not believe that any of its owners exercise the type of control necessary to make it an "affiliate" of any of the owners for these purposes.[8]

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7 Ownership of OVEC's stock is held (directly or indirectly) by the following holding companies: Allegheny (3.5%); AEP (43.47%); Buckeye Power, Inc. (18%); DPL Inc. (4.9%); Duke Energy Corporation (9%); E.ON plc (8.13%); FirstEnergy Corp. ("FirstEnergy") (4.85%); Vectren Corporation (1.5%); and Wolverine Power Supply Cooperative, Inc. (6.65%).

8 In *Morgan Stanley Capital Group Inc.*, 72 FERC ¶ 61,082, the Commission stated that the test for affiliation under Part II of the Federal Power Act would be the same as the test under Section 161.2 of the Commission's regulation regarding interstate pipelines. Under that regulation, an "affiliate" is defined as "another which controls, is controlled by or is under common control with such person," and "control" is defined as including "the possession, directly or indirectly and whether acting alone or with others, of the authority to direct or cause the direction of the management or policies of a company." Although "control" is presumed if a person owns a 10% or greater voting interest in another person, such presumption can be rebutted by specific facts and circumstances. *See e.g., Iroquois Gas Transmission System, L.P.*, 78 FERC ¶ 61,108 (1997) (finding that 19.4% owner lacked the ability to determine operational decisions); *Western Gas Marketing, Inc.*, 63 FERC ¶ 61,172 (1993) (finding that 11% owner lacked operating or management control due to the dispersion of ownership among non-affiliates). As stated above, none of OVEC's owners has a majority interest and, based on the dispersion of ownership interests among nine holding company systems, none of the owners can direct the operation or management of OVEC.

Please note, however, that although OVEC believes that it should not be considered to be an "affiliate" of its owners for these purposes, OVEC has not and does not hereby request exemption from the obligations under the Commission's orders relating to other inter-affiliate relationships, including the standards of conduct between electric utilities and their affiliates under Order Nos. 888, 889, 2004 and related orders. OVEC believes that it is in full compliance with those orders with respect to its relationship to AEP and their affiliates, each of which directly or indirectly controls or is controlled by a company that owns 10% or more of OVEC's stock. Buckeye Power Inc. is an electric cooperative not subject to regulation as a public utility by the Commission.

Second, even assuming OVEC's affiliation with certain owners based solely on stock ownership, the purchases under the Amended ICPA by the Sponsoring Companies that are affiliates of such owners do not raise the potential for the affiliate abuses underlying the Commission's policies in *Mountainview* and related cases. The Amended ICPA does not represent a build-or-buy situation because OVEC's plants are over 50 years old. Neither does it represent a market-based affiliate agreement. Indeed, purchases under the Amended ICPA are more analogous to a vertically integrated utility's entitlement to power from its own generating plants. Under the Current ICPA (and its predecessors), since OVEC's inception the Sponsoring Companies have been responsible to pay for all charges not recovered through retail sales to DOE and to pay demand and energy charges associated with surplus energy released by the DOE under the DOE Power Agreement, which now accounts for all of OVEC's net output. In other words, OVEC's owners and their affiliated Sponsoring Companies have shared the risks and rewards of financing and operating OVEC's facilities for over 50 years. Thus, purchases under the Amended ICPA are more akin to purchases from a jointly-owned plant than from an unregulated, affiliated marketer.

Finally, the continued purchase of power by the Sponsoring Companies does not raise any competitive concerns implicated in *Mountainview*. The continuation of purchases from OVEC under the Amended ICPA will not increase the market share of any Sponsoring Company. In addition, the Sponsoring Companies consist of companies from nine different holding company systems, each of which has multiple interconnections throughout the region. Also, under the scheduling provisions of the Amended ICPA, which are unchanged, available energy from OVEC's generating facilities that is not scheduled by one Sponsoring Company automatically is made available to the other Sponsoring

Companies, which promotes the economic use or competitive marketing of all of OVEC's energy to the customers of any one of the Sponsoring Companies.

B. Analysis under *Mountainview*

The Amended ICPA is a cost-based power agreement requiring OVEC to continue to sell to the Sponsoring Companies all of the power and energy capable of being produced by its generation facilities for an additional 14 years through June 30, 2040. In general, the Amended ICPA requires the Sponsoring Companies to pay their share of all of OVEC's costs resulting from the ownership, operation, financing and maintenance of its generation and transmission facilities. The total charges under the Amended ICPA are based on the same basic formula rates that have been charged to the Sponsoring Companies for over 50 years. The Amended ICPA does not change the rates charged under the Current ICPA.

At OVEC's request, American Electric Power Service Corporation (which is affiliated with certain of the Sponsoring Companies) performed a benchmark study to show that the Amended ICPA represents a low-cost, long-term power supply option for the Sponsoring Companies compared to the available alternatives. A copy of the benchmark study along with supporting data (the "Benchmark Study") is attached hereto as Exhibit A. The Benchmark Study compares OVEC's costs under the Amended ICPA to publicly available market data with respect to the construction of base-load power plants. The Benchmark Study demonstrates that the Amended ICPA satisfies the requirements under *Mountainview* and related precedent to show that the agreement represents a just and reasonable, low-cost supply option for the Sponsoring Companies. This benchmark study and supporting materials are similar to those presented to the Commission in November

2004 in connection with the Commission's acceptance for filing of the Current ICPA and Current OVEC-IKEC Agreement.[9]

VI. Effective Date Request

In order to permit OVEC sufficient time to refinance its current long-term debt and to take other actions to ensure the continued operations consistent with the Amended ICPA, OVEC respectfully requests that the Commission grant an effective date in an order issued as soon as possible, but in any event on or before sixty (60) days after the date of this filing.

OVEC's operations are financed on a project-type basis and thus the advance acceptance of the Amended ICPA by the Commission, as well as other required regulatory approvals and filings, are essential for OVEC to be able to negotiate and put in place acceptable refinancing of its existing long-term debt on reasonable terms. In addition to this filing, the Amended ICPA is subject to filing with, or the approval or non-opposition of, various regulatory authorities, including the Indiana Utility Regulatory Commission, the Kentucky Public Service Commission, the Virginia State Corporation Commission and the West Virginia Public Service Commission.

For the foregoing reasons, OVEC requests a waiver of any applicable requirements to permit the Commission, by order, letter or other issuance on or before sixty (60) days after the date of this filing, to grant the requested effective date.

VII. Filing Requirements

Pursuant to Section 35.13(a)(2) of the Commission's regulations, OVEC provides the following information:

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9 See Exhibit A to Modification No. 1 to the Amended and Restated Inter-Company Power Agreement and Supplemental Filing, Docket No. ER04-1026-001, filed Nov. 18, 2004.

A. General Information

(1) List of documents submitted

Submitted with this letter are:

(a) Amended ICPA (executed);

(b) Amended OVEC-IKEC Agreement (executed);

(c) Certificates of Concurrence of each of the Sponsoring Companies as to the Amended ICPA;

(d) Copies of the Amended ICPA and Amended OVEC-IKEC Agreement (in eTariff format);

(e) A blacklined copy of the Amended ICPA, showing changes from the composite copy of the Current ICPA (including Mod. No. 1) (in eTariff format); and

(f) A blacklined copy of the Amended OVEC-IKEC Agreement, showing changes from the Current OVEC-IKEC Agreement (in eTariff format).

(2) The proposed effective date

OVEC proposes that the Amended ICPA and the Amended OVEC-IKEC Agreement become effective as soon as possible, but in any event within sixty (60) days after the date hereof.

(3) Names and addresses of persons to whom a copy of this filing has been mailed

A copy of this filing has been mailed this date to:

(a) Allegheny Energy Supply Company, LLC
4350 Northern Pike – 4 North
Monroeville, Pennsylvania 15146-2841

(b) Appalachian Power Company
1 Riverside Plaza
Columbus, Ohio 43215

(c) Buckeye Power Generating, LLC
6677 Busch Blvd., P.O. Box 26036
Columbus, Ohio 43226

(d) Columbus Southern Power Company
1 Riverside Plaza
Columbus, Ohio 43215

(e) The Dayton Power and Light Company
1065 Woodman Drive
Dayton, Ohio 45432

(f) Duke Energy Ohio, Inc.
139 East Fourth Street
Cincinnati, Ohio 45202

(g) FirstEnergy Generation Corp.
76 South Main Street
Akron, Ohio 44308

(h) Indiana Michigan Power Company
P. O. Box 60
Ft. Wayne, Indiana 46801

(i) Kentucky Utilities Company
P. O. Box 32010
Louisville, Kentucky 40232

(j) Louisville Gas and Electric Company
P. O. Box 32010
Louisville, Kentucky 40232

(k) Monongahela Power Company
P.O. Box 1392
Fairmont, West Virginia 26555

(l) Ohio Power Company
1 Riverside Plaza
Columbus, Ohio 43215

(m) Peninsula Generation Cooperative
10125 W. Watergate Road
Cadillac, MI 49601

(n) Southern Indiana Gas and Electric Company
20-24 N.W. Fourth Street

Evansville, Indiana 47741

(o) The Utility Regulatory Commission of Indiana
302 West Washington Street
Suite E-306
Indianapolis, Indiana 46204

(p) The Public Service Commission of Kentucky
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602-0615

(q) The Public Service Commission of Michigan
6545 Mercantile Way
P. O. Box 30221
Lansing, Michigan 48909

(r) The Public Utilities Commission of Ohio
180 East Broad Street
Columbus, Ohio 43215

(s) Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, Tennessee 37243-0505

(t) The State Corporation Commission of Virginia
Tyler Building
P. O. Box 1197
Richmond, Virginia 23209

and

(u) The Public Service Commission of West Virginia
201 Brooks Street
P. O. Box 812
Charleston, West Virginia 25323

(4) **Brief description of agreements**

The Amended ICPA is the result of a unanimous agreement among OVEC and the Sponsoring Companies to extend the term of the Current ICPA and to make certain administrative changes. In addition, in connection with the extended term of the Amended ICPA, OVEC and IKEC have executed the Amended OVEC-IKEC Agreement, which extends the term of that agreement to coincide with the term of the Amended ICPA. The Commission's acceptance of this filing will permit OVEC to refinance its long-term debt at favorable rates and allow the Sponsoring Companies to continue to receive lower-cost electricity generated by OVEC (and its subsidiary, IKEC) under the Amended ICPA.

(5) **Statement of the reasons for the filed agreements**

The Amended ICPA and the Amended OVEC-IKEC Agreement represent the result of a unanimous compromise among OVEC and the Sponsoring Companies concerning the terms and conditions of those agreements, including the extension of the term of the Current ICPA and the Current OVEC-IKEC Agreement, both of which would otherwise expire on March 13, 2026.

(6) **Showing that all requisite agreements to the filed agreements have been obtained**

All requisite agreements to the Amended ICPA and the Amended OVEC-IKEC Agreement, including permission to make this filing, have been obtained. As evidenced by the enclosed copies of each agreement, OVEC and all of the Sponsoring Companies have executed the Amended ICPA and the Amended OVEC-IKEC Agreement. In addition, attached for filing are Certificates of Concurrence of each of the Sponsoring Companies as to those agreements.

(7) **Statement concerning whether any expenses or costs have been alleged or adjudged in any administrative or judicial proceeding to be illegal, duplicative or unnecessary costs that are demonstrably the product of discriminatory employment practices**

The rates under the Amended ICPA and the Amended OVEC-IKEC Agreement include no expense or cost that has been alleged or adjudged in any administrative or judicial proceeding to be an illegal, duplicative or unnecessary cost that is demonstrably the product of discriminatory employment practices.

B. **Information relating to the effect of the rate schedule change**

(1) **Table or statement comparing (i) existing sales and services and revenue from existing sales and services to (ii) sales and services and revenue from sales and services if the Commission permits the Amended ICPA and the Amended OVEC-IKEC Agreement to become effective**

There will be no change to OVEC's overall rates or services as a result of the Amended ICPA or the Amended OVEC-IKEC.

(2) **Comparison to similar existing service and rate**

OVEC does not offer other services similar to the proposed service. Consequently, a comparison of the proposed service and rate to a similar existing service and rate cannot be provided.

(3) **Statement concerning new or modified facilities**

No facilities have been or will be installed because of the Amended ICPA or the Amended OVEC-IKEC Agreement.

C. Waiver of Filing Requirements Request

OVEC believes that the information supplied with this filing will permit the Commission to conclude that the Amended ICPA and the Amended OVEC-IKEC Agreement are just and reasonable under the Federal Power Act and that such agreements, along with the attached Certificates of Concurrence, should be accepted for filing. Consequently, OVEC requests this Commission to waive, to the extent necessary, any of the Commission's requirements with which this filing does not comply.

D. Addresses for Correspondence

Correspondence relating to this filing should be addressed to:

Brian Chisling
Simpson Thacher & Bartlett LLP
425 Lexington Ave.
New York, New York 10017-3954
(212) 455-3075
(212) 455-2502 (fax)
bchisling@stblaw.com

and

Scott N. Smith
Ohio Valley Electric Corporation
1 Riverside Plaza
Columbus, Ohio 43215
(614) 716-2860
(614) 716-1094 (Fax)
snsmith@aep.com

Respectfully submitted,

OHIO VALLEY ELECTRIC CORPORATION
INDIANA-KENTUCKY ELECTRIC
CORPORATION

By /s/ Brian E. Chisling
Brian E. Chisling
Simpson Thacher & Bartlett LLP
Counsel for Ohio Valley Electric
Corporation and Indiana-Kentucky Electric
Corporation

Attachments: (1) Exhibit A: Benchmark Study Demonstrating that the Inter-Company Power Agreement Offers Low-Cost Power;

(2) Amended ICPA (executed);

(3) Amended OVEC-IKEC Agreement (executed);

(4) Certificates of Concurrence of each of the Sponsoring Companies as to the Amended ICPA.

Enclosures: (1) Clean Copies of the Amended ICPA and Amended OVEC-IKEC Agreement;

(2) Blacklined Copies of the Amended ICPA, showing changes from the composite copy of the Current ICPA (including Mod. No. 1) and the Amended OVEC-IKEC Agreement, showing changes from the Current OVEC-IKEC Agreement.

cc: Allegheny Energy Supply Company, LLC
Appalachian Power Company
Buckeye Power Generating, LLC
Columbus Southern Power Company
The Dayton Power and Light Company
Duke Energy Ohio, Inc.
FirstEnergy Generation Corp.
Indiana Michigan Power Company
Kentucky Utilities Company
Louisville Gas and Electric Company
Monongahela Power Company
Ohio Power Company
Peninsula Generation Cooperative
Southern Indiana Gas and Electric Company
The Utility Regulatory Commission of Indiana
The Public Service Commission of Kentucky
The Public Service Commission of Michigan
The Public Utilities Commission of Ohio
Tennessee Regulatory Authority
The State Corporation Commission of Virginia
The Public Service Commission of West Virginia

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing Amended ICPA and Amended OVEC-IKEC Agreement of Ohio Valley Electric Corporation upon each person designated on the official service list compiled by the Secretary in Docket No. ER04-1026 and each person listed in section 7(A)(3) above.

/s/ Brian E. Chisling
Brian E. Chisling

Dated this 23rd day of March, 2011.

Exhibit A

Benchmark Study Demonstrating that the Inter-Company Power Agreement Offers Low-Cost Power

At the request of the Ohio Valley Electric Corporation ("OVEC"), American Electric Power Service Corporation ("AEPSC") performed a benchmark study in support of the proposed 14-year extension of the term of the Inter-Company Power Agreement ("ICPA"), originally dated July 10, 1953 and as amended from time to time, among OVEC and the public utilities named therein as "Sponsoring Companies," which include several affiliates of AEPSC. As discussed below, it is clear the ICPA offers low-cost power to the Sponsoring Companies, taking into account both price and non-price factors.

A. Definition of the Relevant Market, Time Period and Products.

1. Relevant Geographic Market

Under Commission precedent, the relevant geographic market is the market where sellers can supply the relevant product to the purchasers under the subject contract.[1] This benchmark study defines the relevant geographic market broadly to include any supplier that is in the reliability regions governed by or under the following: (a) Reliability*First* Corporation ("RFC"), which is a consolidation of the three previous regions East Central Area Reliability Coordination Agreement ("ECAR"), the Mid-Atlantic Area Council ("MAAC") and the Mid-America Interconnected Network ("MAIN"), and (b) Midwest Reliability Organization ("MRO"), which regions collectively include the majority of the service territories of the regional transmission organizations of the PJM Interconnection, LLC ("PJM") and the Midwest Independent Transmission System Operator, Inc. ("MISO").

1 *Ocean State Power II*, 59 FERC ¶ 61,360 at p. 62,333 (1992) ("*Ocean State*").

2. Contemporaneousness

The Commission defines the relevant period for these purposes as the period during which purchasers made their decisions to contract with the supplier.[2] Consequently, this benchmark study is based on a current forecast of generation alternatives through 2040, consistent with the extension period.

3. Comparable Products

The Commission generally requires that the evidence presented in benchmark studies compares transactions involving goods and services similar to those provided within the proposed transaction.[3] Accordingly, this benchmark study defines the relevant comparison to be the ICPA to the construction of base-load power plants over the same long-term time period, since the construction of a power plant is the most comparable alternative to entering into this long-term power supply agreement.

Other products such as power plant acquisitions and long-term power contracts were not considered comparable products since the proposed extension is for the time period March 14, 2026 through June 30, 2040. Such transactions would be near-term agreements that would not be comparable to an extension period that does not begin until 2026, in part since generally no market exists for offers that would provide beginning or closing dates in this timeframe. Construction start dates for new generation, on the other hand, are generally at the discretion of the purchaser, subject to permitting limitations and vendor availability.

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2 *See Electric Generation LLC*, 99 FERC ¶ 61,307, at p. 22 (2002).

3 *See Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 FERC ¶ 61,382 at p. 62,169 (1991); *Ocean State*, 59 FERC at p. 62,333.

B. Summary of Benchmark Study

The benchmark study consists of a comparison of the IPCA for the extension period to construction of new base-load generation.

1. Costs to Construct New Power Plants

Based on information from the U.S. Energy Information Administration ("EIA") document, "*Table 1. Updated Estimates of Power Plant Capital and Operating Costs*". Release Date: November 2010, supplemented by operational assumptions and cost estimates from AEPSC internal sources, the estimated levelized cost of six different types of newly built central station base-load generation are shown on Schedule 1, page 1. The types of power plants reviewed include a new coal plant with flue gas desulphurization (i.e., "scrubbed"), integrated coal-gasification combined cycle (IGCC), with and without carbon capture and sequestration, advanced nuclear generation, and natural gas combined cycle (CC), with and without carbon sequestration. Other potential generation sources were excluded because they were not considered comparable, for example wind and solar, since they are intermittent, non-dispatchable resources.

As shown in Schedule 1, the installed cost of the comparable new units ranges from $1,003/kW for CC without carbon sequestration to $5,348/kW for IGCC with carbon sequestration. For comparison purposes, a typical annual carrying charge was applied to the estimated installed cost to reflect a reasonable amount for depreciation, taxes, administrative and general costs, and other expenses. Estimated fuel costs were also added, along with assumptions regarding the future average costs of carbon dioxide (CO_2) emissions and the ability of sequestration systems to capture the CO_2. These calculations resulted in average levelized total unit costs, including CO_2 costs, ranging from $106 per MWh for a CC plant without carbon sequestration up to $159.20/MWh for an IGCC plant with carbon sequestration. If CO_2 costs are ignored or assumed to be zero, the alternatives range from $96.53/MWh for a new advance gas combined cycle plant to $122.51 per MWh for an advanced nuclear plant.

As shown on Schedule 1, page 2, the average forecasted cost of the ICPA contract for the period 2011 through 2040 is $84.23/MWh including CO_2 cost and $60.90/MWh excluding CO_2 cost. These forecasts already include all of the carrying and operating costs associated with the planned environmental upgrades, including completion of Flue Gas Desulfurization for all Clifty Creek and Kyger Creek units and Selective Catalytic Reduction for Clifty Creek units 1-5 and Kyger Creek units 1-5.

For the cases including CO_2 costs, the cost of the ICPA is expected to be approximately 21% less than the least expensive alternative, the CC plant without carbon sequestration. For the cases excluding CO_2 costs, the ICPA is expected to be approximately 37% less than the least expensive alternative of the new CC plant.

It is recognized that the above values include the period from 2011 through 2040 for the ICPA even though the current request is for the period March 14, 2026 through June 30, 2040. No adjustments were made to attempt to project a near-term completion date and then "remove" the financial impacts of the new build options and the OVEC extension for the period prior to 2026. In practical terms, any such adjustment would require the implicit assumption that a counter-party could be identified that would be willing to purchase the output of the new plant at the fully-loaded cost in the interim period from the plant completion date until a termination date in 2026.

performance based on availability factors. The availability factor for OVEC's Clifty Creek Plant was 85.0% in 2008, 87.1% in 2009 and 83.8% in 2010, while the availability factor for its Kyger Creek Plant was 85.4% in 2008, 84.3% in 2009 and 84.0% in 2010.

b. Dispatchability

Under the ICPA, the Sponsoring Companies have the right to schedule their proportionate share of the full available capacity and energy output of OVEC's generating facilities, subject to scheduling procedures developed by OVEC's Operating Committee.

c. Fuel Price Risk

Fuel costs associated with OVEC's coal-fired generating facilities may increase over the proposed extension of the term of the ICPA, thereby increasing costs to the Sponsoring Companies. However, with respect to construction of comparable units, the purchasers would be subject to the similar cost increases due to fluctuations in fuel prices.

d. Project Development Risk

The Sponsoring Companies are insulated against development risk under the ICPA, as compared to the new construction option, because the OVEC units have already been built and operating for many years.

C. Conclusion

Based on the benchmark study, the charges under the ICPA compare favorably to data concerning prices obtained through review of comparable information for other new generation base load options. The ICPA offers low-cost power to the Sponsoring Companies, taking into account both price and non-price factors.

Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology (1)	Online Year (2)	Size (MW) (3)	Lead time (years) (4)	Overnight Cost (2010 $/kW) (5)	Variable O&M (2010 $/MWh) (6)	Fixed O&M (2010 $/kW) (7)	Heat Rate (Btu/kWhr) (8)	Levelized Cost of Electricty (COE) Including CO_2 (2011 $/MWh) (9)	Levelized Cost of Electricty (COE) Excluding CO_2 (2011 $/MWh) (10)
<u>Coal</u>									
Scrubbed Coal New	2013	650	4	$3,167	$4.25	$35.97	8,800	**$122.78**	**$98.45**
IGCC	2013	600	4	$3,565	$6.87	$59.23	8,700	**$137.24**	**$113.17**
IGCC with carbon sequestration	2016	520	4	$5,348	$8.04	$69.30	10,700	**$159.20**	---
<u>Nuclear</u>									
Advanced Nuclear	2016	2,236	6	$5,335	$2.04	$88.75	N/A	**$122.51**	**$122.51**
<u>Natural Gas</u>									
Advanced Gas/Oil Combined Cycle (CC)	2012	400	3	$1,003	$3.11	$14.62	6,430	**$106.04**	**$96.53**
Advanced CC with carbon sequestration	2016	340	3	$2,060	$6.45	$30.25	7,525	**$144.73**	---

IGCC = Integrated Coal-Gasification Combined Cycle

Note: Information in columns (1) through (8) is based on U.S. Energy Information Administration (EIA), *Table 1. Updated Estimates of Power Plants and Operating Costs*, Release Date: November 2010. Results in columns (9) and (10) are based on this EIA information and AEP internal estimates.

Ohio Valley Electric Corporation
Forecasted Inter-Company Power Agreement (ICPA) Billable Cost Summary
Calendar Years 2011 - 2040

(All dollars in 2011 $000 except where indicated)

	Year														
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Power Production Cost															
Excluding CO_2	$631,114	$605,983	$617,141	$608,778	$597,395	$603,810	$589,464	$589,611	$576,098	$577,863	$568,206	$554,703	$555,728	$544,120	$541,864
Including CO_2	$631,114	$605,983	$617,141	$608,778	$597,395	$603,810	$589,464	$826,552	$794,534	$775,611	$758,160	$737,171	$731,004	$745,364	$766,670
Generation (GWh)	14,737	14,645	14,536	14,752	14,753	14,950	15,108	15,158	15,290	15,185	15,185	15,185	15,185	15,185	15,185

	Year															Total
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2011-2040
Power Production Cost																
Excluding CO_2	$530,713	$528,452	$516,170	$509,683	$505,302	$498,631	$496,214	$487,268	$476,432	$470,607	$464,209	$460,502	$457,885	$452,132	$440,887	$16,056,965
Including CO_2	$784,600	$801,473	$806,423	$815,385	$831,189	$821,065	$815,232	$802,906	$788,726	$779,592	$769,920	$762,974	$757,153	$748,229	$733,847	$22,207,468
Generation (GWh)	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	452,815

Total Levelized Power Production Cost ($/MWh)

Excluding CO_2: $ 60.90 /MWh

Including CO_2: $ 84.23 /MWh

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Ohio Valley Electric Corporation) Docket No. ER11-_____

VERIFICATION OF KELLY D. PEARCE

County of Franklin)
ss:
State of Ohio)

I, Kelly D. Pearce, Director, Contracts and Analysis of American Electric Power Service Corporation, being duly sworn, state that the contents of the foregoing "Benchmark Study Demonstrating that the Inter-Company Power Agreement Offers Low-Cost Power," and the schedule attached thereto, are true, correct, accurate and complete to the best of my knowledge, information, and belief.

Kelly D. Pearce
Kelly D. Pearce
Director, Contracts and Analysis
American Electric Power Service Corporation

Subscribed and sworn to before me this 21st day of March, 2011

My commission expires: 1/4/2014

Donna J. Stephens
Notary Public

DONNA J. STEPHENS
Notary Public, State of Ohio
My Commission Expires 01-04-2014

Execution Copy

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

DATED AS OF SEPTEMBER 10, 2010

AMONG

OHIO VALLEY ELECTRIC CORPORATION,
ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
APPALACHIAN POWER COMPANY,
BUCKEYE POWER GENERATING, LLC,
COLUMBUS SOUTHERN POWER COMPANY,
THE DAYTON POWER AND LIGHT COMPANY,
DUKE ENERGY OHIO, INC.,
FIRSTENERGY GENERATION CORP.,
INDIANA MICHIGAN POWER COMPANY,
KENTUCKY UTILITIES COMPANY,
LOUISVILLE GAS AND ELECTRIC COMPANY,
MONONGAHELA POWER COMPANY,
OHIO POWER COMPANY,
PENINSULA GENERATION COOPERATIVE, and
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

THIS AGREEMENT, dated as of September 10, 2010 (the "Agreement"), by and among OHIO VALLEY ELECTRIC CORPORATION (herein called OVEC), ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C. (herein called Allegheny), APPALACHIAN POWER COMPANY (herein called Appalachian), BUCKEYE POWER GENERATING, LLC (herein called Buckeye), COLUMBUS SOUTHERN POWER COMPANY (herein called Columbus), THE DAYTON POWER AND LIGHT COMPANY (herein called Dayton), DUKE ENERGY OHIO, INC. (formerly known as The Cincinnati Gas & Electric Company and herein called Duke Ohio), FIRSTENERGY GENERATION CORP. (herein called FirstEnergy), INDIANA MICHIGAN POWER COMPANY (herein called Indiana), KENTUCKY UTILITIES COMPANY (herein called Kentucky), LOUISVILLE GAS AND ELECTRIC COMPANY (herein called Louisville), MONONGAHELA POWER COMPANY (herein called Monongahela), OHIO POWER COMPANY (herein called Ohio Power), PENINSULA GENERATION COOPERATIVE (herein called Peninsula), and SOUTHERN INDIANA GAS AND ELECTRIC COMPANY (herein called Southern Indiana, and all of the foregoing, other than OVEC, being herein sometimes collectively referred to as the Sponsoring Companies and individually as a Sponsoring Company) hereby amends and restates in its entirety, the Inter-Company Power Agreement dated as of March 13, 2006, as amended by Modification No. 1, dated as of March 13, 2006 (herein called the Current Agreement), by and among OVEC and the Sponsoring Companies.

WITNESSETH THAT:

WHEREAS, the Current Agreement amended and restated the original Inter-Company Power Agreement, dated as of July 10, 1953, as amended by Modification No. 1, dated as of June 3, 1966; Modification No. 2, dated as of January 7, 1967; Modification No. 3, dated as of November 15, 1967; Modification No. 4, dated as of November 5, 1975; Modification No. 5, dated as of September 1, 1979; Modification No. 6, dated as of August 1, 1981; Modification No. 7, dated as of January 15, 1992; Modification No. 8, dated as of January 19, 1994; Modification No. 9, dated as of August 17, 1995; Modification No. 10, dated as of January 1, 1998; Modification No. 11, dated as of April 1, 1999; Modification No. 12, dated as of November 1, 1999; Modification No. 13, dated as of May 24, 2000; Modification No. 14, dated as of April 1, 2001; and Modification No. 15, dated as of April 30, 2004 (together, herein called the Original Agreement); and

WHEREAS, OVEC designed, purchased, and constructed, and continues to operate and maintain two steam-electric generating stations, one station (herein called Ohio Station) consisting of five turbo-generators and all other necessary equipment, at a location on the Ohio River near Cheshire, Ohio, and the other station (herein called Indiana Station) consisting of six turbogenerators and all other necessary equipment, at a location on the Ohio River near Madison, Indiana, (the Ohio Station and the Indiana Station being herein called the Project Generating Stations); and

WHEREAS, OVEC also designed, purchased, and constructed, and continues to operate and maintain necessary transmission and general plant facilities (herein called the Project Transmission Facilities) and OVEC established or cause to be established interconnections between the Project Generating Stations and the systems of certain of the Sponsoring Companies; and

WHEREAS, OVEC entered into an agreement, attached hereto as Exhibit A, with Indiana-Kentucky Electric Corporation (herein called IKEC), a corporation organized under the laws of the State of Indiana as a wholly owned subsidiary corporation of OVEC, which has been amended and restated as of the date of this Agreement and embodies the terms and conditions for the ownership and operation by IKEC of the Indiana Station and such portion of the Project Transmission Facilities which are to be owned and operated by it; and

WHEREAS, transmission facilities were constructed by certain of the Sponsoring Companies to interconnect the systems of such Sponsoring Companies, directly or indirectly, with the Project Generating Stations and/or the Project Transmission Facilities, and the Sponsoring Companies have agreed to pay for Available Power, as hereinafter defined, as may be available at the Project Generating Stations; and

WHEREAS, the parties hereto desire to amend and restate in their entirety, the Current Agreement to define the terms and conditions governing the rights of the Sponsoring Companies to receive Available Power from the Project Generating Stations and the obligations of the Sponsoring Companies to pay therefor.

NOW, THEREFORE, the parties hereto agree with each other as follows:

ARTICLE 1

DEFINITIONS

1.01. For the purposes of this Agreement, the following terms, wherever used herein, shall have the following meanings:

1.011 "Affiliate" means, with respect to a specified person, any other person that directly or indirectly through one or more intermediaries controls, is controlled by, or is under common control with, such specified person; provided that "control" for these purposes means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract or otherwise.

1.012 "Arbitration Board" has the meaning set forth in Section 9.10.

1.013 "Available Energy" of the Project Generating Stations means the energy associated with Available Power.

1.014 "Available Power" of the Project Generating Stations at any particular time means the total net kilowatts at the 345-kV busses of the Project Generating Stations which Corporation in its sole discretion will determine that the Project Generating Stations will be capable of safely delivering under conditions then prevailing, including all conditions affecting capability.

1.015 "Corporation" means OVEC, IKEC, and all other subsidiary corporations of OVEC.

1.016 "Decommissioning and Demolition Obligation" has the meaning set forth in Section 5.03(f) hereof.

1.017 "Effective Date" means September 10, 2010, or to the extent necessary, such later date on which Corporation notifies the Sponsoring Companies that all conditions to effectiveness, including all required waiting periods and all required regulatory acceptances or approvals, of this Agreement have been satisfied in form and substance satisfactory to the Corporation.

1.018 "Election Period" has the meaning set forth in Section 9.183(a) hereof.

1.019 "Minimum Generating Unit Output" means 80 MW (net) for each of the Corporation's generation units; provided that such "Minimum Generating Unit Output" shall be confirmed from time to time by operating tests on the Corporation's generation units and shall be adjusted by the Operating Committee as appropriate following such tests.

1.0110 "Minimum Loading Event" means a period of time during which one or more of the Corporation's generation units are operating at below the Minimum Generating Output as a result of the Sponsoring Companies' failure to schedule and take delivery of sufficient Available Energy.

1.0111 "Minimum Loading Event Costs" means the sum of the following costs caused by one or more Minimum Loading Events: (i) the actual costs of any of the Corporation's generating units burning fuel oil; and (ii) the estimated actual additional costs to the Corporation resulting from Minimum Loading Events, including without limitation the incremental costs of additional emissions allowances, reflected in the schedule of charges prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedule may be adjusted from time to time as necessary by the Operating Committee.

1.0112 "Month" means a calendar month.

1.0113 "Nominal Power Available" means an individual Sponsoring Company's Power Participation Ratio share of the Corporation's current estimate of the maximum amount of Available Power available for delivery at any given time.

1.0114 "Offer Notice" means the notice required to be given to the other Sponsoring Companies by a Transferring Sponsor offering to sell all or a portion of such Transferring Sponsor's rights, title and interests in, and obligations under this Agreement. At a minimum, the Offer Notice shall be in writing and shall contain (i) the rights, title and interests in, and obligations under this Agreement that the Transferring Sponsor proposes to Transfer; and (ii) the cash purchase price and any other material terms and conditions of such proposed transfer. An Offer Notice may not contain terms or conditions requiring the purchase of any non-OVEC interests.

1.0115 "Permitted Assignee" means a person that is (a) a Sponsoring Company or its Affiliate whose long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, has a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if the proposed assignee's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such assignee's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); or (b) a Sponsoring Company or its Affiliate that does not meet the criteria in subsection (a) above, if the Sponsoring Company or its Affiliate that is assigning its rights, title and interests in, and obligations under, this Agreement agrees in writing (in form and substance satisfactory to Corporation) to remain obligated to satisfy all of the obligations related to the assigned rights, title and interests to the extent such obligations are not satisfied by the assignee of such rights, title and interests; provided that, in no event shall a person be deemed a "Permitted Assignee" if counsel for the Corporation reasonably determines that the assignment of the rights, title or interests in, or obligations under, this Agreement to such person could cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer.

1.0116 "Postretirement Benefit Obligation" has the meaning set forth in Section 5.03(e) hereof.

1.0117 "Power Participation Ratio" as applied to each of the Sponsoring Companies refers to the percentage set forth opposite its respective name in the tabulation below:

Company	Power Participation Ratio—Percent

Allegheny	3.01
Appalachian	15.69
Buckeye	18.00
Columbus	4.44
Dayton	4.90
Duke Ohio	9.00
FirstEnergy	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	0.49
Ohio Power	15.49
Peninsula	6.65
Southern Indiana	1.50
Total	100.0

1.0118 "Tariff" means the open access transmission tariff of the Corporation, as amended from time to time, or any successor tariff, as accepted by the Federal Energy Regulatory Commission or any successor agency.

1.0119 "Third Party" means any person other than a Sponsoring Company or its Affiliate.

1.0120 "Total Minimum Generating Output" means the product of the Minimum Generating Unit Output times the number of the Corporation's generation units available for service at that time.

1.0121 "Transferring Sponsor" has the meaning set forth in Section 9.183(a) hereof.

1.0122 "Uniform System of Accounts" means the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission as in effect on January 1, 2004.

ARTICLE 2

TRANSMISSION AGREEMENT AND FACILITIES

2.01. *Transmission Agreement.* The Corporation shall enter into a transmission service agreement under the Tariff, and the Corporation shall reserve and schedule transmission service, ancillary services and other transmission-related services in accordance with the Tariff to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement.

2.02. *Limited Burdening of Corporation's Transmission Facilities.* Transmission facilities owned by the Corporation, including the Project Transmission Facilities, shall not be burdened by power and energy flows of any Sponsoring Company to an extent which would impair or prevent the transmission of Available Power.

ARTICLE 3

[RESERVED]

ARTICLE 4

AVAILABLE POWER SUPPLY

4.01. *Operation of Project Generating Stations.* Corporation shall operate and maintain the Project Generating Stations in a manner consistent with safe, prudent, and efficient operating practice so that the Available Power available from said stations shall be at the highest practicable level attainable consistent with OVEC's obligations under Reliability*First* Reliability Standard BAL-002-RFC throughout the term of this Agreement.

4.02. *Available Power Entitlement.* The Sponsoring Companies collectively shall be entitled to take from Corporation and Corporation shall be obligated to supply to the Sponsoring Companies any and all Available Power and Available Energy pursuant to the provisions of this Agreement. Each Sponsoring Company's Available Power Entitlement hereunder shall be its Power Participation Ratio, as defined in *subsection* 1.0117, of Available Power.

4.03. *Available Energy.* Corporation shall make Available Energy available to each Sponsoring Company in proportion to said Sponsoring Company's Power Participation Ratio. No Sponsoring Company, however, shall be obligated to avail itself of any Available Energy. Available Energy shall be scheduled and taken by the Sponsoring Companies in accordance with the following procedures:

4.031 Each Sponsoring Company shall schedule the delivery of all or any portion (in whole MW increments) of its entitlement to Available Energy in accordance with scheduling procedures established by the Operating Committee from time to time.

4.032 In the event that any Sponsoring Company does not schedule the delivery of all of its Power Participation Ratio share of Available Energy, then each such other Sponsoring Company may schedule the delivery of all or any portion (in whole MW increments) of any such unscheduled share of Available Energy (through successive allotments if necessary) in proportion to their Power Participation Ratios.

4.033 Notwithstanding any Available Energy schedules made in accordance with this Section 4.03 and the applicable scheduling procedures, (i) the Corporation shall adjust all schedules to the extent that the Corporation's actual generation output is less than or more than the expected Nominal Power Available to all Sponsoring Companies, or to the extent that the Corporation is unable to obtain sufficient transmission service under the Tariff for the delivery of all scheduled Available Energy; and (ii) immediately following a Minimum Loading Event, any Sponsoring Company causing (in whole or part) such Minimum Loading Event shall have its Available Energy schedules increased after the schedules of the Sponsoring Companies not causing such Minimum Load Event, in accordance with the estimated ramp rates associated with the shutdown and start-up of the Corporation's generation units as reflected in the schedules prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedules may be adjusted from time to time as necessary by the Operating Committee.

4.034 Each Sponsoring Company availing itself of Available Energy shall be entitled to an amount of energy (herein called billing kilowatt-hours of Available Energy) equal to its portion, determined as provided in this Section 4.03, of the total Available Energy after deducting therefrom such Sponsoring Company's proportionate share, as defined in this Section 4.03, of all losses as determined in accordance with the Tariff incurred in transmitting the total of such Available Energy from the 345-kV busses of the Project Generating Stations to the applicable delivery points, as scheduled pursuant to Section 9.01, of all Sponsoring Companies availing themselves of Available Energy. The proportionate share of all such losses that shall be so deducted from such Sponsoring Company's portion of Available Energy shall be equal to all such losses multiplied by the ratio of such portion of Available Energy to the total of such Available Energy. Each Sponsoring Company shall have the right, pursuant to this Section 4.03, to avail itself of Available Energy for the purpose of meeting the loads of its own system and/or of supplying energy to other systems in accordance with agreements, other than this Agreement, to which such Sponsoring Company is a party.

4.035 To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then such one or more Sponsoring Companies shall be assessed charges for any Minimum Loading Event Costs in accordance with Section 5.05.

ARTICLE 5

CHARGES FOR AVAILABLE POWER AND MINIMUM LOADING EVENT COSTS

5.01. *Total Monthly Charge.* The amount to be paid to Corporation each month by the Sponsoring Companies for Available Power and Available Energy supplied under this

Agreement shall consist of the sum of an energy charge, a demand charge, and a transmission charge, all determined as set forth in this *Article* 5.

5.02. *Energy Charge.* The energy charge to be paid each month by the Sponsoring Companies for Available Energy shall be determined by Corporation as follows:

5.021 Determine the aggregate of all expenses for fuel incurred in the operation of the Project Generating Stations, in accordance with Account 501 (Fuel), Account 506.5 (Variable Reagent Costs Associated With Pollution Control Facilities) and 509 (Allowances) of the Uniform System of Accounts.

5.022 Determine for such month the difference between the total cost of fuel as described in subsection 5.021 above and the total cost of fuel included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03. For the purposes hereof the difference so determined shall be the fuel cost allocable for such month to the total kilowatt-hours of energy generated at the Project Generating Stations for the supply of Available Energy. For Available Energy availed of by the Sponsoring Companies, each Sponsoring Company shall pay Corporation for each such month an amount obtained by multiplying the ratio of the billing kilowatt-hours of such Available Energy availed of by such Sponsoring Company during such month to the aggregate of the billing kilowatt-hours of all Available Energy availed of by all Sponsoring Companies during such month times the total cost of fuel as described in this subsection 5.022 for such month.

5.03. *Demand Charge*. During the period commencing with the Effective Date and for the remainder of the term of this Agreement, demand charges payable by the Sponsoring Companies to Corporation shall be determined by the Corporation as provided below in this Section 5.03. Each Sponsoring Company's share of the aggregate demand charges shall be the percentage of such charges represented by its Power Participation Ratio.

The aggregate demand charge payable each month by the Sponsoring Companies to Corporation shall be equal to the total costs incurred for such month by Corporation resulting from its ownership, operation, and maintenance of the Project Generating Stations and Project Transmission Facilities determined as follows:

As soon as practicable after the close of each calendar month the following components of costs of Corporation (eliminating any duplication of costs which might otherwise be reflected among the corporate entities comprising Corporation) applicable for such month to the ownership, operation and maintenance of the Project Generating Stations and the Project Transmission Facilities, including additional facilities and/or spare parts (such as fuel processing plants, flue gas or waste product processing facilities, and facilities reasonably required to enable the Corporation to limit the emission of pollutants or the discharge of wastes in compliance with governmental requirements) and replacements necessary or desirable to keep the Project Generating Stations and the Project Transmission Facilities in a dependable and efficient operating condition, and any provision for any taxes that may be applicable to such charges, to be determined and recorded in the following manner:

(a) Component (A) shall consist of fixed charges made up of (i) the amounts of interest properly chargeable to Accounts 427, 430 and 431, less the amount thereof credited to Account 432, of the Uniform System of Accounts, including the interest component of any purchase price, interest, rental or other payment under an installment sale, loan, lease or similar agreement relating to the purchase, lease or acquisition by Corporation of additional facilities and replacements (whether or not such interest or other amounts have come due or are actually payable during such Month), (ii) the amounts of amortization of debt discount or premium and expenses properly chargeable to Accounts 428 and 429, and (iii) an amount equal to the sum of (I) the applicable amount of the debt amortization component for such month required to retire the total amount of indebtedness of Corporation issued and outstanding, (II) the amortization requirement for such month in respect of indebtedness of Corporation incurred in respect of additional facilities and replacements, and (III) to the extent not provided for pursuant to clause (II) of this clause (iii), an appropriate allowance for depreciation of additional facilities and replacements.

(b) Component (B) shall consist of the total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expense, etc., properly chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts (exclusive of Accounts 501, 509, 555, 911, 912, 913, 916, and 917 of the Uniform System of Accounts), minus the total of all non-fuel costs included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03, minus the total of all transmission charges payable to the Corporation for such month pursuant to Section 5.04, and plus any additional amounts which, after provision for all income taxes on such amounts (which shall be included in Component (C) below), shall equal any amounts paid or payable by Corporation as fines or penalties with respect to occasions where it is asserted that Corporation failed to comply with a law or regulation relating to the emission of pollutants or the discharge of wastes.

(c) Component (C) shall consist of the total expenses for taxes, including all taxes on income but excluding any federal income taxes arising from payments to Corporation under Component (D) below, and all operating or other costs or expenses, net of income, not included or specifically excluded in Components (A) or (B) above, including tax adjustments, regulatory adjustments, net losses for the disposition of property and other net costs or expenses associated with the operation of a utility.

(d) Component (D) shall consist of an amount equal to the product of $2.089 multiplied by the total number of shares of capital stock of the par value of $100 per share of Ohio Valley Electric Corporation which shall have been issued and which are outstanding on the last day of such month.

(e) Component (E) shall consist of an amount to be sufficient to pay the costs and other expenses relating to the establishment, maintenance and administration of life insurance, medical insurance and other postretirement benefits other than pensions attributable to the employment and employee service of active employees, retirees, or other employees, including without limitation any premiums due or expected to become due, as well as administrative fees and costs, such amounts being sufficient to provide payment with respect to all periods for which Corporation has committed or is otherwise obligated to make such payments, including amounts attributable to current employee service and any unamortized prior service cost, gain or loss attributable to prior service years ("Postretirement Benefit Obligation"); <u>provided that</u>, the amount payable for Postretirement Benefit Obligations during any month shall be determined by the Corporation based on, among other factors, the Statement of Financial Accounting Standards No. 106 (Employers' Accounting For Postretirement Benefits Other Than Pensions) and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Postretirement Benefit Obligation.

(f) Component (F) shall consist of an amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations, which amount shall include, without limitation the following costs (net of any salvage credits): the costs of demolishing the plants' building structures, disposal of non-salvageable materials, removal and disposal of insulating materials, removal and disposal of storage tanks and associated piping, disposal or removal of materials and supplies (including fuel oil and coal), grading, covering and reclaiming storage and disposal areas, disposing of ash in ash ponds to the extent required by regulatory authorities, undertaking corrective or remedial action required by regulatory authorities, and any other costs incurred in putting the facilities in a condition necessary to protect health or the environment or which are required by regulatory authorities, or which are incurred to fund continuing obligations to monitor or to correct environmental problems which result, or are later discovered to result, from the facilities' operation, closure or post-closure activities ("Decommissioning and Demolition Obligation") provided that, the amount payable for Decommissioning and Demolition Obligations during any month shall be calculated by Corporation based on, among other factors, the then-estimated useful life of the Project Generating Stations and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Decommissioning and Demolition Obligation, and provided further that, the Corporation shall recalculate the amount payable under this Component (F) for future months from time to time, but in no event later than five (5) years after the most recent calculation.

5.04. *Transmission Charge.* The transmission charges to be paid each month by the Sponsoring Companies shall be equal to the total costs incurred for such month by Corporation for the purchase of transmission service, ancillary services and other transmission-related services under the Tariff as reserved and scheduled by the Corporation to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement. Each Sponsoring Company's share of the aggregate transmission charges shall be the percentage of such charges represented by its Power Participation Ratio.

5.05. *Minimum Loading Event Costs.* To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then the sum of all Minimum Loading Event Costs relating to such Minimum Loading Event shall be charged to such Sponsoring Company or group of Sponsoring Companies that failed take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during such period, with such Minimum Loading Event Costs allocated among such Sponsoring Companies on a pro-rata basis in accordance with such Sponsoring Company's MWh share of the MWh reduction in the delivery of Available Energy causing any Minimum Loading Event. The applicable charges for Minimum Loading Event Costs as determined by the corporation in accordance with Section 5.05 shall be paid each month by the applicable Sponsoring Companies.

ARTICLE 6

Metering of Energy Supplied

6.01. *Measuring Instruments.* The parties hereto shall own and maintain such metering equipment as may be necessary to provide complete information regarding the delivery of power and energy to or for the account of any of the parties hereto; and the ownership and expense of such metering shall be in accordance with agreements among them. Each party will at its own expense make such periodic tests and inspections of its meters as may be necessary to maintain them at the highest practical commercial standard of accuracy and will advise all other interested parties hereto promptly of the results of any such test showing an inaccuracy of more than 1%. Each party will make additional tests of its meters at the request of any other interested party. Other interested parties shall be given notice of, and may have representatives present at, any test and inspection made by another party.

ARTICLE 7

COSTS OF REPLACEMENTS AND ADDITIONAL FACILITIES; PAYMENTS FOR EMPLOYEE BENEFITS; DECOMMISSIONING, SHUTDOWN, DEMOLITION AND CLOSING CHARGES

7.01. *Replacement Costs.* The Sponsoring Companies shall reimburse Corporation for the difference between (a) the total cost of replacements chargeable to property and plant made by Corporation during any month prior thereto (and not previously reimbursed) and (b) the amounts received by Corporation as proceeds of fire or other applicable insurance protection, or amounts recovered from third parties responsible for damages requiring replacement, plus provision for all taxes on income on such difference; provided that, to the extent that the Corporation arranges for the financing of any replacements, the payments due under this Section 7.01 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio. The term cost of replacements, as used herein, shall include all components of cost, plus removal expense, less salvage.

7.02. *Additional Facility Costs.* The Sponsoring Companies shall reimburse Corporation for the total cost of additional facilities and/or spare parts purchased and/or installed by Corporation during any month prior thereto (and not previously reimbursed), plus provision for all taxes on income on such costs; provided that, to the extent that the Corporation arranges for the financing of any additional facilities and/or spare parts, the payments due under this Section 7.02 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio.

7.03. *Payments for Employee Benefits.* Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Postretirement Benefit Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to fulfill its commitments or obligations with respect to both postemployment benefit obligations under the Statement of Financial Accounting Standards No. 112 and postretirement benefits other than pensions, as determined by Corporation with the aid of an actuary or actuaries selected by the Corporation based on the terms of the Corporation's then-applicable plans.

7.04. *Decommissioning, Shutdown, Demolition and Closing.* The Sponsoring Companies recognize that a part of the cost of supplying power to it under this Agreement is the amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations. Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Decommissioning and Demolition Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to complete the decommissioning, shutdown, demolition and closing of the Project Generating Stations, based on the Corporation's recalculation of the Decommissioning and Demolition Obligation in accordance with Section 5.03(f) of this Agreement no earlier than twelve (12) months before the effective date of termination of this Agreement.

ARTICLE 8

BILLING AND PAYMENT

8.01. *Available Power, and Replacement and Additional Facility Costs.* As soon as practicable after the end of each month Corporation shall render to each Sponsoring Company a statement of all Available Power and Available Energy supplied to or for the account of such Sponsoring Company during such month, specifying the amount due to the Corporation therefor, including any amounts for reimbursement for the cost of replacements and additional facilities and/or spare parts incurred during such month, pursuant to *Articles* 5 and 7 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case any factor entering into the computation of the amount due for Available Power and Available Energy cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made.

8.02. *Provisional Payments for Available Power.* The Sponsoring Companies shall, from time to time, at the request of the Corporation, make provisional semi-monthly payments for Available Power in amounts approximately equal to the estimated amounts payable for Available Power delivered by Corporation to the Sponsoring Companies during each semi-monthly period. As soon as practicable after the end of each semi-monthly period with respect to which Corporation has requested the Sponsoring Companies to make provisional semi-monthly payments for Available Power, Corporation shall render to each Sponsoring Company a separate statement indicating the amount payable by such Sponsoring Company for such semi-monthly period. Such Sponsoring Company shall make payment therefor promptly upon receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement and the amounts so paid by such Sponsoring Company shall be credited to the account of such Sponsoring Company with respect to future payments to be made pursuant to *Articles* 5 and 7 above by such Sponsoring Company to Corporation for Available Power.

8.03. *Minimum Loading Event Costs.* As soon as practicable after the end of each month, Corporation shall render to each Sponsoring Company a statement indicating any applicable charges for Minimum Loading Event Costs pursuant to Section 5.05 during such month, specifying the amount due to the Corporation therefor pursuant to *Article* 5 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case the computation of the amount due for Minimum Loading Event Costs cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made, and all payments shall be subject to subsequent adjustment.

8.04. *Unconditional Obligation to Pay Demand and Other Charges.* The obligation of each Sponsoring Company to pay its specified portion of the Demand Charge under Section 5.03, the Transmission Charge under Section 5.04, and all charges under *Article* 7 for any Month shall not be reduced irrespective of:

(a) whether or not any Available Power or Available Energy are supplied by the Corporation during such calendar month and whether or not any Available Power or Available Energy are accepted by any Sponsoring Company during such calendar month;

(b) the existence of any claim, set-off, defense, reduction, abatement or other right (other than irrevocable payment, performance, satisfaction or discharge in full) that such Sponsoring Company may have, or which may at any time be available to or be asserted by such Sponsoring Company, against the Corporation , any other Sponsoring Company, any creditor of the Corporation or any other Person (including, without limitation, arising as a result of any breach or alleged breach by either the Corporation, any other Sponsoring Company, any creditor of the Corporation or any other Person under this Agreement or any other agreement (whether or not related to the transactions contemplated by this Agreement or any other agreement) to which such party is a party); or

(c) the validity or enforceability against any other Sponsoring Company of this Agreement or any right or obligation hereunder (or any release or discharge thereof) at any time.

ARTICLE 9

GENERAL PROVISIONS

9.01. *Characteristics of Supply and Points of Delivery.* All power and energy delivered hereunder shall be 3-phase, 60-cycle, alternating current, at a nominal unregulated voltage designated for the point of delivery as described in this *Article* 9. Available Power and Available Energy to be delivered between Corporation and the Sponsoring Companies pursuant to this Agreement shall be delivered under the terms and conditions of the Tariff at the points, as scheduled by the Sponsoring Company in accordance with procedures established by the Operating Committee and in accordance with Section 9.02, where the transmission facilities of Corporation interconnect with the transmission facilities of any Sponsoring Company (or its successor or predecessor); provided that, to the extent that a joint and common market is established for the sale of power and energy by Sponsoring Companies within one or more of the regional transmission organizations or independent system operators approved by the Federal Energy Regulatory Commission in which the Sponsoring Companies are members or otherwise participate, then Corporation and the Sponsoring Companies shall take such action as reasonably necessary to permit the Sponsoring Companies to bid their entitlement to power and energy from Corporation into such market(s) in accordance with the procedures established for such market(s).

9.02. *Modification of Delivery Schedules Based on Available Transmission Capability.* To the extent that transmission capability available for the delivery of Available Power and Available Energy at any delivery point is less than the total amount of Available Power and Available Energy scheduled for delivery by the Sponsoring Companies at such delivery point in accordance with Section 9.01, then the following procedures shall apply and the Corporation and the applicable Sponsoring Companies shall modify their delivery schedules accordingly until the total amount of Available Power and Available Energy scheduled for delivery at such delivery point is equal to or less than the transmission capability available for the delivery of Available Power and Available Energy: (a) the transmission capability available for the delivery of Available Power and Available Energy at the following delivery points shall be allocated first on a pro rata basis (in whole MW increments) to the following Sponsoring Companies up to their Power Participation Ratio share of the total amount of Available Energy available to all Sponsoring Companies (and as applicable, further allocated among Sponsoring Companies entitled to allocation under this Section 9.02(a) in accordance with their Power Participation Ratios): (i) to Allegheny, Appalachian, Buckeye, Columbus, FirstEnergy, Indiana, Monongahela, Ohio Power and Peninsula (or their successors) for deliveries at the points of interconnection between the Corporation and Appalachian, Columbus, Indiana or Ohio Power, or their successors; (ii) to Duke Ohio (or its successor) for deliveries at the points of interconnection between the Corporation and Duke Ohio or its successor; (iii) to Dayton (or its successor) for deliveries at the points of interconnection between the Corporation and Dayton or its successor; and (iv) to Kentucky, Louisville and Southern Indiana (or their successors) for deliveries at the points of interconnection between the Corporation and Louisville or Kentucky, or their successors; and (b) any remaining transmission capability available for the delivery of

Available Power and Available Energy shall be allocated on a pro rata basis (in whole MW increments) to the Sponsoring Companies in accordance with their Power Participation Ratios.

9.03. *Operation and Maintenance of Systems Involved.* Corporation and the Sponsoring Companies shall operate their systems in parallel, directly or indirectly, except during emergencies that temporarily preclude parallel operation. The parties hereto agree to coordinate their operations to assure maximum continuity of service from the Project Generating Stations, and with relation thereto shall cooperate with one another in the establishment of schedules for maintenance and operation of equipment and shall cooperate in the coordination of relay protection, frequency control, and communication and telemetering systems. The parties shall build, maintain and operate their respective systems in such a manner as to minimize so far as practicable rapid fluctuations in energy flow among the systems. The parties shall cooperate with one another in the operation of reactive capacity so as to assure mutually satisfactory power factor conditions among themselves.

The parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of their respective power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of power and energy among their systems. The parties hereto shall provide and/or install on their respective systems such communication, telemetering, frequency and/or tie-line control facilities essential to so minimizing such deviations; and shall fully cooperate with one another and with third parties (such third parties whose systems are either directly or indirectly interconnected with the systems of the Sponsoring Companies and who of necessity together with the parties hereto must unify their efforts cooperatively to achieve effective and efficient interconnected systems operation) in developing and executing operating procedures that will enable the parties hereto to avoid to the extent practicable deviations from scheduled deliveries.

In order to foster coordination of the operation and maintenance of Corporation's transmission facilities with those facilities of Sponsoring Companies that are owned or functionally controlled by a regional transmission organization or independent system operator, Corporation shall use commercially reasonable efforts to enter into a coordination agreement with any regional transmission organization or independent system operator approved by the Federal Energy Regulatory Commission that operates transmission facilities that interconnect with Corporation's transmission facilities, and to enter into a mutually agreeable services agreement with a regional transmission organization or independent system operator to provide the Corporation with reliability and security coordination services and other related services.

9.04. *Power Deliveries as Affected by Physical Characteristics of Systems.* It is recognized that the physical and electrical characteristics of the transmission facilities of the interconnected network of which the transmission systems of the Sponsoring Companies, Corporation, and other systems of third parties not parties hereto are a part, may at times preclude the direct delivery at the points of interconnection between the transmission systems of one or more of the Sponsoring Companies and Corporation, of some portion of the energy supplied under this Agreement, and that in each such case, because of said characteristics, some of the energy will be delivered at points which interconnect the system of one or more of the Sponsoring Companies with systems of companies not parties to this Agreement. The parties hereto shall cooperate in the development of mutually satisfactory arrangements among themselves and with such companies not parties hereto whereby the supply of power and energy contemplated hereunder can be fulfilled.

9.05. *Operating Committee.* There shall be an "Operating Committee" consisting of one member appointed by the Corporation and one member appointed by each of the Sponsoring Companies electing so to do; provided that, if any two or more Sponsoring Companies are Affiliates, then such Affiliates shall together be entitled to appoint only one member to the Operating Committee. The "Operating Committee" shall establish (and modify as necessary) scheduling, operating, testing and maintenance procedures of the Corporation in support of this Agreement, including establishing: (i) procedures for scheduling delivery of Available Energy under Section 4.03, (ii) procedures for power and energy accounting, (iii) procedures for the reservation and scheduling of firm and non-firm transmission service under the Tariff for the delivery of Available Power and Available Energy, (iv) the Minimum Generating Unit Output, and (v) the form of notifications relating to power and energy and the price thereof. In addition, the Operating Committee shall consider and make recommendations to Corporation's Board of Directors with respect to such other problems as may arise affecting the transactions under this Agreement. The decisions of the Operating Committee, including the adoption or modification of any procedure by the Operating Committee pursuant to this Section 9.04, must receive the affirmative vote of at least two-thirds of the members of the Operating Committee, regardless of the number of members of the Operating Committee present at any meeting.

9.06. *Acknowledgment of Certain Rights.* For the avoidance of doubt, all of the parties to this Agreement acknowledge and agree that (i) as of the effective date of the Current Agreement, certain rights and obligations of the Sponsoring Companies or their predecessors under the Original Agreement were changed, modified or otherwise removed, (ii) to the extent that the rights of any Sponsoring Company or their predecessors were thereby changed, modified or otherwise removed as of the effective date of the Current Agreement, such Sponsoring Company may be entitled to rights under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the Federal Energy Regulatory Commission ("FERC"), (iii) as a result of the elimination as of the effective date of the Current Agreement of the firm transmission service previously provided during the term of the Original Agreement to Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems by certain Sponsoring Companies or their predecessors whose transmission systems were directly connected to the Corporation's facilities, such Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems shall have been entitled to such "roll over" firm transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement, to the border of such Sponsoring Company system and intervening Sponsoring Company system, as would be accorded a long-term firm point-to-point transmission service reservation under the then otherwise applicable FERC Open Access Transmission Tariff ("OATT"), (iv) the obligation of any Sponsoring Company to maintain or expand transmission capacity to accommodate another Sponsoring Company's "roll over" rights to transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement shall be consistent with the obligations it would have for long-term firm point-to-point transmission service provided pursuant to the then otherwise applicable OATT, and (v) the parties shall cooperate with any Sponsoring Company that seeks to obtain and/or exercise any such rights available under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the FERC.

9.07. *Term of Agreement.* This Agreement shall become effective upon the Effective Date and shall terminate upon the earlier of: (1) June 30, 2040 or (2) the sale or other disposition of all of the facilities of the Project Generating Stations or the permanent cessation of operation of such facilities; provided that, the provisions of *Articles* 5, 7 and 8, this Section 9.07 and Sections 9.08, 9.09, 9.10, 9.11, 9.12, 9.14, 9.15, 9.16, 9.17 and 9.18 shall survive the termination of this Agreement, and no termination of this Agreement, for whatever reason, shall release any Sponsoring Company of any obligations or liabilities incurred prior to such termination.

9.08. *Access to Records.* Corporation shall, at all reasonable times, upon the request of any Sponsoring Company, grant to its representatives reasonable access to the books, records and accounts of the Corporation, and furnish such Sponsoring Company such information as it may reasonably request, to enable it to determine the accuracy and reasonableness of payments made for energy supplied under this Agreement.

9.09. *Modification of Agreement.* Absent the agreement of all parties to this Agreement, the standard for changes to provisions of this Agreement related to rates proposed by a party, a non-party or the Federal Energy Regulatory Commission (or a successor agency) acting sua sponte shall be the "public interest" standard of review set forth in *United Gas Pipeline Co. v. Mobile Gas Serv. Corp.,* 350 U.S. 332 (1956) and *Federal Power Comm'n v. Sierra Pacific Power Co.,* 350 U.S. 348 (1956).

9.10. *Arbitration.* Any controversy, dispute or claim arising out of this Agreement or the refusal by any party hereto to perform the whole or any part thereof, shall be determined by arbitration, in the City of Columbus, Franklin County, Ohio, in accordance with the Commercial Arbitration Rules of the American Arbitration Association or any successor organization, except as otherwise set forth in this Section 9.10.

The party demanding arbitration shall serve notice in writing upon all other parties hereto, setting forth in detail the controversy, dispute or claim with respect to which arbitration is demanded, and the parties shall thereupon endeavor to agree upon an arbitration board, which shall consist of three members ("Arbitration Board"). If all the parties hereto fail so to agree within a period of thirty (30) days from the original notice, the party demanding arbitration may, by written notice to all other parties hereto, direct that any members of the Arbitration Board that have not been agreed to by the parties shall be selected by the American Arbitration Association, or any successor organization. No person shall be eligible for appointment to the Arbitration Board who is an officer, employee, shareholder of or otherwise interested in any of the parties hereto or in the matter sought to be arbitrated.

The Arbitration Board shall afford adequate opportunity to all parties hereto to present information with respect to the controversy, dispute or claim submitted to arbitration and may request further information from any party hereto; provided, however, that the parties hereto may, by mutual agreement, specify the rules which are to govern any proceeding before the Arbitration Board and limit the matters to be considered by the Arbitration Board, in which event the Arbitration Board shall be governed by the terms and conditions of such agreement.

The determination or award of the Arbitration Board shall be made upon a determination of a majority of the members thereof. The findings and award of the Arbitration Board shall be final and conclusive with respect to the controversy, dispute or claim submitted for arbitration and shall be binding upon the parties hereto, except as otherwise provided by law. The award of the Arbitration Board shall specify the manner and extent of the division of the costs of the arbitration proceeding among the parties hereto.

9.11. *Liability.* The rights and obligations of all the parties hereto shall be several and not joint or joint and several.

9.12. *Force Majeure.* No party hereto shall be held responsible or liable for any loss or damage on account of non-delivery of energy hereunder at any time caused by an event of Force Majeure. "Force Majeure" shall mean the occurrence or non-occurrence of any act or event that could not reasonably have been expected and avoided by exercise of due diligence and foresight and such act or event is beyond the reasonable control of such party, including to the extent caused by act of God, fire, flood, explosion, strike, civil or military authority, insurrection or riot, act of the elements, or failure of equipment. For the avoidance of doubt, "Force Majeure" shall in no event be based on any Sponsoring Company's financial or economic conditions, including without limitation (i) the loss of the Sponsoring Company's markets; or (ii) the Sponsoring Company's inability economically to use or resell the Available Power or Available Energy purchased hereunder.

9.13. *Governing Law.* This Agreement shall be governed by, and construed in accordance with, the laws of the State of Ohio.

9.14. *Regulatory Approvals.* This Agreement is made subject to the jurisdiction of any governmental authority or authorities having jurisdiction in the premises and the performance thereof shall be subject to the following:

(a) The receipt of all regulatory approvals, in form and substance satisfactory to Corporation, necessary to permit Corporation to perform all the duties and obligations to be performed by Corporation hereunder.

(b) The receipt of all regulatory approvals, in form and substance satisfactory to the Sponsoring Companies, necessary to permit the Sponsoring Companies to carry out all transactions contemplated herein.

9.15. *Notices.* All notices, requests or other communications under this Agreement shall be in writing and shall be sufficient in all respects: (i) if delivered in person or by courier, upon receipt by the intended recipient or an employee that routinely accepts packages or letters from couriers or other persons for delivery to personnel at the address identified above (as confirmed by, if delivered by courier, the records of such courier), (ii) if sent by facsimile transmission, when the sender receives confirmation from the sending facsimile machine that such facsimile transmission was transmitted to the facsimile number of the addressee, or (iii) if mailed, upon the date of delivery as shown by the return receipt therefor.

9.16. *Waiver.* Performance by any party to this Agreement of any responsibility or obligation to be performed by such party or compliance by such party with any condition contained in this Agreement may by a written instrument signed by all other parties to this Agreement be waived in any one or more instances, but the failure of any party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

9.17. *Titles of Articles and Sections.* The titles of the Articles and Sections in this Agreement have been inserted as a matter of convenience of reference and are not a part of this Agreement.

9.18. *Successors and Assigns.* This Agreement may be executed in any number of counterparts, all of which shall constitute but one and the same document.

9.181 This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns, but a party to this Agreement may not assign this Agreement or any of its rights, title or interests in or obligations (including without limitation the assumption of debt obligations) under this Agreement, except to a successor to all or substantially all the properties and assets of such party or as provided in Section 9.182 or 9.183, without the written consent of all the other parties hereto.

9.182 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, upon thirty (30) days notice to the Corporation and each other Sponsoring Company, without any further action by the Corporation or the other Sponsoring Companies, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Permitted Assignee, provided that, the assignee and assignor of the rights, title and interests in, and obligations under, this Agreement have executed an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion (including, without limitation; the agreement by the Sponsoring Company assigning such rights, title and interests in, and obligations under, this Agreement to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment).

9.183 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, subject to compliance with all of the requirements of this Section 9.183, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party without any further action by the Corporation or the other Sponsoring Companies.

(a) A Sponsoring Company (the "Transferring Sponsor") that desires to assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party shall deliver an Offer Notice to the Corporation and each other Sponsoring Company. The Offer Notice shall be deemed to be an irrevocable offer of the subject rights, title and interests in, and obligations under this Agreement to each of the other Sponsoring Companies that is not an Affiliate of the Transferring Sponsor, which offer must be held open for no less than thirty (30) days from the date of the Offer Notice (the "Election Period").

(b) The Sponsoring Companies (other than the Transferring Sponsor and its Affiliates) shall first have the right, but not the obligation, to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice at the price and on the terms specified therein by delivering written notice of such election to the Transferring Sponsor and the Corporation within the Election Period; provided that, irrespective of the terms and conditions of the Offer Notice, a Sponsoring Company may condition its election to purchase the interest described in the Offer Notice on the receipt of approval or consent from such Sponsoring Company's Board of Directors; provided further that, written notice of such conditional election must be delivered to the Transferring Sponsor and the Corporation within the Election Period and such conditional election shall be deemed withdrawn (as if it had never been provided) unless the Sponsoring Company that delivered such conditional election subsequently delivers written notice to the Transferring Sponsor and the Corporation on or before the tenth (10^{th}) day after the expiration of the Election Period that all necessary approval or consent of such Sponsoring Company's Board of Directors have been obtained. To the extent that more than one Sponsoring Company exercises its right to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice in accordance with the previous sentence, such rights, title and interests in, and obligations under this Agreement shall be allotted (successively if necessary) among the Sponsoring Companies exercising such right in proportion to their respective Power Participation Ratios.

(c) Each Sponsoring Company exercising its right to purchase any rights, title and interests in, and obligations under this Agreement pursuant to this Section 9.183 may choose to have an Affiliate purchase such rights, title and interests in, and obligations under this Agreement; provided that, notwithstanding anything in this Section 9.183 to the contrary, any assignment to a Sponsoring Company or its Affiliate hereunder must comply with the requirements of Section 9.182.

(d) If one or more Sponsoring Companies have elected to purchase all of the rights, title and interests in, and obligations under this Agreement of the Transferring Sponsor pursuant to the Offer Notice, the assignment of such rights, title and interests in, and obligations under this Agreement shall be consummated as soon as practical after the delivery of the election notices, but in any event no later than fifteen (15) days after the filing and receipt, as applicable, of all necessary governmental filings, consents or other approvals and the expiration of all applicable waiting periods. At the closing of the purchase of such rights, title and interests in, and obligations under this Agreement from the Transferring Sponsor, the Transferring Sponsor shall provide representations and warranties customary for transactions of this type, including those as to its title to such securities and that there are no liens or other encumbrances on such securities (other than pursuant to this Agreement) and shall sign such documents as may reasonably be requested by the Corporation and the other Sponsoring Companies. The Sponsoring Companies or their Affiliates shall only be required to pay cash for the rights, title and interests in, and obligations under this Agreement being assigned by the Transferring Sponsor.

(e) To the extent that the Sponsoring Companies have not elected to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice, the Transferring Sponsor may, within one-hundred and eighty (180) days after the later of the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable), enter into a definitive agreement to, assign such rights, title and interests in, and obligations under this Agreement to a Third Party at a price no less than 92.5% of the purchase price specified in the Offer Notice and on other material terms and conditions no more favorable to the such Third Party than those specified in the Offer Notice; provided that such purchases shall be conditioned upon: (i) such Third Party having long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, with a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if such Third Party's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such Third Party's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); (ii) the filing or receipt, as applicable, of any necessary governmental filings, consents or other approvals; (iii) the determination by counsel for the Corporation that the assignment of the rights, title or interests in, or obligations under, this Agreement to such Third Party would not cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer; and (iv) such Third Party executing a counterpart of this Agreement, and both such Third Party and the Sponsoring Company which is assigning its rights, title and interests in, and obligations under, this Agreement executing such other documents as may be reasonably requested by the Corporation (including, without limitation, an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion and containing the agreement by such Sponsoring Company to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment). In the event that the Sponsoring Company and a Third Party have not entered into a definitive agreement to assign the interests specified in the Offer Notice to such Third Party within the later of one-hundred and eighty (180) days after the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable) for any reason or if either the price to be paid by such Third Party would be less than 92.5% of the purchase price specified in the Offer Notice or the other material terms of such assignment would be more favorable to such Third Party than the terms specified in the Offer Notice, then the restrictions provided for herein shall again be effective, and no assignment of any rights, title and interests in, and obligations under this Agreement may be made thereafter without again offering the same to Sponsoring Companies in accordance with this Section 9.183.

ARTICLE 10

REPRESENTATIONS AND WARRANTIES

10.01. *Representations and Warranties*. Each Sponsoring Company hereby represents and warrants for itself, on and as of the date of this Agreement, as follows:

(a) it is duly organized, validly existing and in good standing under the laws of its state of organization, with full corporate power, authority and legal right to execute and deliver this Agreement and to perform its obligations hereunder;

(b) it has duly authorized, executed and delivered this Agreement, and upon the execution and delivery by all of the parties hereto, this Agreement will be in full force and effect, and will constitute a legal, valid and binding obligation of such Sponsoring Company, enforceable in accordance with the terms hereof, except as enforceability may be limited by applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally;

(c) Except as set forth in Schedule 10.01(c) hereto, no consents or approvals of, or filings or registrations with, any governmental authority or public regulatory authority or agency, federal state or local, or any other entity or person are required in connection with the execution, delivery and performance by it of this Agreement, except for those which have been duly obtained or made and are in full force and effect, have not been revoked, and are not the subject of a pending appeal; and

(d) the execution, delivery and performance by it of this Agreement will not conflict with or result in any breach of any of the terms, conditions or provisions of, or constitute a default under its charter or by-laws or any indenture or other material agreement or instrument to which it is a party or by which it may be bound or result in the imposition of any liens, claims or encumbrances on any of its property.

ARTICLE 11

EVENTS OF DEFAULT AND REMEDIES

11.01. *Payment Default*. If any Sponsoring Company fails to make full payment to Corporation under this Agreement when due and such failure is not remedied within ten (10) days after receipt of notice of such failure from the Corporation, then such failure shall constitute a "Payment Default" on the part of such Sponsoring Company. Upon a Payment Default, the

Corporation may suspend service to the Sponsoring Company that has caused such Payment Default for all or part of the period of continuing default (and such Sponsoring Company shall be deemed to have notified the Corporation and the other Sponsoring Companies that any Available Energy shall be available for scheduling by such other Sponsoring Companies in accordance with Section 4.032). The Corporation's right to suspend service shall not be exclusive, but shall be in addition to all remedies available to the Corporation at law or in equity. No suspension of service or termination of this Agreement shall relieve any Sponsoring Company of its obligations under this Agreement, which are absolute and unconditional.

11.02. *Performance Default.* If the Corporation or any Sponsoring Company fails to comply in any material respect with any of the material terms, conditions and covenants of this Agreement (and such failure does not constitute a Payment Default under Section 11.01), the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall give the defaulting party written notice of the default ("Performance Default"). To the extent that a Performance Default is not cured within thirty (30) days after receipt of notice thereof (or within such longer period of time, not to exceed sixty (60) additional days, as necessary for the defaulting party with the exercise of reasonable diligence to cure such default), then the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall have all of the rights and remedies provided at law and in equity, other than termination of this Agreement or any release of the obligation of the Sponsoring Companies to make payments pursuant to this Agreement, which obligation shall remain absolute and unconditional.

11.03. *Waiver.* No waiver by the Corporation or any Sponsoring Company of any one or more defaults in the performance of any provision of this Agreement shall be construed as a waiver of any other default or defaults, whether of a like kind or different nature.

11.04. *Limitation of Liability and Damages.* TO THE FULLEST EXTENT PERMITTED BY LAW, NEITHER THE CORPORATION, NOR ANY SPONSORING COMPANY SHALL BE LIABLE UNDER THIS AGREEMENT FOR ANY CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST REVENUES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, OR OTHERWISE.

[*Signature pages follow*]

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

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OHIO VALLEY ELECTRIC CORPORATION

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Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

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OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

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Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its VICE PRESIDENT

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

030860-0015-02023-Active 12026116.4

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its Vice President

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By Thomas J. Kolup
Its VICE PRESIDENT

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

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OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By Anthony J. Ahern
Its President & CEO

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By Gary Stephenson
Its EXECUTIVE VICE PRESIDENT
Gary Stephenson

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By Gary R Leidich
Its President

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By [signature]
Its Sr Vice President

030860-0015-02023-Active 12026116.4

LOUISVILLE GAS AND ELECTRIC COMPANY

By [signature]
Its VP Trans. & Generation Services

MONONGAHELA POWER COMPANY

By ____________________
Its ____________________

OHIO POWER COMPANY

By ____________________
Its ____________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

MONONGAHELA POWER COMPANY

By ____________________
Its ____________________

OHIO POWER COMPANY

By ____________________
Its ____________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ______________________
Its ______________________

MONONGAHELA POWER COMPANY

By ______________________
Its General Manager, Electric Supply

OHIO POWER COMPANY

By ______________________
Its ______________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ______________________
Its ______________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

MONONGAHELA POWER COMPANY

By ____________________
Its ____________________

OHIO POWER COMPANY

By ____________________
Its ____________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By Ronald E. Christian
Its President

PENINSULA GENERATION COOPERATIVE

By Daniel B. DeCoeur

Its President

APPROVED AS TO FORM:

B. E. Valice

BRIAN E. VALICE
ATTORNEY FOR PENINSULA
GENERATION COOPERATIVE

SCHEDULE 10.01(c)

Allegheny Energy Supply Company, L.L.C.

and

Monongahela Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Appalachian Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Approval of the Virginia State Corporation Commission

Filing with the Public Service Commission of West Virginia

SCHEDULE 10.01(c)

Buckeye Power Generating, LLC

None

SCHEDULE 10.01(c)

Columbus Southern Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

The Dayton Power and Light Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Duke Energy Ohio, Inc.

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

FirstEnergy Generation Corp.

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Indiana Michigan Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Filing with the Indiana Utility Regulatory Commission

SCHEDULE 10.01(c)

Kentucky Utilities Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Consent or approval of, or filings or registrations with, the Kentucky Public Service Commission may be required

SCHEDULE 10.01(c)

Louisville Gas and Electric Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Consent or approval of, or filings or registrations with, the Kentucky Public Service Commission may be required

SCHEDULE 10.01(c)

Ohio Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Peninsula Generation Cooperative

None

SCHEDULE 10.01(c)

Southern Indiana Gas and Electric Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Exhibit A

AMENDED AND RESTATED

POWER AGREEMENT

BETWEEN

OHIO VALLEY ELECTRIC CORPORATION

AND

INDIANA-KENTUCKY ELECTRIC CORPORATION

Dated as of September 10, 2010

THIS AGREEMENT, dated as of September 10, 2010 by and between OHIO VALLEY ELECTRIC CORPORATION (herein called OVEC) and INDIANA-KENTUCKY ELECTRIC CORPORATION (herein called IKEC), hereby amends and restates in its entirety, the Power Agreement (herein called the Current Agreement), dated March 13, 2006, between OVEC and IKEC.

WITNESSETH THAT:

WHEREAS, IKEC, a wholly owned subsidiary of OVEC, designed, purchased, and constructed, and continues to own, operate and maintain a steam-electric generating station (herein called Indiana Station) consisting of six turbogenerators and all other necessary equipment, at a location on the Ohio River near Madison, Indiana; and

WHEREAS, OVEC designed, purchased, and constructed, and continues to own, operate and maintain a steam-electric generating stations (herein called Ohio Station) consisting of five turbo-generators and all other necessary equipment, at a location on the Ohio River near Cheshire, Ohio (the Ohio Station and the Indiana Station being herein called the Project Generating Stations); and

WHEREAS, OVEC also designed, purchased, and constructed, and continues to operate and maintain necessary transmission and general plant facilities (herein called the Project Transmission Facilities) and OVEC established or cause to be established interconnections between the Project Generating Stations and/or the Project Transmission Facilities, and the systems of certain of the Sponsoring Companies; and

WHEREAS, IKEC owns and operates the portion of the Project Transmission Facilities located in the State of Indiana; and

WHEREAS, IKEC entered into the Current Agreement with OVEC which embodies the terms and conditions for the ownership and operation by IKEC of the Indiana Station and such portion of the Project Transmission Facilities which are to be owned and operated by it; and

WHEREAS, the owners of OVEC or their affiliates that are parties to an Inter-Company Power Agreement, have amended and restated such Inter-Company Power Agreement as of the date hereof, which defines the terms and conditions governing the rights of the "Sponsoring Companies" (as defined thereunder) to receive "Available Power" (as defined thereunder) from the Project Generating Stations and the obligations of the Sponsoring Companies to pay therefor; and

WHEREAS, concurrent with the amendment and restatement of the Inter-Company Power Agreement, IKEC and OVEC hereto desire to amend and restate in their entirety, the Current Agreement in order for IKEC to continue to sell to OVEC any and all power available at the Indiana Station, and energy associated therewith, and to transmit power and energy as provided herein.

NOW, THEREFORE, the parties hereto agree with each other as follows:

ARTICLE 1

POWER AND ENERGY TRANSACTIONS

1.01 IKEC shall transmit any and all power generated at the Indiana Station by any of the generating units thereof in commercial operation and deliver such power, together with the energy associated therewith, but less the transmission losses in the facilities of IKEC applicable thereto from the 330 kV busses of the Indiana Station, at the points of delivery hereinafter designated in *Section* 1.03 hereof, and sell such power and energy at said points of delivery to OVEC. OVEC shall purchase from IKEC all such power so delivered by IKEC to OVEC at said points of delivery, together with the energy associated therewith, and shall from time to time pay IKEC therefor, amounts which, when added to revenues received by IKEC from other sources, will be sufficient to enable IKEC to pay all of its operating and other expenses, including all income and other taxes and any interest and regular amortization requirements applicable to any indebtedness for borrowed funds incurred by IKEC. For the purposes of this *Section* 1.01 the term "operating and other expenses" shall also include, without limitation, all amounts payable to suppliers of fuel requirements (including the handling and shipment thereof) in connection with the cancellation of commitments and the extension of delivery schedules, as well as all expenses accrued to pay for postemployment and postretirement benefits and the costs of the decommissioning, shutdown, demolition and closing of the Project Generating Stations.

1.02 IKEC shall transmit and deliver to OVEC at the points of delivery hereinafter designated in *Section* 1.03 hereof, all power and the energy associated therewith supplied to IKEC by Sponsoring Companies at the points of delivery hereinafter designated in *Section* 1.03 hereof, less the transmission losses in the facilities of IKEC applicable thereto. IKEC shall transmit and deliver to Sponsoring Companies designated by OVEC at the points of delivery hereinafter designated in *Section* 1.03 hereof, all power, and the energy associated therewith, supplied to IKEC by OVEC at the points of delivery hereinafter designated in *Section* 1.03 hereof, less the transmission losses in the facilities of IKEC applicable thereto.

1.03 All power and energy sold, purchased, transmitted or delivered hereunder shall be 3-phase, 60-cycle, alternating current, at nominal unregulated voltage, designated for the points of delivery hereinbelow described. Power and energy transmitted, delivered and sold by IKEC to OVEC pursuant to the provisions of *Section* 1.01 hereof shall be delivered at the points where the transmission facilities of OVEC and the transmission facilities of IKEC interconnect and title to such power and energy shall pass from IKEC to OVEC at said points. Power and energy supplied to IKEC by a Sponsoring Company for transmission to OVEC pursuant to the provisions of *Section* 1.02 hereof, shall be delivered by said Sponsoring Company to IKEC at the points where the transmission facilities of said Sponsoring Company and the transmission facilities of IKEC interconnect and shall be delivered by IKEC to OVEC and title thereto shall pass from said Sponsoring Company to OVEC at the points where the transmission facilities of OVEC and the transmission facilities of IKEC interconnect. Power and energy supplied to IKEC by OVEC for transmission to a Sponsoring Company pursuant to the provisions of *Section* 1.02 hereof shall be delivered by OVEC to IKEC at the points where the transmission facilities of OVEC and the transmission facilities of IKEC interconnect and title to such power and energy shall pass from OVEC to said Sponsoring Company at said points. Such power and energy shall be delivered by IKEC to said Sponsoring Company at the points where the transmission facilities of IKEC and the transmission facilities of said Sponsoring Company interconnect.

1.04 The parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of their respective power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of power and energy among their systems. The parties hereto shall provide and/or install on their respective systems such communication, telemetering, frequency and/or tie-line control facilities essential to so minimizing such deviations; and shall fully cooperate with one another and with third parties (such third parties whose systems are either directly or indirectly interconnected with the systems of the Sponsoring Companies and who of necessity together with the Sponsoring Companies and the parties hereto must unify their efforts cooperatively to achieve effective and efficient interconnected system operation) in developing and executing operating procedures that will enable the parties hereto to avoid to the extent practicable deviations from scheduled deliveries.

1.05 OVEC shall reimburse IKEC for the difference between (a) the total cost of replacements chargeable to property and plant made by IKEC, and the total cost of additional facilities and/or spare parts purchased or installed by Corporation, during any month or prior thereto (and not previously reimbursed) and (b) the amounts paid for by IKEC out of proceeds of fire or other applicable insurance protection, or out of amounts recovered from third parties responsible for damages requiring replacement. OVEC shall pay to IKEC such amount in lieu of the amounts to be paid as above provided, which, after provision for all taxes on income, shall equal the costs of the replacements reimbursable by OVEC to IKEC as above provided. The term cost of replacements, as used herein, shall include all components of costs, plus removal expense, less salvage. The amounts reimbursed by OVEC to IKEC for such replacements shall be accounted for on the books of IKEC in a special balance sheet account provided for such purposes.

ARTICLE 2

MISCELLANEOUS

2.01 This Agreement shall become effective on September 10, 2010, or to the extent necessary, such later date on which all conditions to effectiveness, including all required waiting periods and all required regulatory acceptances or approvals, of this Agreement have been satisfied in form and substance satisfactory to OVEC, and shall terminate upon the earlier of: (1) June 30, 2040 or (2) the sale or other disposition of all of the facilities of the Project Generating Stations or the permanent cessation of operation of such facilities.

2.02 No party hereto shall be held responsible or liable for any loss or damage on account of non-delivery of energy hereunder at any time caused by act of God, fire, flood, explosion, strike, civil or military authority, insurrection or riot, act of the elements, failure of equipment, or for any other cause beyond its control.

2.03 This Agreement is made subject to the jurisdiction of any governmental authority or authorities having jurisdiction in the premises and the performance thereof shall be subject to the receipt of all regulatory approvals, in form and substance satisfactory to the parties hereto, necessary to permit the parties hereto to perform all the duties and obligations to be performed by such parties hereunder.

2.04 This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns, but this Agreement shall not be assigned by either party hereto without the written consent of the other, except (a) to a successor to all or substantially all the properties and assets of such party, or (b) to a trustee under an indenture securing any indebtedness of such party.

2.05 All notices and requests under this Agreement shall be in writing and shall be sufficient in all respects if delivered in person or sent by registered mail addressed to the party to be served at such party's general office or at such other address as such party may from time to time in writing designate.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be duly executed as of the day and year first above written.

OHIO VALLEY ELECTRIC CORPORATION

By ______________
Its

INDIANA-KENTUCKY ELECTRIC CORPORATION

By ______________
Its

Execution Copy

AMENDED AND RESTATED
POWER AGREEMENT

BETWEEN

OHIO VALLEY ELECTRIC CORPORATION

AND

INDIANA-KENTUCKY ELECTRIC CORPORATION

Dated as of September 10, 2010

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WITNESSETH THAT:

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WHEREAS, OVEC designed, purchased, and constructed, and continues to own, operate and maintain a steam-electric generating stations (herein called Ohio Station) consisting of five turbo-generators and all other necessary equipment, at a location on the Ohio River near Cheshire, Ohio (the Ohio Station and the Indiana Station being herein called the Project Generating Stations); and

WHEREAS, OVEC also designed, purchased, and constructed, and continues to operate and maintain necessary transmission and general plant facilities (herein called the Project Transmission Facilities) and OVEC established or cause to be established interconnections between the Project Generating Stations and/or the Project Transmission Facilities, and the systems of certain of the Sponsoring Companies; and

WHEREAS, IKEC owns and operates the portion of the Project Transmission Facilities located in the State of Indiana; and

WHEREAS, IKEC entered into the Current Agreement with OVEC which embodies the terms and conditions for the ownership and operation by IKEC of the Indiana Station and such portion of the Project Transmission Facilities which are to be owned and operated by it; and

WHEREAS, the owners of OVEC or their affiliates that are parties to an Inter-Company Power Agreement, have amended and restated such Inter-Company Power Agreement as of the date hereof, which defines the terms and conditions governing the rights of the "Sponsoring Companies" (as defined thereunder) to receive "Available Power" (as defined thereunder) from the Project Generating Stations and the obligations of the Sponsoring Companies to pay therefor; and

WHEREAS, concurrent with the amendment and restatement of the Inter-Company Power Agreement, IKEC and OVEC hereto desire to amend and restate in their entirety, the Current Agreement in order for IKEC to continue to sell to OVEC any and all power available at the Indiana Station, and energy associated therewith, and to transmit power and energy as provided herein.

NOW, THEREFORE, the parties hereto agree with each other as follows:

ARTICLE 1

POWER AND ENERGY TRANSACTIONS

1.01 IKEC shall transmit any and all power generated at the Indiana Station by any of the generating units thereof in commercial operation and deliver such power, together with the energy associated therewith, but less the transmission losses in the facilities of IKEC applicable thereto from the 330 kV busses of the Indiana Station, at the points of delivery hereinafter designated in *Section* 1.03 hereof, and sell such power and energy at said points of delivery to OVEC. OVEC shall purchase from IKEC all such power so delivered by IKEC to OVEC at said points of delivery, together with the energy associated therewith, and shall from time to time pay IKEC therefor, amounts which, when added to revenues received by IKEC from other sources, will be sufficient to enable IKEC to pay all of its operating and other expenses, including all income and other taxes and any interest and regular amortization requirements applicable to any indebtedness for borrowed funds incurred by IKEC. For the purposes of this *Section* 1.01 the term "operating and other expenses" shall also include, without limitation, all amounts payable to suppliers of fuel requirements (including the handling and shipment thereof) in connection with the cancellation of commitments and the extension of delivery schedules, as well as all expenses accrued to pay for postemployment and postretirement benefits and the costs of the decommissioning, shutdown, demolition and closing of the Project Generating Stations.

1.02 IKEC shall transmit and deliver to OVEC at the points of delivery hereinafter designated in *Section* 1.03 hereof, all power and the energy associated therewith supplied to IKEC by Sponsoring Companies at the points of delivery hereinafter designated in *Section* 1.03 hereof, less the transmission losses in the facilities of IKEC applicable thereto. IKEC shall transmit and deliver to Sponsoring Companies designated by OVEC at the points of delivery hereinafter designated in *Section* 1.03 hereof, all power, and the energy associated therewith, supplied to IKEC by OVEC at the points of delivery hereinafter designated in *Section* 1.03 hereof, less the transmission losses in the facilities of IKEC applicable thereto.

1.03 All power and energy sold, purchased, transmitted or delivered hereunder shall be 3-phase, 60-cycle, alternating current, at nominal unregulated voltage, designated for the points of delivery hereinbelow described. Power and energy transmitted, delivered and sold by IKEC to OVEC pursuant to the provisions of *Section* 1.01 hereof shall be delivered at the points where the transmission facilities of OVEC and the transmission facilities of IKEC interconnect and title to such power and energy shall pass from IKEC to OVEC at said points. Power and energy supplied to IKEC by a Sponsoring Company for transmission to OVEC pursuant to the provisions of *Section* 1.02 hereof, shall be delivered by said Sponsoring Company to IKEC at the points where the transmission facilities of said Sponsoring Company and the transmission facilities of IKEC interconnect and shall be delivered by IKEC to OVEC and title thereto shall pass from said Sponsoring Company to OVEC at the points where the transmission facilities of OVEC and the transmission facilities of IKEC interconnect. Power and energy supplied to IKEC by OVEC for transmission to a Sponsoring Company pursuant to the provisions of *Section* 1.02 hereof shall be delivered by OVEC to IKEC at the points where the transmission facilities of OVEC and the transmission facilities of IKEC interconnect and title to such power and energy shall pass from OVEC to said Sponsoring Company at said points. Such power and energy shall be delivered by IKEC to said Sponsoring Company at the points where the transmission facilities of IKEC and the transmission facilities of said Sponsoring Company interconnect.

1.04 The parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of their respective power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of power and energy among their systems. The parties hereto shall provide and/or install on their respective systems such communication, telemetering, frequency and/or tie-line control facilities essential to so minimizing such deviations; and shall fully cooperate with one another and with third parties (such third parties whose systems are either directly or indirectly interconnected with the systems of the Sponsoring Companies and who of necessity together with the Sponsoring Companies and the parties hereto must unify their efforts cooperatively to achieve effective and efficient interconnected system operation) in developing and executing operating procedures that will enable the parties hereto to avoid to the extent practicable deviations from scheduled deliveries.

1.05 OVEC shall reimburse IKEC for the difference between (a) the total cost of replacements chargeable to property and plant made by IKEC, and the total cost of additional facilities and/or spare parts purchased or installed by Corporation, during any month or prior thereto (and not previously reimbursed) and (b) the amounts paid for by IKEC out of proceeds of fire or other applicable insurance protection, or out of amounts recovered from third parties responsible for damages requiring replacement. OVEC shall pay to IKEC such amount in lieu of the amounts to be paid as above provided, which, after provision for all taxes on income, shall equal the costs of the replacements reimbursable by OVEC to IKEC as above provided. The term cost of replacements, as used herein, shall include all components of costs, plus removal expense, less salvage. The amounts reimbursed by OVEC to IKEC for such replacements shall be accounted for on the books of IKEC in a special balance sheet account provided for such purposes.

ARTICLE 2

MISCELLANEOUS

2.01 This Agreement shall become effective on September 10, 2010, or to the extent necessary, such later date on which all conditions to effectiveness, including all required waiting periods and all required regulatory acceptances or approvals, of this Agreement have been satisfied in form and substance satisfactory to OVEC, and shall terminate upon the earlier of: (1) June 30, 2040 or (2) the sale or other disposition of all of the facilities of the Project Generating Stations or the permanent cessation of operation of such facilities.

2.02 No party hereto shall be held responsible or liable for any loss or damage on account of non-delivery of energy hereunder at any time caused by act of God, fire, flood, explosion, strike, civil or military authority, insurrection or riot, act of the elements, failure of equipment, or for any other cause beyond its control.

2.03 This Agreement is made subject to the jurisdiction of any governmental authority or authorities having jurisdiction in the premises and the performance thereof shall be subject to the receipt of all regulatory approvals, in form and substance satisfactory to the parties hereto, necessary to permit the parties hereto to perform all the duties and obligations to be performed by such parties hereunder.

2.04 This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns, but this Agreement shall not be assigned by either party hereto without the written consent of the other, except (a) to a successor to all or substantially all the properties and assets of such party, or (b) to a trustee under an indenture securing any indebtedness of such party.

2.05 All notices and requests under this Agreement shall be in writing and shall be sufficient in all respects if delivered in person or sent by registered mail addressed to the party to be served at such party's general office or at such other address as such party may from time to time in writing designate.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be duly executed as of the day and year first above written.

OHIO VALLEY ELECTRIC CORPORATION

By
Its Vice President and
Assistant to the President

INDIANA-KENTUCKY ELECTRIC CORPORATION

By
Its Vice President-Operations

CERTIFICATE OF CONCURRENCE

This is to certify that Allegheny Energy Supply Company, LLC assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

> Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

ALLEGHENY ENERGY SUPPLY COMPANY, LLC

By: Harvey L Wagner

Name: HARVEY L. WAGNER

Title: VP + Controller

Dated: March 22, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that Appalachian Power Company assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

> Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

APPALACHIAN POWER COMPANY

By: ______________________

Name: ______________________

Title: ______________________

Dated: ______________, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that Buckeye Power Generating, LLC assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

> Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

BUCKEYE POWER
GENERATING, LLC

By: Anthony J. Ahern

Name: Anthony J. Ahern

Title: President & CEO

Dated: March 15, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that Columbus Southern Power Company assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

> Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

COLUMBUS SOUTHERN
POWER COMPANY

By: ____________________

Name: ____________________

Title: ____________________

Dated: ______________, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that The Dayton Power and Light Company assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

THE DAYTON POWER AND LIGHT COMPANY

By: Gary Stephenson

Name: Gary Stephenson

Title: Exec. V.P

Dated: March 17, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that Duke Energy Ohio, Inc. assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

> Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

DUKE ENERGY OHIO, INC.

By: [signature]

Name: Charles R. Whitlock, Jr.

Title: President, Commercial Asset Management and Operations

Dated: March 18, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that FirstEnergy Generation Corp. assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

FIRSTENERGY GENERATION CORP.

By: Harvey L Wagner

Name: HARVEY L. WAGNER

Title: VP & CONTROLLER

Dated: March 22, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that Indiana Michigan Power Company assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

> Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

INDIANA MICHIGAN POWER COMPANY

By: ____________________

Name: ____________________

Title: ____________________

Dated: ______________, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that Kentucky Utilities Company assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

> Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

KENTUCKY UTILITIES
COMPANY

By: [signature]

Name: Paul W. Thompson

Title: SVP Energy Services

Dated: 3/17/2011, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that Louisville Gas and Electric Company assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

> Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

LOUISVILLE GAS AND
ELECTRIC COMPANY

By: [signature]

Name: JOHN N. VOYLES JR

Title: VICE PRESIDENT -
-TRANSMISSION + GENERATION SERVICES

Dated: 3/17, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that Monongahela Power Company assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

> Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

MONONGAHELA POWER COMPANY

By: Harvey L Wagner

Name: HARVEY L. WAGNER

Title: VP + CONTROLLER

Dated: March 22, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that Ohio Power Company assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

> Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

OHIO POWER COMPANY

By: ____________________

Name: ____________________

Title: ____________________

Dated: ____________, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that Peninsula Generation Cooperative assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

> Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

PENINSULA GENERATION COOPERATIVE

By: ____________________

Name: Daniel H. DeCoeur

Title: President

Dated: March 9, 2011

CERTIFICATE OF CONCURRENCE

This is to certify that Southern Indiana Gas and Electric Company assents to and concurs with the rate schedule supplement described below, which Ohio Valley Electric Corporation has filed, and hereby files this Certificate of Concurrence in lieu of the filing of the rate schedule supplement specified.

Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010, among Ohio Valley Electric Corporation, Allegheny Energy Supply Company, LLC, Appalachian Power Company, Buckeye Power Generating, LLC, Columbus Southern Power Company, The Dayton Power and Light Company, Duke Energy Ohio, Inc., FirstEnergy Generation Corp., Indiana Michigan Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Ohio Power Company, Peninsula Generation Cooperative and Southern Indiana Gas and Electric Company.

SOUTHERN INDIANA GAS AND
ELECTRIC COMPANY

By: ____________

Name: William S. Doty

Title: Exec V.P.

Dated: Mar 17, 2011