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EXHIBIT 97

UPDATED PRODUCTION COST MODEL

Changes made in this model run - Henwood Update

1. Updated non fuel VOM
2. Updated Outage Schedules
3. Updated Start Charges
4.

Tab Description	
Tab	**Description**
Portfolio Report	Overall Summary of production, emissions, contract purchases/sales and market interaction
Production Report	Operational summary of generating resources
Fuel Report	Summary of fuel statistics by generating resource
Emissions Report	Summary of emissions statistics by generating resource
Outage Report	Summary of planned and forced outage statistics by generating resource
Resource Report-Full	Unit specific operating details
Portfolio Data	Henwood Output - Sources and Uses
Resource Data	Henwood Output - Generating Unit Output Data
Prices	Henwood Output - Market Prices
EXPORTS	henwood Output - BREC Market Power Sales
IMPORTS	Henwood Output - BREC Market Power Purchases

Tab Color	Description
	Output Reports for BREC
	Intermediate Calcs
	Raw Henwood Model Outputs

Portfolio Report
Production Cost Model - 9-8-08 - BREC Update.xls.xls

	A	B	C	E	F	G	H	I	J
1	**Resource Costs**	2006	2007	2009	2010	2011	2012	2013	2014
2	DBWilson			$ 70,991	$ 77.946	$ 76,533	$ 104,888	$ 102.969	$ 81.567
3	HMPL1			$ 28,198	$ 38,687	$ 35,112	$ 40,903	$ 41.352	$ 30,756
4	HMPL2			$ 31,817	$ 38,284	$ 41.722	$ 38.650	$ 44.993	$ 30,334
5	Coleman 1			$ 32.804	$ 33,758	$ 32.253	$ 38,141	$ 40,058	$ 25,504
6	Coleman 2			$ 33,919	$ 32.768	$ 35,677	$ 38,450	$ 38,323	$ 26,985
7	Coleman 3			$ 31.079	$ 34,895	$ 35.958	$ 33,719	$ 41.125	$ 27.426
8	Reid ST			$ 2.394	$ 3,099	$ 5,663	$ 3,706	$ 1,683	$ 3.401
9	Reid GT			$ 418	$ 448	$ 698	$ 1.132	$ 1.475	$ 931
10	Green 1			$ 45,227	$ 48.952	$ 56,774	$ 53,805	$ 63,530	$ 43,242
11	Green 2			$ 40,304	$ 51.328	$ 47.359	$ 54,107	$ 59.354	$ 47.538
12									
13									
14	SEPA			$ 6,809	$ 6,847	$ 6,842	$ 8,585	$ 7,735	$ 7,938
15	**Total Op Costs**			**$ 323,961**	**$ 367.011**	**$ 374,590**	**$ 416,065**	**$ 442,595**	**$ 325,624**
16									
17	**Emissions Costs**								
18	SO2 Price			$140	$115	$434	$439	$438	$425
19	SO2(ktons) - emitted			20.430	21.740	20.538	21.040	20.628	21.140
20	SO2(ktons) - REQUIRED for compliance			20.430	21.740	41.076	42.080	41.256	42.281
21	SO2 cost($000)			$ 2,860	$ 2,500	$ 17,827	$ 18,473	$ 18,050	$ 17.969
22	SO2 Allowances			52.487	52.487	52.487	52.487	52.487	52.487
23	SO2 Allowance Credits			$ (7,348)	$ (6,036)	$ (22,779)	$ (23,042)	$ (22,963)	$ (22,307)
24	HMPL SO2(ktons) - emitted			4.285	4.289	4.122	4.092	4.289	4.285
25	HMPL SO2(ktons) - REQUIRED for compliance			4.285	4.289	8.244	8.184	8.578	8.569
26	HMPL Allowances			11.694	11.694	11.694	11.694	11.694	11.694
27	Excess HMPL Allowances Back to City (30% of net)			2.223	2.221	1.035	1.053	0.935	0.937
28	Allowance $ to City			$ 311	$ 255	$ 449	$ 462	$ 409	$ 398
29									
30									
31	NOx Price			$ 700	$ 650	$ 2,120	$ 1,951	$ 1,909	$ 2,570
32	NOx(ktons)			5.248	5.212	13 779	13.672	13.832	13.642
33	NOx Emissions Alloc to City (ktons)			0.107	0.107	0.290	0.301	0.301	0.301
34	Net NOx Emissions			5.141	5.105	13.489	13.371	13.531	13.340
35	NOx cost($000)			$ 3,599	$ 3,318	$ 28,597	$ 26,086	$ 25,831	$ 34,285
36	NOx Allowances			4.799	4.799	11.398	11.398	11.398	11 398
37	NOx Allowances Alloc to City (ktons)			0.147	0.147	0.330	0.341	0.341	0.341
38	Net NOx Allowances			4.652	4.652	11.068	11.057	11.057	11 057
39	NOx Allowance Credits			$ (3,256)	$ (3,024)	$ (23,465)	$ (21.572)	$ (21.108)	$ (28,415)
40									
41	**Net Emissions Costs**			**$ (3,835)**	**$ (2,986)**	**$ 628**	**$ 408**	**$ 218**	**$ 1.930**
42									
43	**Market Purchases**								
44	Purchased GWh			240	159	308	224	300	265
45	Price per MWh			$ 65.53	$ 66.17	$ 67.28	$ 74.14	$ 71.54	$ 65.38
46	Purchases - $			$ 15,742	$ 10,505	$ 20,726	$ 16,613	$ 21.449	$ 17.322
47									
48	**Smelter Sales**								
49	Smelter GWh			(7,297)	(7,297)	(7,297)	(7,317)	(7,297)	(7,297)
50	Price per MWh			$ 27.05	$ 27.05	$ 30.25	$ 30.25	$ 30.25	$ 30.25
51	Smelter Revs			$ (197.386)	$ (197.386)	$ (220,737)	$ (221.341)	$ (220,737)	$ (220,737)
52									
53	**Henderson Sales**								
54	Henderson GWh - at Gen Bus			(632)	(632)	(632)	(666)	(666)	(666)
55	Price per MWh			$ 25.02	$ 32.06	$ 33.31	$ 34.75	$ 35.99	$ 25.48
56	Contract Revs			$ (15,824)	$ (20,277)	$ (21.063)	$ (23.131)	$ (23,954)	$ (16,964)
57	Payments to HMPL (@ $2.50/MWh)			$ 518	$ 518	$ 518	$ 552	$ 546	$ 546
58									
59	**Contract Sales**								
60	Contract GWh			-	-	-	-	-	-
61	Price per MWh			$ -	$ -	$ -	$ -	$ -	$ -
62	Contract Revs			$ -	$ -	$ -	$ -	$ -	$ -
63									
64	**Market Sales**								
65	Market GWh			(1,548)	(1,833)	(1,379)	(1,360)	(1,409)	(1,324)
66	Price per MWh			$ 58.04	$ 56.39	$ 60.56	$ 63.63	$ 67.19	$ 59.17
67	Market Revs			$ (89.846)	$ (103,349)	$ (83,498)	$ (86,557)	$ (94,683)	$ (78,324)
68									
69									
70	Total System Costs			$ 33,331	$ 54.037	$ 71.166	$ 102.627	$ 125,434	$ 29.397
71	Native Load			3,501	3,584	3,674	3,760	3,852	3,939
72	Native Load Cost per MWh			9 52	15.08	19.37	27.29	32 57	7.46
73									
74	Gross System Costs			$ 335,869	$ 374,530	$ 395,945	$ 433,105	$ 464.262	$ 344,876
75	Gross Source GWh			13,075	13,444	13,081	13,206	13,328	13,331
76	Average System per MWh			25.688	27.859	30.269	32 796	34.834	25.870
77									
78									
79									
80	**Sources and Uses of Energy**								
81	**Sources**								
82	System Gen			12.531	12.980	12.468	12,679	12.762	12.799
83	SEPA			303	305	305	303	266	267
84	Market Purchases			240	159	308	224	300	265
85	**Total Sources**			**13,075**	**13,444**	**13,081**	**13,206**	**13,328**	**13,331**
86									
87	**Uses**								
88	Native Load			3,501	3,584	3,674	3,760	3,852	3,939
89									
90	Smelter Load			7.297	7.297	7.297	7.317	7.297	7.297
91	Henderson Load			627	627	627	660	660	660
92	Sales Load			-	-	-	-	-	-
93	Mkt Sales			1.548	1.833	1,379	1.360	1.409	1.324
94	Losses			102	103	104	109	110	112
95	**Total Uses**			**13,075**	**13,444**	**13,081**	**13,206**	**13,328**	**13,331**

Portfolio Report

Production Cost Model - 9-8-08 - BREC Update.xls.xls

	A	K	L	M	N	O	P	Q	R	S
1	**Resource Costs**	2015	2016	2017	2018	2019	2020	2021	2022	2023
2	DBWilson	$ 78,463	$ 83,637	$ 76,233	$ 85,517	$ 83,141	$ 88,447	$ 85,383	$ 91.564	$ 87.896
3	HMPL1	$ 30,506	$ 33,269	$ 30,959	$ 34.075	$ 31.024	$ 32.466	$ 34,043	$ 36,382	$ 33,967
4	HMPL2	$ 33,679	$ 32.689	$ 34,963	$ 33,111	$ 36,019	$ 32.325	$ 37.136	$ 36,055	$ 37.834
5	Coleman 1	$ 27.240	$ 27.276	$ 24.236	$ 28,062	$ 28,609	$ 27.398	$ 29.026	$ 29,451	$ 28,333
6	Coleman 2	$ 27.686	$ 24,614	$ 28,353	$ 28,791	$ 27.175	$ 29,595	$ 29.872	$ 28,790	$ 30,564
7	Coleman 3	$ 26,053	$ 27.631	$ 28,342	$ 27,248	$ 28,771	$ 29,337	$ 26,304	$ 30,261	$ 30,837
8	Reid ST	$ 1.576	$ 2.790	$ 3,024	$ -	$ 3,056	$ 2.887	$ 2.534	$ 5.584	$ 3,217
9	Reid GT	$ 902	$ 967	$ 1.154	$ 1.127	$ 951	$ 952	$ 1.020	$ 1.053	$ 1.085
10	Green 1	$ 53,220	$ 49,180	$ 54,490	$ 51.826	$ 56,468	$ 54,429	$ 58,127	$ 51.740	$ 59,854
11	Green 2	$ 49,019	$ 50,881	$ 50,380	$ 51.726	$ 47.866	$ 55,435	$ 53,846	$ 56,922	$ 55.603
12										
13										
14	SEPA	$ 7,948	$ 7,944	$ 7,971	$ 8,117	$ 8,321	$ 8,293	$ 8,373	$ 8,395	$ 8,574
15	**Total Op Costs**	**$ 336,292**	**$ 340,878**	**$ 340,104**	**$ 349,599**	**$ 351,401**	**$ 361,564**	**$365,663**	**$376,197**	**$377,765**
16										
17	**Emissions Costs**									
18	SO2 Price	$294	$288	$265	$247	$196	$144	$122	$106	$98
19	SO2(ktons) - emitted	20.836	21.282	19.910	21.199	20.456	21.001	20.812	21.263	20.716
20	SO2(ktons) - REQUIRED for compliance	59.591	60.865	56.944	60.630	58.504	60.063	59.521	60.812	59.247
21	SO2 cost($000)	$ 17.544	$ 17.557	$ 15,072	$ 14,967	$ 11.476	$ 8,673	$ 7.284	$ 6,421	$ 5.780
22	SO2 Allowances	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487
23	SO2 Allowance Credits	$ (15,452)	$ (15,140)	$ (13,893)	$ (12,957)	$ (10,296)	$ (7,579)	$ (6,423)	$ (5,542)	$ (5,120)
24	HMPL SO2(ktons) - emitted	4.297	4.317	4.259	4.273	4.143	3.928	4.314	4.328	4.217
25	HMPL SO2(ktons) - REQUIRED for compliance	12.289	12.346	12 180	12.220	11.849	11.233	12.339	12.379	12.061
26	HMPL Allowances	11.694	11.694	11.694	11 694	11.694	11.694	11 694	11.694	11.694
27	Excess HMPL Allowances Back to City (30% of net)	-	-	-	-	-	0.138	-	-	-
28	Allowance $ to City	$ -	$ -	$ -	$ -	$ -	$ 20	$ -	$ -	$ -
29										
30										
31	NOx Price	$ 3,071	$ 2,863	$ 2,764	$ 2,665	$ 2,564	$ 2,574	$ 2,578	$ 2,581	$ 2,584
32	NOx(ktons)	13.880	13.680	13.603	13.714	13.515	13.854	13.746	13.666	13.859
33	NOx Emissions Alloc to City (ktons)	0.301	0.301	0.301	0.301	0.301	0.301	0.301	0.301	0.301
34	Net NOx Emissions	13.579	13.378	13.303	13.413	13.214	13.553	13.445	13.365	13.558
35	NOx cost($000)	$ 41,702	$ 38,303	$ 36,769	$ 35,746	$ 33,880	$ 34,886	$ 34,660	$ 34,495	$ 35,034
36	NOx Allowances	9.285	9.285	8.832	8.638	8.494	8.289	8.054	7.832	7.76
37	NOx Allowances Alloc to City (ktons)	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341
38	Net NOx Allowances	8.944	8.944	8.491	8.297	8 153	7.948	7.713	7.491	7.419
39	NOx Allowance Credits	$ (27.468)	$ (25,606)	$ (23,470)	$ (22.112)	$ (20,904)	$ (20,458)	$ (19.884)	$ (19,335)	$ (19,172)
40										
41	**Net Emissions Costs**	**$ 16,325**	**$ 15,113**	**$ 14,478**	**$ 15,644**	**$ 14,156**	**$ 15,542**	**$ 15,637**	**$ 16,039**	**$ 16,522**
42										
43	**Market Purchases**									
44	Purchased GWh	300	324	622	400	536	423	528	489	607
45	Price per MWh	$ 65.42	$ 66.75	$ 64.85	$ 63.37	$ 67.39	$ 67.48	$ 76.46	$ 74.47	$ 76.94
46	Purchases - $	$ 19.657	$ 21.624	$ 40,334	$ 25.321	$ 36,120	$ 28.562	$ 40,377	$ 36,405	$ 46,703
47										
48	**Smelter Sales**									
49	Smelter GWh	(7,297)	(7,317)	(7,297)	(7,297)	(7,297)	(7,317)	(7,297)	(7,297)	(7,297)
50	Price per MWh	$ 30.25	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 36.50	$ 36.50	$ 36.50
51	Smelter Revs	$ (220,737)	$ (241.463)	$ (240,804)	$ (240,804)	$ (240,804)	$ (241.463)	$ (266,343)	$ (266,343)	$ (266,343)
52										
53	**Henderson Sales**									
54	Henderson GWh - at Gen Bus	(666)	(666)	(666)	(666)	(666)	(666)	(666)	(666)	(666)
55	Price per MWh	$ 26.70	$ 27.31	$ 27.67	$ 28.11	$ 28.93	$ 29.48	$ 29.49	$ 29.92	$ 30.43
56	Contract Revs	$ (17.774)	$ (18,180)	$ (18.419)	$ (18,709)	$ (19,256)	$ (19,624)	$ (19,629)	$ (19.915)	$ (20,257)
57	Payments to HMPL (@ $2.50/MWh)	$ 546	$ 552	$ 546	$ 546	$ 546	$ 552	$ 546	$ 546	$ 546
58										
59	**Contract Sales**									
60	Contract GWh	-	-	-	-	-	-	-	-	-
61	Price per MWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Contract Revs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63										
64	**Market Sales**									
65	Market GWh	(1,294)	(1,240)	(1,048)	(1,115)	(866)	(885)	(873)	(846)	(783)
66	Price per MWh	$ 60.41	$ 60.50	$ 61.46	$ 62.88	$ 65.67	$ 64.01	$ 64.46	$ 65.72	$ 66.47
67	Market Revs	$ (78,194)	$ (75,027)	$ (64,396)	$ (70,142)	$ (56,881)	$ (56,665)	$ (56,308)	$ (55,619)	$ (52.068)
68										
69										
70	Total System Costs	$ 56,115	$ 43,496	$ 71.844	$ 61.456	$ 85,281	$ 88,467	$ 79,942	$ 87.310	$ 102.867
71	Native Load	4,032	4,122	4,217	4,308	4,404	4,498	4,596	4,691	4,786
72	Native Load Cost per MWh	13 92	10 55	17.04	14.27	19.36	19.67	17 39	18.61	21.49
73										
74	Gross System Costs	$ 372,274	$ 377.615	$ 394.916	$ 390,565	$ 401.676	$ 405.668	$ 421.677	$ 428,642	$ 440,990
75	Gross Source GWh	13,394	13,454	13,336	13.497	13,344	13,479	13,545	13,614	13,646
76	Average System per MWh	27.794	28.067	29.613	28.938	30.103	30.095	31 132	31.486	32 317
77										
78										
79										
80	**Sources and Uses of Energy**									
81	**Sources**									
82	System Gen	12.826	12.863	12.446	12.831	12.541	12.791	12.749	12.856	12.771
83	SEPA	267	267	268	266	266	265	268	269	268
84	Market Purchases	300	324	622	400	536	423	528	489	607
85	**Total Sources**	**13,394**	**13,454**	**13,336**	**13,497**	**13,344**	**13,479**	**13,545**	**13,614**	**13,646**
86										
87	**Uses**									
88	Native Load	4.032	4,122	4,217	4.308	4,404	4,498	4,596	4.691	4.786
89										
90	Smelter Load	7.297	7.317	7.297	7.297	7.297	7.317	7.297	7.297	7.297
91	Henderson Load	660	660	660	660	660	660	660	660	660
92	Sales Load	-	-	-	-	-	-	-	-	-
93	Mkt Sales	1.294	1.240	1.048	1.115	866	885	873	846	783
94	Losses	111	115	114	117	116	119	118	120	119
95	**Total Uses**	**13,394**	**13,454**	**13,336**	**13,497**	**13,344**	**13,479**	**13,545**	**13,614**	**13,646**

Production Report
Production Cost Model - 9-8-08 - BREC Update.xls.xls

EntityName		2008	2009	2010	2011	2012	2013	2014
D B Wilson 1	Max Capacity(MW)	420	417	417	417	417	417	417
	Min Capacity(MW)	200	325	325	325	325	325	325
	Generation(GWh)	-	3,019	3,433	3,141	3,317	3.161	3,380
	Annual Cap. Fac	0.00%	82.64%	93.98%	85.97%	90.57%	86.54%	92.53%
	Fuel used(GBtu)	-	33.953	38,601	35,542	37,044	34.679	37,098
	Coal(Tons)	-	1.476,213	1,678,323	1,545,319	1,610,606	1.507.769	1,612,949
	Heat Rate	#DIV/0!	11 247	11.245	11 317	11.166	10.970	10.975
	Fuel cost($000)	$ -	$ 60,097	$ 65,622	$ 62.199	$ 90,758	$ 89.124	$ 66,776
	Fuel Cost per MMBTu	#DIV/0!	$ 1 770	$ 1.700	$ 1 750	$ 2.450	$ 2 570	$ 1.800
	VOM cost($000)	$ -	$ 7.352	$ 8,454	$ 10.678	$ 11,264	$ 10,685	$ 11,729
	VOM per MWh	#DIV/0!	$ 2 435	$ 2.463	$ 3.400	$ 3.395	$ 3 380	$ 3.470
	Num starts()	-	10	11	11	10	9	10
	Start Fuel used(GBtu)	-	66	72	67	52	56	54
	Start cost($000)	$ -	$ 3,542	$ 3,870	$ 3,656	$ 2,867	$ 3,160	$ 3,062
	Total Operating Cost ($000)	$ -	$ 70,991	$ 77,946	$ 76,533	$ 104,888	$ 102,969	$ 81,567
	Op Cost per MWh	#DIV/0!	$ 23.52	$ 22.71	$ 24.37	$ 31.62	$ 32.57	$ 24.13

EntityName		2008	2009	2010	2011	2012	2013	2014
HMPL 1	Max Capacity(MW)	153	153	152	152	152	152	152
	Min Capacity(MW)	110	140	140	140	140	140	140
	Generation(GWh)	-	1.128	1,217	1.055	1,194	1.154	1,215
	Annual Cap. Fac	0.00%	84 30%	91.25%	79.13%	89.34%	86.55%	91.15%
	Fuel used(GBtu)	-	12.204	13,167	11,417	12,928	12,491	13,156
	Coal(Tons)	-	530.591	572,467	496,400	562,095	543.093	571,994
	Heat Rate	#DIV/0!	10 822	10.823	10.821	10.823	10 824	10.826
	Fuel cost($000)	$ -	$ 23.187	$ 33,180	$ 29,114	$ 34,260	$ 34,725	$ 23,549
	Fuel Cost per MMBTu	#DIV/0!	$ 1 900	$ 2.520	$ 2.550	$ 2.650	$ 2.780	$ 1.790
	VOM cost($000)	$ -	$ 3.412	$ 3,977	$ 4.474	$ 5,208	$ 5.170	$ 5,590
	VOM per MWh	#DIV/0!	$ 3 026	$ 3.269	$ 4 240	$ 4.360	$ 4.480	$ 4.600
	Num starts()	-	16	15	15	14	14	15
	Start Fuel used(GBtu)	-	30	28	28	26	26	28
	Start cost($000)	$ -	$ 1,599	$ 1,529	$ 1,525	$ 1,435	$ 1,457	$ 1,617
	Total Operating Cost ($000)	$ -	$ 28,198	$ 38,687	$ 35,112	$ 40,903	$ 41,352	$ 30,756
	Op Cost per MWh	#DIV/0!	$ 25.01	$ 31.80	$ 33.28	$ 34.24	$ 35.83	$ 25.31

EntityName		2008	2009	2010	2011	2012	2013	2014
HMPL 2	Max Capacity(MW)	159	158	158	158	158	158	158
	Min Capacity(MW)	110	140	140	140	140	140	140
	Generation(GWh)	-	1,271	1,184	1,252	1,095	1.245	1,182
	Annual Cap. Fac	0.00%	91.80%	85.43%	90.32%	78.79%	89.87%	85.28%
	Fuel used(GBtu)	-	13.767	12,827	13,564	11,868	13.501	12,809
	Coal(Tons)	-	598,547	557,704	589,741	515,988	586,981	556,934
	Heat Rate	#DIV/0!	10.835	10.835	10 837	10.840	10.840	10.838
	Fuel cost($000)	$ -	$ 26,157	$ 32,325	$ 34.588	$ 31,449	$ 37,532	$ 22,929
	Fuel Cost per MMBTu	#DIV/0!	$ 1 900	$ 2.520	$ 2 550	$ 2.650	$ 2.780	$ 1.790
	VOM cost($000)	$ -	$ 3.801	$ 3,952	$ 5.307	$ 4,774	$ 5,580	$ 5,437
	VOM per MWh	#DIV/0!	$ 2 992	$ 3.339	$ 4 240	$ 4.360	$ 4.480	$ 4.600
	Num starts()	-	17	19	17	23	17	17
	Start Fuel used(GBtu)	-	35	37	33	44	34	34
	Start cost($000)	$ -	$ 1,859	$ 2,007	$ 1,826	$ 2,427	$ 1,882	$ 1,969
	Total Operating Cost ($000)	$ -	$ 31,817	$ 38,284	$ 41,722	$ 38,650	$ 44,993	$ 30,334
	Op Cost per MWh	#DIV/0!	$ 25.04	$ 32.34	$ 33.33	$ 35.30	$ 36.13	$ 25.67

EntityName		2008	2009	2010	2011	2012	2013	2014
Coleman 1	Max Capacity(MW)	150	149	149	149	149	149	149
	Min Capacity(MW)	70	70	70	70	70	70	70
	Generation(GWh)	-	1,198	1,193	1.102	1,202	1.207	1,144
	Annual Cap. Fac	0.00%	91 80%	91.41%	84.42%	91.83%	92 50%	87.67%
	Fuel used(GBtu)	-	12.853	12,800	11.884	12,967	13,028	12,348
	Coal(Tons)	-	558,821	556,517	516,694	563,766	566,453	536,879
	Heat Rate	#DIV/0!	10 727	10.728	10 785	10.789	10 791	10.791
	Fuel cost($000)	$ -	$ 30,847	$ 31,744	$ 30.304	$ 36,047	$ 37.913	$ 23,388
	Fuel Cost per MMBTu	#DIV/0!	$ 2.400	$ 2.480	$ 2 550	$ 2.780	$ 2.910	$ 1.894
	VOM cost($000)	$ -	$ 1.390	$ 1,432	$ 1.377	$ 1,538	$ 1.594	$ 1,545
	VOM per MWh	#DIV/0!	$ 1 160	$ 1.200	$ 1 250	$ 1.280	$ 1 320	$ 1.350
	Num starts()	-	17	17	16	15	15	15
	Start Fuel used(GBtu)	-	26	26	25	24	24	24
	Start cost($000)	$ -	$ 567	$ 583	$ 572	$ 555	$ 551	$ 572
	Total Operating Cost ($000)	$ -	$ 32,804	$ 33,758	$ 32,253	$ 38,141	$ 40,058	$ 25,504
	Op Cost per MWh	#DIV/0!	$ 27.38	$ 28.29	$ 29.27	$ 31.73	$ 33.18	$ 22.29

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EntityName		2008	2009	2010	2011	2012	2013	2014
Coleman 2	Max Capacity(MW)	139	138	138	138	138	138	138
	Min Capacity(MW)	70	70	70	70	70	70	70
	Generation(GWh)	-	1.111	1,040	1.101	1,090	1,038	1,093
	Annual Cap. Fac	0.00%	91.91%	85.99%	91.04%	89.94%	85.89%	90.39%
	Fuel used(GBtu)	-	13.369	12,508	13,237	13,115	12.493	13,144
	Coal(Tons)	-	581.246	543,816	575.501	570,236	543.177	571,487
	Heat Rate	#DIV/0!	12 033	12.032	12.028	12.030	12.032	12.029
	Fuel cost($000)	$ -	$ 32.085	$ 31,019	$ 33.753	$ 36,461	$ 36,355	$ 24,895
	Fuel Cost per MMBTu	#DIV/0!	$ 2 400	$ 2.480	$ 2 550	$ 2.780	$ 2 910	$ 1.894
	VOM cost($000)	$ -	$ 1.289	$ 1,247	$ 1.376	$ 1,428	$ 1.402	$ 1,508
	VOM per MWh	#DIV/0!	$ 1 160	$ 1.200	$ 1.250	$ 1.310	$ 1 350	$ 1.380
	Num starts()	-	16	15	15	15	15	15
	Start Fuel used(GBtu)	-	25	22	24	25	24	25
	Start cost($000)	$ -	$ 545	$ 501	$ 548	$ 561	$ 567	$ 582
	Total Operating Cost ($000)	$ -	$ 33,919	$ 32,768	$ 35,677	$ 38,450	$ 38,323	$ 26,985
	Op Cost per MWh	#DIV/0!	$ 30.53	$ 31.52	$ 32.42	$ 35.27	$ 36.91	$ 24.70

EntityName		2008	2009	2010	2011	2012	2013	2014
Coleman 3	Max Capacity(MW)	155	154	154	154	154	154	154
	Min Capacity(MW)	110	110	110	110	110	110	110
	Generation(GWh)	-	1.126	1,225	1.225	1,050	1.237	1,229
	Annual Cap. Fac.	0.00%	83.44%	90.79%	90.80%	77.65%	91 70%	91.12%
	Fuel used(GBtu)	-	12,176	13,249	13.258	11,371	13.398	13,308
	Coal(Tons)	-	529.400	576,047	576.428	494,391	582.521	578,596
	Heat Rate	#DIV/0!	10.817	10.817	10.823	10.826	10 830	10.826
	Fuel cost($000)	$ -	$ 29,223	$ 32,858	$ 33.808	$ 31,611	$ 38,988	$ 25,205
	Fuel Cost per MMBTu	#DIV/0!	$ 2.400	$ 2.480	$ 2 550	$ 2.780	$ 2 910	$ 1.894
	VOM cost($000)	$ -	$ 1.306	$ 1,470	$ 1.531	$ 1,376	$ 1,670	$ 1,696
	VOM per MWh	#DIV/0!	$ 1 160	$ 1.200	$ 1 250	$ 1.310	$ 1 350	$ 1.380
	Num starts()	-	18	18	19	24	14	16
	Start Fuel used(GBtu)	-	25	25	27	32	20	22
	Start cost($000)	$ -	$ 551	$ 568	$ 619	$ 732	$ 467	$ 524
	Total Operating Cost ($000)	$ -	$ 31,079	$ 34,895	$ 35,958	$ 33,719	$ 41,125	$ 27,426
	Op Cost per MWh	#DIV/0!	$ 27.61	$ 28.49	$ 29.35	$ 32.10	$ 33.24	$ 22.31

EntityName		2008	2009	2010	2011	2012	2013	2014
Reid ST	Max Capacity(MW)	50	50	50	50	50	50	50
	Min Capacity(MW)	40	40	40	40	40	40	40
	Generation(GWh)	-	7	12	32	29	13	29
	Annual Cap. Fac	0.00%	1.52%	2.77%	7 36%	6.51%	3 00%	6.67%
	Fuel used(GBtu)	-	90	165	437	387	178	396
	Coal(Tons)	-	75	-	-	-	-	-
	Heat Rate	#DIV/0!	13 564	13.571	13 545	13.556	13 572	13.547
	Fuel cost($000)	$ -	$ 792	$ 1,551	$ 3.776	$ 3,518	$ 1.683	$ 3,300
	Fuel Cost per MMBTu	#DIV/0!	$ 8.785	$ 9.420	$ 8.646	$ 9.081	$ 9.451	$ 8.344
	VOM cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	VOM per MWh	#DIV/0!	$ -	$ -	$ -	$ -	$ -	$ -
	Num starts()	-	33	31	39	5	-	3
	Start Fuel used(GBtu)	-	30	29	36	5	-	2
	Start cost($000)	$ -	$ 1,602	$ 1,548	$ 1,887	$ 188	$ -	$ 101
	Total Operating Cost ($000)	$ -	$ 2,394	$ 3,099	$ 5,663	$ 3,706	$ 1,683	$ 3,401
	Op Cost per MWh	#DIV/0!	$ 360.30	$ 255.47	$ 175.64	$ 129.66	$ 128.27	$ 116.48

EntityName		2008	2009	2010	2011	2012	2013	2014
Reid GT	Max Capacity(MW)	65	65	65	65	65	65	65
	Min Capacity(MW)	-	-	-	-	-	-	-
	Generation(GWh)	-	4	4	7	11	15	9
	Annual Cap. Fac	0.00%	0.70%	0.75%	1.19%	1.97%	2 58%	1.63%
	Fuel used(GBtu)	-	48	51	80	133	175	111
	Coal(Tons)	-	-	-	-	-	-	-
	Heat Rate	#DIV/0!	12 046	11.931	11 905	11.785	11 899	11.947
	Fuel cost($000)	$ -	$ 418	$ 448	$ 698	$ 1,132	$ 1.475	$ 931
	Fuel Cost per MMBTu	#DIV/0!	$ 8.733	$ 8.814	$ 8 675	$ 8.522	$ 8.432	$ 8.412
	VOM cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	VOM per MWh	#DIV/0!	$ -	$ -	$ -	$ -	$ -	$ -
	Num starts()	-	154	148	154	174	251	196
	Start Fuel used(GBtu)	-	-	-	-	-	-	-
	Start cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Operating Cost ($000)	$ -	$ 418	$ 448	$ 698	$ 1,132	$ 1,475	$ 931
	Op Cost per MWh	#DIV/0!	$ 105.20	$ 105.15	$ 103.27	$ 100.43	$ 100.33	$ 100.50

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EntityName		2008	2009	2010	2011	2012	2013	2014
Green 1	Max Capacity(MW)	231	231	231	231	231	231	231
	Min Capacity(MW)	180	180	180	180	180	180	180
	Generation(GWh)	-	1.956	1,800	1,950	1,840	1.927	1,652
	Annual Cap. Fac.	0.00%	96.66%	88.97%	96.36%	90.69%	95 23%	81.64%
	Fuel used(GBtu)	-	21,874	19,784	21.426	20,229	21.186	18,159
	Coal(Tons)	-	1.093.713	989,179	1.071.290	1,011,426	1.059.279	907,961
	Heat Rate	#DIV/0!	11 183	10.988	10 988	10.992	10.994	10.992
	Fuel cost($000)	$ -	$ 36,749	$ 40,358	$ 46,922	$ 43,491	$ 52.964	$ 32,632
	Fuel Cost per MMBTu	#DIV/0!	$ 1 680	$ 2.040	$ 2 190	$ 2.150	$ 2 500	$ 1.797
	VOM cost($000)	$ -	$ 7.559	$ 7,490	$ 8,872	$ 8,594	$ 9.250	$ 8,144
	VOM per MWh	#DIV/0!	$ 3.865	$ 4.160	$ 4 550	$ 4.670	$ 4 800	$ 4.930
	Num starts()	-	7	8	7	14	13	18
	Start Fuel used(GBtu)	-	17	20	18	31	23	43
	Start cost($000)	$ -	$ 919	$ 1,104	$ 979	$ 1,719	$ 1,316	$ 2,466
	Total Operating Cost ($000)	$ -	$ 45,227	$ 48,952	$ 56,774	$ 53,805	$ 63,530	$ 43,242
	Op Cost per MWh	#DIV/0!	$ 23.12	$ 27.19	$ 29.12	$ 29.24	$ 32.97	$ 26.18
EntityName		2008	2009	2010	2011	2012	2013	2014
Green 2	Max Capacity(MW)	223	223	223	223	223	223	223
	Min Capacity(MW)	180	180	180	180	180	180	180
	Generation(GWh)	-	1.713	1,872	1.604	1,850	1.763	1,865
	Annual Cap. Fac	0.00%	87 68%	95.85%	82 12%	94.42%	90 26%	95.49%
	Fuel used(GBtu)	-	19.358	20,800	17.820	20,557	19.594	20,731
	Coal(Tons)	-	967.890	1,040,003	891.016	1,027,860	979,697	1,036,537
	Heat Rate	#DIV/0!	11 302	11.109	11 109	11.115	11 112	11.114
	Fuel cost($000)	$ -	$ 32.521	$ 42,432	$ 39.026	$ 44,198	$ 48,985	$ 37,253
	Fuel Cost per MMBTu	#DIV/0!	$ 1 680	$ 2.040	$ 2 190	$ 2.150	$ 2 500	$ 1.797
	VOM cost($000)	$ -	$ 6,609	$ 7,789	$ 7.299	$ 8,637	$ 8,464	$ 9,196
	VOM per MWh	#DIV/0!	$ 3.859	$ 4.160	$ 4 550	$ 4.670	$ 4.800	$ 4.930
	Num starts()	-	8	7	6	13	14	11
	Start Fuel used(GBtu)	-	25	23	22	24	38	20
	Start cost($000)	$ -	$ 1,174	$ 1,107	$ 1,034	$ 1,271	$ 1,905	$ 1,089
	Total Operating Cost ($000)	$ -	$ 40,304	$ 51,328	$ 47,359	$ 54,107	$ 59,354	$ 47,538
	Op Cost per MWh	#DIV/0!	$ 23.53	$ 27.41	$ 29.52	$ 29.25	$ 33.66	$ 25.49
		2008	2009	2010	2011	2012	2013	2014
Total	Max Capacity(MW)	1,743	1.738	1,737	1,737	1,737	1.737	1,737
	Min Capacity(MW)	1,070	1,255	1,255	1.255	1,255	1.255	1,255
	Generation(GWh)	-	12.531	12,980	12.468	12,679	12.762	12,799
	Annual Cap. Fac.	0.00%	82 32%	85.28%	81.92%	83.08%	83 85%	84.10%
	Fuel used(GBtu)	-	139,691	143,951	138,665	140,599	140,722	141,260
	Coal(Tons)	-	6,336,497	6,514,057	6,262,389	6,356,369	6,368,971	6,373,339
	Heat Rate	#DIV/0!	11 147	11.090	11.122	11.089	11 027	11.037
	Fuel cost($000)	$ -	$ 272,074	$ 311,537	$ 314.188	$ 352,926	$ 379.743	$ 260,858
	Fuel Cost per MMBTu	#DIV/0!	$ 1.948	$ 2.164	$ 2 266	$ 2.510	$ 2 699	$ 1.847
	VOM cost($000)	$ -	$ 32.718	$ 35,812	$ 40,914	$ 42,820	$ 43.814	$ 44,845
	VOM per MWh	#DIV/0!	$ 2 611	$ 2.759	$ 3 282	$ 3.377	$ 3 433	$ 3.504
	Num starts()	-	295	289	299	306	363	315
	Start Fuel used(GBtu)	-	279	283	281	262	246	253
	Start cost($000)	$ -	$ 12,359	$ 12,815	$ 12,646	$ 11,754	$ 11,304	$ 11,982
	Total Operating Cost ($000)	$ -	$ 317,152	$ 360,164	$ 367,748	$ 407,500	$ 434,861	$ 317,686
	Op Cost per MWh	#DIV/0!	$ 25.31	$ 27.75	$ 29.50	$ 32.14	$ 34.08	$ 24.82

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EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
D B Wilson 1	Max Capacity(MW)	417	417	417	417	417	417	417	417	417
	Min Capacity(MW)	325	325	325	325	325	325	325	325	325
	Generation(GWh)	3.218	3,390	2,965	3,384	3.216	3,385	3.223	3,409	3,211
	Annual Cap. Fac	88 09%	92.54%	81 17%	92.63%	88.04%	92.41%	88.24%	93.32%	87.89%
	Fuel used(GBtu)	35.301	37,206	32.550	37,130	35,285	37,151	35,366	37,416	35,220
	Coal(Tons)	1,534,805	1,617,640	1.415,201	1,614,347	1.534.116	1,615,270	1.537.664	1,626,778	1.531.301
	Heat Rate	10.970	10.976	10 977	10.973	10.972	10.975	10 972	10.976	10.970
	Fuel cost($000)	$ 64.070	$ 68,198	$ 60,314	$ 69,545	$ 66,794	$ 71,070	$ 68,469	$ 73,260	$ 69.771
	Fuel Cost per MMBTu	$ 1.815	$ 1.833	$ 1.853	$ 1.873	$ 1 893	$ 1.913	$ 1.936	$ 1.958	$ 1 981
	VOM cost($000)	$ 11,488	$ 12,441	$ 11.179	$ 13,095	$ 12.800	$ 13,845	$ 13.538	$ 14,693	$ 14.223
	VOM per MWh	$ 3.570	$ 3.670	$ 3 770	$ 3.870	$ 3 980	$ 4.090	$ 4 200	$ 4.310	$ 4 430
	Num starts()	9	10	14	8	10	10	9	10	9
	Start Fuel used(GBtu)	50	50	77	46	55	53	50	52	55
	Start cost($000)	$ 2,905	$ 2,999	$ 4,740	$ 2,877	$ 3,547	$ 3,532	$ 3,375	$ 3,610	$ 3,903
	Total Operating Cost ($000)	$ 78,463	$ 83,637	$ 76,233	$ 85,517	$ 83,141	$ 88,447	$ 85,383	$ 91,564	$ 87,896
	Op Cost per MWh	$ 24.38	$ 24.67	$ 25.71	$ 25.27	$ 25.85	$ 26.13	$ 26.49	$ 26.86	$ 27.38

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
HMPL 1	Max Capacity(MW)	152	152	152	152	152	152	152	152	152
	Min Capacity(MW)	140	140	140	140	140	140	140	140	140
	Generation(GWh)	1.136	1,226	1,124	1,224	1.061	1,127	1.158	1,227	1.122
	Annual Cap. Fac	85.22%	91.72%	84.28%	91.80%	79 59%	84.29%	86 87%	92.05%	84.17%
	Fuel used(GBtu)	12,298	13,274	12.164	13,247	11.488	12,194	12.537	13,289	12.148
	Coal(Tons)	534.695	577,143	528,875	575,974	499,477	530,194	545,066	577,791	528,166
	Heat Rate	10.824	10.826	10.825	10.824	10 826	10.822	10 824	10.828	10 825
	Fuel cost($000)	$ 22,186	$ 24,186	$ 22.406	$ 24,653	$ 21.620	$ 23,182	$ 24.120	$ 25,861	$ 23.919
	Fuel Cost per MMBTu	$ 1.804	$ 1.822	$ 1 842	$ 1.861	$ 1.882	$ 1.901	$ 1 924	$ 1.946	$ 1 969
	VOM cost($000)	$ 6,669	$ 7,394	$ 6,967	$ 7,796	$ 6,940	$ 7,572	$ 8,003	$ 8,714	$ 8,181
	VOM per MWh	$ 5 870	$ 6,030	$ 6.200	$ 6.370	$ 6.540	$ 6.720	$ 6.910	$ 7.100	$ 7 290
	Num starts()	15	15	14	14	21	14	15	14	14
	Start Fuel used(GBtu)	28	28	26	26	38	26	28	26	26
	Start cost($000)	$ 1,651	$ 1,689	$ 1,585	$ 1,625	$ 2,463	$ 1,712	$ 1,920	$ 1,807	$ 1,867
	Total Operating Cost ($000)	$ 30,506	$ 33,269	$ 30,959	$ 34,075	$ 31,024	$ 32,466	$ 34,043	$ 36,382	$ 33,967
	Op Cost per MWh	$ 26.85	$ 27.13	$ 27.55	$ 27.84	$ 29.24	$ 28.81	$ 29.39	$ 29.64	$ 30.27

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
HMPL 2	Max Capacity(MW)	158	158	158	158	158	158	158	158	158
	Min Capacity(MW)	140	140	140	140	140	140	140	140	140
	Generation(GWh)	1.268	1,189	1.259	1,167	1.256	1,071	1.255	1,194	1.237
	Annual Cap. Fac	91.46%	85.55%	90.82%	84.18%	90.66%	77.06%	90.60%	86.14%	89 27%
	Fuel used(GBtu)	13,741	12,885	13,645	12,645	13,619	11,606	13.609	12,940	13.409
	Coal(Tons)	597.448	560,235	593,241	549,785	592.109	504,590	591,708	562,596	582.997
	Heat Rate	10.841	10.838	10.840	10.840	10.839	10.837	10.840	10.839	10 839
	Fuel cost($000)	$ 24,789	$ 23,477	$ 25.133	$ 23,532	$ 25,630	$ 22,062	$ 26,184	$ 25,181	$ 26,402
	Fuel Cost per MMBTu	$ 1.804	$ 1.822	$ 1.842	$ 1.861	$ 1.882	$ 1.901	$ 1 924	$ 1.946	$ 1 969
	VOM cost($000)	$ 7.440	$ 7,169	$ 7.804	$ 7,431	$ 8,217	$ 7,196	$ 8,675	$ 8,476	$ 9,019
	VOM per MWh	$ 5.870	$ 6.030	$ 6.200	$ 6.370	$ 6.540	$ 6.720	$ 6 910	$ 7.100	$ 7.290
	Num starts()	13	17	17	17	17	24	17	17	17
	Start Fuel used(GBtu)	25	34	33	34	34	46	34	34	34
	Start cost($000)	$ 1,449	$ 2,043	$ 2,026	$ 2,147	$ 2,172	$ 3,066	$ 2,276	$ 2,398	$ 2,413
	Total Operating Cost ($000)	$ 33,679	$ 32,689	$ 34,963	$ 33,111	$ 36,019	$ 32,325	$ 37,136	$ 36,055	$ 37,834
	Op Cost per MWh	$ 26.57	$ 27.50	$ 27.78	$ 28.38	$ 28.67	$ 30.19	$ 29.58	$ 30.20	$ 30.58

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman 1	Max Capacity(MW)	149	149	149	149	149	149	149	149	149
	Min Capacity(MW)	70	70	70	70	70	70	70	70	70
	Generation(GWh)	1,213	1,200	1.042	1,204	1.212	1,144	1.198	1,199	1.136
	Annual Cap. Fac	92.92%	91.68%	79.79%	92.21%	92.84%	87.43%	91.81%	91.89%	87.02%
	Fuel used(GBtu)	13.090	12,950	11.238	12,989	13,078	12,348	12.932	12,943	12,253
	Coal(Tons)	569.113	563,044	488,625	564,718	568,613	536,879	562.255	562,727	532.750
	Heat Rate	10.792	10.792	10.790	10.791	10 792	10.791	10 791	10.791	10 788
	Fuel cost($000)	$ 25,001	$ 24,994	$ 21,937	$ 25,639	$ 26,117	$ 24,919	$ 26,420	$ 26,753	$ 25.634
	Fuel Cost per MMBTu	$ 1 910	$ 1.930	$ 1 952	$ 1.974	$ 1 997	$ 2.018	$ 2.043	$ 2.067	$ 2 092
	VOM cost($000)	$ 1.686	$ 1,716	$ 1.531	$ 1,817	$ 1.878	$ 1,819	$ 1.953	$ 2,015	$ 1.965
	VOM per MWh	$ 1 390	$ 1.430	$ 1 470	$ 1.510	$ 1 550	$ 1.590	$ 1 630	$ 1.680	$ 1 730
	Num starts()	15	15	20	15	15	15	15	15	15
	Start Fuel used(GBtu)	23	23	30	23	23	24	23	24	25
	Start cost($000)	$ 553	$ 567	$ 767	$ 605	$ 614	$ 659	$ 653	$ 683	$ 734
	Total Operating Cost ($000)	$ 27,240	$ 27,276	$ 24,236	$ 28,062	$ 28,609	$ 27,398	$ 29,026	$ 29,451	$ 28,333
	Op Cost per MWh	$ 22.46	$ 22.73	$ 23.27	$ 23.32	$ 23.61	$ 23.94	$ 24.22	$ 24.55	$ 24.94

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EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman 2	Max Capacity(MW)	138	138	138	138	138	138	138	138	138
	Min Capacity(MW)	70	70	70	70	70	70	70	70	70
	Generation(GWh)	1.111	966	1.115	1,113	1.036	1,117	1.112	1,056	1.115
	Annual Cap. Fac	91.88%	79.69%	92 22%	92.10%	85.66%	92.18%	91.99%	87.39%	92.23%
	Fuel used(GBtu)	13.363	11,622	13.414	13,398	12.460	13,445	13.378	12,710	13,416
	Coal(Tons)	581.001	505,289	583.233	582,528	541.749	584,586	581.663	552,592	583,315
	Heat Rate	12 031	12.031	12 033	12.034	12 033	12.033	12 030	12.031	12.033
	Fuel cost($000)	$ 25,523	$ 22,430	$ 26,185	$ 26,448	$ 24.883	$ 27,133	$ 27.332	$ 26,271	$ 28,067
	Fuel Cost per MMBTu	$ 1 910	$ 1.930	$ 1 952	$ 1.974	$ 1 997	$ 2.018	$ 2 043	$ 2.067	$ 2 092
	VOM cost($000)	$ 1.577	$ 1,410	$ 1.672	$ 1,715	$ 1.636	$ 1,821	$ 1.857	$ 1,817	$ 1,973
	VOM per MWh	$ 1 420	$ 1.460	$ 1 500	$ 1.540	$ 1 580	$ 1.630	$ 1 670	$ 1.720	$ 1 770
	Num starts()	15	21	13	15	15	15	15	15	11
	Start Fuel used(GBtu)	24	31	20	24	25	24	24	25	18
	Start cost($000)	$ 586	$ 774	$ 496	$ 629	$ 655	$ 641	$ 683	$ 702	$ 524
	Total Operating Cost ($000)	$ 27,686	$ 24,614	$ 28,353	$ 28,791	$ 27,175	$ 29,595	$ 29,872	$ 28,790	$ 30,564
	Op Cost per MWh	$ 24.93	$ 25.48	$ 25.43	$ 25.86	$ 26.24	$ 26.49	$ 26.86	$ 27.25	$ 27.41

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman 3	Max Capacity(MW)	154	154	154	154	154	154	154	154	154
	Min Capacity(MW)	110	110	110	110	110	110	110	110	110
	Generation(GWh)	1.155	1,211	1.227	1,162	1.212	1,222	1,068	1,229	1.233
	Annual Cap. Fac	85 59%	89.55%	90 98%	86.13%	89 87%	90.30%	79.16%	91.10%	91.43%
	Fuel used(GBtu)	12.501	13,115	13,288	12,579	13.126	13,225	11.565	13,309	13.356
	Coal(Tons)	543,527	570,214	577.757	546,905	570,700	574,991	502.839	578,646	580,686
	Heat Rate	10.827	10.826	10 827	10.826	10 827	10.826	10 829	10.829	10.829
	Fuel cost($000)	$ 23,877	$ 25,312	$ 25,939	$ 24,831	$ 26.213	$ 26,688	$ 23,628	$ 27,509	$ 27,940
	Fuel Cost per MMBTu	$ 1 910	$ 1.930	$ 1.952	$ 1.974	$ 1 997	$ 2.018	$ 2 043	$ 2.067	$ 2.092
	VOM cost($000)	$ 1.640	$ 1,769	$ 1,841	$ 1,789	$ 1.916	$ 1,991	$ 1.783	$ 2,114	$ 2.183
	VOM per MWh	$ 1.420	$ 1.460	$ 1.500	$ 1.540	$ 1 580	$ 1.630	$ 1 670	$ 1.720	$ 1 770
	Num starts()	16	16	16	17	17	17	24	16	17
	Start Fuel used(GBtu)	22	22	22	24	24	24	32	22	24
	Start cost($000)	$ 536	$ 551	$ 562	$ 628	$ 643	$ 659	$ 892	$ 638	$ 714
	Total Operating Cost ($000)	$ 26,053	$ 27,631	$ 28,342	$ 27,248	$ 28,771	$ 29,337	$ 26,304	$ 30,261	$ 30,837
	Op Cost per MWh	$ 22.56	$ 22.81	$ 23.09	$ 23.45	$ 23.73	$ 24.02	$ 24.63	$ 24.62	$ 25.00

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Reid ST	Max Capacity(MW)	50	50	50	50	50	50	50	50	50
	Min Capacity(MW)	40	40	40	40	40	40	40	40	40
	Generation(GWh)	13	23	22	-	24	22	19	37	22
	Annual Cap. Fac	2.90%	5.12%	5.09%	0.00%	5.37%	5.02%	4 25%	8.55%	5 00%
	Fuel used(GBtu)	172	305	302	-	318	298	252	507	297
	Coal(Tons)	-	-	-	-	-	-	-	-	-
	Heat Rate	13.510	13.560	13 537	#DIV/0!	13.531	13.548	13 566	13.552	13 555
	Fuel cost($000)	$ 1.473	$ 2,689	$ 2.808	$ -	$ 2.943	$ 2,774	$ 2.418	$ 5,009	$ 3,095
	Fuel Cost per MMBTu	$ 8 576	$ 8.811	$ 9.311	#DIV/0!	$ 9 251	$ 9.296	$ 9 579	$ 9.875	$ 10.434
	VOM cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	VOM per MWh	$ -	$ -	$ -	#DIV/0!	$ -	$ -	$ -	$ -	$ -
	Num starts()	3	2	5	-	3	2	2	12	2
	Start Fuel used(GBtu)	2	2	5	-	2	2	2	11	2
	Start cost($000)	$ 103	$ 102	$ 215	$ -	$ 113	$ 113	$ 115	$ 575	$ 121
	Total Operating Cost ($000)	$ 1,576	$ 2,790	$ 3,024	$ -	$ 3,056	$ 2,887	$ 2,534	$ 5,584	$ 3,217
	Op Cost per MWh	$ 123.95	$ 123.99	$ 135.70	#DIV/0!	$ 129.98	$ 131.06	$ 136.15	$ 149.19	$ 146.98

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Reid GT	Max Capacity(MW)	65	65	65	65	65	65	65	65	65
	Min Capacity(MW)	-	-	-	-	-	-	-	-	-
	Generation(GWh)	9	9	11	10	9	9	9	9	9
	Annual Cap. Fac	1 55%	1.64%	1 93%	1.84%	1 54%	1.49%	1 58%	1.57%	1 59%
	Fuel used(GBtu)	104	110	130	125	103	101	106	106	107
	Coal(Tons)	-	-	-	-	-	-	-	-	-
	Heat Rate	11 831	11.772	11 819	11.901	11 825	11.916	11 764	11.935	11 789
	Fuel cost($000)	$ 902	$ 967	$ 1.154	$ 1,127	$ 951	$ 952	$ 1.020	$ 1,053	$ 1.085
	Fuel Cost per MMBTu	$ 8.650	$ 8.749	$ 8 890	$ 9.044	$ 9 204	$ 9.390	$ 9 646	$ 9.896	$ 10 168
	VOM cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	VOM per MWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Num starts()	173	173	182	121	199	186	229	173	155
	Start Fuel used(GBtu)	-	-	-	-	-	-	-	-	-
	Start cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Operating Cost ($000)	$ 902	$ 967	$ 1,154	$ 1,127	$ 951	$ 952	$ 1,020	$ 1,053	$ 1,085
	Op Cost per MWh	$ 102.34	$ 102.99	$ 105.08	$ 107.64	$ 108.83	$ 111.89	$ 113.48	$ 118.10	$ 119.87

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EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Green 1	Max Capacity(MW)	231	231	231	231	231	231	231	231	231
	Min Capacity(MW)	180	180	180	180	180	180	180	180	180
	Generation(GWh)	1.957	1,782	1,940	1,797	1.955	1,822	1,947	1,635	1.938
	Annual Cap. Fac	96.70%	87.82%	95.85%	88.81%	96.61%	89.78%	96.21%	80.78%	95.76%
	Fuel used(GBtu)	21.520	19,586	21,325	19,754	21.497	20,022	21.406	17,969	21.301
	Coal(Tons)	1,075,977	979,276	1.066,246	987,704	1.074.845	1,001,121	1.070.298	898,461	1.065,074
	Heat Rate	10.997	10.991	10 994	10.992	10.996	10.991	10 995	10.993	10.993
	Fuel cost($000)	$ 38.993	$ 34,921	$ 39,451	$ 36,940	$ 40.629	$ 38,243	$ 41.356	$ 35,130	$ 42.134
	Fuel Cost per MMBTu	$ 1 812	$ 1.783	$ 1 850	$ 1.870	$ 1.890	$ 1.910	$ 1 932	$ 1.955	$ 1 978
	VOM cost($000)	$ 13,071	$ 12,224	$ 13,675	$ 13,029	$ 14.564	$ 13,936	$ 15,303	$ 13,207	$ 16,083
	VOM per MWh	$ 6.680	$ 6.860	$ 7 050	$ 7.250	$ 7.450	$ 7.650	$ 7 860	$ 8.080	$ 8 300
	Num starts()	13	15	13	13	13	15	13	21	13
	Start Fuel used(GBtu)	20	34	22	30	20	34	22	49	23
	Start cost($000)	$ 1,155	$ 2,034	$ 1,364	$ 1,857	$ 1,274	$ 2,251	$ 1,468	$ 3,403	$ 1,636
	Total Operating Cost ($000)	$ 53,220	$ 49,180	$ 54,490	$ 51,826	$ 56,468	$ 54,429	$ 58,127	$ 51,740	$ 59,854
	Op Cost per MWh	$ 27.20	$ 27.60	$ 28.09	$ 28.84	$ 28.88	$ 29.88	$ 29.86	$ 31.65	$ 30.89

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Green 2	Max Capacity(MW)	223	223	223	223	223	223	223	223	223
	Min Capacity(MW)	180	180	180	180	180	180	180	180	180
	Generation(GWh)	1.748	1,867	1.742	1,770	1.561	1,873	1.759	1,860	1.748
	Annual Cap. Fac	89 50%	95.30%	89 16%	90.63%	79.89%	95.59%	90.02%	95.22%	89 48%
	Fuel used(GBtu)	19.425	20,750	19.355	19,675	17.344	20,816	19,543	20,674	19.424
	Coal(Tons)	971.248	1,037,522	967.733	983,764	867.178	1,040,808	977.149	1,033,688	971.204
	Heat Rate	11 110	11.115	11 112	11.114	11.113	11.117	11 113	11.115	11 112
	Fuel cost($000)	$ 35,198	$ 36,998	$ 35,806	$ 36,793	$ 32.779	$ 39,759	$ 37.757	$ 40,417	$ 38,421
	Fuel Cost per MMBTu	$ 1.812	$ 1.783	$ 1.850	$ 1.870	$ 1.890	$ 1.910	$ 1 932	$ 1.955	$ 1.978
	VOM cost($000)	$ 11.679	$ 12,807	$ 12,279	$ 12,835	$ 11.627	$ 14,325	$ 13.823	$ 15,029	$ 14.508
	VOM per MWh	$ 6 680	$ 6.860	$ 7.050	$ 7.250	$ 7.450	$ 7.650	$ 7 860	$ 8.080	$ 8.300
	Num starts()	15	11	15	13	21	12	14	12	15
	Start Fuel used(GBtu)	41	19	42	38	61	21	37	22	42
	Start cost($000)	$ 2,142	$ 1,076	$ 2,294	$ 2,098	$ 3,460	$ 1,351	$ 2,266	$ 1,476	$ 2,674
	Total Operating Cost ($000)	$ 49,019	$ 50,881	$ 50,380	$ 51,726	$ 47,866	$ 55,435	$ 53,846	$ 56,922	$ 55,603
	Op Cost per MWh	$ 28.04	$ 27.25	$ 28.92	$ 29.22	$ 30.67	$ 29.60	$ 30.62	$ 30.60	$ 31.81

		2015	2016	2017	2018	2019	2020	2021	2022	2023
Total	Max Capacity(MW)	1.737	1,737	1.737	1,737	1,737	1,737	1.737	1,737	1.737
	Min Capacity(MW)	1,255	1,255	1.255	1,255	1.255	1,255	1.255	1,255	1.255
	Generation(GWh)	12.826	12,863	12.446	12,831	12.541	12,791	12,749	12,856	12.771
	Annual Cap. Fac	84 28%	84.28%	81 78%	84.31%	82 40%	83.81%	83.76%	84.47%	83.91%
	Fuel used(GBtu)	141,514	141,804	137.410	141,542	138,318	141,208	140,695	141,863	140,931
	Coal(Tons)	6,407.813	6,410,364	6,220.910	6,405,725	6,248,787	6,388,439	6,368,643	6,393,278	6,375.494
	Heat Rate	11 033	11.024	11 041	11.031	11 029	11.040	11.036	11.035	11.035
	Fuel cost($000)	$ 262.013	$ 264,171	$ 261.135	$ 269,508	$ 268,560	$ 276,781	$ 278,705	$ 286,444	$ 286,469
	Fuel Cost per MMBTu	$ 1 852	$ 1.863	$ 1 900	$ 1.904	$ 1.942	$ 1.960	$ 1 981	$ 2.019	$ 2.033
	VOM cost($000)	$ 55,250	$ 56,929	$ 56,948	$ 59,508	$ 59.578	$ 62,506	$ 64.936	$ 66,065	$ 68,135
	VOM per MWh	$ 4.308	$ 4.426	$ 4.576	$ 4.638	$ 4 751	$ 4.887	$ 5.094	$ 5.139	$ 5 335
	Num starts()	287	296	309	233	330	310	354	304	269
	Start Fuel used(GBtu)	236	244	278	245	283	255	253	265	249
	Start cost($000)	$ 11,080	$ 11,834	$ 14,050	$ 12,467	$ 14,942	$ 13,983	$ 13,649	$ 15,293	$ 14,587
	Total Operating Cost ($000)	$ 328,344	$ 332,934	$ 332,133	$ 341,483	$ 343,080	$ 353,271	$ 357,290	$ 367,803	$ 369,191
	Op Cost per MWh	$ 25.60	$ 25.88	$ 26.69	$ 26.61	$ 27.36	$ 27.62	$ 28.03	$ 28.61	$ 28.91

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EntityName		2008	2009	2010	2011	2012	2013	2014
D B Wilson 1	Generation(GWh)	-	3,019	3,433	3,141	3,317	3,161	3,380
	Fuel used(GBtu)	-	33,953	38,601	35,542	37,044	34,679	37,098
	Coal(Tons)	-	1,476,213	1,678,323	1,545,319	1,610,606	1,507,769	1,612,949
	Heat Rate	#DIV/0!	11 247	11.245	11 317	11.166	10 970	10.975
	Fuel cost($000)	$ -	$ 60,097	$ 65,622	$ 62,199	$ 90,758	$ 89,124	$ 66,776
	Fuel Cost per MMBTu	#DIV/0!	$ 1.770	$ 1.700	$ 1.750	$ 2.450	$ 2.570	$ 1.800

EntityName		2008	2009	2010	2011	2012	2013	2014
HMPL 1	Generation(GWh)	-	1,128	1,217	1,055	1,194	1,154	1,215
	Fuel used(GBtu)	-	12,204	13,167	11,417	12,928	12,491	13,156
	Coal(Tons)	-	530,591	572,467	496,400	562,095	543,093	571,994
	Heat Rate	#DIV/0!	10 822	10.823	10 821	10.823	10 824	10.826
	Fuel cost($000)	$ -	$ 23,187	$ 33,180	$ 29,114	$ 34,260	$ 34,725	$ 23,549
	Fuel Cost per MMBTu	#DIV/0!	$ 1.900	$ 2.520	$ 2.550	$ 2.650	$ 2.780	$ 1.790

EntityName		2008	2009	2010	2011	2012	2013	2014
HMPL 2	Generation(GWh)	-	1,271	1,184	1,252	1,095	1,245	1,182
	Fuel used(GBtu)	-	13,767	12,827	13,564	11,868	13,501	12,809
	Coal(Tons)	-	598,547	557,704	589,741	515,988	586,981	556,934
	Heat Rate	#DIV/0!	10 835	10.835	10 837	10.840	10 840	10.838
	Fuel cost($000)	$ -	$ 26,157	$ 32,325	$ 34,588	$ 31,449	$ 37,532	$ 22,929
	Fuel Cost per MMBTu	#DIV/0!	$ 1.900	$ 2.520	$ 2.550	$ 2.650	$ 2.780	$ 1.790

EntityName		2008	2009	2010	2011	2012	2013	2014
Coleman 1	Generation(GWh)	-	1,198	1,193	1,102	1,202	1,207	1,144
	Fuel used(GBtu)	-	12,853	12,800	11,884	12,967	13,028	12,348
	Coal(Tons)	-	558,821	556,517	516,694	563,766	566,453	536,879
	Heat Rate	#DIV/0!	10 727	10.728	10 785	10.789	10 791	10.791
	Fuel cost($000)	$ -	$ 30,847	$ 31,744	$ 30,304	$ 36,047	$ 37,913	$ 23,388
	Fuel Cost per MMBTu	#DIV/0!	$ 2.400	$ 2.480	$ 2.550	$ 2.780	$ 2.910	$ 1.894

EntityName		2008	2009	2010	2011	2012	2013	2014
Coleman 2	Generation(GWh)	-	1,111	1,040	1,101	1,090	1,038	1,093
	Fuel used(GBtu)	-	13,369	12,508	13,237	13,115	12,493	13,144
	Coal(Tons)	-	581,246	543,816	575,501	570,236	543,177	571,487
	Heat Rate	#DIV/0!	12 033	12.032	12 028	12.030	12 032	12.029
	Fuel cost($000)	$ -	$ 32,085	$ 31,019	$ 33,753	$ 36,461	$ 36,355	$ 24,895
	Fuel Cost per MMBTu	#DIV/0!	$ 2.400	$ 2.480	$ 2.550	$ 2.780	$ 2.910	$ 1.894

EntityName		2008	2009	2010	2011	2012	2013	2014
Coleman 3	Generation(GWh)	-	1,126	1,225	1,225	1,050	1,237	1,229
	Fuel used(GBtu)	-	12,176	13,249	13,258	11,371	13,398	13,308
	Coal(Tons)	-	529,400	576,047	576,428	494,391	582,521	578,596
	Heat Rate	#DIV/0!	10 817	10.817	10 823	10.826	10 830	10.826
	Fuel cost($000)	$ -	$ 29,223	$ 32,858	$ 33,808	$ 31,611	$ 38,988	$ 25,205
	Fuel Cost per MMBTu	#DIV/0!	$ 2.400	$ 2.480	$ 2.550	$ 2.780	$ 2.910	$ 1.894

EntityName		2008	2009	2010	2011	2012	2013	2014
Reid ST	Generation(GWh)	-	7	12	32	29	13	29
	Fuel used(GBtu)	-	90	165	437	387	178	396
	Coal(Tons)	-	75	-	-	-	-	-
	Heat Rate	#DIV/0!	13 564	13.571	13 545	13.556	13 572	13.547
	Fuel cost($000)	$ -	$ 792	$ 1,551	$ 3,776	$ 3,518	$ 1,683	$ 3,300
	Fuel Cost per MMBTu	#DIV/0!	$ 8.785	$ 9.420	$ 8.646	$ 9.081	$ 9.451	$ 8.344

EntityName		2008	2009	2010	2011	2012	2013	2014
Reid GT	Generation(GWh)	-	4	4	7	11	15	9
	Fuel used(GBtu)	-	48	51	80	133	175	111
	Coal(Tons)	-	-	-	-	-	-	-
	Heat Rate	#DIV/0!	12 046	11.931	11 905	11.785	11 899	11.947
	Fuel cost($000)	$ -	$ 418	$ 448	$ 698	$ 1,132	$ 1,475	$ 931
	Fuel Cost per MMBTu	#DIV/0!	$ 8.733	$ 8.814	$ 8.675	$ 8.522	$ 8.432	$ 8.412

EntityName		2008	2009	2010	2011	2012	2013	2014
Green 1	Generation(GWh)	-	1,956	1,800	1,950	1,840	1,927	1,652
	Fuel used(GBtu)	-	21,874	19,784	21,426	20,229	21,186	18,159
	Coal(Tons)	-	1,093,713	989,179	1,071,290	1,011,426	1,059,279	907,961
	Heat Rate	#DIV/0!	11 183	10.988	10 988	10.992	10 994	10.992
	Fuel cost($000)	$ -	$ 36,749	$ 40,358	$ 46,922	$ 43,491	$ 52,964	$ 32,632
	Fuel Cost per MMBTu	#DIV/0!	$ 1.680	$ 2.040	$ 2.190	$ 2.150	$ 2.500	$ 1.797

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EntityName			2008	2009	2010	2011	2012	2013	2014
Green 2	Generation(GWh)		-	1,713	1,872	1,604	1,850	1,763	1,865
	Fuel used(GBtu)		-	19,358	20,800	17,820	20,557	19,594	20,731
	Coal(Tons)		-	967,890	1,040,003	891,016	1,027,860	979,697	1,036,537
	Heat Rate		#DIV/0!	11 302	11.109	11 109	11.115	11 112	11.114
	Fuel cost($000)		$ -	$ 32,521	$ 42,432	$ 39,026	$ 44,198	$ 48,985	$ 37,253
	Fuel Cost per MMBTu		#DIV/0!	$ 1.680	$ 2.040	$ 2.190	$ 2.150	$ 2.500	$ 1.797

			2008	2009	2010	2011	2012	2013	2014
Total	Generation(GWh)		-	12,531	12,980	12,468	12,679	12,762	12,799
	Fuel used(GBtu)		-	139,691	143,951	138,665	140,599	140,722	141,260
	Coal(Tons)		-	6,336,497	6,514,057	6,262,389	6,356,369	6,368,971	6,373,339
	Heat Rate		#DIV/0!	11 147	11.090	11 122	11.089	11 027	11.037
	Fuel cost($000)		$ -	$ 272,074	$ 311,537	$ 314,188	$ 352,926	$ 379,743	$ 260,858
	Fuel Cost per MMBTu		#DIV/0!	$ 1.948	$ 2.164	$ 2.266	$ 2.510	$ 2.699	$ 1.847

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EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
D B Wilson 1	Generation(GWh)	3,218	3,390	2,965	3,384	3,216	3,385	3,223	3,409	3,211
	Fuel used(GBtu)	35,301	37,206	32,550	37,130	35,285	37,151	35,366	37,416	35,220
	Coal(Tons)	1,534,805	1,617,640	1,415,201	1,614,347	1,534,116	1,615,270	1,537,664	1,626,778	1,531,301
	Heat Rate	10 970	10.976	10 977	10.973	10 972	10.975	10 972	10.976	10 970
	Fuel cost($000)	$ 64,070	$ 68,198	$ 60,314	$ 69,545	$ 66,794	$ 71,070	$ 68,469	$ 73,260	$ 69,771
	Fuel Cost per MMBTu	$ 1.815	$ 1.833	$ 1.853	$ 1.873	$ 1.893	$ 1.913	$ 1.936	$ 1.958	$ 1.981

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
HMPL 1	Generation(GWh)	1,136	1,226	1,124	1,224	1,061	1,127	1,158	1,227	1,122
	Fuel used(GBtu)	12,298	13,274	12,164	13,247	11,488	12,194	12,537	13,289	12,148
	Coal(Tons)	534,695	577,143	528,875	575,974	499,477	530,194	545,066	577,791	528,166
	Heat Rate	10 824	10.826	10 825	10.824	10 826	10.822	10 824	10.828	10 825
	Fuel cost($000)	$ 22,186	$ 24,186	$ 22,406	$ 24,653	$ 21,620	$ 23,182	$ 24,120	$ 25,861	$ 23,919
	Fuel Cost per MMBTu	$ 1.804	$ 1.822	$ 1.842	$ 1.861	$ 1.882	$ 1.901	$ 1.924	$ 1.946	$ 1.969

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
HMPL 2	Generation(GWh)	1,268	1,189	1,259	1,167	1,256	1,071	1,255	1,194	1,237
	Fuel used(GBtu)	13,741	12,885	13,645	12,645	13,619	11,606	13,609	12,940	13,409
	Coal(Tons)	597,448	560,235	593,241	549,785	592,109	504,590	591,708	562,596	582,997
	Heat Rate	10 841	10.838	10 840	10.840	10 839	10.837	10 840	10.839	10 839
	Fuel cost($000)	$ 24,789	$ 23,477	$ 25,133	$ 23,532	$ 25,630	$ 22,062	$ 26,184	$ 25,181	$ 26,402
	Fuel Cost per MMBTu	$ 1.804	$ 1.822	$ 1.842	$ 1.861	$ 1.882	$ 1.901	$ 1.924	$ 1.946	$ 1.969

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman 1	Generation(GWh)	1,213	1,200	1,042	1,204	1,212	1,144	1,198	1,199	1,136
	Fuel used(GBtu)	13,090	12,950	11,238	12,989	13,078	12,348	12,932	12,943	12,253
	Coal(Tons)	569,113	563,044	488,625	564,718	568,613	536,879	562,255	562,727	532,750
	Heat Rate	10 792	10.792	10 790	10.791	10 792	10.791	10 791	10.791	10 788
	Fuel cost($000)	$ 25,001	$ 24,994	$ 21,937	$ 25,639	$ 26,117	$ 24,919	$ 26,420	$ 26,753	$ 25,634
	Fuel Cost per MMBTu	$ 1.910	$ 1.930	$ 1.952	$ 1.974	$ 1.997	$ 2.018	$ 2.043	$ 2.067	$ 2.092

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman 2	Generation(GWh)	1,111	966	1,115	1,113	1,036	1,117	1,112	1,056	1,115
	Fuel used(GBtu)	13,363	11,622	13,414	13,398	12,460	13,445	13,378	12,710	13,416
	Coal(Tons)	*581,001*	*505,289*	*583,233*	*582,528*	*541,749*	*584,586*	*581,663*	*552,592*	*583,315*
	Heat Rate	12 031	12.031	12 033	12.034	12 033	12.033	12 030	12.031	12 033
	Fuel cost($000)	$ 25,523	$ 22,430	$ 26,185	$ 26,448	$ 24,883	$ 27,133	$ 27,332	$ 26,271	$ 28,067
	Fuel Cost per MMBTu	$ 1.910	$ 1.930	$ 1.952	$ 1.974	$ 1.997	$ 2.018	$ 2.043	$ 2.067	$ 2.092

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman 3	Generation(GWh)	1,155	1,211	1,227	1,162	1,212	1,222	1,068	1,229	1,233
	Fuel used(GBtu)	12,501	13,115	13,288	12,579	13,126	13,225	11,565	13,309	13,356
	Coal(Tons)	543,527	570,214	577,757	546,905	570,700	574,991	502,839	578,646	580,686
	Heat Rate	10 827	10.826	10 827	10.826	10 827	10.826	10 829	10.829	10 829
	Fuel cost($000)	$ 23,877	$ 25,312	$ 25,939	$ 24,831	$ 26,213	$ 26,688	$ 23,628	$ 27,509	$ 27,940
	Fuel Cost per MMBTu	$ 1.910	$ 1.930	$ 1.952	$ 1.974	$ 1.997	$ 2.018	$ 2.043	$ 2.067	$ 2.092

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Reid ST	Generation(GWh)	13	23	22	-	24	22	19	37	22
	Fuel used(GBtu)	172	305	302	-	318	298	252	507	297
	Coal(Tons)	-	-	-	-	-	-	-	-	-
	Heat Rate	13 510	13.560	13 537	#DIV/0!	13 531	13.548	13 566	13.552	13 555
	Fuel cost($000)	$ 1,473	$ 2,689	$ 2,808	$ -	$ 2,943	$ 2,774	$ 2,418	$ 5,009	$ 3,095
	Fuel Cost per MMBTu	$ 8.576	$ 8.811	$ 9.311	#DIV/0!	$ 9.251	$ 9.296	$ 9.579	$ 9.875	$ 10.434

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Reid GT	Generation(GWh)	9	9	11	10	9	9	9	9	9
	Fuel used(GBtu)	104	110	130	125	103	101	106	106	107
	Coal(Tons)	-	-	-	-	-	-	-	-	-
	Heat Rate	11 831	11.772	11 819	11.901	11 825	11.916	11 764	11.935	11 789
	Fuel cost($000)	$ 902	$ 967	$ 1,154	$ 1,127	$ 951	$ 952	$ 1,020	$ 1,053	$ 1,085
	Fuel Cost per MMBTu	$ 8.650	$ 8.749	$ 8.890	$ 9.044	$ 9.204	$ 9.390	$ 9.646	$ 9.896	$ 10.168

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Green 1	Generation(GWh)	1,957	1,782	1,940	1,797	1,955	1,822	1,947	1,635	1,938
	Fuel used(GBtu)	21,520	19,586	21,325	19,754	21,497	20,022	21,406	17,969	21,301
	Coal(Tons)	1,075,977	979,276	1,066,246	987,704	1,074,845	1,001,121	1,070,298	898,461	1,065,074
	Heat Rate	10 997	10.991	10 994	10.992	10 996	10.991	10 995	10.993	10 993
	Fuel cost($000)	$ 38,993	$ 34,921	$ 39,451	$ 36,940	$ 40,629	$ 38,243	$ 41,356	$ 35,130	$ 42,134
	Fuel Cost per MMBTu	$ 1.812	$ 1.783	$ 1.850	$ 1.870	$ 1.890	$ 1.910	$ 1.932	$ 1.955	$ 1.978

Fuel Report

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EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Green 2	Generation(GWh)	1,748	1,867	1,742	1,770	1,561	1,873	1,759	1,860	1,748
	Fuel used(GBtu)	19,425	20,750	19,355	19,675	17,344	20,816	19,543	20,674	19,424
	Coal(Tons)	971,248	1,037,522	967,733	983,764	867,178	1,040,808	977,149	1,033,688	971,204
	Heat Rate	11.110	11.115	11 112	11.114	11 113	11.117	11.113	11.115	11 112
	Fuel cost($000)	$ 35,198	$ 36,998	$ 35,806	$ 36,793	$ 32,779	$ 39,759	$ 37,757	$ 40,417	$ 38,421
	Fuel Cost per MMBTu	$ 1.812	$ 1.783	$ 1.850	$ 1.870	$ 1.890	$ 1.910	$ 1.932	$ 1.955	$ 1.978

		2015	2016	2017	2018	2019	2020	2021	2022	2023
Total	Generation(GWh)	12,826	12,863	12,446	12,831	12,541	12,791	12,749	12,856	12,771
	Fuel used(GBtu)	141,514	141,804	137,410	141,542	138,318	141,208	140,695	141,863	140,931
	Coal(Tons)	6,407,813	6,410,364	6,220,910	6,405,725	6,248,787	6,388,439	6,368,643	6,393,278	6,375,494
	Heat Rate	11.033	11.024	11.041	11.031	11 029	11.040	11 036	11.035	11 035
	Fuel cost($000)	$ 262,013	$ 264,171	$ 261,135	$ 269,508	$ 268,560	$ 276,781	$ 278,705	$ 286,444	$ 286,469
	Fuel Cost per MMBTu	$ 1.852	$ 1.863	$ 1.900	$ 1.904	$ 1.942	$ 1.960	$ 1.981	$ 2.019	$ 2.033

Emissions Report

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EntityName			2008	2009	2010	2011	2012	2013	2014
D B Wilson 1	SO2(ktons)		-	9.932	11.292	10.397	10.836	10.144	10.852
	SO2 Emit Rate		#DIV/0!	0.585	0.585	0.585	0.585	0.585	0.585
	SO2 cost($000)		$ -	$ 1,390	$ 1,299	$ 9,025	$ 9,514	$ 8,876	$ 9,224
	NOx(ktons)		-	0.384	0.406	1.092	1.070	0.998	1.072
	NOx Emit Rate		-	0.023	0.021	0.061	0.058	0.058	0.058
	NOx cost($000)		$ -	$ 1,093	$ 978	$ 2,352	$ 2,123	$ 1,897	$ 2,047
	Total Emissions Cost ($000)		$ -	$ 2,483	$ 2,277	$ 11,376	$ 11,637	$ 10,773	$ 11,271
	Emit Cost per MWh		#DIV/0!	$ 0.82	$ 0.66	$ 3.62	$ 3.51	$ 3.41	$ 3.33
EntityName			2008	2009	2010	2011	2012	2013	2014
HMPL 1	SO2(ktons)		-	2.014	2.173	1.884	2.133	2.061	2.171
	SO2 Emit Rate		#DIV/0!	0.330	0.330	0.330	0.330	0.330	0.330
	SO2 cost($000)		$ -	$ 282	$ 250	$ 1,635	$ 1,873	$ 1,804	$ 1,845
	NOx(ktons)		-	0.198	0.201	0.488	0.542	0.521	0.552
	NOx Emit Rate		-	0.032	0.031	0.086	0.084	0.083	0.084
	NOx cost($000)		$ -	$ 580	$ 484	$ 1,052	$ 1,075	$ 990	$ 1,053
	Total Emissions Cost ($000)		$ -	$ 862	$ 734	$ 2,688	$ 2,948	$ 2,794	$ 2,898
	Emit Cost per MWh		#DIV/0!	$ 0.76	$ 0.60	$ 2.55	$ 2.47	$ 2.42	$ 2.39
EntityName			2008	2009	2010	2011	2012	2013	2014
HMPL 2	SO2(ktons)		-	2.272	2.117	2.238	1.959	2.228	2.114
	SO2 Emit Rate		#DIV/0!	0.330	0.330	0.330	0.330	0.330	0.330
	SO2 cost($000)		$ -	$ 318	$ 243	$ 1,943	$ 1,720	$ 1,949	$ 1,797
	NOx(ktons)		-	0.207	0.206	0.568	0.494	0.563	0.534
	NOx Emit Rate		-	0.030	0.032	0.084	0.083	0.083	0.083
	NOx cost($000)		$ -	$ 591	$ 496	$ 1,224	$ 980	$ 1,069	$ 1,019
	Total Emissions Cost ($000)		$ -	$ 909	$ 739	$ 3,167	$ 2,700	$ 3,018	$ 2,816
	Emit Cost per MWh		#DIV/0!	$ 0.72	$ 0.62	$ 2.53	$ 2.47	$ 2.42	$ 2.38
EntityName			2008	2009	2010	2011	2012	2013	2014
Coleman 1	SO2(ktons)		-	0.733	0.730	0.677	0.739	0.743	0.704
	SO2 Emit Rate		#DIV/0!	0.114	0.114	0.114	0.114	0.114	0.114
	SO2 cost($000)		$ -	$ 103	$ 84	$ 588	$ 649	$ 650	$ 598
	NOx(ktons)		-	0.846	0.858	1.913	2.082	2.087	1.976
	NOx Emit Rate		-	0.132	0.134	0.322	0.321	0.320	0.320
	NOx cost($000)		$ -	$ 2,408	$ 2,067	$ 4,122	$ 4,134	$ 3,965	$ 3,772
	Total Emissions Cost ($000)		$ -	$ 2,510	$ 2,151	$ 4,710	$ 4,783	$ 4,615	$ 4,370
	Emit Cost per MWh		#DIV/0!	$ 2.10	$ 1.80	$ 4.27	$ 3.98	$ 3.82	$ 3.82
EntityName			2008	2009	2010	2011	2012	2013	2014
Coleman 2	SO2(ktons)		-	0.762	0.713	0.755	0.748	0.712	0.749
	SO2 Emit Rate		#DIV/0!	0.114	0.114	0.114	0.114	0.114	0.114
	SO2 cost($000)		$ -	$ 107	$ 82	$ 655	$ 656	$ 623	$ 637
	NOx(ktons)		-	0.873	0.883	2.134	2.110	2.005	2.117
	NOx Emit Rate		-	0.131	0.141	0.322	0.322	0.321	0.322
	NOx cost($000)		$ -	$ 2,487	$ 2,126	$ 4,599	$ 4,189	$ 3,810	$ 4,040
	Total Emissions Cost ($000)		$ -	$ 2,593	$ 2,208	$ 5,254	$ 4,845	$ 4,433	$ 4,677
	Emit Cost per MWh		#DIV/0!	$ 2.33	$ 2.12	$ 4.77	$ 4.44	$ 4.27	$ 4.28
EntityName			2008	2009	2010	2011	2012	2013	2014
Coleman 3	SO2(ktons)		-	0.694	0.755	0.755	0.648	0.764	0.759
	SO2 Emit Rate		#DIV/0!	0.114	0.114	0.114	0.114	0.114	0.114
	SO2 cost($000)		$ -	$ 97	$ 87	$ 656	$ 569	$ 668	$ 645
	NOx(ktons)		-	0.726	0.866	2.138	1.749	2.040	2.035
	NOx Emit Rate		-	0.119	0.131	0.323	0.308	0.305	0.306
	NOx cost($000)		$ -	$ 1,996	$ 2,085	$ 4,608	$ 3,472	$ 3,876	$ 3,885
	Total Operating Cost ($000)		$ -	$ 31,079	$ 34,895	$ 35,958	$ 33,719	$ 41,125	$ 27,426
	Op Cost per MWh		#DIV/0!	$ 27.61	$ 28.49	$ 29.35	$ 32.10	$ 33.24	$ 22.31
	Total Emissions Cost ($000)		$ -	$ 2,093	$ 2,172	$ 5,264	$ 4,041	$ 4,544	$ 4,529
	Emit Cost per MWh		#DIV/0!	$ 1.86	$ 1.77	$ 4.30	$ 3.85	$ 3.67	$ 3.68
EntityName			2008	2009	2010	2011	2012	2013	2014
Reid ST	SO2(ktons)		-	0.004	0.004	0.005	0.001	0.000	0.000
	SO2 Emit Rate		#DIV/0!	4.500	4.500	0.021	0.004	0.001	0.002
	SO2 cost($000)		$ -	$ 1	$ 0	$ 4	$ 1	$ 0	$ 0
	NOx(ktons)		-	0.007	-	0.033	0.029	0.013	0.030
	NOx Emit Rate		#DIV/0!	0.150	-	0.152	0.151	0.147	0.150

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		2008	2009	2010	2011	2012	2013	2014
	NOx cost($000)	$ -	$ 20	$ -	$ 71	$ 58	$ 25	$ 56
	Total Emissions Cost ($000)	$ -	$ 20	$ 0	$ 75	$ 59	$ 25	$ 57
	Emit Cost per MWh	#DIV/0!	$ 3.01	$ 0.03	$ 2.33	$ 2.05	$ 1.90	$ 1.95

EntityName		2008	2009	2010	2011	2012	2013	2014
Reid GT	SO2(ktons)	-	-	-	-	-	0.000	-
	SO2 Emit Rate	#DIV/0!	-	-	-	-	0.001	-
	SO2 cost($000)	$ -	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	NOx(ktons)	-	0.004	0.004	0.006	0.009	0.011	0.007
	NOx Emit Rate	-	-	0.150	0.150	0.150	0.150	0.150
	NOx cost($000)	$ -	$ 10	$ 9	$ 13	$ 17	$ 22	$ 14
	Total Emissions Cost ($000)	$ -	$ 10	$ 9	$ 13	$ 17	$ 22	$ 14
	Emit Cost per MWh	#DIV/0!	$ 2.57	$ 2.09	$ 1.93	$ 1.54	$ 1.48	$ 1.49

EntityName		2008	2009	2010	2011	2012	2013	2014
Green 1	SO2(ktons)	-	2.133	1.929	2.089	1.972	2.066	1.771
	SO2 Emit Rate	#DIV/0!	0.195	0.195	0.195	0.195	0.195	0.195
	SO2 cost($000)	$ -	$ 299	$ 222	$ 1,813	$ 1,732	$ 1,807	$ 1,505
	NOx(ktons)	-	1.013	0.815	2.979	2.775	2.919	2.482
	NOx Emit Rate	-	0.093	0.082	0.278	0.274	0.276	0.273
	NOx cost($000)	$ -	$ 2,885	$ 1,964	$ 6,419	$ 5,508	$ 5,546	$ 4,738
	Total Emissions Cost ($000)	$ -	$ 3,183	$ 2,186	$ 8,232	$ 7,240	$ 7,354	$ 6,244
	Emit Cost per MWh	#DIV/0!	$ 1.63	$ 1.21	$ 4.22	$ 3.93	$ 3.82	$ 3.78

EntityName		2008	2009	2010	2011	2012	2013	2014
Green 2	SO2(ktons)	-	1.888	2.028	1.738	2.004	1.911	2.021
	SO2 Emit Rate	#DIV/0!	0.195	0.195	0.195	0.195	0.195	0.195
	SO2 cost($000)	$ -	$ 264	$ 233	$ 1,508	$ 1,760	$ 1,672	$ 1,718
	NOx(ktons)	-	0.990	0.975	2.428	2.812	2.674	2.838
	NOx Emit Rate	-	0.102	0.094	0.273	0.274	0.273	0.274
	NOx cost($000)	$ -	$ 2,818	$ 2,348	$ 5,233	$ 5,582	$ 5,081	$ 5,418
	Total Emissions Cost ($000)	$ -	$ 3,082	$ 2,581	$ 6,741	$ 7,341	$ 6,753	$ 7,136
	Emit Cost per MWh	#DIV/0!	$ 1.80	$ 1.38	$ 4.20	$ 3.97	$ 3.83	$ 3.83

		2008	2009	2010	2011	2012	2013	2014
Total	SO2(ktons)	-	20.430	21.740	20.538	21.040	20.628	21.140
	SO2 Emit Rate	#DIV/0!	0.293	0.302	0.296	0.299	0.293	0.299
	SO2 cost($000)	$ -	$ 2,860	$ 2,500	$ 17,827	$ 18,473	$ 18,049	$ 17,969
	NOx(ktons)	-	5.248	5.212	13.779	13.672	13.832	13.642
	NOx Emit Rate	-	0.075	0.072	0.199	0.194	0.197	0.193
	NOx cost($000)	$ -	$ 14,886	$ 12,557	$ 29,693	$ 27,138	$ 26,281	$ 26,042
	Total Emissions Cost ($000)	$ -	$ 17,746	$ 15,057	$ 47,520	$ 45,612	$ 44,330	$ 44,012
	Emit Cost per MWh	#DIV/0!	$ 1.42	$ 1.16	$ 3.81	$ 3.60	$ 3.47	$ 3.44
	SO2 Allowances (000 Tons)	52.487	52.487	52.487	52.487	52.487	52.487	52.487
	SO2 Allowance Price per Ton	$ 454	$ 140	$ 115	$ 434	$ 439	$ 438	$ 425
	SO2 Allowance Value ($000)	$ (23,829)	$ (7,348)	$ (6,036)	$ (22,779)	$ (23,042)	$ (22,963)	$ (22,307)
	NOx Allowances (000 Tons)	4.799	4.799	4.799	11.398	11.398	11.398	11.398
	NOx Allowance Price per Ton	$ 837	$ 700	$ 650	$ 2,120	$ 1,951	$ 1,909	$ 2,570
	NOx Allowance Value ($000)	#DIV/0!	$ (3,256)	$ (3,024)	$ (23,465)	$ (21,572)	$ (21,108)	$ (28,415)
	Net Emissions Costs	#DIV/0!	$ (3,835)	$ (2,986)	$ 628	$ 408	$ 218	$ 1,930

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EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
D B Wilson 1	SO2(ktons)	10.326	10.883	9.522	10.861	10.321	10.867	10.345	10.945	10.303
	SO2 Emit Rate	0.585	0.585	0.585	0.585	0.585	0.585	0.585	0.585	0.585
	SO2 cost($000)	$ 8,694	$ 8,979	$ 7,208	$ 7,668	$ 5,790	$ 4,488	$ 3,621	$ 3,305	$ 2,874
	NOx(ktons)	1.015	1.073	0.934	1.074	1.016	1.076	1.017	1.083	1.014
	NOx Emit Rate	0.058	0.058	0.057	0.058	0.058	0.058	0.057	0.058	0.058
	NOx cost($000)	$ 1,898	$ 1,876	$ 1,517	$ 1,685	$ 1,534	$ 1,636	$ 1,548	$ 1,651	$ 1,548
	Total Emissions Cost ($000)	$ 10,592	$ 10,855	$ 8,725	$ 9,353	$ 7,324	$ 6,124	$ 5,169	$ 4,957	$ 4,422
	Emit Cost per MWh	$ 3.29	$ 3.20	$ 2.94	$ 2.76	$ 2.28	$ 1.81	$ 1.60	$ 1.45	$ 1.38

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
HMPL 1	SO2(ktons)	2.029	2.190	2.007	2.186	1.896	2.012	2.069	2.193	2.005
	SO2 Emit Rate	0.330	0.330	0.330	0.330	0.330	0.330	0.330	0.330	0.330
	SO2 cost($000)	$ 1,709	$ 1,807	$ 1,519	$ 1,543	$ 1,064	$ 831	$ 724	$ 662	$ 559
	NOx(ktons)	0.514	0.556	0.507	0.555	0.479	0.510	0.524	0.556	0.505
	NOx Emit Rate	0.084	0.084	0.083	0.084	0.083	0.084	0.084	0.084	0.083
	NOx cost($000)	$ 960	$ 972	$ 823	$ 870	$ 724	$ 775	$ 798	$ 847	$ 772
	Total Emissions Cost ($000)	$ 2,669	$ 2,779	$ 2,342	$ 2,413	$ 1,787	$ 1,606	$ 1,522	$ 1,509	$ 1,331
	Emit Cost per MWh	$ 2.35	$ 2.27	$ 2.08	$ 1.97	$ 1.68	$ 1.43	$ 1.31	$ 1.23	$ 1.19

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
HMPL 2	SO2(ktons)	2.268	2.126	2.252	2.087	2.247	1.915	2.246	2.135	2.213
	SO2 Emit Rate	0.330	0.330	0.330	0.330	0.330	0.330	0.330	0.330	0.330
	SO2 cost($000)	$ 1,909	$ 1,754	$ 1,704	$ 1,473	$ 1,261	$ 791	$ 786	$ 645	$ 617
	NOx(ktons)	0.572	0.537	0.569	0.526	0.569	0.484	0.568	0.539	0.560
	NOx Emit Rate	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.084
	NOx cost($000)	$ 1,069	$ 938	$ 925	$ 825	$ 858	$ 736	$ 865	$ 821	$ 855
	Total Emissions Cost ($000)	$ 2,978	$ 2,693	$ 2,629	$ 2,299	$ 2,119	$ 1,527	$ 1,651	$ 1,466	$ 1,473
	Emit Cost per MWh	$ 2.35	$ 2.26	$ 2.09	$ 1.97	$ 1.69	$ 1.43	$ 1.31	$ 1.23	$ 1.19

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman 1	SO2(ktons)	0.746	0.738	0.641	0.740	0.746	0.704	0.737	0.738	0.698
	SO2 Emit Rate	0.114	0.114	0.114	0.114	0.114	0.114	0.114	0.114	0.114
	SO2 cost($000)	$ 628	$ 609	$ 485	$ 523	$ 418	$ 291	$ 258	$ 223	$ 195
	NOx(ktons)	2.094	2.072	1.808	2.079	2.092	1.976	2.071	2.074	1.968
	NOx Emit Rate	0.320	0.320	0.322	0.320	0.320	0.320	0.320	0.320	0.321
	NOx cost($000)	$ 3,913	$ 3,622	$ 2,938	$ 3,263	$ 3,159	$ 3,005	$ 3,154	$ 3,162	$ 3,006
	Total Emissions Cost ($000)	$ 4,541	$ 4,231	$ 3,423	$ 3,785	$ 3,577	$ 3,296	$ 3,412	$ 3,385	$ 3,201
	Emit Cost per MWh	$ 3.74	$ 3.53	$ 3.29	$ 3.14	$ 2.95	$ 2.88	$ 2.85	$ 2.82	$ 2.82

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman 2	SO2(ktons)	0.762	0.662	0.765	0.764	0.710	0.766	0.763	0.724	0.765
	SO2 Emit Rate	0.114	0.114	0.114	0.114	0.114	0.114	0.114	0.114	0.114
	SO2 cost($000)	$ 641	$ 547	$ 579	$ 539	$ 398	$ 317	$ 267	$ 219	$ 213
	NOx(ktons)	2.147	1.877	2.148	2.148	1.998	2.156	2.152	2.041	2.146
	NOx Emit Rate	0.321	0.323	0.320	0.321	0.321	0.321	0.322	0.321	0.320
	NOx cost($000)	$ 4,012	$ 3,280	$ 3,491	$ 3,370	$ 3,018	$ 3,280	$ 3,278	$ 3,113	$ 3,277
	Total Emissions Cost ($000)	$ 4,654	$ 3,827	$ 4,069	$ 3,909	$ 3,416	$ 3,596	$ 3,545	$ 3,331	$ 3,490
	Emit Cost per MWh	$ 4.19	$ 3.96	$ 3.65	$ 3.51	$ 3.30	$ 3.22	$ 3.19	$ 3.15	$ 3.13

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman 3	SO2(ktons)	0.713	0.748	0.757	0.717	0.748	0.754	0.659	0.759	0.761
	SO2 Emit Rate	0.114	0.114	0.114	0.114	0.114	0.114	0.114	0.114	0.114
	SO2 cost($000)	$ 600	$ 617	$ 573	$ 506	$ 420	$ 311	$ 231	$ 229	$ 212
	NOx(ktons)	1.907	2.005	2.030	1.922	2.007	2.023	1.773	2.028	2.039
	NOx Emit Rate	0.305	0.306	0.306	0.306	0.306	0.306	0.307	0.305	0.305
	NOx cost($000)	$ 3,564	$ 3,504	$ 3,299	$ 3,016	$ 3,031	$ 3,077	$ 2,700	$ 3,093	$ 3,113
	Total Operating Cost ($000)	$ 26,053	$ 27,631	$ 28,342	$ 27,248	$ 28,771	$ 29,337	$ 26,304	$ 30,261	$ 30,837
	Op Cost per MWh	$ 22.56	$ 22.81	$ 23.09	$ 23.45	$ 23.73	$ 24.02	$ 24.63	$ 24.62	$ 25.00
	Total Emissions Cost ($000)	$ 4,164	$ 4,121	$ 3,872	$ 3,522	$ 3,450	$ 3,388	$ 2,931	$ 3,322	$ 3,325
	Emit Cost per MWh	$ 3.61	$ 3.40	$ 3.15	$ 3.03	$ 2.85	$ 2.77	$ 2.74	$ 2.70	$ 2.70

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Reid ST	SO2(ktons)	0.000	0.000	0.001	-	0.000	0.000	0.000	0.002	0.000
	SO2 Emit Rate	0.003	0.003	0.005	#DIV/0!	0.003	0.003	0.003	0.006	0.003
	SO2 cost($000)	$ 0	$ 0	$ 0	$ -	$ 0	$ 0	$ 0	$ 0	$ 0
	NOx(ktons)	0.013	0.023	0.023	-	0.024	0.022	0.019	0.039	0.022
	NOx Emit Rate	0.153	0.150	0.153	#DIV/0!	0.150	0.150	0.151	0.154	0.150

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	NOx cost($000)	$ 25	$ 40	$ 37	$ -	$ 36	$ 34	$ 29	$ 60	$ 34
	Total Emissions Cost ($000)	$ 25	$ 40	$ 38	$ -	$ 36	$ 34	$ 29	$ 60	$ 34
	Emit Cost per MWh	$ 1.95	$ 1.79	$ 1.70	#DIV/0!	$ 1.54	$ 1.55	$ 1.56	$ 1.60	$ 1.55
EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Reid GT	SO2(ktons)	-	-	-	-	-	-	-	-	-
	SO2 Emit Rate	-	-	-	-	-	-	-	-	-
	SO2 cost($000)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	NOx(ktons)	0.007	0.007	0.009	0.008	0.007	0.007	0.007	0.007	0.007
	NOx Emit Rate	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150
	NOx cost($000)	$ 13	$ 13	$ 14	$ 13	$ 10	$ 10	$ 11	$ 11	$ 11
	Total Emissions Cost ($000)	$ 13	$ 13	$ 14	$ 13	$ 10	$ 10	$ 11	$ 11	$ 11
	Emit Cost per MWh	$ 1.45	$ 1.35	$ 1.26	$ 1.23	$ 1.17	$ 1.18	$ 1.18	$ 1.19	$ 1.19
EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Green 1	SO2(ktons)	2.098	1.910	2.079	1.926	2.096	1.952	2.087	1.752	2.077
	SO2 Emit Rate	0.195	0.195	0.195	0.195	0.195	0.195	0.195	0.195	0.195
	SO2 cost($000)	$ 1,767	$ 1,576	$ 1,574	$ 1,360	$ 1,176	$ 806	$ 731	$ 529	$ 579
	NOx(ktons)	2.955	2.695	2.934	2.700	2.955	2.754	2.944	2.462	2.935
	NOx Emit Rate	0.275	0.275	0.275	0.273	0.275	0.275	0.275	0.274	0.276
	NOx cost($000)	$ 5,522	$ 4,711	$ 4,767	$ 4,236	$ 4,462	$ 4,189	$ 4,484	$ 3,755	$ 4,482
	Total Emissions Cost ($000)	$ 7,289	$ 6,286	$ 6,341	$ 5,596	$ 5,637	$ 4,995	$ 5,215	$ 4,284	$ 5,061
	Emit Cost per MWh	$ 3.72	$ 3.53	$ 3.27	$ 3.11	$ 2.88	$ 2.74	$ 2.68	$ 2.62	$ 2.61
EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Green 2	SO2(ktons)	1.894	2.023	1.887	1.919	1.691	2.030	1.906	2.016	1.894
	SO2 Emit Rate	0.195	0.195	0.195	0.195	0.195	0.195	0.195	0.195	0.195
	SO2 cost($000)	$ 1,595	$ 1,669	$ 1,429	$ 1,354	$ 949	$ 838	$ 667	$ 609	$ 528
	NOx(ktons)	2.657	2.835	2.643	2.702	2.368	2.847	2.671	2.838	2.662
	NOx Emit Rate	0.274	0.273	0.273	0.275	0.273	0.274	0.273	0.275	0.274
	NOx cost($000)	$ 4,966	$ 4,955	$ 4,294	$ 4,239	$ 3,576	$ 4,331	$ 4,068	$ 4,327	$ 4,065
	Total Emissions Cost ($000)	$ 6,561	$ 6,625	$ 5,723	$ 5,594	$ 4,524	$ 5,169	$ 4,735	$ 4,936	$ 4,594
	Emit Cost per MWh	$ 3.75	$ 3.55	$ 3.29	$ 3.16	$ 2.90	$ 2.76	$ 2.69	$ 2.65	$ 2.63
		2015	2016	2017	2018	2019	2020	2021	2022	2023
Total	SO2(ktons)	20.836	21.282	19.910	21.199	20.456	21.001	20.812	21.263	20.716
	SO2 Emit Rate	0.294	0.300	0.290	0.300	0.296	0.297	0.296	0.300	0.294
	SO2 cost($000)	$ 17,544	$ 17,557	$ 15,072	$ 14,967	$ 11,476	$ 8,674	$ 7,284	$ 6,421	$ 5,780
	NOx(ktons)	13.880	13.680	13.603	13.714	13.515	13.854	13.746	13.666	13.859
	NOx Emit Rate	0.196	0.193	0.198	0.194	0.195	0.196	0.195	0.193	0.197
	NOx cost($000)	$ 25,941	$ 23,912	$ 22,105	$ 21,517	$ 20,407	$ 21,072	$ 20,935	$ 20,840	$ 21,162
	Total Emissions Cost ($000)	$ 43,485	$ 41,469	$ 37,178	$ 36,484	$ 31,883	$ 29,746	$ 28,219	$ 27,262	$ 26,942
	Emit Cost per MWh	$ 3.39	$ 3.22	$ 2.99	$ 2.84	$ 2.54	$ 2.33	$ 2.21	$ 2.12	$ 2.11
	SO2 Allowances (000 Tons)	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487
	SO2 Allowance Price per Ton	$ 294	$ 288	$ 265	$ 247	$ 196	$ 144	$ 122	$ 106	$ 98
	SO2 Allowance Value ($000)	$ (15,452)	$ (15,140)	$ (13,893)	$ (12,957)	$ (10,296)	$ (7,579)	$ (6,423)	$ (5,542)	$ (5,120)
	NOx Allowances (000 Tons)	9.285	9.285	8.832	8.638	8.494	8.289	8.054	7.832	7.760
	NOx Allowance Price per Ton	$ 3,071	$ 2,863	$ 2,764	$ 2,665	$ 2,564	$ 2,574	$ 2,578	$ 2,581	$ 2,584
	NOx Allowance Value ($000)	$ (27,468)	$ (25,606)	$ (23,470)	$ (22,112)	$ (20,904)	$ (20,458)	$ (19,884)	$ (19,335)	$ (19,172)
	Net Emissions Costs	$ 16,325	$ 15,113	$ 14,478	$ 15,644	$ 14,156	$ 15,542	$ 15,637	$ 16,039	$ 16,522

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EntityName		2009	2010	2011	2012	2013	2014
D B Wilson 1	Max Capacity(MW)	417	417	417	417	417	417
	Min Capacity(MW)	325	325	325	325	325	325
	Generation(GWh)	3,019	3,433	3,141	3,317	3,161	3,380
	Planned Outage Hours	1,248	168	672	168	672	168
	Forced Outage Hours	350	350	350	351	350	350
	FOR - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
	Num starts()	10	11	11	10	9	10
	Start Fuel used(GBtu)	66	72	67	52	56	54
	Start cost($000)	$ 3,542	$ 3,870	$ 3,656	$ 2,867	$ 3,160	$ 3,062
		101.08%	99.89%	97.33%	96.54%	97.97%	98.35%

EntityName		2009	2010	2011	2012	2013	2014
HMPL 1	Max Capacity(MW)	153	152	152	152	152	152
	Min Capacity(MW)	140	140	140	140	140	140
	Generation(GWh)	1,128	1,217	1,055	1,194	1,154	1,215
	Planned Outage Hours	744	-	1,176	-	504	-
	Forced Outage Hours	613	613	613	615	613	613
	FOR - %	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
	Num starts()	16	15	15	14	14	15
	Start Fuel used(GBtu)	30	28	28	26	26	28
	Start cost($000)	*$ 1,599*	*$ 1,529*	*$ 1,525*	*$ 1,435*	*$ 1,457*	*$ 1,617*
		99.76%	98.12%	99.45%	96.35%	99.20%	98.01%

EntityName		2009	2010	2011	2012	2013	2014
HMPL 2	Max Capacity(MW)	158	158	158	158	158	158
	Min Capacity(MW)	140	140	140	140	140	140
	Generation(GWh)	*1,271*	*1,184*	*1,252*	*1,095*	*1,245*	*1,182*
	Planned Outage Hours	-	504	-	1,176	-	504
	Forced Outage Hours	701	701	701	703	701	701
	FOR - %	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
	Num starts()	17	19	17	23	17	17
	Start Fuel used(GBtu)	35	37	33	44	34	34
	Start cost($000)	$ 1,859	$ 2,007	$ 1,826	$ 2,427	$ 1,882	$ 1,969
		99.78%	99.05%	98.17%	100.57%	97.69%	98.88%

EntityName		2009	2010	2011	2012	2013	2014
Coleman 1	Max Capacity(MW)	149	149	149	149	149	149
	Min Capacity(MW)	70	70	70	70	70	70
	Generation(GWh)	1,198	1,193	1,102	1,202	1,207	1,144
	Planned Outage Hours	-	-	600	-	-	504
	Forced Outage Hours	613	613	613	615	613	613
	FOR - %	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
	Num starts()	17	17	16	15	15	15
	Start Fuel used(GBtu)	26	26	25	24	24	24
	Start cost($000)	$ 567	$ 583	$ 572	$ 555	$ 551	$ 572
		98.71%	98.29%	97.99%	99.03%	99.46%	100.49%

EntityName		2009	2010	2011	2012	2013	2014
Coleman 2	Max Capacity(MW)	138	138	138	138	138	138
	Min Capacity(MW)	70	70	70	70	70	70
	Generation(GWh)	1,111	1,040	1,101	1,090	1,038	1,093
	Planned Outage Hours	-	600	-	-	600	-
	Forced Outage Hours	613	613	613	615	613	613
	FOR - %	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
	Num starts()	16	15	15	15	15	15
	Start Fuel used(GBtu)	25	22	24	25	24	25
	Start cost($000)	$ 545	$ 501	$ 548	$ 561	$ 567	$ 582
		98.82%	*99.81%*	*97.89%*	*96.99%*	*99.70%*	*97.19%*

EntityName		2009	2010	2011	2012	2013	2014
Coleman 3	Max Capacity(MW)	154	154	154	154	154	154
	Min Capacity(MW)	110	110	110	110	110	110
	Generation(GWh)	1,126	1,225	1,225	1,050	1,237	1,229
	Planned Outage Hours	*600*	-	-	*1,176*	-	-
	Forced Outage Hours	701	701	701	703	701	701
	FOR - %	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
	Num starts()	18	18	19	24	14	16
	Start Fuel used(GBtu)	25	25	27	32	20	22
	Start cost($000)	$ 551	$ 568	$ 619	$ 732	$ 467	$ 524
		97.99%	98.69%	98.70%	99.12%	99.68%	99.04%

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EntityName		2009	2010	2011	2012	2013	2014
Reid ST	Max Capacity(MW)	50	50	50	50	50	50
	Min Capacity(MW)	40	40	40	40	40	40
	Generation(GWh)	7	12	32	29	13	29
	Planned Outage Hours	-	504	-	-	-	-
	Forced Outage Hours	876	876	876	878	876	876
	FOR - %	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Num starts()	33	31	39	5	-	3
	Start Fuel used(GBtu)	30	29	36	5	-	2
	Start cost($000)	$ 1,602	$ 1,548	$ 1,887	$ 188	$ -	$ 101

EntityName		2009	2010	2011	2012	2013	2014
Reid GT	Max Capacity(MW)	65	65	65	65	65	65
	Min Capacity(MW)	-	-	-	-	-	-
	Generation(GWh)	4	4	7	11	15	9
	Planned Outage Hours						
	Forced Outage Hours	-	-	-	-	-	-
	FOR - %	-	-	-	-	-	-
	Num starts()	154	148	154	174	251	196
	Start Fuel used(GBtu)	-	-	-	-	-	-
	Start cost($000)	$ -	$ -	$ -	$ -	$ -	$ -

EntityName		2009	2010	2011	2012	2013	2014
Green 1	Max Capacity(MW)	231	231	231	231	231	231
	Min Capacity(MW)	180	180	180	180	180	180
	Generation(GWh)	1,956	1,800	1,950	1,840	1,927	1,652
	Planned Outage Hours	-	672	-	504	-	1,224
	Forced Outage Hours	289	289	289	290	289	289
	FOR - %	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%
	Num starts()	7	8	7	14	13	18
	Start Fuel used(GBtu)	17	20	18	31	23	43
	Start cost($000)	$ 919	$ 1,104	$ 979	$ 1,719	$ 1,316	$ 2,466
		99.96%	99.94%	99.65%	100.01%	98.48%	98.68%

EntityName		2009	2010	2011	2012	2013	2014
Green 2	Max Capacity(MW)	223	223	223	223	223	223
	Min Capacity(MW)	180	180	180	180	180	180
	Generation(GWh)	1,713	1,872	1,604	1,850	1,763	1,865
	Planned Outage Hours	792	-	1,176	-	504	-
	Forced Outage Hours	289	289	289	290	289	289
	FOR - %	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%
	Num starts()	8	7	6	13	14	11
	Start Fuel used(GBtu)	25	23	22	24	38	20
	Start cost($000)	$ 1,174	$ 1,107	$ 1,034	$ 1,271	$ 1,905	$ 1,089
		100.02%	99.12%	98.61%	97.92%	99.25%	98.74%

		2009	2010	2011	2012	2013	2014
Total	Max Capacity(MW)	1,738	1,737	1,737	1,737	1,737	1,737
	Min Capacity(MW)	1,255	1,255	1,255	1,255	1,255	1,255
	Generation(GWh)	12,531	12,980	12,468	12,679	12,762	12,799
	Planned Outage Hours	3,384	2,448	3,624	3,024	2,280	2,400
	Forced Outage Hours	5,046	5,046	5,046	5,060	5,046	5,046
	FOR - %	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%
	Num starts()	295	289	299	306	363	315
	Start Fuel used(GBtu)	279	283	281	262	246	253
	Start cost($000)	$ 12,359	$ 12,815	$ 12,646	$ 11,754	$ 11,304	$ 11,982

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EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
D B Wilson 1	Max Capacity(MW)	417	417	417	417	417	417	417	417	417
	Min Capacity(MW)	325	325	325	325	325	325	325	325	325
	Generation(GWh)	3,218	3,390	2,965	3,384	3,216	3,385	3,223	3,409	3,211
	Planned Outage Hours	672	168	1,224	168	672	168	672	168	672
	Forced Outage Hours	350	351	350	350	350	351	350	350	350
	FOR - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
	Num starts()	9	10	14	8	10	10	9	10	9
	Start Fuel used(GBtu)	50	50	77	46	55	53	50	52	55
	Start cost($000)	$ 2,905	$ 2,999	$ 4,740	$ 2,877	$ 3,547	$ 3,532	$ 3,375	$ 3,610	$ 3,903
		99.73%	98.65%	98.96%	98.46%	99.67%	98.51%	99.90%	99.19%	99.50%

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
HMPL 1	Max Capacity(MW)	152	152	152	152	152	152	152	152	152
	Min Capacity(MW)	140	140	140	140	140	140	140	140	140
	Generation(GWh)	1,136	1,226	1,124	1,224	1,061	1,127	1,158	1,227	1,122
	Planned Outage Hours	504	-	672	-	1,176	672	504	-	672
	Forced Outage Hours	613	615	613	613	613	615	613	613	613
	FOR - %	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
	Num starts()	15	15	14	14	21	14	15	14	14
	Start Fuel used(GBtu)	28	28	26	26	38	26	28	26	26
	Start cost($000)	$ 1,651	$ 1,689	$ 1,585	$ 1,625	$ 2,463	$ 1,712	$ 1,920	$ 1,807	$ 1,867
		97.67%	98.91%	98.78%	98.70%	100.02%	99.07%	99.57%	98.98%	98.64%

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
HMPL 2	Max Capacity(MW)	158	158	158	158	158	158	158	158	158
	Min Capacity(MW)	140	140	140	140	140	140	140	140	140
	Generation(GWh)	1,268	1,189	1,259	1,167	1,256	1,071	1,255	1,194	1,237
	Planned Outage Hours	-	504	-	672	-	1,176	-	504	-
	Forced Outage Hours	701	703	701	701	701	703	701	701	701
	FOR - %	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
	Num starts()	13	17	17	17	17	24	17	17	17
	Start Fuel used(GBtu)	25	34	33	34	34	46	34	34	34
	Start cost($000)	$ 1,449	$ 2,043	$ 2,026	$ 2,147	$ 2,172	$ 3,066	$ 2,276	$ 2,398	$ 2,413
		99.42%	99.49%	98.72%	99.82%	98.54%	98.37%	98.47%	99.88%	97.03%

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman 1	Max Capacity(MW)	149	149	149	149	149	149	149	149	149
	Min Capacity(MW)	70	70	70	70	70	70	70	70	70
	Generation(GWh)	1,213	1,200	1,042	1,204	1,212	1,144	1,198	1,199	1,136
	Planned Outage Hours	-	-	1,176	-	-	504	-	-	504
	Forced Outage Hours	613	615	613	613	613	615	613	613	613
	FOR - %	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
	Num starts()	15	15	20	15	15	15	15	15	15
	Start Fuel used(GBtu)	23	23	30	23	23	24	23	24	25
	Start cost($000)	$ 553	$ 567	$ 767	$ 605	$ 614	$ 659	$ 653	$ 683	$ 734
		99.92%	98.87%	100.28%	99.15%	99.83%	100.51%	98.72%	98.81%	99.74%

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman 2	Max Capacity(MW)	138	138	138	138	138	138	138	138	138
	Min Capacity(MW)	70	70	70	70	70	70	70	70	70
	Generation(GWh)	1,111	966	1,115	1,113	1,036	1,117	1,112	1,056	1,115
	Planned Outage Hours	-	1,176	-	-	600	-	-	504	-
	Forced Outage Hours	613	615	613	613	613	615	613	613	613
	FOR - %	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
	Num starts()	15	21	13	15	15	15	15	15	11
	Start Fuel used(GBtu)	24	31	20	24	25	24	24	25	18
	Start cost($000)	$ 586	$ 774	$ 496	$ 629	$ 655	$ 641	$ 683	$ 702	$ 524
		98.79%	100.44%	99.16%	99.03%	99.43%	99.41%	98.92%	100.16%	99.17%

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman 3	Max Capacity(MW)	154	154	154	154	154	154	154	154	154
	Min Capacity(MW)	110	110	110	110	110	110	110	110	110
	Generation(GWh)	1,155	1,211	1,227	1,162	1,212	1,222	1,068	1,229	1,233
	Planned Outage Hours	600	-	-	504	-	-	1,176	-	-
	Forced Outage Hours	701	703	701	701	701	703	701	701	701
	FOR - %	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
	Num starts()	16	16	16	17	17	17	24	16	17
	Start Fuel used(GBtu)	22	22	22	24	24	24	32	22	24
	Start cost($000)	$ 536	$ 551	$ 562	$ 628	$ 643	$ 659	$ 892	$ 638	$ 714
		100.51%	97.63%	98.89%	99.86%	97.68%	98.45%	100.75%	99.02%	99.38%

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EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Reid ST	Max Capacity(MW)	50	50	50	50	50	50	50	50	50
	Min Capacity(MW)	40	40	40	40	40	40	40	40	40
	Generation(GWh)	13	23	22	-	24	22	19	37	22
	Planned Outage Hours	-	-	-	-	-	-	-	-	-
	Forced Outage Hours	876	878	876	876	876	878	876	876	876
	FOR - %	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Num starts()	3	2	5	-	3	2	2	12	2
	Start Fuel used(GBtu)	2	2	5	-	2	2	2	11	2
	Start cost($000)	$ 103	$ 102	$ 215	$ -	$ 113	$ 113	$ 115	$ 575	$ 121

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Reid GT	Max Capacity(MW)	65	65	65	65	65	65	65	65	65
	Min Capacity(MW)	-	-	-	-	-	-	-	-	-
	Generation(GWh)	9	9	11	10	9	9	9	9	9
	Planned Outage Hours									
	Forced Outage Hours	-	-	-	-	-	-	-	-	-
	FOR - %	-	-	-	-	-	-	-	-	-
	Num starts()	173	173	182	121	199	186	229	173	155
	Start Fuel used(GBtu)	-	-	-	-	-	-	-	-	-
	Start cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Green 1	Max Capacity(MW)	231	231	231	231	231	231	231	231	231
	Min Capacity(MW)	180	180	180	180	180	180	180	180	180
	Generation(GWh)	1,957	1,782	1,940	1,797	1,955	1,822	1,947	1,635	1,938
	Planned Outage Hours	-	504	-	504	-	504	-	1,176	-
	Forced Outage Hours	289	290	289	289	289	290	289	289	289
	FOR - %	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%
	Num starts()	13	15	13	13	13	15	13	21	13
	Start Fuel used(GBtu)	20	34	22	30	20	34	22	49	23
	Start cost($000)	$ 1,155	$ 2,034	$ 1,364	$ 1,857	$ 1,274	$ 2,251	$ 1,468	$ 3,403	$ 1,636
		100.00%	96.84%	99.12%	97.65%	99.91%	98.99%	99.50%	97.00%	99.03%

EntityName		2015	2016	2017	2018	2019	2020	2021	2022	2023
Green 2	Max Capacity(MW)	223	223	223	223	223	223	223	223	223
	Min Capacity(MW)	180	180	180	180	180	180	180	180	180
	Generation(GWh)	1,748	1,867	1,742	1,770	1,561	1,873	1,759	1,860	1,748
	Planned Outage Hours	504	-	504	336	1,176	-	504	-	504
	Forced Outage Hours	289	290	289	289	289	290	289	289	289
	FOR - %	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%	3.3%
	Num starts()	15	11	15	13	21	12	14	12	15
	Start Fuel used(GBtu)	41	19	42	38	61	21	37	22	42
	Start cost($000)	$ 2,142	$ 1,076	$ 2,294	$ 2,098	$ 3,460	$ 1,351	$ 2,266	$ 1,476	$ 2,674
		98.41%	98.84%	98.04%	97.59%	95.94%	99.14%	98.99%	98.47%	98.39%

		2015	2016	2017	2018	2019	2020	2021	2022	2023
Total	Max Capacity(MW)	1,737	1,737	1,737	1,737	1,737	1,737	1,737	1,737	1,737
	Min Capacity(MW)	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255
	Generation(GWh)	12,826	12,863	12,446	12,831	12,541	12,791	12,749	12,856	12,771
	Planned Outage Hours	2,280	2,352	3,576	2,184	3,624	3,024	2,856	2,352	2,352
	Forced Outage Hours	5,046	5,060	5,046	5,046	5,046	5,060	5,046	5,046	5,046
	FOR - %	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%
	Num starts()	287	296	309	233	330	310	354	304	269
	Start Fuel used(GBtu)	236	244	278	245	283	255	253	265	249
	Start cost($000)	$ 11,080	$ 11,834	$ 14,050	$ 12,467	$ 14,942	$ 13,983	$ 13,649	$ 15,293	$ 14,587

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EntityName		2008	2009	2010	2011	2012	2013	2014	2015
D B Wilson 1	Max Capacity(MW)	419	417	417	417	417	417	417	417
	Min Capacity(MW)	200	325	325	325	325	325	325	325
	Generation(GWh)	-	3,019	3,433	3,141	3,317	3,161	3,380	3,218
	Annual Cap. Fac	0.00%	82 64%	93.98%	85 97%	90.57%	86.54%	92.53%	88.09%
	Fuel used(GBtu)	-	33,953	38,601	35,542	37,044	34,679	37,098	35,301
	Coal(Tons)	-	1,476,213	1,678,323	1,545,319	1,610,606	1,507,769	1,612,949	1.534,805
	Heat Rate	#DIV/0!	11 247	11.245	11 317	11.166	10 970	10.975	10 970
	Fuel cost($000)	$ -	$ 60,097	$ 65,622	$ 62.199	$ 90,758	$ 89.124	$ 66,776	$ 64,070
	Fuel Cost per MMBTu	#DIV/0!	$ 1 770	$ 1.700	$ 1.750	$ 2.450	$ 2 570	$ 1.800	$ 1 815
	VOM cost($000)	$ -	$ 7,352	$ 8,454	$ 10,678	$ 11,264	$ 10,685	$ 11,729	$ 11,488
	VOM per MWh	#DIV/0!	$ 2.435	$ 2.463	$ 3.400	$ 3.395	$ 3.380	$ 3.470	$ 3 570
	Num starts()	-	**10.17**	**11.00**	**10.83**	**10.03**	**9.18**	**10.03**	**9.20**
	Start Fuel used(GBtu)	-	66	72	67	52	56	54	50
	Start cost($000)	$ -	$ 3,542	$ 3,870	$ 3,656	$ 2,867	$ 3,160	$ 3,062	$ 2,905
	SO2(ktons)	-	9.932	11.292	10.397	10.836	10.144	10.852	10.326
	SO2 Emit Rate	#DIV/0!	0.59	0.59	0.59	0.59	0.59	0.59	0.59
	SO2 cost($000)	$ -	$ 1,390	$ 1,299	$ 9,025	$ 9,514	$ 8,876	$ 9,224	$ 8,694
0	NOx(ktons)	-	**0.384**	**0.406**	**1.092**	**1.070**	**0.998**	**1.072**	**1.015**
	NOx Emit Rate		0.02	0.02	0.06	0.06	0.06	0.06	0.06
	NOx cost($000)	$ -	$ 1,093	$ 978	$ 2,352	$ 2,123	$ 1,897	$ 2,047	$ 1,898
	Total Operating Cost ($000)	$ -	$ 70,991	$ 77,946	$ 76,533	$ 104,888	$ 102,969	$ 81,567	$ 78,463
	Op Cost per MWh	#DIV/0!	$ 23.52	$ 22.71	$ 24.37	$ 31.62	$ 32.57	$ 24.13	$ 24.38
	Total Emissions Cost ($000)	$ -	$ 2,483	$ 2,277	$ 11,376	$ 11,637	$ 10,773	$ 11,271	$ 10,592
	Emit Cost per MWh	#DIV/0!	$ 0.82	$ 0.66	$ 3.62	$ 3.51	$ 3.41	$ 3.33	$ 3.29
		#DIV/0!	348.44	351.82	337.52	285.88	344.34	305.41	315 62

EntityName		2008	2009	2010	2011	2012	2013	2014	2015
HMPL 1	Max Capacity(MW)	153	153	152	152	152	152	152	152
	Min Capacity(MW)	110	140	140	140	140	140	140	140
	Generation(GWh)	-	1,128	1,217	1,055	1,194	1,154	1,215	1,136
	Annual Cap. Fac	0.00%	84.30%	91.25%	79 13%	89.34%	86.55%	91.15%	85 22%
	Fuel used(GBtu)	-	12,204	13,167	11,417	12,928	12,491	13,156	12,298
	Coal(Tons)	-	530,591	572,467	496,400	562,095	543,093	571,994	534,695
	Heat Rate	#DIV/0!	10.822	10.823	10 821	10.823	10 824	10.826	10 824
	Fuel cost($000)	$ -	$ 23,187	$ 33,180	$ 29,114	$ 34,260	$ 34,725	$ 23,549	$ 22,186
	Fuel Cost per MMBTu	#DIV/0!	$ 1 900	$ 2.520	$ 2 550	$ 2.650	$ 2 780	$ 1.790	$ 1 804
	VOM cost($000)	$ -	$ 3,412	$ 3,977	$ 4,474	$ 5,208	$ 5,170	$ 5,590	$ 6,669
	VOM per MWh	#DIV/0!	$ 3.026	$ 3.269	$ 4.240	$ 4.360	$ 4.480	$ 4.600	$ 5.870
	Num starts()	-	**16.13**	**15.38**	**15.13**	**13.80**	**13.80**	**15.04**	**15.04**
	Start Fuel used(GBtu)	-	30	28	28	26	26	28	28
	Start cost($000)	$ -	$ 1,599	$ 1,529	$ 1,525	$ 1,435	$ 1,457	$ 1,617	$ 1,651
0	SO2(ktons)	-	**2.014**	**2.173**	**1.884**	**2.133**	**2.061**	**2.171**	**2.029**
	SO2 Emit Rate	#DIV/0!	0.33	0.33	0.33	0.33	0.33	0.33	0.33
	SO2 cost($000)	$ -	$ 282	$ 250	$ 1,635	$ 1,873	$ 1,804	$ 1,845	$ 1,709
0	NOx(ktons)	-	**0.198**	**0.201**	**0.488**	**0.542**	**0.521**	**0.552**	**0.514**
	NOx Emit Rate		0.03	0.03	0.09	0.08	0.08	0.08	0.08
	NOx cost($000)	$ -	$ 580	$ 484	$ 1,052	$ 1,075	$ 990	$ 1,053	$ 960
	Total Operating Cost ($000)	$ -	$ 28,198	$ 38,687	$ 35,112	$ 40,903	$ 41,352	$ 30,756	$ 30,506
	Op Cost per MWh	#DIV/0!	$ 25.01	$ 31.80	$ 33.28	$ 34.24	$ 35.83	$ 25.31	$ 26.85
	Total Emissions Cost ($000)	$ -	$ 862	$ 734	$ 2,688	$ 2,948	$ 2,794	$ 2,898	$ 2,669
	Emit Cost per MWh	#DIV/0!	$ 0.76	$ 0.60	$ 2.55	$ 2.47	$ 2.42	$ 2.39	$ 2.35

EntityName		2008	2009	2010	2011	2012	2013	2014	2015
HMPL 2	Max Capacity(MW)	159	158	158	158	158	158	158	158
	Min Capacity(MW)	110	140	140	140	140	140	140	140
	Generation(GWh)	-	1,271	1,184	1,252	1,095	1,245	1,182	1,268
	Annual Cap. Fac	0.00%	91 80%	85.43%	90 32%	78.79%	89.87%	85.28%	91 46%
	Fuel used(GBtu)	-	13,767	12,827	13,564	11,868	13,501	12,809	13,741
	Coal(Tons)	-	598,547	557,704	589,741	515,988	586,981	556,934	597,448
	Heat Rate	#DIV/0!	10 835	10.835	10 837	10.840	10 840	10.838	10 841
	Fuel cost($000)	$ -	$ 26,157	$ 32,325	$ 34,588	$ 31,449	$ 37,532	$ 22,929	$ 24,789
	Fuel Cost per MMBTu	#DIV/0!	$ 1 900	$ 2.520	$ 2 550	$ 2.650	$ 2 780	$ 1.790	$ 1 804
	VOM cost($000)	$ -	$ 3,801	$ 3,952	$ 5,307	$ 4,774	$ 5,580	$ 5,437	$ 7,440
	VOM per MWh	#DIV/0!	$ 2.992	$ 3.339	$ 4.240	$ 4.360	$ 4.480	$ 4.600	$ 5 870
	Num starts()	-	**17.29**	**18.58**	**16 58**	**22.74**	**17 05**	**17.05**	**12.75**
	Start Fuel used(GBtu)	-	35	37	33	44	34	34	25
	Start cost($000)	$ -	$ 1,859	$ 2,007	$ 1,826	$ 2,427	$ 1,882	$ 1,969	$ 1,449
0	SO2(ktons)	-	**2.272**	**2.117**	**2.238**	**1.959**	**2.228**	**2.114**	**2.268**
	SO2 Emit Rate	#DIV/0!	0.33	0.33	0.33	0.33	0.33	0.33	0.33
	SO2 cost($000)	$ -	$ 318	$ 243	$ 1,943	$ 1,720	$ 1,949	$ 1,797	$ 1,909
0	NOx(ktons)	-	**0.207**	**0.206**	**0.568**	**0.494**	**0.563**	**0.534**	**0.572**
	NOx Emit Rate		0.03	0.03	0.08	0.08	0.08	0.08	0.08
	NOx cost($000)	$ -	$ 591	$ 496	$ 1,224	$ 980	$ 1,069	$ 1,019	$ 1,069
	Total Operating Cost ($000)	$ -	$ 31,817	$ 38,284	$ 41,722	$ 38,650	$ 44,993	$ 30,334	$ 33,679
	Op Cost per MWh	#DIV/0!	$ 25.04	$ 32.34	$ 33.33	$ 35.30	$ 36.13	$ 25.67	$ 26.57
	Total Emissions Cost ($000)	$ -	$ 909	$ 739	$ 3,167	$ 2,700	$ 3,018	$ 2,816	$ 2,978
	Emit Cost per MWh	#DIV/0!	$ 0.72	$ 0.62	$ 2.53	$ 2.47	$ 2.42	$ 2.38	$ 2.35

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EntityName		2008	2009	2010	2011	2012	2013	2014	2015
Coleman 1	Max Capacity(MW)	150	149	149	149	149	149	149	149
	Min Capacity(MW)	70	70	70	70	70	70	70	70
	Generation(GWh)	-	1,198	1,193	1,102	1,202	1,207	1,144	1,213
	Annual Cap. Fac	0.00%	91 80%	91.41%	84.42%	91.83%	92 50%	87.67%	92 92%
	Fuel used(GBtu)	-	12,853	12,800	11,884	12,967	13,028	12,348	13,090
	Coal(Tons)	-	558,821	556,517	516,694	563,766	566,453	536,879	569,113
	Heat Rate	#DIV/0!	10 727	10.728	10 785	10.789	10 791	10.791	10 792
	Fuel cost($000)	$ -	$ 30,847	$ 31,744	$ 30,304	$ 36,047	$ 37,913	$ 23,388	$ 25,001
	Fuel Cost per MMBTu	#DIV/0!	$ 2 400	$ 2.480	$ 2 550	$ 2.780	$ 2 910	$ 1.894	$ 1 910
	VOM cost($000)	$ -	$ 1,390	$ 1,432	$ 1,377	$ 1,538	$ 1,594	$ 1,545	$ 1,686
	VOM per MWh	#DIV/0!	$ 1 160	$ 1.200	$ 1 250	$ 1.280	$ 1 320	$ 1.350	$ 1 390
	Num starts()	-	17	17	16	15	15	15	15
	Start Fuel used(GBtu)	-	26	26	25	24	24	24	23
	Start cost($000)	$ -	$ 567	$ 583	$ 572	$ 555	$ 551	$ 572	$ 553
	SO2(ktons)	-	0.733	0.730	0.677	0.739	0.743	0.704	0.746
	SO2 Emit Rate	#DIV/0!	0.11	0.11	0.11	0.11	0.11	0.11	0.11
	SO2 cost($000)	$ -	$ 103	$ 84	$ 588	$ 649	$ 650	$ 598	$ 628
	NOx(ktons)	-	0.846	0.858	1 913	2.082	2 087	1.976	2.094
	NOx Emit Rate		0.132	0.134	0 322	0.321	0 320	0.320	0 320
	NOx cost($000)	$ -	$ 2,408	$ 2,067	$ 4,122	$ 4,134	$ 3,965	$ 3,772	$ 3,913
	Total Operating Cost ($000)	$ -	$ 32,804	$ 33,758	$ 32,253	$ 38,141	$ 40,058	$ 25,504	$ 27,240
	Op Cost per MWh	#DIV/0!	$ 27.38	$ 28.29	$ 29.27	$ 31.73	$ 33.18	$ 22.29	$ 22.46
	Total Emissions Cost ($000)	$ -	$ 2,510	$ 2,151	$ 4,710	$ 4,783	$ 4,615	$ 4,370	$ 4,541
	Emit Cost per MWh	#DIV/0!	$ 2.10	$ 1.80	$ 4.27	$ 3.98	$ 3.82	$ 3.82	$ 3.74

EntityName		2008	2009	2010	2011	2012	2013	2014	2015
Coleman 2	Max Capacity(MW)	139	138	138	138	138	138	138	138
	Min Capacity(MW)	70	70	70	70	70	70	70	70
	Generation(GWh)	-	1,111	1,040	1,101	1,090	1,038	1,093	1,111
	Annual Cap. Fac	0.00%	91 91%	85.99%	91 04%	89.94%	85 89%	90.39%	91 88%
	Fuel used(GBtu)	-	13,369	12,508	13,237	13,115	12,493	13,144	13,363
	Coal(Tons)	-	581,246	543,816	575,501	570,236	543,177	571,487	581,001
	Heat Rate	#DIV/0!	12 033	12.032	12 028	12.030	12 032	12.029	12 031
	Fuel cost($000)	$ -	$ 32,085	$ 31,019	$ 33,753	$ 36,461	$ 36,355	$ 24,895	$ 25,523
	Fuel Cost per MMBTu	#DIV/0!	$ 2 400	$ 2.480	$ 2 550	$ 2.780	$ 2 910	$ 1.894	$ 1 910
	VOM cost($000)	$ -	$ 1,289	$ 1,247	$ 1,376	$ 1,428	$ 1,402	$ 1,508	$ 1.577
	VOM per MWh	#DIV/0!	$ 1 160	$ 1.200	$ 1 250	$ 1.310	$ 1 350	$ 1.380	$ 1 420
	Num starts()	-	16	15	15	15	15	15	15
	Start Fuel used(GBtu)	-	25	22	24	25	24	25	24
	Start cost($000)	$ -	$ 545	$ 501	$ 548	$ 561	$ 567	$ 582	$ 586
	SO2(ktons)	-	0.762	0.713	0.755	0.748	0.712	0.749	0.762
	SO2 Emit Rate	#DIV/0!	0.11	0.11	0.11	0.11	0.11	0.11	0.11
	SO2 cost($000)	$ -	$ 107	$ 82	$ 655	$ 656	$ 623	$ 637	$ 641
	NOx(ktons)	-	0 873	0.883	2 134	2.110	2 005	2.117	2 147
	NOx Emit Rate		0 131	0.141	0.322	0.322	0.321	0.322	0.321
	NOx cost($000)	$ -	$ 2,487	$ 2,126	$ 4,599	$ 4,189	$ 3,810	$ 4,040	$ 4,012
	Total Operating Cost ($000)	$ -	$ 33,919	$ 32,768	$ 35,677	$ 38,450	$ 38,323	$ 26,985	$ 27,686
	Op Cost per MWh	#DIV/0!	$ 30.53	$ 31.52	$ 32.42	$ 35.27	$ 36.91	$ 24.70	$ 24.93
	Total Emissions Cost ($000)	$ -	$ 2,593	$ 2,208	$ 5,254	$ 4,845	$ 4,433	$ 4,677	$ 4,654
	Emit Cost per MWh	#DIV/0!	$ 2.33	$ 2.12	$ 4.77	$ 4.44	$ 4.27	$ 4.28	$ 4.19

EntityName		2008	2009	2010	2011	2012	2013	2014	2015
Coleman 3	Max Capacity(MW)	155	154	154	154	154	154	154	154
	Min Capacity(MW)	110	110	110	110	110	110	110	110
	Generation(GWh)	-	1,126	1,225	1,225	1,050	1,237	1,229	1,155
	Annual Cap. Fac	0.00%	83 44%	90.79%	90 80%	77.65%	91 70%	91.12%	85 59%
	Fuel used(GBtu)	-	12,176	13,249	13,258	11,371	13,398	13,308	12,501
	Coal(Tons)	-	529,400	576,047	576,428	494,391	582,521	578,596	543,527
	Heat Rate	#DIV/0!	10 817	10.817	10 823	10.826	10 830	10.826	10 827
	Fuel cost($000)	$ -	$ 29,223	$ 32,858	$ 33,808	$ 31,611	$ 38,988	$ 25,205	$ 23,877
	Fuel Cost per MMBTu	#DIV/0!	$ 2.400	$ 2.480	$ 2 550	$ 2.780	$ 2 910	$ 1.894	$ 1 910
	VOM cost($000)	$ -	$ 1,306	$ 1,470	$ 1,531	$ 1,376	$ 1,670	$ 1,696	$ 1,640
	VOM per MWh	#DIV/0!	$ 1 160	$ 1.200	$ 1 250	$ 1.310	$ 1 350	$ 1.380	$ 1.420
	Num starts()	-	18	18	19	24	14	16	16
	Start Fuel used(GBtu)	-	25	25	27	32	20	22	22
	Start cost($000)	$ -	$ 551	$ 568	$ 619	$ 732	$ 467	$ 524	$ 536
	SO2(ktons)	-	0.694	0.755	0.755	0.648	0.764	0.759	0.713
	SO2 Emit Rate	#DIV/0!	0 11	0.11	0.11	0.11	0.11	0.11	0.11
	SO2 cost($000)	$ -	$ 97	$ 87	$ 656	$ 569	$ 668	$ 645	$ 600
	NOx(ktons)	-	0.726	0.866	2 138	1.749	2 040	2.035	1 907
	NOx Emit Rate		0.119	0.131	0 323	0.308	0.305	0.306	0.305
	NOx cost($000)	$ -	$ 1,996	$ 2,085	$ 4,608	$ 3,472	$ 3,876	$ 3,885	$ 3,564
	Total Operating Cost ($000)	$ -	$ 31,079	$ 34,895	$ 35,958	$ 33,719	$ 41,125	$ 27,426	$ 26,053
	Op Cost per MWh	#DIV/0!	$ 27.61	$ 28.49	$ 29.35	$ 32.10	$ 33.24	$ 22.31	$ 22.56
	Total Emissions Cost ($000)	$ -	$ 2,093	$ 2,172	$ 5,264	$ 4,041	$ 4,544	$ 4,529	$ 4,164
	Emit Cost per MWh	#DIV/0!	$ 1.86	$ 1.77	$ 4.30	$ 3.85	$ 3.67	$ 3.68	$ 3.61

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EntityName		2008	2009	2010	2011	2012	2013	2014	2015
Reid ST	Max Capacity(MW)	50	50	50	50	50	50	50	50
	Min Capacity(MW)	40	40	40	40	40	40	40	40
	Generation(GWh)	-	7	12	32	29	13	29	13
	Annual Cap. Fac	0.00%	1 52%	2.77%	7 36%	6.51%	3 00%	6.67%	2 90%
	Fuel used(GBtu)	-	90	165	437	387	178	396	172
	Coal(Tons)	-	75						
	Heat Rate	#DIV/0!	13 564	13.571	13 545	13.556	13 572	13.547	13 510
	Fuel cost($000)	$ -	$ 792	$ 1,551	$ 3,776	$ 3,518	$ 1,683	$ 3,300	$ 1.473
	Fuel Cost per MMBTu	#DIV/0!	$ 8 785	$ 9.420	$ 8 646	$ 9.081	$ 9.451	$ 8.344	$ 8 576
	VOM cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	VOM per MWh	#DIV/0!	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Num starts()	-	33	31	39	5	-	3	3
	Start Fuel used(GBtu)	-	30	29	36	5	-	2	2
	Start cost($000)	$ -	$ 1,602	$ 1,548	$ 1,887	$ 188	$ -	$ 101	$ 103
	SO2(ktons)	-	0 004	0.004	0.005	0.001	0.000	0.000	0.000
	SO2 Emit Rate	#DIV/0!	4.50	4.50	0 02	0.00	0 00	0.00	0.00
	SO2 cost($000)	$ -	$ 1	$ 0	$ 4	$ 1	$ 0	$ 0	$ 0
	NOx(ktons)	-	0.007	-	0.033	0.029	0.013	0.030	0.013
	NOx Emit Rate	#DIV/0!	0 15	-	0 15	0.15	0 15	0.15	0 15
	NOx cost($000)	$ -	$ 20	$ -	$ 71	$ 58	$ 25	$ 56	$ 25
	Total Operating Cost ($000)	$ -	$ 2,394	$ 3,099	$ 5,663	$ 3,706	$ 1,683	$ 3,401	$ 1,576
	Op Cost per MWh	#DIV/0!	$ 360.30	$ 255.47	$ 175 64	$ 129.66	$ 128 27	$ 116.48	$ 123 95
	Total Emissions Cost ($000)	$ -	$ 20	$ 0	$ 75	$ 59	$ 25	$ 57	$ 25
	Emit Cost per MWh	#DIV/0!	$ 3.01	$ 0.03	$ 2.33	$ 2.05	$ 1.90	$ 1.95	$ 1.95

EntityName		2008	2009	2010	2011	2012	2013	2014	2015
Reid GT	Max Capacity(MW)	65	65	65	65	65	65	65	65
	Min Capacity(MW)	-	-	-	-	-	-	-	-
	Generation(GWh)	-	4	4	7	11	15	9	9
	Annual Cap. Fac	0.00%	0 70%	0.75%	1 19%	1.97%	2 58%	1.63%	1 55%
	Fuel used(GBtu)	-	48	51	80	133	175	111	104
	Coal(Tons)								
	Heat Rate	#DIV/0!	12 046	11.931	11 905	11.785	11 899	11.947	11 831
	Fuel cost($000)	$ -	$ 418	$ 448	$ 698	$ 1,132	$ 1,475	$ 931	$ 902
	Fuel Cost per MMBTu	#DIV/0!	$ 8 733	$ 8.814	$ 8 675	$ 8.522	$ 8.432	$ 8.412	$ 8 650
	VOM cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	VOM per MWh	#DIV/0!	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Num starts()	-	154	148	154	174	251	196	173
	Start Fuel used(GBtu)	-	-	-	-	-	-	-	-
	Start cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SO2(ktons)	-	-	-	-	-	0.000	-	-
	SO2 Emit Rate	#DIV/0!	-	-	-	-	0.00	-	-
	SO2 cost($000)	$ -	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	NOx(ktons)	-	0.004	0.004	0.006	0.009	0.011	0.007	0.007
	NOx Emit Rate			0.15	0 15	0.15	0 15	0.15	0.15
	NOx cost($000)	$ -	$ 10	$ 9	$ 13	$ 17	$ 22	$ 14	$ 13
	Total Operating Cost ($000)	$ -	$ 418	$ 448	$ 698	$ 1,132	$ 1,475	$ 931	$ 902
	Op Cost per MWh	#DIV/0!	$ 105.20	$ 105.15	$ 103 27	$ 100.43	$ 100.33	$ 100.50	$ 102 34
	Total Emissions Cost ($000)	$ -	$ 10	$ 9	$ 13	$ 17	$ 22	$ 14	$ 13
	Emit Cost per MWh	#DIV/0!	$ 2.57	$ 2.09	$ 1.93	$ 1.54	$ 1.48	$ 1.49	$ 1.45

EntityName		2008	2009	2010	2011	2012	2013	2014	2015
Green 1	Max Capacity(MW)	231	231	231	231	231	231	231	231
	Min Capacity(MW)	180	180	180	180	180	180	180	180
	Generation(GWh)	-	1,956	1,800	1,950	1,840	1,927	1,652	1,957
	Annual Cap. Fac	0.00%	96 66%	88.97%	96 36%	90.69%	95.23%	81.64%	96 70%
	Fuel used(GBtu)	-	21,874	19,784	21,426	20,229	21,186	18,159	21,520
	Coal(Tons)	-	1,093,713	989,179	1,071.290	1,011,426	1,059,279	907,961	1,075,977
	Heat Rate	#DIV/0!	11 183	10.988	10 988	10.992	10 994	10.992	10 997
	Fuel cost($000)	$ -	$ 36,749	$ 40,358	$ 46,922	$ 43,491	$ 52,964	$ 32,632	$ 38,993
	Fuel Cost per MMBTu	#DIV/0!	$ 1 680	$ 2.040	$ 2 190	$ 2.150	$ 2 500	$ 1.797	$ 1 812
	VOM cost($000)	$ -	$ 7,559	$ 7,490	$ 8,872	$ 8,594	$ 9.250	$ 8,144	$ 13,071
	VOM per MWh	#DIV/0!	$ 3 865	$ 4.160	$ 4.550	$ 4.670	$ 4 800	$ 4.930	$ 6 680
	Num starts()	-	7	8	7	14	13	18	13
	Start Fuel used(GBtu)	-	17	20	18	31	23	43	20
	Start cost($000)	$ -	$ 919	$ 1,104	$ 979	$ 1,719	$ 1,316	$ 2,466	$ 1.155
	SO2(ktons)	-	2.133	1.929	2.089	1.972	2.066	1.771	2.098
	SO2 Emit Rate	#DIV/0!	0.20	0.20	0.20	0.20	0.20	0.20	0.20
	SO2 cost($000)	$ -	$ 299	$ 222	$ 1.813	$ 1,732	$ 1,807	$ 1,505	$ 1,767
	NOx(ktons)	-	1.013	0.815	2.979	2.775	2.919	2.482	2.955
	NOx Emit Rate		0.09	0.08	0.28	0.27	0.28	0.27	0.27
	NOx cost($000)	$ -	$ 2,885	$ 1,964	$ 6,419	$ 5,508	$ 5,546	$ 4,738	$ 5,522
	Total Operating Cost ($000)	$ -	$ 45,227	$ 48,952	$ 56,774	$ 53,805	$ 63,530	$ 43,242	$ 53,220
	Op Cost per MWh	#DIV/0!	$ 23.12	$ 27.19	$ 29.12	$ 29.24	$ 32.97	$ 26.18	$ 27.20
	Total Emissions Cost ($000)	$ -	$ 3,183	$ 2,186	$ 8,232	$ 7,240	$ 7,354	$ 6,244	$ 7,289
	Emit Cost per MWh	#DIV/0!	$ 1.63	$ 1.21	$ 4.22	$ 3.93	$ 3.82	$ 3.78	$ 3.72

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EntityName		2008	2009	2010	2011	2012	2013	2014	2015
Green 2	Max Capacity(MW)	223	223	223	223	223	223	223	223
	Min Capacity(MW)	180	180	180	180	180	180	180	180
	Generation(GWh)	-	1.713	1,872	1.604	1,850	1.763	1,865	1,748
	Annual Cap. Fac	0.00%	87 68%	95.85%	82 12%	94.42%	90.26%	95.49%	89 50%
	Fuel used(GBtu)	-	19.358	20,800	17,820	20,557	19,594	20,731	19,425
	Coal(Tons)	-	967,890	1,040,003	891,016	1,027,860	979,697	1,036,537	971,248
	Heat Rate	#DIV/0!	11 302	11.109	11 109	11.115	11 112	11.114	11 110
	Fuel cost($000)	$ -	$ 32,521	$ 42,432	$ 39,026	$ 44,198	$ 48,985	$ 37,253	$ 35,198
	Fuel Cost per MMBTu	#DIV/0!	$ 1 680	$ 2.040	$ 2 190	$ 2.150	$ 2 500	$ 1.797	$ 1 812
	VOM cost($000)	$ -	$ 6,609	$ 7,789	$ 7,299	$ 8,637	$ 8,464	$ 9,196	$ 11.679
	VOM per MWh	#DIV/0!	$ 3 859	$ 4.160	$ 4.550	$ 4.670	$ 4 800	$ 4.930	$ 6 680
	Num starts()	-	8	7	6	13	14	11	15
	Start Fuel used(GBtu)	-	25	23	22	24	38	20	41
	Start cost($000)	$ -	$ 1,174	$ 1,107	$ 1,034	$ 1,271	$ 1.905	$ 1,089	$ 2,142
	SO2(ktons)	-	1.888	2.028	1.738	2.004	1.911	2.021	1.894
	SO2 Emit Rate	#DIV/0!	0.20	0.19	0.20	0.20	0.20	0.20	0.20
	SO2 cost($000)	$ -	$ 264	$ 233	$ 1,508	$ 1,760	$ 1,672	$ 1,718	$ 1,595
	NOx(ktons)	-	0.990	0.975	2.428	2.812	2.674	2.838	2.657
	NOx Emit Rate		0.10	0.09	0.27	0.27	0.27	0.27	0.27
	NOx cost($000)	$ -	$ 2,818	$ 2,348	$ 5,233	$ 5,582	$ 5,081	$ 5,418	$ 4,966
	Total Operating Cost ($000)	$ -	$ 40,304	$ 51,328	$ 47,359	$ 54,107	$ 59,354	$ 47,538	$ 49,019
	Op Cost per MWh	#DIV/0!	$ 23.53	$ 27.41	$ 29.52	$ 29.25	$ 33.66	$ 25.49	$ 28.04
	Total Emissions Cost ($000)	$ -	$ 3,082	$ 2,581	$ 6,741	$ 7,341	$ 6,753	$ 7,136	$ 6,561
	Emit Cost per MWh	#DIV/0!	$ 1.80	$ 1.38	$ 4.20	$ 3.97	$ 3.83	$ 3.83	$ 3.75

		2008	2009	2010	2011	2012	2013	2014	2015
Total	Max Capacity(MW)	1,743	1,738	1,737	1,737	1,737	1,737	1,737	1.737
	Min Capacity(MW)	1,070	1,255	1,255	1,255	1,255	1,255	1,255	1,255
	Generation(GWh)	-	12,531	12,980	12,468	12,679	12,762	12,799	12,826
	Annual Cap. Fac	0.00%	82 32%	85.28%	81 92%	83.08%	83 85%	84.10%	84 28%
	Fuel used(GBtu)	-	139,691	143,951	138,665	140,599	140,722	141,260	141,514
	Coal(Tons)	-	6,336,497	6,514,057	6,262,389	6,356,369	6,368,971	6,373,339	6,407,813
	Heat Rate	#DIV/0!	11 147	11.090	11 122	11.089	11 027	11.037	11.033
	Fuel cost($000)	$ -	$ 272,074	$ 311,537	$ 314,188	$ 352,926	$ 379,743	$ 260,858	$ 262.013
	Fuel Cost per MMBTu	#DIV/0!	$ 1 948	$ 2.164	$ 2 266	$ 2.510	$ 2 699	$ 1.847	$ 1 852
	VOM cost($000)	$ -	$ 32,718	$ 35,812	$ 40,914	$ 42,820	$ 43,814	$ 44,845	$ 55,250
	VOM per MWh	#DIV/0!	$ 2 611	$ 2.759	$ 3 282	$ 3.377	$ 3 433	$ 3.504	$ 4 308
	Num starts()	-	295	289	299	306	363	315	287
	Start Fuel used(GBtu)	-	279	283	281	262	246	253	236
	Start cost($000)	$ -	$ 12,359	$ 12,815	$ 12,646	$ 11,754	$ 11,304	$ 11,982	$ 11,080
	SO2(ktons)	-	20.430	21.740	20.538	21.040	20.628	21.140	20.836
	SO2 Emit Rate	#DIV/0!	0.29	0.30	0.30	0.30	0.29	0.30	0.29
	SO2 cost($000)	$ -	$ 2,860	$ 2,500	$ 17,827	$ 18,473	$ 18,049	$ 17,969	$ 17,544
	NOx(ktons)	-	5 248	5.212	13.779	13.672	13.832	13.642	13.880
	NOx Emit Rate		0 075	0.07	0.20	0.19	0.20	0.19	0.20
	NOx cost($000)	$ -	$ 14,886	$ 12,557	$ 29,693	$ 27,138	$ 26,281	$ 26,042	$ 25,941
	Total Operating Cost ($000)	$ -	$ 317,152	$ 360,164	$ 367,748	$ 407,500	$ 434,861	$ 317,686	$ 328,344
	Op Cost per MWh	#DIV/0!	$ 25.31	$ 27.75	$ 29.50	$ 32.14	$ 34.08	$ 24.82	$ 25.60
	Total Emissions Cost ($000)	$ -	$ 17,746	$ 15,057	$ 47,520	$ 45,612	$ 44,330	$ 44,012	$ 43,485
	Emit Cost per MWh	#DIV/0!	$ 1.42	$ 1.16	$ 3.81	$ 3.60	$ 3.47	$ 3.44	$ 3.39

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EntityName		2016	2017	2018	2019	2020	2021	2022	2023
D B Wilson 1	Max Capacity(MW)	417	417	417	417	417	417	417	417
	Min Capacity(MW)	325	325	325	325	325	325	325	325
	Generation(GWh)	3,390	2,965	3,384	3,216	3,385	3,223	3,409	3,211
	Annual Cap. Fac	92.54%	81 17%	92.63%	88 04%	92.41%	88 24%	93.32%	87 89%
	Fuel used(GBtu)	37,206	32,550	37,130	35,285	37,151	35,366	37,416	35,220
	Coal(Tons)	1,617,640	1,415.201	1,614,347	1.534,116	1,615,270	1,537,664	1,626,778	1,531,301
	Heat Rate	10.976	10 977	10.973	10 972	10.975	10.972	10.976	10 970
	Fuel cost($000)	$ 68,198	$ 60,314	$ 69,545	$ 66,794	$ 71,070	$ 68,469	$ 73,260	$ 69,771
	Fuel Cost per MMBTu	$ 1.833	$ 1 853	$ 1.873	$ 1 893	$ 1.913	$ 1 936	$ 1.958	$ 1 981
	VOM cost($000)	$ 12,441	$ 11,179	$ 13,095	$ 12.800	$ 13,845	$ 13,538	$ 14,693	$ 14,223
	VOM per MWh	$ 3.670	$ 3.770	$ 3.870	$ 3.980	$ 4.090	$ 4 200	$ 4.310	$ 4 430
	Num starts()	**10.03**	**14.23**	**8.32**	**10.03**	**10.03**	**9 20**	**10.03**	**9 18**
	Start Fuel used(GBtu)	50	77	46	55	53	50	52	55
	Start cost($000)	$ 2,999	$ 4,740	$ 2,877	$ 3,547	$ 3,532	$ 3,375	$ 3,610	$ 3,903
	SO2(ktons)	10.883	9.522	10.861	10.321	10.867	10.345	10.945	10.303
	SO2 Emit Rate	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59
	SO2 cost($000)	$ 8,979	$ 7,208	$ 7,668	$ 5,790	$ 4,488	$ 3,621	$ 3,305	$ 2,874
0	NOx(ktons)	**1.073**	**0 934**	**1.074**	**1 016**	**1.076**	**1 017**	**1.083**	**1.014**
	NOx Emit Rate	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
	NOx cost($000)	$ 1,876	$ 1,517	$ 1,685	$ 1,534	$ 1,636	$ 1,548	$ 1,651	$ 1,548
	Total Operating Cost ($000)	$ 83,637	$ 76,233	$ 85,517	$ 83,141	$ 88,447	$ 85,383	$ 91,564	$ 87,896
	Op Cost per MWh	$ 24.67	$ 25.71	$ 25.27	$ 25.85	$ 26.13	$ 26.49	$ 26.86	$ 27.38
	Total Emissions Cost ($000)	$ 10,855	$ 8,725	$ 9,353	$ 7,324	$ 6,124	$ 5,169	$ 4,957	$ 4,422
	Emit Cost per MWh	$ 3.20	$ 2.94	$ 2.76	$ 2.28	$ 1.81	$ 1.60	$ 1.45	$ 1.38
		299.04	333.10	345.64	353.75	352.20	366.74	360.06	425.37

EntityName		2016	2017	2018	2019	2020	2021	2022	2023
HMPL 1	Max Capacity(MW)	152	152	152	152	152	152	152	152
	Min Capacity(MW)	140	140	140	140	140	140	140	140
	Generation(GWh)	1,226	1,124	1,224	1,061	1,127	1,158	1,227	1,122
	Annual Cap. Fac	91.72%	84 28%	91.80%	79.59%	84.29%	86 87%	92.05%	84 17%
	Fuel used(GBtu)	13,274	12,164	13,247	11,488	12,194	12,537	13,289	12,148
	Coal(Tons)	577,143	528,875	575,974	499,477	530,194	545,066	577,791	528,166
	Heat Rate	10.826	10 825	10.824	10 826	10.822	10 824	10.828	10 825
	Fuel cost($000)	$ 24,186	$ 22,406	$ 24,653	$ 21,620	$ 23,182	$ 24.120	$ 25,861	$ 23,919
	Fuel Cost per MMBTu	$ 1.822	$ 1 842	$ 1.861	$ 1 882	$ 1.901	$ 1 924	$ 1.946	$ 1 969
	VOM cost($000)	$ 7,394	$ 6,967	$ 7,796	$ 6,940	$ 7,572	$ 8,003	$ 8,714	$ 8,181
	VOM per MWh	$ 6.030	$ 6.200	$ 6.370	$ 6 540	$ 6.720	$ 6.910	$ 7.100	$ 7.290
	Num starts()	**15.04**	**13.76**	**13.76**	**21.35**	**13.76**	**15 04**	**13.80**	**13 89**
	Start Fuel used(GBtu)	28	26	26	38	26	28	26	26
	Start cost($000)	$ 1,689	$ 1,585	$ 1,625	$ 2,463	$ 1,712	$ 1,920	$ 1,807	$ 1,867
0	SO2(ktons)	**2.190**	**2.007**	**2.186**	**1.896**	**2.012**	**2.069**	**2.193**	**2.005**
	SO2 Emit Rate	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
	SO2 cost($000)	$ 1,807	$ 1,519	$ 1,543	$ 1,064	$ 831	$ 724	$ 662	$ 559
0	NOx(ktons)	**0.556**	**0.507**	**0.555**	**0.479**	**0.510**	**0 524**	**0.556**	**0.505**
	NOx Emit Rate	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
	NOx cost($000)	$ 972	$ 823	$ 870	$ 724	$ 775	$ 798	$ 847	$ 772
	Total Operating Cost ($000)	$ 33,269	$ 30,959	$ 34,075	$ 31,024	$ 32,466	$ 34,043	$ 36,382	$ 33,967
	Op Cost per MWh	$ 27.13	$ 27.55	$ 27.84	$ 29.24	$ 28.81	$ 29.39	$ 29.64	$ 30.27
	Total Emissions Cost ($000)	$ 2,779	$ 2,342	$ 2,413	$ 1,787	$ 1,606	$ 1,522	$ 1,509	$ 1,331
	Emit Cost per MWh	$ 2.27	$ 2.08	$ 1.97	$ 1.68	$ 1.43	$ 1.31	$ 1.23	$ 1.19

EntityName		2016	2017	2018	2019	2020	2021	2022	2023
HMPL 2	Max Capacity(MW)	158	158	158	158	158	158	158	158
	Min Capacity(MW)	140	140	140	140	140	140	140	140
	Generation(GWh)	1,189	1,259	1,167	1,256	1,071	1,255	1,194	1,237
	Annual Cap. Fac	85.55%	90 82%	84.18%	90 66%	77.06%	90.60%	86.14%	89.27%
	Fuel used(GBtu)	12,885	13,645	12,645	13,619	11,606	13,609	12,940	13,409
	Coal(Tons)	560,235	593,241	549,785	592,109	504,590	591,708	562,596	582.997
	Heat Rate	10.838	10 840	10.840	10 839	10.837	10 840	10.839	10 839
	Fuel cost($000)	$ 23,477	$ 25,133	$ 23,532	$ 25,630	$ 22,062	$ 26,184	$ 25,181	$ 26,402
	Fuel Cost per MMBTu	$ 1.822	$ 1 842	$ 1.861	$ 1 882	$ 1.901	$ 1 924	$ 1.946	$ 1 969
	VOM cost($000)	$ 7,169	$ 7,804	$ 7,431	$ 8,217	$ 7,196	$ 8,675	$ 8,476	$ 9,019
	VOM per MWh	$ 6.030	$ 6.200	$ 6.370	$ 6.540	$ 6.720	$ 6.910	$ 7.100	$ 7.290
	Num starts()	**17.05**	**17 05**	**17.05**	**17 05**	**24.19**	**17.05**	**17.05**	**17 05**
	Start Fuel used(GBtu)	34	33	34	34	46	34	34	34
	Start cost($000)	$ 2,043	$ 2,026	$ 2,147	$ 2,172	$ 3,066	$ 2,276	$ 2,398	$ 2,413
0	SO2(ktons)	**2.126**	**2 252**	**2.087**	**2.247**	**1.915**	**2 246**	**2.135**	**2.213**
	SO2 Emit Rate	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
	SO2 cost($000)	$ 1,754	$ 1,704	$ 1,473	$ 1,261	$ 791	$ 786	$ 645	$ 617
0	NOx(ktons)	**0.537**	**0.569**	**0.526**	**0 569**	**0.484**	**0.568**	**0.539**	**0 560**
	NOx Emit Rate	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
	NOx cost($000)	$ 938	$ 925	$ 825	$ 858	$ 736	$ 865	$ 821	$ 855
	Total Operating Cost ($000)	$ 32,689	$ 34,963	$ 33,111	$ 36,019	$ 32,325	$ 37,136	$ 36,055	$ 37,834
	Op Cost per MWh	$ 27.50	$ 27.78	$ 28.38	$ 28.67	$ 30.19	$ 29.58	$ 30.20	$ 30.58
	Total Emissions Cost ($000)	$ 2,693	$ 2,629	$ 2,299	$ 2,119	$ 1,527	$ 1.651	$ 1,466	$ 1,473
	Emit Cost per MWh	$ 2.26	$ 2.09	$ 1.97	$ 1.69	$ 1.43	$ 1.31	$ 1.23	$ 1.19

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EntityName		2016	2017	2018	2019	2020	2021	2022	2023
Coleman 1	Max Capacity(MW)	149	149	149	149	149	149	149	149
	Min Capacity(MW)	70	70	70	70	70	70	70	70
	Generation(GWh)	1,200	1,042	1,204	1,212	1,144	1,198	1,199	1,136
	Annual Cap. Fac	91.68%	79.79%	92.21%	92 84%	87.43%	91 81%	91.89%	87 02%
	Fuel used(GBtu)	12,950	11,238	12,989	13,078	12,348	12,932	12,943	12,253
	Coal(Tons)	563,044	488,625	564,718	568,613	536,879	562,255	562,727	532,750
	Heat Rate	10.792	10 790	10.791	10 792	10.791	10.791	10.791	10 788
	Fuel cost($000)	$ 24,994	$ 21,937	$ 25,639	$ 26,117	$ 24,919	$ 26,420	$ 26,753	$ 25,634
	Fuel Cost per MMBTu	$ 1.930	$ 1 952	$ 1.974	$ 1 997	$ 2.018	$ 2 043	$ 2.067	$ 2 092
	VOM cost($000)	$ 1,716	$ 1,531	$ 1,817	$ 1,878	$ 1,819	$ 1,953	$ 2,015	$ 1,965
	VOM per MWh	$ 1.430	$ 1 470	$ 1.510	$ 1 550	$ 1.590	$ 1 630	$ 1.680	$ 1 730
	Num starts()	15	20	15	15	15	15	15	15
	Start Fuel used(GBtu)	23	30	23	23	24	23	24	25
	Start cost($000)	$ 567	$ 767	$ 605	$ 614	$ 659	$ 653	$ 683	$ 734
	SO2(ktons)	0.738	0.641	0.740	0.746	0.704	0.737	0.738	0.698
	SO2 Emit Rate	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
	SO2 cost($000)	$ 609	$ 485	$ 523	$ 418	$ 291	$ 258	$ 223	$ 195
	NOx(ktons)	2.072	1 808	2.079	2 092	1.976	2 071	2.074	1 968
	NOx Emit Rate	0.320	0 322	0.320	0 320	0.320	0 320	0.320	0.321
	NOx cost($000)	$ 3,622	$ 2,938	$ 3,263	$ 3,159	$ 3,005	$ 3,154	$ 3,162	$ 3,006
	Total Operating Cost ($000)	$ 27,276	$ 24,236	$ 28,062	$ 28,609	$ 27,398	$ 29,026	$ 29,451	$ 28,333
	Op Cost per MWh	$ 22.73	$ 23.27	$ 23.32	$ 23.61	$ 23.94	$ 24.22	$ 24.55	$ 24.94
	Total Emissions Cost ($000)	$ 4,231	$ 3,423	$ 3,785	$ 3,577	$ 3,296	$ 3,412	$ 3,385	$ 3,201
	Emit Cost per MWh	$ 3.53	$ 3.29	$ 3.14	$ 2.95	$ 2.88	$ 2.85	$ 2.82	$ 2.82

EntityName		2016	2017	2018	2019	2020	2021	2022	2023
Coleman 2	Max Capacity(MW)	138	138	138	138	138	138	138	138
	Min Capacity(MW)	70	70	70	70	70	70	70	70
	Generation(GWh)	966	1,115	1,113	1,036	1,117	1,112	1,056	1,115
	Annual Cap. Fac	79.69%	92 22%	92.10%	85 66%	92.18%	91 99%	87.39%	92 23%
	Fuel used(GBtu)	11,622	13,414	13,398	12,460	13,445	13,378	12,710	13,416
	Coal(Tons)	505,289	583,233	582,528	541,749	584,586	581,663	552,592	583,315
	Heat Rate	12.031	12 033	12.034	12 033	12.033	12 030	12.031	12 033
	Fuel cost($000)	$ 22,430	$ 26,185	$ 26,448	$ 24,883	$ 27,133	$ 27,332	$ 26,271	$ 28,067
	Fuel Cost per MMBTu	$ 1.930	$ 1 952	$ 1.974	$ 1 997	$ 2.018	$ 2 043	$ 2.067	$ 2 092
	VOM cost($000)	$ 1,410	$ 1,672	$ 1,715	$ 1,636	$ 1,821	$ 1,857	$ 1,817	$ 1,973
	VOM per MWh	$ 1.460	$ 1 500	$ 1.540	$ 1 580	$ 1.630	$ 1 670	$ 1.720	$ 1 770
	Num starts()	21	13	15	15	15	15	15	11
	Start Fuel used(GBtu)	31	20	24	25	24	24	25	18
	Start cost($000)	$ 774	$ 496	$ 629	$ 655	$ 641	$ 683	$ 702	$ 524
	SO2(ktons)	0.662	0.765	0.764	0.710	0.766	0.763	0.724	0.765
	SO2 Emit Rate	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
	SO2 cost($000)	$ 547	$ 579	$ 539	$ 398	$ 317	$ 267	$ 219	$ 213
	NOx(ktons)	1.877	2 148	2.148	1 998	2.156	2 152	2.041	2 146
	NOx Emit Rate	0.323	0 320	0.321	0.321	0.321	0 322	0.321	0 320
	NOx cost($000)	$ 3,280	$ 3,491	$ 3,370	$ 3,018	$ 3,280	$ 3,278	$ 3,113	$ 3,277
	Total Operating Cost ($000)	$ 24,614	$ 28,353	$ 28,791	$ 27,175	$ 29,595	$ 29,872	$ 28,790	$ 30,564
	Op Cost per MWh	$ 25.48	$ 25.43	$ 25.86	$ 26.24	$ 26.49	$ 26.86	$ 27.25	$ 27.41
	Total Emissions Cost ($000)	$ 3,827	$ 4,069	$ 3,909	$ 3,416	$ 3,596	$ 3,545	$ 3,331	$ 3,490
	Emit Cost per MWh	$ 3.96	$ 3.65	$ 3.51	$ 3.30	$ 3.22	$ 3.19	$ 3.15	$ 3.13

EntityName		2016	2017	2018	2019	2020	2021	2022	2023
Coleman 3	Max Capacity(MW)	154	154	154	154	154	154	154	154
	Min Capacity(MW)	110	110	110	110	110	110	110	110
	Generation(GWh)	1,211	1,227	1,162	1,212	1,222	1,068	1,229	1,233
	Annual Cap. Fac	89.55%	90 98%	86.13%	89 87%	90.30%	79 16%	91.10%	91.43%
	Fuel used(GBtu)	13,115	13,288	12,579	13,126	13,225	11,565	13,309	13,356
	Coal(Tons)	570,214	577,757	546,905	570,700	574,991	502,839	578,646	580,686
	Heat Rate	10.826	10 827	10.826	10.827	10.826	10 829	10.829	10 829
	Fuel cost($000)	$ 25,312	$ 25,939	$ 24,831	$ 26,213	$ 26,688	$ 23,628	$ 27,509	$ 27,940
	Fuel Cost per MMBTu	$ 1.930	$ 1 952	$ 1.974	$ 1 997	$ 2.018	$ 2 043	$ 2.067	$ 2.092
	VOM cost($000)	$ 1,769	$ 1,841	$ 1,789	$ 1,916	$ 1,991	$ 1,783	$ 2,114	$ 2,183
	VOM per MWh	$ 1.460	$ 1 500	$ 1.540	$ 1 580	$ 1.630	$ 1 670	$ 1.720	$ 1 770
	Num starts()	16	16	17	17	17	24	16	17
	Start Fuel used(GBtu)	22	22	24	24	24	32	22	24
	Start cost($000)	$ 551	$ 562	$ 628	$ 643	$ 659	$ 892	$ 638	$ 714
	SO2(ktons)	0.748	0.757	0.717	0.748	0.754	0.659	0.759	0.761
	SO2 Emit Rate	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
	SO2 cost($000)	$ 617	$ 573	$ 506	$ 420	$ 311	$ 231	$ 229	$ 212
	NOx(ktons)	2.005	2 030	1.922	2 007	2.023	1 773	2.028	2 039
	NOx Emit Rate	0.306	0 306	0.306	0 306	0.306	0 307	0.305	0 305
	NOx cost($000)	$ 3,504	$ 3,299	$ 3,016	$ 3,031	$ 3,077	$ 2,700	$ 3,093	$ 3,113
	Total Operating Cost ($000)	$ 27,631	$ 28,342	$ 27,248	$ 28,771	$ 29,337	$ 26,304	$ 30,261	$ 30,837
	Op Cost per MWh	$ 22.81	$ 23.09	$ 23.45	$ 23.73	$ 24.02	$ 24.63	$ 24.62	$ 25.00
	Total Emissions Cost ($000)	$ 4,121	$ 3,872	$ 3,522	$ 3,450	$ 3,388	$ 2,931	$ 3,322	$ 3,325
	Emit Cost per MWh	$ 3.40	$ 3.15	$ 3.03	$ 2.85	$ 2.77	$ 2.74	$ 2.70	$ 2.70

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EntityName		2016	2017	2018	2019	2020	2021	2022	2023
Reid ST	Max Capacity(MW)	50	50	50	50	50	50	50	50
	Min Capacity(MW)	40	40	40	40	40	40	40	40
	Generation(GWh)	23	22	-	24	22	19	37	22
	Annual Cap. Fac.	5.12%	5 09%	0.00%	5 37%	5.02%	4 25%	8.55%	5 00%
	Fuel used(GBtu)	305	302	-	318	298	252	507	297
	Coal(Tons)								
	Heat Rate	13,560	13 537	#DIV/0!	13 531	13,548	13 566	13,552	13 555
	Fuel cost($000)	$ 2,689	$ 2,808	$ -	$ 2,943	$ 2,774	$ 2,418	$ 5,009	$ 3,095
	Fuel Cost per MMBTu	$ 8.811	$ 9 311	#DIV/0!	$ 9.251	$ 9.296	$ 9 579	$ 9.875	$ 10 434
	VOM cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	VOM per MWh	$ -	$ -	#DIV/0!	$ -	$ -	$ -	$ -	$ -
	Num starts()	2	5	-	3	2	2	12	2
	Start Fuel used(GBtu)	2	5	-	2	2	2	11	2
	Start cost($000)	$ 102	$ 215	$ -	$ 113	$ 113	$ 115	$ 575	$ 121
	SO2(ktons)	0.000	0.001	-	0.000	0.000	0.000	0.002	0.000
	SO2 Emit Rate	0.00	0 00	#DIV/0!	0.00	0.00	0 00	0.01	0.00
	SO2 cost($000)	$ 0	$ 0	$ -	$ 0	$ 0	$ 0	$ 0	$ 0
	NOx(ktons)	0.023	0.023	-	0.024	0.022	0.019	0.039	0.022
	NOx Emit Rate	0.15	0.15	#DIV/0!	0 15	0.15	0 15	0.15	0 15
	NOx cost($000)	$ 40	$ 37	$ -	$ 36	$ 34	$ 29	$ 60	$ 34
	Total Operating Cost ($000)	$ 2,790	$ 3,024	$ -	$ 3,056	$ 2,887	$ 2,534	$ 5,584	$ 3,217
	Op Cost per MWh	$ 123.99	$ 135 70	#DIV/0!	$ 129 98	$ 131.06	$ 136.15	$ 149.19	$ 146 98
	Total Emissions Cost ($000)	$ 40	$ 38	$ -	$ 36	$ 34	$ 29	$ 60	$ 34
	Emit Cost per MWh	$ 1.79	$ 1.70	#DIV/0!	$ 1.54	$ 1.55	$ 1.56	$ 1.60	$ 1.55

EntityName		2016	2017	2018	2019	2020	2021	2022	2023
Reid GT	Max Capacity(MW)	65	65	65	65	65	65	65	65
	Min Capacity(MW)	-	-	-	-	-	-	-	-
	Generation(GWh)	9	11	10	9	9	9	9	9
	Annual Cap. Fac	1.64%	1 93%	1.84%	1 54%	1.49%	1 58%	1.57%	1 59%
	Fuel used(GBtu)	110	130	125	103	101	106	106	107
	Coal(Tons)								
	Heat Rate	11,772	11 819	11,901	11 825	11,916	11 764	11,935	11 789
	Fuel cost($000)	$ 967	$ 1,154	$ 1,127	$ 951	$ 952	$ 1,020	$ 1,053	$ 1,085
	Fuel Cost per MMBTu	$ 8.749	$ 8 890	$ 9.044	$ 9.204	$ 9.390	$ 9 646	$ 9.896	$ 10 168
	VOM cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	VOM per MWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Num starts()	173	182	121	199	186	229	173	155
	Start Fuel used(GBtu)	-	-	-	-	-	-	-	-
	Start cost($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SO2(ktons)	-	-	-	-	-	-	-	-
	SO2 Emit Rate	-	-	-	-	-	-	-	-
	SO2 cost($000)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	NOx(ktons)	0.007	0.009	0.008	0.007	0.007	0.007	0.007	0.007
	NOx Emit Rate	0.15	0 15	0.15	0 15	0.15	0 15	0.15	0 15
	NOx cost($000)	$ 13	$ 14	$ 13	$ 10	$ 10	$ 11	$ 11	$ 11
	Total Operating Cost ($000)	$ 967	$ 1,154	$ 1,127	$ 951	$ 952	$ 1,020	$ 1,053	$ 1,085
	Op Cost per MWh	$ 102.99	$ 105.08	$ 107.64	$ 108 83	$ 111.89	$ 113 48	$ 118.10	$ 119 87
	Total Emissions Cost ($000)	$ 13	$ 14	$ 13	$ 10	$ 10	$ 11	$ 11	$ 11
	Emit Cost per MWh	$ 1.35	$ 1.26	$ 1.23	$ 1.17	$ 1.18	$ 1.18	$ 1.19	$ 1.19

EntityName		2016	2017	2018	2019	2020	2021	2022	2023
Green 1	Max Capacity(MW)	231	231	231	231	231	231	231	231
	Min Capacity(MW)	180	180	180	180	180	180	180	180
	Generation(GWh)	1,782	1,940	1,797	1,955	1,822	1,947	1,635	1,938
	Annual Cap. Fac	87.82%	95 85%	88.81%	96 61%	89.78%	96 21%	80.78%	95 76%
	Fuel used(GBtu)	19,586	21,325	19,754	21,497	20,022	21,406	17,969	21,301
	Coal(Tons)	979,276	1,066,246	987,704	1,074,845	1,001,121	1,070,298	898,461	1,065,074
	Heat Rate	10,991	10 994	10,992	10 996	10,991	10 995	10,993	10 993
	Fuel cost($000)	$ 34,921	$ 39,451	$ 36,940	$ 40,629	$ 38,243	$ 41,356	$ 35,130	$ 42,134
	Fuel Cost per MMBTu	$ 1.783	$ 1 850	$ 1.870	$ 1 890	$ 1.910	$ 1 932	$ 1.955	$ 1 978
	VOM cost($000)	$ 12,224	$ 13,675	$ 13,029	$ 14,564	$ 13,936	$ 15,303	$ 13,207	$ 16,083
	VOM per MWh	$ 6.860	$ 7 050	$ 7.250	$ 7 450	$ 7.650	$ 7 860	$ 8.080	$ 8 300
	Num starts()	15	13	13	13	15	13	21	13
	Start Fuel used(GBtu)	34	22	30	20	34	22	49	23
	Start cost($000)	$ 2,034	$ 1,364	$ 1,857	$ 1,274	$ 2,251	$ 1,468	$ 3,403	$ 1,636
	SO2(ktons)	1.910	2.079	1.926	2.096	1.952	2.087	1.752	2.077
	SO2 Emit Rate	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
	SO2 cost($000)	$ 1,576	$ 1,574	$ 1,360	$ 1,176	$ 806	$ 731	$ 529	$ 579
	NOx(ktons)	2.695	2.934	2.700	2.955	2.754	2.944	2.462	2.935
	NOx Emit Rate	0.28	0.28	0.27	0.27	0.28	0.28	0.27	0.28
	NOx cost($000)	$ 4,711	$ 4,767	$ 4,236	$ 4,462	$ 4,189	$ 4,484	$ 3,755	$ 4,482
	Total Operating Cost ($000)	$ 49,180	$ 54,490	$ 51,826	$ 56,468	$ 54,429	$ 58,127	$ 51,740	$ 59,854
	Op Cost per MWh	$ 27.60	$ 28.09	$ 28.84	$ 28.88	$ 29.88	$ 29.86	$ 31.65	$ 30.89
	Total Emissions Cost ($000)	$ 6,286	$ 6,341	$ 5,596	$ 5,637	$ 4,995	$ 5,215	$ 4,284	$ 5,061
	Emit Cost per MWh	$ 3.53	$ 3.27	$ 3.11	$ 2.88	$ 2.74	$ 2.68	$ 2.62	$ 2.61

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EntityName		2016	2017	2018	2019	2020	2021	2022	2023
Green 2	Max Capacity(MW)	223	223	223	223	223	223	223	223
	Min Capacity(MW)	180	180	180	180	180	180	180	180
	Generation(GWh)	1,867	1,742	1,770	1,561	1,873	1,759	1,860	1,748
	Annual Cap. Fac	95.30%	89.16%	90.63%	79.89%	95.59%	90.02%	95.22%	89.48%
	Fuel used(GBtu)	20,750	19,355	19,675	17,344	20,816	19,543	20,674	19,424
	Coal(Tons)	1,037,522	967.733	983,764	867,178	1,040,808	977,149	1,033,688	971,204
	Heat Rate	11.115	11 112	11.114	11 113	11.117	11 113	11.115	11 112
	Fuel cost($000)	$ 36,998	$ 35.806	$ 36,793	$ 32.779	$ 39,759	$ 37,757	$ 40,417	$ 38,421
	Fuel Cost per MMBTu	$ 1.783	$ 1 850	$ 1.870	$ 1 890	$ 1.910	$ 1 932	$ 1.955	$ 1 978
	VOM cost($000)	$ 12,807	$ 12,279	$ 12,835	$ 11,627	$ 14,325	$ 13,823	$ 15,029	$ 14,508
	VOM per MWh	$ 6.860	$ 7 050	$ 7.250	$ 7.450	$ 7.650	$ 7 860	$ 8.080	$ 8.300
	Num starts()	11	15	13	21	12	14	12	15
	Start Fuel used(GBtu)	19	42	38	61	21	37	22	42
	Start cost($000)	$ 1,076	$ 2,294	$ 2,098	$ 3,460	$ 1,351	$ 2,266	$ 1,476	$ 2,674
	SO2(ktons)	2.023	1.887	1.919	1.691	2.030	1.906	2.016	1.894
	SO2 Emit Rate	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
	SO2 cost($000)	$ 1,669	$ 1,429	$ 1,354	$ 949	$ 838	$ 667	$ 609	$ 528
	NOx(ktons)	2.835	2.643	2.702	2.368	2.847	2.671	2.838	2.662
	NOx Emit Rate	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
	NOx cost($000)	$ 4,955	$ 4,294	$ 4,239	$ 3,576	$ 4,331	$ 4,068	$ 4,327	$ 4,065
	Total Operating Cost ($000)	$ 50,881	$ 50,380	$ 51,726	$ 47,866	$ 55,435	$ 53,846	$ 56,922	$ 55,603
	Op Cost per MWh	$ 27.25	$ 28.92	$ 29.22	$ 30.67	$ 29.60	$ 30.62	$ 30.60	$ 31.81
	Total Emissions Cost ($000)	$ 6,625	$ 5,723	$ 5,594	$ 4,524	$ 5,169	$ 4,735	$ 4,936	$ 4,594
	Emit Cost per MWh	$ 3.55	$ 3.29	$ 3.16	$ 2.90	$ 2.76	$ 2.69	$ 2.65	$ 2.63

		2016	2017	2018	2019	2020	2021	2022	2023
Total	Max Capacity(MW)	1,737	1,737	1,737	1,737	1,737	1,737	1,737	1,737
	Min Capacity(MW)	1,255	1,255	1,255	1,255	1,255	1,255	1,255	1,255
	Generation(GWh)	12,863	12,446	12,831	12,541	12,791	12,749	12,856	12,771
	Annual Cap. Fac	84.28%	81 78%	84.31%	82.40%	83.81%	83 76%	84.47%	83 91%
	Fuel used(GBtu)	141,804	137,410	141,542	138,318	141,208	140,695	141,863	140,931
	Coal(Tons)	6,410,364	6,220,910	6,405,725	6,248,787	6,388,439	6,368,643	6,393,278	6,375,494
	Heat Rate	11.024	11 041	11.031	11 029	11.040	11 036	11.035	11.035
	Fuel cost($000)	$ 264,171	$ 261,135	$ 269,508	$ 268,560	$ 276,781	$ 278,705	$ 286,444	$ 286,469
	Fuel Cost per MMBTu	$ 1.863	$ 1 900	$ 1.904	$ 1 942	$ 1.960	$ 1 981	$ 2.019	$ 2 033
	VOM cost($000)	$ 56,929	$ 56,948	$ 59,508	$ 59,578	$ 62,506	$ 64,936	$ 66,065	$ 68,135
	VOM per MWh	$ 4.426	$ 4 576	$ 4.638	$ 4.751	$ 4.887	$ 5 094	$ 5.139	$ 5 335
	Num starts()	296	309	233	330	310	354	304	269
	Start Fuel used(GBtu)	244	278	245	283	255	253	265	249
	Start cost($000)	$ 11,834	$ 14,050	$ 12,467	$ 14,942	$ 13,983	$ 13,649	$ 15,293	$ 14,587
	SO2(ktons)	21.282	19.910	21.199	20.456	21.001	20.812	21.263	20.716
	SO2 Emit Rate	0.30	0.29	0.30	0.30	0.30	0.30	0.30	0.29
	SO2 cost($000)	$ 17,557	$ 15,072	$ 14,967	$ 11,476	$ 8,674	$ 7.284	$ 6,421	$ 5,780
	NOx(ktons)	13.680	13.603	13.714	13.515	13.854	13.746	13.666	13.859
	NOx Emit Rate	0.19	0.20	0.19	0.20	0.20	0.20	0.19	0.20
	NOx cost($000)	$ 23,912	$ 22,105	$ 21,517	$ 20,407	$ 21,072	$ 20,935	$ 20,840	$ 21,162
	Total Operating Cost ($000)	$ 332,934	$ 332,133	$ 341,483	$ 343,080	$ 353,271	$ 357,290	$ 367,803	$ 369,191
	Op Cost per MWh	$ 25.88	$ 26.69	$ 26.61	$ 27.36	$ 27.62	$ 28.03	$ 28.61	$ 28.91
	Total Emissions Cost ($000)	$ 41,469	$ 37,178	$ 36,484	$ 31,883	$ 29,746	$ 28,219	$ 27,262	$ 26,942
	Emit Cost per MWh	$ 3.22	$ 2.99	$ 2.84	$ 2.54	$ 2.33	$ 2.21	$ 2.12	$ 2.11

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
BREC_TA	Off Peak																	
	On Peak																	
BREC_TA Total			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KY	Off Peak																	
	On Peak																	
KY Total			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W-ECAR	Model Off Peak			$ 49.83	$ 50.97	$ 51.36	$ 52.73	$ 54.30	$ 44.62	$ 45.28	$ 45.93	$ 46.15	$ 47.19	$ 47.99	$ 47.46	$ 49.81	$ 49.42	$ 50.31
	Model On Peak			$ 69.37	$ 78.64	$ 72.10	$ 76.37	$ 77.67	$ 73.16	$ 73.86	$ 74.57	$ 75.85	$ 76.82	$ 79.78	$ 80.41	$ 83.38	$ 84.21	$ 86.67
W-ECAR Total - This Run	Model 7x24		$ -	$ 59.11	$ 64.12	$ 61.21	$ 63.96	$ 65.40	$ 58.18	$ 58.85	$ 59.53	$ 60.26	$ 61.26	$ 63.09	$ 63.11	$ 65.76	$ 65.94	$ 67.58

Data	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Generation(GWh)			12,531	12,980	12,468	12,679	12,762	12,799	12,826	12,863	12,446	12,831	12,541	12,791	12,749	12,856	12,771
Trans Recv Engy(GWh)			303	305	305	303	266	267	267	267	268	266	266	265	268	269	268
Sum of Import egy(GWh)			240	159	308	224	300	265	300	324	622	400	536	423	528	489	607
Total load(GWh)			11,527	11,611	11,702	11,846	11,919	12,007	12,100	12,214	12,288	12,381	12,477	12,594	12,671	12,767	12,862
Trans Delv Engy(GWh)			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sum of Export egy(GWh)			1,548	1,833	1,379	1,360	1,409	1,324	1,294	1,240	1,048	1,115	866	885	873	846	783
Total Sources																	
Gen			12,531	12,980	12,468	12,679	12,762	12,799	12,826	12,863	12,446	12,831	12,541	12,791	12,749	12,856	12,771
SEPA			303	305	305	303	266	267	267	267	268	266	266	265	268	269	268
Market Purchases			240	159	308	224	300	265	300	324	622	400	536	423	528	489	607
Total Sources			13,075	13,444	13,081	13,206	13,328	13,331	13,394	13,454	13,336	13,497	13,344	13,479	13,545	13,614	13,646
Total Uses																	
Native Load			3,501	3,584	3,674	3,760	3,852	3,939	4,032	4,122	4,217	4,308	4,404	4,498	4,596	4,691	4,786
Smelter Load			7,297	7,297	7,297	7,317	7,297	7,297	7,297	7,317	7,297	7,297	7,297	7,317	7,297	7,297	7,297
City of Henderson Load			627	627	627	660	660	660	660	660	660	660	660	660	660	660	660
Sales Load			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mkt Sales			1,548	1,833	1,379	1,360	1,409	1,324	1,294	1,240	1,048	1,115	866	885	873	846	783
Losses			102	103	104	109	110	112	111	115	114	117	116	119	118	120	119
Total Uses			13,075	13,444	13,081	13,206	13,328	13,331	13,394	13,454	13,336	13,497	13,344	13,479	13,545	13,614	13,646
			0.90%	0.90%	0.90%	0.93%	0.93%	0.94%	0.92%	0.95%	0.94%	0.95%	0.94%	0.95%	0.94%	0.95%	0.93%
Hend Share adj for losses			95.85	95.85	95.85	100.90	100.90	100.90	100.90	100.90	100.90	100.90	100.90	100.90	100.90	100.90	100.90
Hend share at 100% CF			839.7	839.7	839.7	886.3	883.9	883.9	883.9	886.3	883.9	883.9	883.9	886.3	883.9	883.9	883.9
Hend Est Energy Use			632.4	632.4	632.4	665.6	665.6	665.6	665.6	665.6	665.6	665.6	665.6	665.6	665.6	665.6	665.6
BREC use of HMPL Share			207.31	207.31	207.31	220.64	218.22	218.22	218.22	220.64	218.22	218.22	218.22	220.64	218.22	218.22	218.22
Cost to BREC of Excess Hend use			$ 518	$ 518	$ 518	$ 552	$ 546	$ 546	$ 546	$ 552	$ 546	$ 546	$ 546	$ 552	$ 546	$ 546	$ 546
SEPA Price			$ 22.440	$ 22.440	$ 22.440	$ 28.330	$ 29.040	$ 29.750	$ 29.750	$ 29.750	$ 29.750	$ 30.500	$ 31.240	$ 31.240	$ 31.240	$ 31.240	$ 32.000
			95.8530925	95.8530925	95.85309252	95.85309252	100.8979921	100.8979921	100.8979921	100.8979921	100.8979921	100.8979921	100.8979921	100.8979921	100.8979921	100.8979921	100.8979921

EntityName	Data	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
D B Wilson 1	Generation(GWh)			3,019	3,433	3,141	3,317	3,161	3,380	3,218	3,390	2,965	3,384	3,216	3,385	3,223	3,409	3,211
	Fuel used(GBtu)			33,953	38,601	35,542	37,044	34,679	37,098	35,301	37,206	32,550	37,130	35,285	37,151	35,366	37,416	35,220
	Fuel cost($000)			60,097	65,622	62,199	90,758	89,124	66,776	64,070	68,198	60,314	69,545	66,794	71,070	68,469	73,260	69,771
	VOM cost($000)			7,352	8,454	10,678	11,264	10,685	11,729	11,488	12,441	11,179	13,095	12,800	13,845	13,538	14,693	14,223
	Num starts()			10	11	11	10	9	10	9	10	14	8	10	10	9	10	9
	Start Fuel used(GBtu)			66	72	67	52	56	54	50	50	77	46	55	53	50	52	55
	Start cost($000)			3,542	3,870	3,656	2,867	3,160	3,062	2,905	2,999	4,740	2,877	3,547	3,532	3,375	3,610	3,903
	SO2(ktons)			10	11	10	11	10	11	10	11	10	11	10	11	10	11	10
	SO2 cost($000)			1,390	1,299	9,025	9,514	8,876	9,224	8,694	8,979	7,208	7,668	5,790	4,488	3,621	3,305	2,874
	NOx(ktons)			0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
	NOx cost($000)			1,093	978	2,352	2,123	1,897	2,047	1,698	1,876	1,517	1,685	1,534	1,636	1,548	1,651	1,548
HMP&L Station 1	Generation(GWh)			1,128	1,217	1,055	1,194	1,154	1,215	1,136	1,226	1,124	1,224	1,061	1,127	1,158	1,227	1,122
	Fuel used(GBtu)			12,204	13,167	11,417	12,928	12,491	13,156	12,298	13,274	12,164	13,247	11,488	12,194	12,537	13,289	12,148
	Fuel cost($000)			23,187	33,180	29,114	34,260	34,725	23,549	22,186	24,186	22,406	24,653	21,620	23,182	24,120	25,861	23,919
	VOM cost($000)			3,412	3,977	4,474	5,208	5,170	5,590	6,669	7,394	6,967	7,796	6,940	7,572	8,003	8,714	8,181
	Num starts()			16	15	15	14	14	15	15	15	14	14	21	14	15	14	14
	Start Fuel used(GBtu)			30	28	28	26	26	28	28	28	26	26	38	26	28	26	26
	Start cost($000)			1,599	1,529	1,525	1,435	1,457	1,617	1,651	1,689	1,585	1,625	2,463	1,712	1,920	1,807	1,867
	SO2(ktons)			2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	SO2 cost($000)			282	250	1,635	1,873	1,804	1,845	1,709	1,807	1,519	1,543	1,064	831	724	662	559
	NOx(ktons)			0	0	0	1	1	1	1	1	1	1	0	1	1	1	1
	NOx cost($000)			580	484	1,052	1,075	990	1,053	960	972	823	870	724	775	798	847	772
HMP&L Station 2	Generation(GWh)			1,271	1,184	1,252	1,095	1,245	1,182	1,268	1,189	1,259	1,167	1,256	1,071	1,255	1,194	1,237
	Fuel used(GBtu)			13,767	12,827	13,564	11,868	13,501	12,809	13,741	12,885	13,645	12,645	13,619	11,606	13,609	12,940	13,409
	Fuel cost($000)			26,157	32,325	34,588	31,449	37,532	22,929	24,789	23,477	25,133	23,532	25,630	22,062	26,184	25,181	26,402
	VOM cost($000)			3,801	3,952	5,307	4,774	5,580	5,437	7,440	7,169	7,804	7,431	8,217	7,196	8,675	8,476	9,019
	Num starts()			17	19	17	23	17	17	13	17	17	17	17	24	17	17	17
	Start Fuel used(GBtu)			35	37	33	44	34	34	25	34	33	34	34	46	34	34	34
	Start cost($000)			1,859	2,007	1,826	2,427	1,882	1,969	1,449	2,043	2,026	2,147	2,172	3,066	2,276	2,398	2,413
	SO2(ktons)			2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	SO2 cost($000)			318	243	1,943	1,720	1,949	1,797	1,909	1,754	1,704	1,473	1,261	791	786	645	617
	NOx(ktons)			0	0	1	0	1	1	1	1	1	1	1	0	1	1	1
	NOx cost($000)			591	496	1,224	980	1,069	1,019	1,069	938	925	825	858	736	865	821	855
K C Coleman 1	Generation(GWh)			1,198	1,193	1,102	1,202	1,207	1,144	1,213	1,200	1,042	1,204	1,212	1,144	1,198	1,199	1,136
	Fuel used(GBtu)			12,853	12,800	11,884	12,967	13,028	12,348	13,090	12,950	11,238	12,989	13,078	12,348	12,932	12,943	12,253
	Fuel cost($000)			30,847	31,744	30,304	36,047	37,913	23,388	25,001	24,994	21,937	25,639	26,117	24,919	26,420	26,753	25,634
	VOM cost($000)			1,390	1,432	1,377	1,538	1,594	1,545	1,686	1,716	1,531	1,817	1,878	1,819	1,953	2,015	1,965
	Num starts()			17	17	16	15	15	15	15	15	20	15	15	15	15	15	15
	Start Fuel used(GBtu)			26	26	25	24	24	24	23	23	30	23	23	24	23	24	25
	Start cost($000)			567	583	572	555	551	572	553	567	767	605	614	659	653	683	734
	SO2(ktons)			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	SO2 cost($000)			103	84	588	649	650	598	628	609	485	523	418	291	258	223	195
	NOx(ktons)			1	1	2	2	2	2	2	2	2	2	2	2	2	2	2
	NOx cost($000)			2,408	2,067	4,122	4,134	3,965	3,772	3,913	3,622	2,938	3,263	3,159	3,005	3,154	3,162	3,006
K C Coleman 2	Generation(GWh)			1,111	1,040	1,101	1,090	1,038	1,093	1,111	966	1,115	1,113	1,036	1,117	1,112	1,056	1,115
	Fuel used(GBtu)			13,369	12,508	13,237	13,115	12,493	13,144	13,363	11,622	13,414	13,398	12,460	13,445	13,378	12,710	13,416
	Fuel cost($000)			32,085	31,019	33,753	36,461	36,355	24,895	25,523	22,430	26,185	26,448	24,883	27,133	27,332	26,271	28,067
	VOM cost($000)			1,289	1,247	1,376	1,428	1,402	1,508	1,577	1,410	1,672	1,715	1,636	1,821	1,857	1,817	1,973
	Num starts()			16	15	15	15	15	15	15	21	13	15	15	15	15	15	11
	Start Fuel used(GBtu)			25	22	24	25	24	25	24	31	20	24	25	24	24	25	18
	Start cost($000)			545	501	548	561	567	582	586	774	496	629	655	641	683	702	524
	SO2(ktons)			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	SO2 cost($000)			107	82	655	656	623	637	641	547	579	539	398	317	267	219	213
	NOx(ktons)			1	1	2	2	2	2	2	2	2	2	2	2	2	2	2
	NOx cost($000)			2,487	2,126	4,599	4,189	3,810	4,040	4,012	3,280	3,491	3,370	3,018	3,280	3,278	3,113	3,277
K C Coleman 3	Generation(GWh)			1,126	1,225	1,225	1,050	1,237	1,229	1,155	1,211	1,227	1,162	1,212	1,222	1,068	1,229	1,233
	Fuel used(GBtu)			12,176	13,249	13,258	11,371	13,398	13,308	12,501	13,115	13,288	12,579	13,126	13,225	11,565	13,309	13,356
	Fuel cost($000)			29,223	32,858	33,808	31,611	38,988	25,205	23,877	25,312	25,939	24,831	26,213	26,688	23,628	27,509	27,940
	VOM cost($000)			1,306	1,470	1,531	1,376	1,670	1,696	1,640	1,769	1,841	1,769	1,916	1,991	1,783	2,114	2,183
	Num starts()			18	18	19	24	14	16	16	16	16	17	17	17	24	16	17
	Start Fuel used(GBtu)			25	25	27	32	20	22	22	22	22	24	24	24	32	22	24
	Start cost($000)			551	568	619	732	467	524	536	551	562	628	643	659	892	638	714
	SO2(ktons)			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	SO2 cost($000)			97	87	656	569	668	645	600	617	573	506	420	311	231	229	212
	NOx(ktons)			1	1	2	2	2	2	2	2	2	2	2	2	2	2	2
	NOx cost($000)			1,996	2,085	4,608	3,472	3,876	3,885	3,564	3,504	3,299	3,016	3,031	3,077	2,700	3,093	3,113

RA Reid GT	Generation(GWh)	4	4	7	11	15	9	9	9	11	10	9	9	9	9	9
	Fuel used(GBtu)	48	51	80	133	175	111	104	110	130	125	103	101	106	106	107
	Fuel cost($000)	418	448	698	1,132	1,475	931	902	967	1,154	1,127	951	952	1,020	1,053	1,085
	VOM cost($000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Num starts()	154	148	154	174	251	196	173	173	182	121	199	186	229	173	155
	Start Fuel used(GBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Start cost($000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SO2(ktons)	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-
	SO2 cost($000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NOx(ktons)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NOx cost($000)	10	9	13	17	22	14	13	13	14	13	10	10	11	11	11
RA Reid Coal	Generation(GWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Fuel used(GBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Fuel cost($000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	VOM cost($000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Num starts()	31	29	33	-	-	-	-	-	-	-	-	-	-	-	-
	Start Fuel used(GBtu)	29	27	30	-	-	-	-	-	-	-	-	-	-	-	-
	Start cost($000)	1,540	1,478	1,646	-	-	-	-	-	-	-	-	-	-	-	-
	SO2(ktons)	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
	SO2 cost($000)	0	0	3	-	-	-	-	-	-	-	-	-	-	-	-
	NOx(ktons)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NOx cost($000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
R A Reid Gas	Generation(GWh)	7	12	32	29	13	29	13	23	22	-	24	22	19	37	22
	Fuel used(GBtu)	90	165	437	387	178	396	172	305	302		318	298	252	507	297
	Fuel cost($000)	792	1,551	3,776	3,518	1,683	3,300	1,473	2,689	2,808		2,943	2,774	2,418	5,009	3,095
	VOM cost($000)	-	-	-	-			-	-	-	-	-	-	-	-	-
	Num starts()	2	2	6	5		3	3	2	5	-	3	2	2	12	2
	Start Fuel used(GBtu)	2	2	6	5		2	2	2	5	-	2	2	2	11	2
	Start cost($000)	63	70	241	168	-	101	103	102	215	-	113	113	115	575	121
	SO2(ktons)	0	0	0	0	0	0	0	0	0	-	0	0	0	0	0
	SO2 cost($000)	0	0	1	1	0	0	0	0	0	-	0	0	0	0	0
	NOx(ktons)	0	-	0	0	0	0	0	0	0		0	0	0	0	0
	NOx cost($000)	20	-	71	58	25	56	25	40	37		36	34	29	60	34
R D Green Stat 1	Generation(GWh)	1,956	1,800	1,950	1,840	1,927	1,652	1,957	1,782	1,940	1,797	1,955	1,822	1,947	1,635	1,938
	Fuel used(GBtu)	21,874	19,784	21,426	20,229	21,186	18,159	21,520	19,586	21,325	19,754	21,497	20,022	21,406	17,969	21,301
	Fuel cost($000)	36,749	40,358	46,922	43,491	52,964	32,632	38,993	34,921	39,451	36,940	40,629	38,243	41,356	35,130	42,134
	VOM cost($000)	7,559	7,490	8,872	8,594	9,250	8,144	13,071	12,224	13,675	13,029	14,564	13,936	15,303	13,207	16,083
	Num starts()	7	8	7	14	13	18	13	15	13	13	13	15	13	21	13
	Start Fuel used(GBtu)	17	20	18	31	23	43	20	34	22	30	20	34	22	49	23
	Start cost($000)	919	1,104	979	1,719	1,316	2,466	1,155	2,034	1,364	1,857	1,274	2,251	1,468	3,403	1,636
	SO2(ktons)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	SO2 cost($000)	299	222	1,813	1,732	1,807	1,505	1,767	1,576	1,574	1,360	1,176	806	731	529	579
	NOx(ktons)	1	1	3	3	3	2	3	3	3	3	3	3	3	2	3
	NOx cost($000)	2,885	1,964	6,419	5,508	5,546	4,738	5,522	4,711	4,767	4,236	4,462	4,189	4,484	3,755	4,482
R D Green Stat 2	Generation(GWh)	1,713	1,872	1,604	1,850	1,763	1,865	1,748	1,867	1,742	1,770	1,561	1,873	1,759	1,860	1,748
	Fuel used(GBtu)	19,358	20,800	17,820	20,557	19,594	20,731	19,425	20,750	19,355	19,675	17,344	20,816	19,543	20,674	19,424
	Fuel cost($000)	32,521	42,432	39,026	44,198	48,985	37,253	35,198	36,998	35,806	36,793	32,779	39,759	37,757	40,417	38,421
	VOM cost($000)	6,609	7,789	7,299	8,637	8,464	9,196	11,679	12,807	12,279	12,835	11,627	14,325	13,823	15,029	14,508
	Num starts()	8	7	6	13	14	11	15	11	15	13	21	12	14	12	15
	Start Fuel used(GBtu)	25	23	22	24	38	20	41	19	42	38	61	21	37	22	42
	Start cost($000)	1,174	1,107	1,034	1,271	1,905	1,089	2,142	1,076	2,294	2,098	3,460	1,351	2,266	1,476	2,674
	SO2(ktons)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	SO2 cost($000)	264	233	1,508	1,760	1,672	1,718	1,595	1,669	1,429	1,354	949	838	667	609	528
	NOx(ktons)	1	1	2	3	3	3	3	3	3	3	2	3	3	3	3
	NOx cost($000)	2,818	2,348	5,233	5,582	5,081	5,418	4,966	4,955	4,294	4,239	3,576	4,331	4,068	4,327	4,065

Study	Data	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Delivered Energy(GWh)			1,548	1,833	1,379	1,360	1,409	1,324	1,294	1,240	1,048	1,115	866	885	873	846	783
	Delivering Cost($000)			87,963	100,516	81,998	85,218	93,792	75,932	75,239	72,642	62,277	67,403	54,904	54,824	54,731	53,107	50,372
	Received Energy(GWh)			1,548	1,833	1,379	1,360	1,409	1,324	1,294	1,240	1,048	1,115	866	885	873	846	783
	Receiving Cost($000)			89,845	103,349	83,498	86,557	94,683	78,325	78,194	75,027	64,396	70,142	56,881	56,665	56,308	55,619	52,068
	Mkt Sales			1,548	1,833	1,379	1,360	1,409	1,324	1,294	1,240	1,048	1,115	866	885	873	846	783
	BREC Rev - Model		#DIV/0!	$ 58.04	$ 56.39	$ 60.56	$ 63.63	$ 67.19	$ 59.17	$ 60.41	$ 60.50	$ 61.46	$ 62.88	$ 65.67	$ 64.01	$ 64.46	$ 65.72	$ 66.47
	Adj Revenue		#DIV/0!	$ 89,845	$ 103,349	$ 83,498	$ 86,557	$ 94,683	$ 78,325	$ 78,194	$ 75,027	$ 64,396	$ 70,142	$ 56,881	$ 56,665	$ 56,308	$ 55,619	$ 52,068
	Adjusted Price		#DIV/0!	$ 58.04	$ 56.39	$ 60.56	$ 63.63	$ 67.19	$ 59.17	$ 60.41	$ 60.50	$ 61.46	$ 62.88	$ 65.67	$ 64.01	$ 64.46	$ 65.72	$ 66.47
			#DIV/0!	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			#DIV/0!															

Study	Data	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Delivered Energy(GWh)			240	159	308	224	300	265	300	324	622	400	536	423	528	489	607
	Delivering Cost($000)			14,613	9,752	19,379	15,455	19,846	16,161	18,489	20,354	37,604	23,775	33,812	26,725	37,652	34,185	43,950
	Received Energy(GWh)			240	159	308	224	300	265	300	324	622	400	536	423	528	489	607
	Receiving Cost($000)			15,742	10,505	20,726	16,613	21,449	17,322	19,657	21,624	40,334	25,321	36,120	28,562	40,377	36,405	46,703
	Market Purchases	-	-	240	159	308	224	300	265	300	324	622	400	536	423	528	489	607
	BREC Price	$ -	$ -	$ 65.53	$ 66.17	$ 67.28	$ 74.14	$ 71.54	$ 65.38	$ 65.42	$ 66.75	$ 64.85	$ 63.37	$ 67.39	$ 67.48	$ 76.46	$ 74.47	$ 76.94
	Adj Costs	#DIV/0!	#DIV/0!	$ 15,742	$ 10,505	$ 20,726	$ 16,613	$ 21,449	$ 17,322	$ 19,657	$ 21,624	$ 40,334	$ 25,321	$ 36,120	$ 28,562	$ 40,377	$ 36,405	$ 46,703
	Adjusted Price	#DIV/0!	#DIV/0!	$ 65.53	$ 66.17	$ 67.28	$ 74.14	$ 71.54	$ 65.38	$ 65.42	$ 66.75	$ 64.85	$ 63.37	$ 67.39	$ 67.48	$ 76.46	$ 74.47	$ 76.94
			#DIV/0!	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

EXHIBIT 98

SUPPLEMENTAL DIRECT TESTIMONY OF ROBERT S. MUDGE

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2007-00455

SUPPLEMENTAL DIRECT TESTIMONY OF
ROBERT S. MUDGE

ON BEHALF OF
APPLICANTS

OCTOBER 2008

SUPPLEMENTAL DIRECT TESTIMONY OF ROBERT S. MUDGE

I. INTRODUCTION

Q. Please state your name.

A. My name is Robert S. Mudge.

Q. Are you the same Robert S. Mudge who previously submitted direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your supplemental direct testimony in this proceeding?

A. The purpose of my supplemental testimony is to present the updated Unwind Financial Model depicting the transaction (the "Unwind Transaction") under which Big Rivers has proposed to terminate its 1998 power purchase and lease transaction with E.ON US, LLC ("E.ON") (the "Lease Transaction"), and the financial impact of operations thereafter, through the period of the existing arrangements which terminate in 2023. Specifically, I discuss the material changes in the Unwind Financial Model since the most recently filed version of June 2008, including the financial resolution of the Ambac Assurance Company ("Ambac") credit downgrade resulting in the expected termination of the lease transaction with Phillip Morris Capital Corporation ("PMCC') and its subsidiary, Bluegrass Leasing, (the "PMCC Buyout"), as well as other changes to the Unwind Financial Model due to changes in cost inputs and assumptions. I also present comparisons of revenue requirements, Member rates, and balance sheet and credit metrics produced by the updated Unwind Financial Model as compared to the June 2008 version of the Unwind Financial Model.

II. <u>DESCRIPTION OF CHANGES TO THE UNWIND FINANCIAL MODEL FROM THE JUNE 2008 UNWIND FINANCIAL MODEL</u>

Q. Would you please list the material changes in the Unwind Financial Model since the most recently filed version of June 2008.

A. The Unwind Financial Model has been updated in a number of important respects since the version presented to the Kentucky Public Service Commission in June 2008. The updated model is attached as Exhibit 79. Many of these changes in inputs to the Unwind Financial Model, including the reasons for the changes, are explained in the Third Supplemental Direct Testimony of C. William Blackburn (Exhibit 78).

First, the projected closing date of the Unwind Transaction to be used in the Unwind Financial Model has been changed from April 30, 2008, as reflected in the original December 2007 application, to December 31, 2008.

Second, financial statements prior to the new December 31, 2008 closing date have been updated to reflect actual results for 2007, which were not available for the original December 2007 filing. Big Rivers' 2008 financial statements have been projected based on actual results through July 2008 and using Big Rivers' budgets for the balance of the year.

Third, compensation from E.ON has been revised to reflect the new December 31, 2008 closing date. This change primarily concerns more accurate estimates of the value of fuel and other inventory at closing, an updated estimate of contributed SO_2 allowances, as well as other adjustments.

Q. Have there been other material changes to the Unwind Financial Model?

A. Yes. Fourth, the Unwind Financial Model has been updated to reflect the results of the September 8, 2008 run of the updated Big Rivers Production Cost Model prepared by ACES Power Marketing at the direction of Big Rivers (attached as Exhibit 97). The results of the updated Production Cost Model change the anticipated plant dispatch used in the Unwind Financial Model resulting from changes in market electricity prices, projected fuel costs, projected variable O&M costs and related items.

Fifth, the Unwind Financial Model has been updated to reflect changed labor costs based in part on an updated workplan provided by Western Kentucky Energy Corp. ("WKEC") (Exhibit 105) and in part on estimates by Big Rivers of projected payroll and overhead items.

Sixth, the Unwind Financial Model has been updated to incorporate changes to non-labor fixed costs and capital expenditures. These non-labor fixed costs and projected capital expenditures have been revised based on the updated workplan provided by WKEC (Exhibit 105) and estimates made by Big Rivers. These changes are made in four major categories: fixed production O&M, administrative and general costs, marketing fees, and capital expenditures.

Q. Does the Unwind Financial Model also change to reflect the terms and financial effects of the PMCC Buyout and the termination of the leases with Bank of America Leasing (the "BoA Buyout")?

A. Yes. The Unwind Financial Model has been revised to model the financial effects of the PMCC Buyout and the actual terms of the BoA Buyout (which had been reflected on a pro forma basis in the June 2008 model).

Q. How are the costs of the PMCC Buyout and the BoA Buyouts modeled?

A. The costs of buying out these leveraged lease transaction are recognized in income on the closing date of the Unwind Transaction (now projected to be December 31, 2008). With offsets from recognizing the unamortized gain generated by the original lease transactions (that of both PMCC and BoA), the net expense is approximately $16.1 million. Mr. Blackburn explains Big Rivers' request for this proposed accounting treatment in his testimony (Exhibit 78).

For purposes of the Unwind Financial Model, Big Rivers' cash outlay associated with the PMCC Buyout is modeled as a net $60.9 million once the WKEC contribution of $60.9 million is received at closing of the Unwind

Transaction. This net amount reflects full repayment of the $12.38 million loan from PMCC undertaken at the time of the PMCC Buyout. The Unwind Financial Model treats this net amount as financed using funds that would otherwise have been used to prepay the RUS New Note on the date of closing of the Unwind Transaction. The balance of the RUS prepayment is then deferred to 2012. Big Rivers' cash net inflow associated with the BoA Buyout is modeled as $1.2 million.

Q. How does the reduction in the amount to be prepaid under the RUS New Note change Big Rivers' expected financings?

A. In order to cover cash requirements, including capital expenditures and RUS payments, the Unwind Financial Model assumes additional borrowings in the capital markets will occur in 2011 and 2018 (both at year end). Moreover, the Unwind Financial Model retains the assumption of a $200 million borrowing in 2015 (year end), which is already included in the June 2008 Unwind Financial Model.

Q. What other assumptions in the Unwind Financial Model are changed in the updated version?

A. The new Unwind Financial Model no longer incorporates the Member Discount Adjustment, which expired in August 2008, as explained by Mr. Blackburn in his testimony (Exhibit 78). In addition, as Mr. Blackburn also explains, the new Unwind Financial Model no longer incorporates a 2% Member rate increase, which was originally modeled for 2010 as established in the original Section 4.7.5(a) of the Smelter Agreements. Also, in order to reflect the terms of the new Smelter Agreements discussed in Mr. Blackburn's testimony (Exhibit 78), the Unwind Financial Model reduces the Smelter Surcharge by $200,000 per month for the first 96 months following closing and converts the Smelter Economic Reserve of $7 million included in the June 2008 Financial Model into an equivalent cash payment by Big Rivers to the Smelters on the date of closing of the Unwind Transaction.

Further, the Unwind Financial Model reflects Big Rivers' change to the Member Rate Stability Mechanism ("MRSM") to incorporate a feathering of the Fuel Adjustment Clause ("FAC") and Environmental Surcharge expenses flowed through to the Non-Smelter Rates. For 2009, the MRSM provides full crediting of all FAC and Environmental Surcharge expenses not otherwise offset. In 2010, the amount of the MRSM crediting of FAC and Environmental Surcharges expenses not otherwise offset is reduced by an amount equivalent to $2.00/MWh multiplied by the load. In 2011, the amount of the MRSM crediting of FAC and Environmental Surcharge expenses not otherwise offset is reduced by an amount equivalent to $4.00/MWh multiplied by the load. And during 2012, the amount of the MRSM crediting of FAC and Environmental Surcharges not otherwise offset is reduced by an amount equivalent to $6.00/MWh multiplied by the load.

A Kentucky coal tax credit also has been incorporated into the new Unwind Financial Model, serving to offset fuel costs to a modest degree in 2010 and 2011.

Finally, the Unwind Financial Model has been updated to change the assumed interest earnings rate applied to cash balances from 4.28% to 4.00%.

III. COMPARISON OF KEY RESULTS BETWEEN THE JUNE 2008 UNWIND FINANCIAL MODEL AND THE UPDATED UNWIND FINANCIAL MODEL

Q. Have you prepared any comparisons between the results of the Updated Unwind Financial Model and the previously-supplied June 2008 Unwind Financial Model?

A. Yes. In my testimony below I provide comparisons of these two versions of the Unwind Financial Model across a number of dimensions.

A. Changes to Overall Revenue Requirements

Q. What is the effect on the overall revenue requirements of Big Rivers between the updated Unwind Financial Model and the June 2008 version of the Unwind Financial Model?

A. Below I provide the changes in the overall revenue requirements over the period 2009 – 2023:

Overall Revenue Requirements:

Analysis of Change in Total Revenue Requirement ($M; 2009 - 2023)

1	*Filed Model (6/08)*	8,325.2
2	Increases from Operations	
3	Fuel Costs	184.5
4	Non-Fuel Variable Production O&M	112.2
5	A&G	69.0
6	Fixed Production O&M	43.5
7	Gain on Sale of Emissions Allowances	24.0
8	Marketing Fees	18.7
9	Smelter Economic Reserve	7.7
10	Transmission O&M	3.2
11	Interest Earnings	10.2
12	Subtotal - Increases	473.1
13		
14	Reductions from Operations	
15	Offsystem Sales	(243.5)
16	SEPA & Other Purchases	(20.6)
17	Depreciation & Amortization	(7.3)
18	Member Economic Reserve	(16.2)
19	Income Tax	(1.0)
20	RUS Note & PCB Restructuring Charge	(0.4)
21	Subtotal - Reductions	(288.9)
22		
23	Lease Buyout	
24	Discontinuation of Net Lease Income	25.9
25	Discontinuation of CoBank Patronage	13.0
26	BoA Lease Gain not Amortized	10.6
27	Subtotal - Lease Buyout	49.5
28		
29	Interest Expense (Incl. Financing Fees)	45.9
30		
31	Net Margin	(37.8)
32		
33	Rebate Realized	6.9
34	Total	248.7
35	*December Close/ $60.9m Buyout*	8,573.9
36		
37	Percent Change	3%

Q. Could you explain the reason for the estimated cost increases shown?

A. The estimated cost increases result from a combination of factors, including: 1) the results of the updated Production Cost Model to reflect current market conditions and commodity price escalations; 2) changes in other operating cost assumptions revised in consultation with WKEC through changes to the workplan and otherwise; 3) certain reductions in income accompanying the PMCC Buyout and the BoA Buyout; and 4) changes in financing and interest charges.

Q. Have you assessed the potential effect on revenue requirements and rates produced solely from the PMCC Buyout and the BoA Buyout?

A. Yes. I separately provide the revenue requirements and rate impacts of the PMCC Buyout and the BoA Buyout alone as Exhibit RSM-3.

B. Changes to Member Rates

Q. What is the effect on Member Rates of the various changes to the updated Unwind Financial Model as compared to the June 2008 Unwind Financial Model?

A. The increase in revenue requirements equates to a weighted average increase of \$1.38/MWh to the Non-Smelter Members over the period from 2009 to 2023. I present these results in the table below:

Non-Smelter Member Rates:

Rate Impact Analysis (\$/ MWh)

1. Non-Smelter Members

1	*Filed Model (6/08)*	46.11
2	Discontinued MRDA	0.89
3	GRA	(0.79)
4	Regulatory Account	(0.18)
5		
6	FAC	0.63
7	Environmental Surcharge	0.69
8	Surcharge Credit	0.31
9	Rebate Realized	0.08
10	Economic Reserve/ MRSM	(0.26)
11	*Net*	1.45
12		
13	*Overall Change*	1.38
14	*December Close/ \$60.9m Buyout*	47.49

C. Changes to Smelter Rates

Q. What is the effect on Smelter Rates of the various changes to the updated Unwind Financial Model as compared to the June 2008 Unwind Financial Model?

A. The increase in revenue requirements equates to a weighted average increase of \$1.49/MWh to the Smelter Members over the 2009 to 2023 period. I present these results in the table below:

Smelter Member Rates:

Rate Impact Analysis ($/ MWh)

2. Smelters

1	*Filed Model (6/08)*	49.93
2	Discontinued MRDA	0.71
3	GRA	(0.56)
4	TIER Adjustment	0.20
5	FAC	0.65
6	Smelter Economic Reserve	0.07
7	Environmental Surcharge	0.68
8	Power Purchases	(0.14)
9	Surcharge	(0.18)
10	TIER Related Rebate	0.05
11	*Overall Change*	1.49
12	*December Close/ $60.9m Buyout*	51.42

D. Changes to Balance Sheet and Credit Metrics

Q. Have you estimated the effect of the changes to the Unwind Financial Model between June 2008 and October 2008 as they relate to Big Rivers' equity?

A. Yes. The June 2008 version of the Unwind Financial Model indicated Big Rivers would have a minimum 24% positive equity. The updated Unwind Financial Model submitted herein shows a minimum positive 26% equity level.

Q. Have you estimated the effect of the changes to the Unwind Financial Model between June 2008 and October 2008 as they relate to TIER?

A. Yes. The June 2008 version of the Unwind Financial Model indicated Big Rivers would have a minimum 1.22 TIER. The updated Unwind Financial Model submitted herein shows a minimum 1.27 TIER.

Q. And have you estimated the effect of the changes to the Unwind Financial Model between June 2008 and October 2008 as they relate to ending cash balances?

A. I have. When expressed in terms of unrestricted cash on hand and the funds being held in the Transition Reserve Account, and excluding all funds available under lines of credit, the June 2008 version of the Unwind Financial Model indicated $74 million cash on hand, and the updated Unwind Financial Model shows $73.1 million cash on hand.

Q. Does this conclude your testimony at this time?

A. Yes.

Exhibit RSM-3

Combined Impact of BofA and PMCC Lease Buyouts in Isolation [10/04/08]:

	Analysis of Change in Total Revenue Requirement ($M; 2009 - 2023)	
1	*December Close/ $60.9m PMCC Buyout*	8,573.9
2	Increases from Operations	
3	Fuel Costs	-
4	Non-Fuel Variable Production O&M	-
5	A&G	-
6	Fixed Production O&M	-
7	Gain on Sale of Emissions Allowances	-
8	Marketing Fees	-
9	Smelter Economic Reserve	-
10	Transmission O&M	-
11	Interest Earnings	4.2
12	Subtotal - Increases	4.2
13		
14	Reductions from Operations	
15	Offsystem Sales	-
16	SEPA & Other Purchases	-
17	Depreciation & Amortization	-
18	Member Economic Reserve	0.1
19	Income Tax	-
20	RUS Note & PCB Restructuring Charge	0.4
21	Subtotal - Reductions	0.5
22		
23	Lease Buyout	
24	Continuation of Net Lease Income	(36.2)
25	Continuation of CoBank Patronage	(13.0)
26	Subtotal - Lease Buyout	(49.2)
27		
28	Interest Expense (Incl. Financing Fees)	(58.9)
29		
30	Net Margin	49.2
31		
32	Rebate Realized	-
33	Total	(54.2)
34	*December Close/ No BofA or PMCC Buyout*	8,519.7
35		
36	Percent Change	-1%

Non-Smelter Member Rates [10/04/08]:

Rate Impact Analysis ($/ MWh)

1. Non-Smelter Members

1	*December Close/ $60.9m PMCC Buyout*	47.49
2	MRDA Continued	(0.89)
3	GRA	0.47
4	Regulatory Account	-
5		
6	FAC	-
7	Environmental Surcharge	-
8	*Surcharge Credit*	-
9	Rebate Realized	0.02
10	Economic Reserve/ MRSM	0.00
11	*Net*	0.02
12		
13	*Overall Change*	(0.39)
14	*December Close/ No BofA or PMCC Buyout*	47.09

Smelter Rates [10/04/08]:

Rate Impact Analysis ($/ MWh)

2. Smelters

1	*December Close/ $60.9m PMCC Buyout*	51.42
2	MRDA Continued	(0.71)
3	GRA	0.36
4	TIER Adjustment	0.05
5	FAC	-
6	Smelter Economic Reserve	-
7	Environmental Surcharge	-
8	Power Purchases	-
9	Surcharge	-
10	TIER Related Rebate	0.02
11	*Overall Change*	(0.27)
12	*December Close/ No BofA or PMCC Buyout*	51.15

VERIFICATION

I verify, state, and affirm that the foregoing testimony is true and correct to the best of my knowledge and belief.

Robert S. Mudge

District of Columbia, ss:)
Washington, DC)

SUBSCRIBED AND SWORN TO before me by Robert S. Mudge on this the 7th day of October, 2008.

Notary Public____________
My Commission Expires________

ANGELA GILBERT
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires January 1, 2009

EXHIBIT 99

SUPPLEMENTAL DIRECT TESTIMONY OF DAVID A. SPAINHOWARD

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2007-00455

SUPPLEMENTAL DIRECT TESTIMONY OF DAVID A. SPAINHOWARD

ON BEHALF OF
APPLICANTS

OCTOBER 2008

SUPPLEMENTAL DIRECT TESTIMONY OF DAVID A. SPAINHOWARD

I. INTRODUCTION

Q. Please state your name, address and position with Big Rivers Electric Corporation ("Big Rivers").

A. My name is David A. Spainhoward. My business address is 201 Third Street, Henderson, Kentucky, 42420. I am Vice President External Relations & Interim Chief Production Officer at Big Rivers.

Q. Are you the same David A. Spainhoward who previously submitted direct testimony in this proceeding?

A. Yes, I am.

Q. Please summarize the purpose of your supplemental direct testimony in this proceeding.

A. The purpose of my supplemental testimony is to address certain developments that have occurred with respect to the proposed unwind ("Unwind Transaction") of the 1998 transactions between Big Rivers and

E.ON U.S. LLC ("E.ON") (formerly LG&E Energy Corp.) and certain E.ON affiliates approved by the Kentucky Public Service Commission ("Commission") in Case Nos. 97-204 and 98-265 ("1998 Transactions").

First, I describe several agreements that Big Rivers proposes to enter into relating to the resumption by Big Rivers of the rights and responsibilities under pre-1998 contracts ("Station Two Contracts") between Big Rivers, the City of Henderson, Kentucky (the "City") and the City of Henderson Utility Commission doing business as Henderson Municipal Power & Light ("HMP&L") (collectively, "Henderson") concerning the City's Station Two generating facility ("Station Two"). For each of these agreements, all of which are attached at Exhibit 87, I briefly describe the purpose of the agreement, whether Big Rivers is seeking Commission approval for the agreement or is merely filing the agreement for informational purposes, and for those agreements for which Big Rivers is seeking Commission approval, why such approval is necessary. In addition, to the extent that there is an exchange of consideration under any of these agreements, I explain why the consideration involved is reasonable.

I then briefly summarize changes to the Big Rivers tariff for which Big Rivers seeks approval in this proceeding, and also describe revisions to Big Rivers' open access transmission tariff ("OATT") that is being filed with the

Commission and that will be filed with the Federal Energy Regulatory Commission ("FERC") (attached hereto as Exhibit 85).

Next, to support Big Rivers' ongoing conduct of due diligence with respect to its proposed resumption of the responsibility for operating and maintaining the generating facilities currently leased to E.ON, I sponsor a list of due diligence closing conditions and discuss Big Rivers' understanding of how those conditions are expected to be satisfied.

Finally, I address the effect on Big Rivers of the United States Court of Appeals for the District of Columbia Circuit's ("D.C. Circuit") recent decision in *State of North Carolina v. EPA*, in which the court struck down the Clean Air Interstate Rule ("CAIR") promulgated by the United States Environmental Protection Agency ("EPA"). I describe the CAIR and the court's basis for striking the rule down. I then explain how I believe the court's ruling is likely to impact Big Rivers and how Big Rivers is responding to this development.

II. <u>HENDERSON STATION TWO AGREEMENTS</u>

A. INTRODUCTION

Q. What is the purpose of the agreements relating to Station Two that Big Rivers is filing with the Commission?

A. The purpose of the agreements is to restore Big Rivers and Henderson to the relationship that prevailed among the parties with respect to Station Two prior to the 1998 Transactions. As the Commission is aware, in 1970 Big Rivers and Henderson entered into a series of contracts concerning Station Two ("Station Two Contracts"), including a Power Sales Contract, a Power Plan Construction and Operation Agreement, and a Joint Facilities Agreement. As part of the 1998 Transactions, E.ON, acting through a subsidiary, assumed certain of Big Rivers' operational responsibilities with respect to Station Two pursuant to a series of agreements entered into by and among Big Rivers, E.ON, the City of Henderson, Kentucky, and the City of Henderson Utility Commission, including the Agreement and Amendments to Agreements by and among the City, the City of Henderson Utility Commission, Big Rivers Electric Corporation, WKE Station Two Inc., LG&E Energy Marketing Inc. ("LEM"), and Western Kentucky Energy Corp. ("WKEC") dated July 15, 1998 ("Station Two Agreement"). The new agreements are meant to act in concert to eliminate the role of E.ON as the entity responsible for operating Station Two, and to permit Big Rivers to resume that role. The agreements further restore to Big Rivers other rights and responsibilities that were assigned to E.ON in 1998.

Q. Have these agreements been executed by the relevant parties?

A. No. Certain of these agreements require execution by the City and the City of Henderson Utility Commission. Although the agreements have been briefly discussed with those entities, they have not yet agreed to the terms proposed or to execute the agreements. The other agreements, although not requiring execution by the City and the City of Henderson Utility Commission, are dependent for their effectiveness on agreement by those entities to the terms Big Rivers proposes for the resumption by Big Rivers of its rights and responsibilities with respect to Station Two. Unless the City and the City of Henderson Utility Commission agree to and execute these agreements, the remaining agreements will have no force and effect, and therefore have not been executed by the parties thereto.

Q. What is Big Rivers asking the Commission to do with respect to these *unexecuted* agreements?

A. The agreements Big Rivers is filing herewith fall into two categories: agreements that require Commission approval and for which Big Rivers is seeking Commission approval, and agreements that do not require Commission approval, but which Big Rivers is filing with the Commission for informational purposes. In my testimony below, I specifically identify those agreements for which Big Rivers requires and is seeking Commission approval. With respect to those agreements, Big Rivers requests that the Commission approve the agreements as filed, with the understanding that it is reasonable to anticipate that at least some of those agreements may be amended prior to execution.

Q. If one or more of the agreements at issue are amended subsequent to Commission approval, will Big Rivers seek Commission approval of the amended agreements?

A. In the event that any of the agreements for which Big Rivers is seeking Commission approval is amended in a material way, Big Rivers will resubmit the amended agreement(s) for Commission approval.

B. DESCRIPTION OF AGREEMENTS RELATING TO STATION TWO

Q. Please identify the Station Two-related agreements that Big Rivers is submitting to the Commission.

A. There are five agreements that Big Rivers is submitting to the Commission with respect to the Station Two transaction:

1. Amendment to Contract Among City of Henderson, Kentucky, the City of Henderson Utility Commission and Big Rivers Electric Corporation;
2. Second Amendatory Agreement (between Big Rivers, WKEC, the City, and the City of Henderson Utility Commission);
3. Station Two Termination and Release Agreement (between Big Rivers and E.ON);
4. Station Two G&A Allocation Agreement (between Big Rivers and HMP&L); and
5. Agreement for Assignment of Responsibility for Complying with Reliability Standards Between Henderson Municipal Power & Light and Big Rivers Electric Corporation.

These agreements are included in Exhibit 87.

Q. What is the purpose of the Amendment to Contract Among City of Henderson, Kentucky, the City of Henderson Utility Commission and Big Rivers Electric Corporation?

A. Under Section 3.8 of the 1970 Station Two Power Sales Contract, Big Rivers is permitted or obligated to purchase certain energy generated from Station Two. Specifically, Big Rivers may purchase all or any portion of such energy associated with HMP&L's reserved capacity which is not scheduled or taken by HMP&L ("Excess Henderson Energy"). Further, if Station Two generates Capacity in excess of the Total Capacity determined according to Section 3.6 of the Station Two Power Sales Contract ("Excess Henderson Capacity"), Big Rivers is obligated to take and utilize all Energy associated with such Excess Henderson Capacity. (The capitalized terms are defined in the Station Two Power Sales Contract.)

Section 3.8(c) of the Station Two Power Sales Contract provides that the price for Excess Henderson Energy or Energy associated with Excess Henderson Capacity shall be $1.50 per MWh. The amendment revises Section 3.8 by increasing the price to be paid by Big Rivers for Excess Henderson Energy or Energy associated with Excess Henderson Capacity to $2.50 per MWh. This increase will take effect on a prospective basis following the effective date of the amendment. Big Rivers requests that the Commission approve this amendment.

Additionally, to resolve any questions about how much energy Big Rivers is purchasing, Big Rivers proposes to amend the contract to make it clear it will take and pay for all energy associated with HMP&L's reserved capacity not used by HMP&L to serve its (HMP&L's) own needs or those of its native load customers. This ensures that HMP&L will have a buyer for all of its excess energy.

Q. Why is Big Rivers agreeing to this increase in the price for Excess Henderson Energy and Energy associated with Excess Henderson Capacity?

A. Big Rivers is agreeing to this increase as an incentive to secure agreement of the City and the City of Henderson Utility Commission to the early termination of E.ON's assumption of Big Rivers' rights and responsibilities with respect to Station Two, which agreement is a condition to closing the Unwind Transaction. Big Rivers is also agreeing to this increase and contract changes to eliminate future questions about the amount of energy Big Rivers must pay for under Section 3.8 of the Power Sales Agreement. Big Rivers is obligating itself to take and pay for all unused energy as described above. Accordingly, Big Rivers requests that the Commission approve this amendment as fair, just and reasonable.

Q. Please describe the Second Amendatory Agreement.

A. The Second Amendatory Agreement, between Big Rivers, LEM, WKEC, the City, and the City of Henderson Utility Commission provides for acceleration of the expiration date of the Station Two Agreement, while preserving for the City any contractual rights in its favor that, by the terms of the Station Two Agreement itself, are intended to survive the expiration thereof. This contract sets the stage for the termination of LEM's and WKEC's assumption of Big Rivers' rights and responsibilities with respect to Station Two. It provides for WKEC to pay an as yet undetermined expiration fee to HMP&L and incorporates various releases, including the termination and release of certain deeds and assignments of easements and rights of way. Big Rivers requests that the Commission approve this agreement in order to permit the parties to implement the Unwind Transaction.

Q. What does the Station Two Termination and Release Agreement accomplish?

A. This agreement, between Big Rivers and E.ON, provides for the termination of obligations as between Big Rivers and E.ON with respect to the Station Two Agreement and related agreements, letter agreements, guaranties, easements, implementing letters, directives, and other instruments and documents. It further provides for mutual releases by Big Rivers and E.ON of potential claims against one another. Big Rivers requests that the

Commission approve this agreement in order to permit the parties to implement the Unwind Transaction.

Q. What is the purpose of the Station Two G&A Allocation Agreement?

A. This agreement between Big Rivers and HMP&L provides for the allocation of general and administrative ("G&A") expenses (*i.e.*, labor, office expenses, etc.) associated with the operation and maintenance of Station Two. Big Rivers requests that the Commission approve this agreement.

Q. Please explain the purpose of the Agreement for Assignment of Responsibility for Complying with Reliability Standards Between Henderson Municipal Power & Light and Big Rivers Electric Corporation.

A. This agreement is designed to allocate responsibility as between Big Rivers and HMP&L for complying with North American Electric Reliability Corporation electric reliability standards with respect to Station Two and HMP&L's operation of its transmission system. Big Rivers requests that the Commission approve this agreement.

III. TARIFF CHANGES

Q. Please identify the areas of Big Rivers' Tariff which Big Rivers is proposing to change.

A. First, Big Rivers is filing a new Tariff superseding its Tariff filed on December 28, 2007, attached hereto as Exhibit 83 (clean) and Exhibit 84 (redlined), to remove references to the Member Discount Adjustment ("MDA"), which expired as described by C. William Blackburn in his Third Supplemental Direct Testimony, Exhibit 78. Second, there have been a number of changes in the Big Rivers' Large Industrial Customer Expansion Rate to comply with the Commission's Order in Case No. 2007-00164, dated February 1, 2008. Third, Big Rivers is making a small clarifying change to the Environmental Surcharge consistent with the Commission's Order in Case No. 2007-00460, dated June 25, 2008. And fourth, Big Rivers is updating the Member Rate Stability Mechanism included in the Tariff to reflect both an updated Economic Reserve Account amount and to include "feathering" of the use of the Economic Reserve, as described in Mr. Blackburn's testimony.

Q. What tariff changes did Big Rivers make to remove references to the MDA?

A. Big Rivers has deleted the Member Discount Adjustment Rider ("MDA"). That rider expired by its own terms on August 31, 2008. In addition, Big Rivers has eliminated references to the MDA in: (1) the Rural Delivery Point Tariff; (2) the Big Rivers Large Industrial Customer Tariff; and (3) the Renewable Resource Energy Service Tariff Rider.

Q. Please describe the tariff changes made to the Large Industrial Customer Expansion Rate.

A. In Case No. 2007-00164, the Commission ordered changes to the Large Industrial Customer Expansion Rate. The changes Big Rivers now makes implement the Commission's Order, as well as modifications Big Rivers proposed in its original application in this case.

Q. Please explain the clarifying change to the Environmental Surcharge.

A. On Original Sheet No. 72 of the Environmental Surcharge, definition (5) has been deleted to implement the Commission's Order in Case No. 2007-00460.

Q. Please describe the change to the Member Rate Stability Mechanism.

A. The Member Rate Stability Mechanism, incorporated at Original Sheet No. 76 to the Tariff, originally referenced the establishment of an Economic Reserve of $75 million. Due to the changes to the compensation between Big Rivers and E.ON relating to fuel costs reported in the June 2008 update, Big Rivers will be establishing an Economic Reserve of $157 million, and Original Sheet No. 76 reflects this updated amount. In addition, the Member Rate Stability Mechanism is revised to incorporate the feathering of the use of the Economic Reserve as briefly described in Mr. Blackburn's Third Supplemental Direct Testimony, Exhibit 78, and described in detail in the Supplemental Direct Testimony of William Steven Seelye, Exhibit 103, at pages 3 through 10. Specifically, the revisions incorporate the Expense Mitigation Adjustment to regulate the rate at which the Member Rate Stability Mechanism uses up the Economic Reserve.

IV. <u>OPEN ACCESS TRANSMISSION TARIFF FILING</u>

Q. What changes does Big Rivers now propose with respect to its Open Access Transmission Tariff?

A. Big Rivers in December 2007 filed a newly restated OATT (filed as Exhibit 33 to the Application) to replace in its entirety the OATT previously filed with and approved by the Commission (filed as Exhibit 32 to the Application). Because the revised OATT in this filing is based on the FERC's new transmission tariff requirements set forth in Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service,* 72 FR 12,266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007), and because the current OATT is based on the E.ON generation lease transaction in which Big Rivers owned the transmission and E.ON supplied generation-based services from the leased assets, Big Rivers recognized that it would not be practical to attempt to present the changes to the new OATT as a revision to the currently approved OATT. Instead, Big Rivers submitted a new and restated First Revised Big Rivers OATT as part of the December 2007 Application (Exhibit 33).

Soon after Big Rivers' filing of its new OATT in December 2007, the FERC on January 16, 2008 issued its order on rehearing of its Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2008). Order No. 890-A changed a variety of the required terms and conditions of FERC's *pro forma* OATT. On January 30, 2008, Big Rivers submitted a replacement First Revised OATT to the Commission to reflect these FERC changes (Exhibit A to Big Rivers' January 30, 2008 Motion to Amend Application).

Subsequently, on June 23, 2008, FERC issued an order on rehearing of Order No. 890-A, Order No. 890-B, *Preventing Undue Discrimination and Preference in Transmission Service*, 123 FERC ¶ 61,299 (2008). Once again FERC changed certain of the terms and conditions of its *pro forma* OATT on which Big Rivers' filed OATT in these proceedings is based. Moreover, FERC precedent interpreting other utilities' submitted OATTs has continued to cause Big Rivers to modify certain terms included in the February 2008 version of the First Restated Big Rivers OATT. Big Rivers now believes that it is necessary to replace the February 2008 version of the OATT with another replacement First Restated Big Rivers OATT containing provisions conforming to FERC's most recent OATT precedent. Accordingly, Big Rivers has submitted a new First Restated Big Rivers OATT as Exhibit 85.

Q. Why is it important to harmonize Big Rivers' OATT with these changes in FERC precedent?

A. Prior to closing of the Unwind Transaction, Big Rivers intends to make a filing at the FERC seeking a declaratory order that its updated OATT meets the requirements of a valid reciprocity tariff. In order to obtain that declaratory order, FERC must find that the terms and conditions of Big Rivers' OATT are consistent with or superior to the most recently adopted version of the FERC Order No. 890-B *pro forma* tariff. Accordingly it is important that Big Rivers' OATT be updated to reflect FERC's most recent precedent so that Big Rivers can file with both FERC and this Commission the same version of the OATT.

Q. Can you identify the changes made to the new Order No. 890-B version of the OATT as compared to the Order No. 890-A version of the OATT submitted in February?

A. Yes. These changes are reflected in Exhibit 86 to the Application Supplement and show changes between Exhibit 85 and the version of the OATT Big Rivers submitted as Exhibit A to Big Rivers' January 30, 2008 Motion to Amend Application (substitute Exhibit 33).

First, Big Rivers has generically implemented all of the FERC's Order No. 890-B changes to the OATT. These changes are minor, and consist largely of removing a descriptive requirement of FERC approval from references to reserve sharing programs and a clarification that non-Network Resources can be relied upon to serve Network Load when used as part of a reserves sharing agreement. Certain other minor wording changes from Order No. 890-B are also implemented.

Second, in response to FERC's clarification that all Transmission Providers, including non-jurisdictional Transmission Providers such as Big Rivers, must be subject to the FERC's proposed penalties for failure to meet certain customer response deadlines regarding the processing of system impact studies and facilities studies, Big Rivers has revised Section 19.9 to incorporate the *pro forma* Order No. 890 requirements that require penalizing the Transmission Provider in those situations. Big Rivers has incorporated the penalty levels required by the FERC in this section.

Third, in response to FERC clarification regarding the permissible amount of unreserved use penalties and the proper method of allocating those penalties to customers, Big Rivers has revised Sections 3, 13.7(c), 14.5, 15.8, 28.6, and 30.4, as well as Schedules 4 and 9, of the OATT to provide greater clarity in its unreserved use charges. Charges for unreserved use are revised to make clear that the total amount charged for the unreserved service taken including the penalty cannot exceed 200 percent of the otherwise applicable rate. References to penalties are changed to refer to charges for unreserved use to reflect this change. And the methodology for crediting these various penalty charges has been revised to make clear that amounts received for unreserved use in a given hour will be returned to all customers who did not incur an unreserved use charge in that hour, regardless of whether they may incur an unreserved use charge in other hours during the month. This is a change from the prior crediting methodology which provided for crediting only to customers that incurred no penalties in a given month, and is made to comply with FERC's clarified requirements.

V. DUE DILIGENCE

Q. What is the status of Big Rivers' conduct of due diligence concerning its generating units and sites?

A. Mark A. Bailey provides a discussion of Big Rivers' conduct of due diligence in his Supplemental Direct Testimony, Exhibit 104. As Mr. Bailey explains, Big Rivers is continuing to engage in due diligence, and will keep on doing so up to closing of the Unwind Transaction. I have attached as Exhibit DAS-2 to my supplemental testimony a list of certain due diligence closing conditions and our current understanding of how those conditions are expected to be satisfied. Big Rivers is continuing to pursue the outstanding issues with E.ON.

As discussed in the Supplemental Testimony of Paul W. Thompson (Exhibit 91), the Third Amendment to Transaction Termination Agreement, Exhibit 80, reflects the resolution of various environmental, operational, and other issues between WKEC and Big Rivers that have been identified in the course of due diligence. The Third Amendment also updates certain Schedules to the Transaction Termination Agreement updating SO_2 allowance allocations and capital expenditure fundings by WKEC in order to accommodate a 2009 closing. The Third Amendment is filed in substantially final form pending execution by the parties.

VI. ENVIRONMENTAL ISSUES

A. THE CAIR AND THE EFFECT OF COURT REVIEW

Q. Please briefly describe the CAIR.

A. The CAIR was promulgated by the EPA in 2005. Its purpose was to facilitate attainment of the National Ambient Air Quality Standards ("NAAQS") for fine particulate matter by reducing or eliminating the impact of SO_2 and NOx emissions generated at power plants located in "upwind" states, including Kentucky, on air quality in "downwind" states, particularly those east of the Mississippi River. The reductions were to occur in two phases: NOx reductions were to start in 2009, SO_2 reductions were to start in 2010, and a second phase for both pollutants was to begin in 2015, at which time emissions were to be reduced by approximately 70 percent. The CAIR provided for utilization of a "cap and trade" approach to achieve these reductions, including an optional interstate allowance trading program.

Under the cap and trade approach, the EPA allocates a specific amount of SO_2 and NO_x emissions allowances to specific states. The states, in turn, allocate the allowances to electric generating units ("EGUs") located within their borders. The plants then surrender the allowances back to the state for compliance purposes, based on each EGU's actual annual emissions. If a plant has installed emissions controls on its EGU(s), it likely will have a surplus of allowances that it can either bank for use in future years or sell to other power plants that need to obtain additional allowances for compliance purposes. If a plant has not installed SO_2 and NOx emissions controls on its EGU(s), it likely will be in a deficit position, and will need to purchase allowances from other sources and/or install control units.

Q. Why did the D.C. Circuit court strike down the CAIR?

A. The court concluded that the CAIR was inconsistent with the Clean Air Act in numerous respects. Among other things, the court rejected the EPA's proposed cap and trade approach because allowances were to be distributed based on regional contributions to SO_2 and NOx emissions, as opposed to contributions by individual states. As a result, states that are heavily dependent on coal-fired generation would receive more allowances than states that rely mainly on oil or gas generation, causing the latter states to subsidize emission reductions in the former states. The court concluded that the federal Clean Air Act required each state to prohibit emissions within its borders that significantly contribute to downwind pollution, rather than paying for emissions reductions in other states.

In addition, the court rejected as inconsistent with the Clean Air Act the EPA's mandated surrender rate for SO_2 allowances, which was intended to provide for the retirement of excess allowances under the pre-existing SO_2 allowance trading program. The EPA had determined that EGUs in states electing to participate in the CAIR allowance trading program would surrender two allowances for each ton of actual emissions beginning in 2010, and would surrender 2.85 allowances per ton beginning in 2015. The court ruled that the EPA could not remove allowances from the market in this manner. The court also found that the 2015 compliance deadline did not provide sufficient protection to downwind states projected to be in non-attainment with the NAAQS for fine particulates in 2010. The court found other defects as well, and concluded that because the EPA put forth the CAIR as an integrated whole, the CAIR should be vacated in its entirety and remanded the case to the EPA to promulgate a new rule consistent with the court's rulings.

Q. When will the court's ruling become effective?

A. The ruling will become legally effective when the court issues its mandate. I understand that the court has ordered that the mandate not be issued until after disposition of any timely petition for rehearing. I further understand that, at the EPA's request, the court has extended the deadline for filing petitions for rehearing until September 24, 2008. I anticipate that petitions for rehearing will be filed, and that ultimately the case will be appealed to the United States Supreme Court. Thus, it is uncertain when the court's ruling will become effective.

Q. Is the fate of the CAIR regulations relevant to Big Rivers' application in this case?

A. Yes, it is. As part of its application in this case, to support the proposed Environmental Surcharge, Big Rivers submitted a limited Big Rivers Electric Corporation Environmental Compliance Plan ("Environmental Compliance Plan"), which was included as Exhibit DAS-1 to my previous testimony, Exhibit 18. This plan included separate SO_2, NOx, and SO_3 programs. As I explained in my previous testimony, the SO_2 and NOx programs in the Environmental Compliance Plan were premised, in part, on the provisions of the CAIR, including the allowance cap and trade program. Moreover, Kentucky's proposed state implementation plan ("SIP") for fine particulates relies significantly on the reductions that would have been produced under the CAIR. The D.C. Circuit's decision to strike down the CAIR creates substantial uncertainties regarding what steps Big Rivers will need to take in order to be compliant with SO_2 and NOx emissions rules, and also creates uncertainties concerning how the Kentucky SIP will be brought into compliance with federal mandates.

B. IMPACT ON BIG RIVERS

Q. What do you anticipate will be the impact of the CAIR ruling on Big Rivers?

A. It is difficult to determine the impact of the court's ruling with any degree of certainty at this time. As I noted previously, the ruling is subject to likely petitions for rehearing before the D.C. Circuit, and possible Supreme Court review. If the D.C. Circuit's decision stands, upon issuance of the mandate the EPA will be obligated to go back to the drawing board and attempt to craft a new rule that complies with the court's holdings; this is unlikely to occur in 2008, and some have estimated that there may not be new regulations for a period of two to three years. I also anticipate that any such rule would be subject to further litigation. It is also conceivable that federal legislation could be enacted to address these issues.

Q. What is Big Rivers' status with respect to SO_2 emissions?

A. Big Rivers currently has control devices (Flue Gas Desulphurization Systems or scrubbers) on all units except for Reid Station Unit One, which accounts for less than 5 percent of Big Rivers' annual generation. Following the installation of the Coleman Station scrubber in 2006, Big Rivers has an annual surplus of SO_2 allowances under the pre-CAIR allowances regime, which allowances can either be banked for future use or sold on the open market for financial gain. This annual surplus should continue pending reinstatement of the CAIR regulations or promulgation of a new rule. Based on modeled load demand, Big Rivers also should be in a relatively solid position to comply with future SO_2 regulations.

Q. What is Big Rivers' status with respect to NOx emissions?

A. The pre-CAIR program, known as the "NOx SIP Call," requires that EGUs maintain NOx emissions at a level below their allowance allocation only during the Ozone Season (between May 1 and September 30). Under this program, Big Rivers operates at a slight deficit for NOx emissions, in large measure because neither the Green Station nor the Coleman Station has significant Selective Catalytic Reduction ("SCR") control units installed for NOx reduction. The CAIR was structured to have two NOx emissions control periods: the existing Ozone Season and an Annual Season, the latter covering the entire calendar year. Under the CAIR, Big Rivers' deficit for NOx emissions would have grown greater, due to the requirement to control emissions on a year-round basis. This would have required Big Rivers to purchase significantly more allowances in the market, and would have confronted Big Rivers with a choice as to whether to install SCR units prior to 2015, a choice that would be driven in part by the estimated future price of NOx allowances.

Q. Does the court's ruling impact the results of the financial model employed by Big Rivers in modeling the Unwind Transaction?

A. Yes. With the CAIR vacated, and until a new rule is developed, Big Rivers will have more SO_2 allowances to bank or sell than modeled, and fewer NOx allowances to purchase than modeled. However, the current price per allowance has decreased as a result of the court's ruling, which lowers the revenue projected from sales of allowances under the financial model. As described in Mr. Blackburn's Third Supplemental Direct Testimony, Big Rivers has re-run the financial model to reflect, among other matters, the elimination of the CAIR. Mr. Blackburn describes the changes to the financial model that result from the D.C. Circuit's decision.

Q. Does the vacation of the CAIR have other implications for Big Rivers' environmental compliance?

A. Yes. The Kentucky Department of Air Quality ("DAQ") enforces other federally mandated clean air programs, some of which were dependent on emissions reductions resulting from the CAIR to ensure EGU compliance with federal air quality standards. These include the Clean Air Visibility Rule and, as I noted above, the NAAQS for fine particulate matter. The D.C. Circuit's decision to strike down the CAIR raises uncertainty as to how EGUs in Kentucky, including Big Rivers, will meet the attainment standards under these programs.

Q. How is Big Rivers responding to the state of uncertainty produced by the striking down of the CAIR?

A. At this time, Big Rivers is monitoring developments as they occur, in the judicial process as well as in the state and federal regulatory and legislative arenas. Big Rivers is a member of the Utility Information Exchange of Kentucky ("UIEK"), which held a meeting on August 27, 2008 with the

Kentucky Energy and Environmental Cabinet to discuss the ramifications of the court's ruling. UIEK informed the Kentucky Energy and Environmental Cabinet that new construction projects of control equipment will not be discontinued based on the CAIR rule being struck down, and that operation of control equipment will likely continue for the most part as is. Big Rivers will continue to stay in close contact with the DAQ to keep abreast of developments and will participate in any new rulemaking proceedings through the UIEK.

Q. Has Big Rivers revised its environmental projections to reflect the vacation of the CAIR?

A. Yes. Big Rivers currently anticipates that that there will be no replacement for the CAIR until January 1, 2011 at the earliest. Accordingly, Big Rivers has revised its projections for its three separate environmental programs to reflect the assumption that existing emissions rules will remain in place for the years 2009 and 2010. Big Rivers' revisions are reflected in the Production Work Plan filed as Exhibit 105 and reflected in the Unwind Financial Model.

Q. Do these changes have any effect on the Environmental Surcharge that the Commission has approved in Case No. 2007-00460?

A. Neither the Environmental Surcharge mechanism nor Big Rivers' limited Environmental Compliance Plan has changed. Only the costs estimated in Big Rivers' limited Environmental Compliance Plan have changed. These changes, of course, flow through the Unwind Financial Model. The Commission does not need to take any further action with respect to the Environmental Surcharge mechanism or Big Rivers' ES tariff.

Q. Does this conclude your testimony at this time?

A. Yes.

Exhibit DAS-2

Status of Disposition of Certain Closing Conditions

Section 10.3 of the Termination Agreement contains 42 closing conditions, certain of which require continuing due diligence and resolution of identified issues. Some of those due diligence closing conditions are time sensitive; for example Section 10.3 (w) No Damage to Generating Plants. For instance, if there is an occurrence the day of the close that would result in a "Material Casualty Damage," then Big Rivers and WKEC would have to either not close or satisfactorily resolve the situation in order to close.

Closing condition 10.3 (y), Environmental Conditions –As a result of information gained through the Environmental Audit and other due diligence, Big Rivers has identified several issues that are resolved in the Third Amendment to the Termination Agreement. In anticipation that subsequent issues could arise prior to closing, an attempt has been made to develop a process to address them.

Closing condition 10.3 (cc), Gypsum Facilities of Plant Green. The facilities have been restored, and the condition satisfied.

Closing condition 10.3 (dd), Condition of Generating Plants. See description of Section 10.3(w) in the first paragraph, above. Additionally, Big Rivers identified an issue regarding the Wilson stack which is resolved in the Third Amendment.

Closing condition 10.3 (ee), Capabilities of Generating Plants. Physical testing of the Generating Plant capabilities has been conducted with the exception of the Reid combustion turbine, which is part of the "2 Unit Plant Reid" test. This condition has been met with respect to the Generating Plants that have been tested.

Closing condition 10.3 (ff), No Forced Outage at Generating Plants. For obvious reasons, this condition cannot be met or considered met until the close.

Closing condition 10.3 (hh), Gypsum Offtake. WKEC is negotiating the terms of a different gypsum offtake contract which Big Rivers will review. It is too soon to determine the outcome of this as a closing condition.

Closing condition 10.3 (ii), Operating Plans. Big Rivers has submitted a revised operating plan in this filing. That plan is based in large part on the WKEC operating plan. Big Rivers will continue to monitor the current WKEC operating plan for deviations and will treat this as a closing condition to be addressed on the date of the closing.

Closing condition 10.3 (jj), Clean Out of Wilson Ponds. The referenced ponds have been cleaned out. The Third Amendment to the Termination Agreement addresses ponds to be cleaned out prior to the close.

Closing condition 10.3 (mm), No Unresolved Disputes. This closing condition cannot be met until the date of the close. Big Rivers and E.On are working through issues as they occur in an attempt to make sure this condition is met.

Big Rivers has worked through hundreds of closing condition issues in an attempt to eliminate all questions before the date of the closing. The above information is being provided to give the Commission and the other parties to this proceeding additional confidence that Big Rivers and the E.ON Parties are working diligently to resolve issues as they occur in order to minimize closing condition issues that must be resolved on the date of the closing.

VERIFICATION

I verify, state, and affirm that the foregoing testimony is true and correct to the best of my knowledge and belief.

David A. Spainhoward

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by David A. Spainhoward on this the 7th day of October, 2008.

Paula Mitchell
Notary Public, Ky. State at Large
My Commission Expires 1-12-09

EXHIBIT 100

COMPARISON OF RATES UNDER THE UNWIND TRANSACTION AND RATES UNDER THE EXISTING TRANSACTION

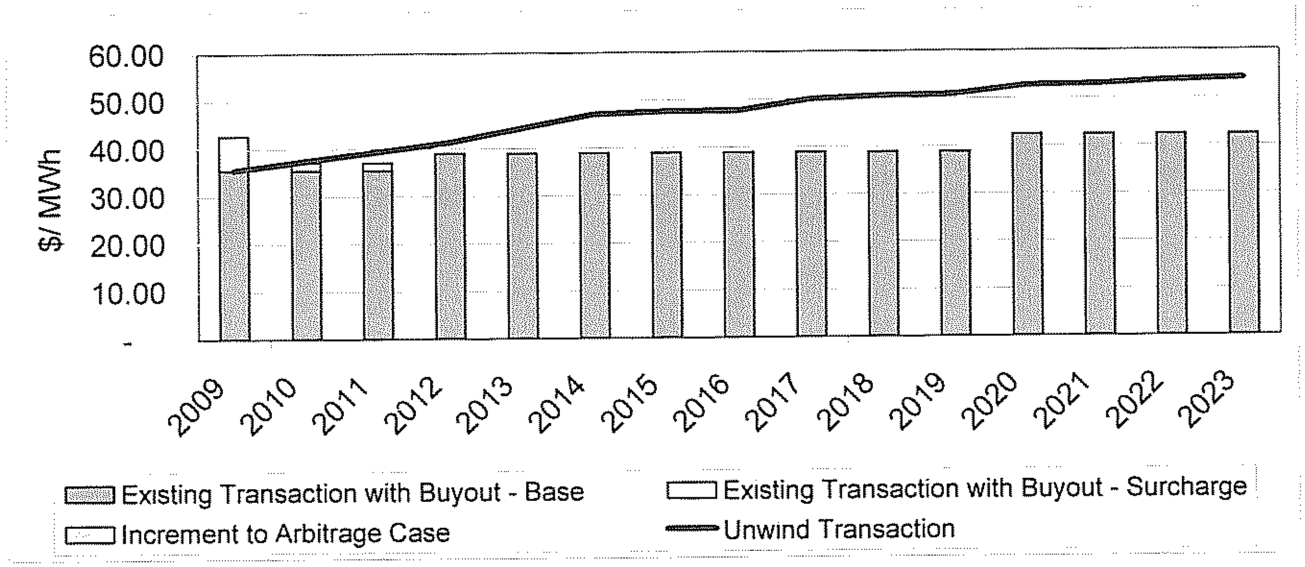
Existing Transaction Economics, 10/08/08

Existing Transaction/ Arbitrage Case

Rates Compared to Unwind

Member Rate Summary (Blended Basis)	Wtd. Avg.	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Existing Transaction (9/30/08)																
Base	39.23	35.45	35.42	35.39	38.90	38.87	38.84	38.81	38.79	38.76	38.74	38.72	42.24	42.21	42.19	42.17
% Change			0%	0%	10%	0%	0%	0%	0%	0%	0%	0%	9%	0%	0%	0%
Surcharge	0.60	7.14	1.67	1.63	-	-	-	-	-	-	-	-	-	-	-	-
Increment to Arbitrage Case	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	39.83	42.59	37.09	37.02	38.90	38.87	38.84	38.81	38.79	38.76	38.74	38.72	42.24	42.21	42.19	42.17
Overall % Change			-13%	0%	5%	0%	0%	0%	0%	0%	0%	0%	9%	0%	0%	0%
Unwind (10/4/08)	47.49	35.45	37.42	39.29	41.26	44.14	47.01	47.49	47.64	49.94	50.54	50.84	52.67	52.88	53.57	53.98

Comparative Rate Graph:



Existing Transaction/ Arbitrage Case

Energy Balance and Rates

		PMCC Lease Buyout @ 12/31/08	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Energy Balance (GWh)**																
2																	
3	*Sales*																
4	Members		3,501	3,584	3,674	3,760	3,852	3,939	4,032	4,122	4,217	4,308	4,404	4,498	4,596	4,691	4,786
5	Arbitrage		2,042	1,961	2,924	3,568	3,440	3,356	3,264	3,179	3,084	2,995	2,901	2,812	2,714	2,612	2,517
6	Smelters		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	*Losses*		44	44	52	58	57	57	57	57	57	57	57	57	57	57	57
8	Sales + Losses		5,586	5,588	6,650	7,386	7,349	7,352	7,354	7,358	7,358	7,360	7,363	7,368	7,367	7,360	7,361
9	*Purchases*																
10	Base (LEM)		5,254	5,252	6,322	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008
11	SEPA		305	305	305	267	267	267	267	267	267	267	267	267	267	267	267
12	Market		28	32	24	111	74	77	79	83	83	85	88	93	92	85	86
13	Total		5,586	5,588	6,650	7,386	7,349	7,352	7,354	7,358	7,358	7,360	7,363	7,368	7,367	7,360	7,361
14																	
15	**Energy Rates ($/ Mwh)**																
16																	
17	*Sales*																
18	Members																
19	Base		35.45	35.42	35.39	38.90	38.87	38.84	38.81	38.79	38.76	38.74	38.72	42.24	42.21	42.19	42.17
20	Base % Change			0%	0%	10%	0%	0%	0%	0%	0%	0%	0%	9%	0%	0%	0%
21	Surcharge		7.14	1.67	1.63	-	-	-	-	-	-	-	-	-	-	-	-
22	Increment to Arbitrage Case		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total		42.59	37.09	37.02	38.90	38.87	38.84	38.81	38.79	38.76	38.74	38.72	42.24	42.21	42.19	42.17
24	Overall % Change			-13%	0%	5%	0%	0%	0%	0%	0%	0%	0%	9%	0%	0%	0%
25	Arbitrage		49.42	48.14	47.44	51.17	59.97	53.15	54.32	53.21	54.11	54.71	57.13	54.39	54.82	55.16	55.02
26	Smelters		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	*Purchases*																
28	Base (LEM)		20.33	20.63	20.95	20.27	20.59	20.92	21.25	21.59	21.93	22.28	22.63	22.99	23.36	23.72	24.08
29	SEPA		22.44	22.44	22.44	28.33	29.04	29.75	29.75	29.75	29.75	30.50	31.24	31.24	31.24	31.24	32.00
30	Market (Peak)		200	200	200	200	200	200	200	200	200	200	200	200	200	200	200

Existing Transaction/ Arbitrage Case

Cash Flows

			PMCC Lease Buyout @ 12/31/08	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
32	**Cash Flow ($M)**																	
33																		
34	*Beginning Balance*	146.0	147.2	37.9	33.1	44.0	54.4	53.4	78.6	96.0	111.5	117.8	121.8	121.1	119.5	127.0	156.9	159.8
35																		
36	*Receipts*																	
37	Members			149.1	132.9	136.0	146.3	149.7	153.0	156.5	159.9	163.4	166.9	170.5	190.0	194.0	197.9	201.9
38	Arbitrage			100.9	94.4	138.7	182.6	206.3	178.4	177.3	169.1	166.9	163.9	165.7	152.9	148.8	144.1	138.5
39	Smelters			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Other			57.6	57.2	55.0	49.9	52.1	53.1	53.8	54.4	54.7	54.9	54.8	55.4	55.7	56.9	57.1
41	Total			307.6	284.5	329.7	378.8	408.1	384.4	387.6	383.5	385.0	385.6	391.1	398.4	398.5	398.9	397.4
42	*Disbursements*																	
43	Base Purchases			106.8	108.3	132.4	142.0	144.3	146.6	148.9	151.3	153.7	156.1	158.6	161.1	163.7	166.2	168.8
44	SEPA Purchases			6.8	6.8	6.8	7.6	7.8	7.9	7.9	7.9	7.9	8.1	8.3	8.3	8.3	8.3	8.5
45	Market Energy Purchases			5.6	6.5	4.8	22.2	14.9	15.3	15.7	16.6	16.6	17.1	17.5	18.6	18.4	17.0	17.2
46	Market Purchase Related			17.7	18.4	10.8	12.6	12.3	12.3	12.1	12.0	11.9	11.9	11.8	11.7	11.6	11.5	11.4
47	A&G			17.3	17.8	18.3	18.9	19.5	20.0	20.6	21.3	21.9	22.6	23.2	23.9	24.6	25.4	26.1
48	RVP			-	-	-	-	-	-	-	-	-	-	-	-	-	-	376.6
49	Purchase of Production Inventory			-	-	-	-	-	-	-	-	-	-	-	-	-	-	80.1
50	Other			28.5	7.6	35.1	45.1	55.8	43.2	50.1	48.9	50.7	52.0	54.4	53.3	57.0	57.7	57.1
51	Total			182.8	165.5	208.2	248.4	254.5	245.3	255.4	258.0	262.7	267.7	273.8	276.9	283.6	286.1	745.9
52	*BREC Share of Capital Expenditures*			24.5	18.4	13.6	13.3	8.2	7.9	8.4	9.5	11.1	11.7	13.3	12.3	12.8	13.0	13.5
53	*Debt Service*																	
54	New Borrowing			-	-	-	-	-	-	-	-	-	-	-	-	-	-	(390.3)
55	Principal Repayment (incl. ARVP)			39.2	41.0	53.3	77.0	80.7	78.6	77.0	82.5	84.5	88.3	91.2	91.2	66.2	93.6	115.3
56	Interest			52.9	48.7	44.3	41.1	39.5	35.2	31.2	27.2	22.8	18.5	14.5	10.5	6.0	3.4	-
57	Total			92.1	89.7	97.6	118.1	120.2	113.8	108.3	109.7	107.3	106.8	105.7	101.7	72.2	97.0	(275.0)
58	*PMCC Lease Buyout*																	
59	Termination Payment (net)		(214.0)															
60	GIC		92.6															
61	B Loan		(0.3)															
62	Net		(121.7)															
63	PMCC Loan		12.4	(13.0)														
64	*Net Cash Flow*		(109.3)	(4.8)	10.9	10.4	(1.0)	25.2	17.4	15.5	6.3	3.9	(0.6)	(1.6)	7.5	29.9	2.8	(87.0)
65	*Ending Balance*		37.9	33.1	44.0	54.4	53.4	78.6	96.0	111.5	117.8	121.8	121.1	119.5	127.0	156.9	159.8	72.8

Existing Transaction Economics, 10/08/08

Existing Transaction/ Arbitrage Case

Income Statement and Balance Sheet

	PMCC Lease Buyout @ 12/31/08	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Income Statement																
Revenues																
Members		149.1	132.9	136.0	146.3	149.7	153.0	156.5	159.9	163.4	166.9	170.5	190.0	194.0	197.9	201.9
Arbitrage		100.9	94.4	138.7	182.6	206.3	178.4	177.3	169.1	166.9	163.9	165.7	152.9	148.8	144.1	138.5
Other		37.9	38.1	12.2	10.1	10.4	11.7	12.8	13.8	14.5	15.3	16.2	18.0	19.9	23.9	29.7
Total		287.9	265.4	287.0	338.9	366.4	343.0	346.6	342.8	344.8	346.1	352.4	360.9	362.7	365.8	370.1
Expenses																
Base Purchases		106.8	108.3	132.4	142.0	144.3	146.6	148.9	151.3	153.7	156.1	158.6	161.1	163.7	166.2	168.8
SEPA Purchases		6.8	6.8	6.8	7.6	7.8	7.9	7.9	7.9	7.9	8.1	8.3	8.3	8.3	8.3	8.5
Market Purchases and Related		23.3	24.9	15.5	34.8	27.2	27.6	27.9	28.6	28.6	28.9	29.3	30.3	30.0	28.4	28.6
A&G		17.3	17.8	18.3	18.9	19.5	20.0	20.6	21.3	21.9	22.6	23.2	23.9	24.6	25.4	26.1
Interest		59.9	55.2	53.0	50.0	46.7	42.5	39.4	35.6	31.9	28.0	25.2	21.2	17.6	16.5	14.0
Other		32.7	24.3	46.3	51.1	56.0	51.0	55.6	55.0	56.1	57.6	59.2	57.8	61.9	62.6	62.6
Total		246.9	237.4	272.4	304.5	301.3	295.7	300.3	299.7	300.1	301.3	303.9	302.7	306.2	307.5	308.6
Net Margin		40.9	28.0	14.6	34.5	65.0	47.3	46.2	43.1	44.8	44.8	48.5	58.3	56.5	58.4	61.5
Balance Sheet																
Assets																
Net Utility Plant	913	955	964	967	951	942	925	908	889	872	857	845	830	814	798	782
Sale-Leaseback Investments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cash & Investments	38	33	44	54	53	79	96	112	118	122	121	120	127	157	160	73
Receivables & Other	132	129	124	115	113	112	104	99	93	88	83	78	73	68	63	138
Assets	1,083	1,118	1,131	1,136	1,117	1,132	1,125	1,118	1,100	1,082	1,061	1,043	1,030	1,039	1,021	994
Liabilities & Equities																
Equities	(135)	(94)	(66)	(52)	(17)	48	95	141	184	229	274	323	381	437	496	557
Sale-Leaseback Obligation & Unamorti	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt	1,040	994	960	913	843	770	699	630	556	480	402	320	239	184	102	390
RVP/ Lease Advance	153	191	200	232	244	269	286	302	315	328	341	355	365	373	378	0
Payables & Other	27	27	38	42	48	46	46	45	45	45	45	45	45	45	45	46
Liabilities & Equities	1,083	1,118	1,131	1,136	1,117	1,132	1,125	1,118	1,100	1,082	1,061	1,043	1,030	1,039	1,021	994

Exhibit 100

Existing Transaction/ Smelter Sale Case (200MW)

Rates Compared to Unwind

Member Rate Summary (Blended Basis)	Wtd. Avg.	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Existing Transaction (9/30/08)																
Base	39.23	35.45	35.42	35.39	38.90	38.87	38.84	38.81	38.79	38.76	38.74	38.72	42.24	42.21	42.19	42.17
% Change			0%	0%	10%	0%	0%	0%	0%	0%	0%	0%	9%	0%	0%	0%
Surcharge	0.60	7.14	1.67	1.63	-	-	-	-	-	-	-	-	-	-	-	-
Increment to Arbitrage Case	5.74	-	-	8.71	8.05	4.59	4.59	4.59	7.15	7.15	7.14	7.14	6.31	6.30	6.30	6.30
Total	45.56	42.59	37.09	45.73	46.95	43.46	43.42	43.40	45.94	45.91	45.88	45.85	48.55	48.52	48.49	48.47
Overall % Change			-13%	23%	3%	-7%	0%	0%	6%	0%	0%	0%	6%	0%	0%	0%
Unwind (10/4/08)	47.49	35.45	37.42	39.29	41.26	44.14	47.01	47.49	47.64	49.94	50.54	50.84	52.67	52.88	53.57	53.98

Comparative Rate Graph:

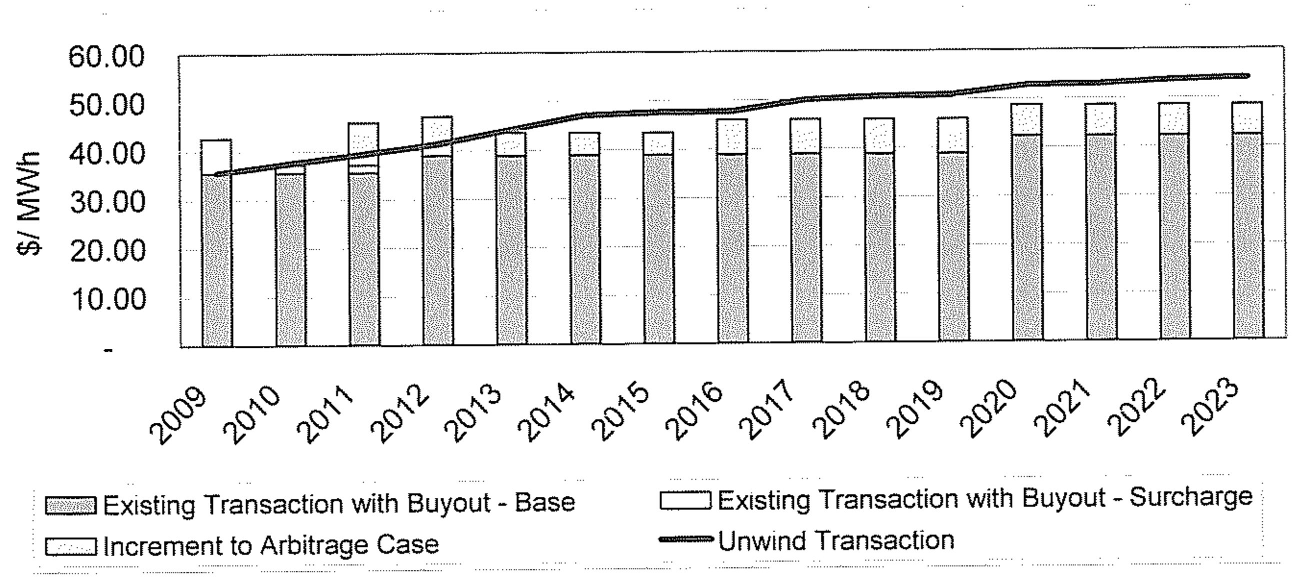


Exhibit 100

Existing Transaction/ Smelter Sale Case (200MW)

Energy Balance and Rates

		PMCC Lease Buyout @ 12/31/08	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Energy Balance (GWh)**																
2																	
3	*Sales*																
4	Members		3,501	3,584	3,674	3,760	3,852	3,939	4,032	4,122	4,217	4,308	4,404	4,498	4,596	4,691	4,786
5	Arbitrage		2,042	1,961	1,873	1,816	1,688	1,604	1,512	1,427	1,332	1,243	1,149	1,060	962	860	765
6	Smelters		-	-	1,051	1,752	1,752	1,752	1,752	1,752	1,752	1,752	1,752	1,752	1,752	1,752	1,752
7	*Losses*		44	44	52	58	57	57	57	57	57	57	57	57	57	57	57
8	Sales + Losses		5,586	5,588	6,650	7,386	7,349	7,352	7,354	7,358	7,358	7,360	7,363	7,368	7,367	7,360	7,361
9	*Purchases*																
10	Base (LEM)		5,254	5,252	6,322	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008
11	SEPA		305	305	305	267	267	267	267	267	267	267	267	267	267	267	267
12	Market		28	32	24	111	74	77	79	83	83	85	88	93	92	85	86
13	Total		5,586	5,588	6,650	7,386	7,349	7,352	7,354	7,358	7,358	7,360	7,363	7,368	7,367	7,360	7,361
14																	
15	**Energy Rates ($/ Mwh)**																
16																	
17	*Sales*																
18	Members																
19	Base		35.45	35.42	35.39	38.90	38.87	38.84	38.81	38.79	38.76	38.74	38.72	42.24	42.21	42.19	42.17
20	Base % Change			0%	0%	10%	0%	0%	0%	0%	0%	0%	0%	9%	0%	0%	0%
21	Surcharge		7.14	1.67	1.63	-	-	-	-	-	-	-	-	-	-	-	-
22	Increment to Arbitrage Case		-	-	8.71	8.05	4.59	4.59	4.59	7.15	7.15	7.14	7.14	6.31	6.30	6.30	6.30
23	Total		42.59	37.09	45.73	46.95	43.46	43.42	43.40	45.94	45.91	45.88	45.85	48.55	48.52	48.49	48.47
24	Overall % Change			-13%	23%	3%	-7%	0%	0%	6%	0%	0%	0%	6%	0%	0%	0%
25	Arbitrage		49.42	48.14	42.49	40.76	41.89	38.64	38.97	38.86	39.05	39.40	40.19	39.41	39.33	39.49	39.47
26	Smelters		-	-	27.87	34.22	34.22	34.22	34.22	36.23	36.23	36.23	36.23	38.36	38.36	38.36	38.36
27	*Purchases*																
28	Base (LEM)		20.33	20.63	20.95	20.27	20.59	20.92	21.25	21.59	21.93	22.28	22.63	22.99	23.36	23.72	24.08
29	SEPA		22.44	22.44	22.44	28.33	29.04	29.75	29.75	29.75	29.75	30.50	31.24	31.24	31.24	31.24	32.00
30	Market (Peak)		200	200	200	200	200	200	200	200	200	200	200	200	200	200	200

Existing Transaction/ Smelter Sale Case (200MW)

Cash Flows

Row			PMCC Lease Buyout @ 12/31/08	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
32	**Cash Flow ($M)**																	
33																		
34	*Beginning Balance*	146.0	147.2	37.9	33.1	44.0	54.5	54.8	61.9	68.3	73.2	84.5	94.6	99.0	99.5	114.3	151.6	161.5
35																		
36	*Receipts*																	
37	Members			149.1	132.9	168.0	176.5	167.4	171.0	175.0	189.4	193.6	197.6	202.0	218.4	223.0	227.5	232.0
38	Arbitrage			100.9	94.4	79.6	74.0	70.7	62.0	58.9	55.4	52.0	49.0	46.2	41.8	37.8	33.9	30.2
39	Smelters			-	-	29.3	60.0	60.0	60.0	60.0	63.5	63.5	63.5	63.5	67.2	67.2	67.2	67.2
40	Other			57.6	57.2	55.0	48.7	48.5	48.7	48.8	49.1	49.4	49.6	49.6	49.6	50.0	51.2	51.4
41	Total			307.6	284.5	331.9	359.2	346.6	341.7	342.7	357.4	358.4	359.7	361.2	377.0	378.0	379.9	380.8
42	*Disbursements*																	
43	Base Purchases			106.8	108.3	132.4	142.0	144.3	146.6	148.9	151.3	153.7	156.1	158.6	161.1	163.7	166.2	168.8
44	SEPA Purchases			6.8	6.8	6.8	7.6	7.8	7.9	7.9	7.9	7.9	8.1	8.3	8.3	8.3	8.3	8.5
45	Market Energy Purchases			5.6	6.5	4.8	22.2	14.9	15.3	15.7	16.6	16.6	17.1	17.5	18.6	18.4	17.0	17.2
46	Market Purchase Related			17.7	18.4	22.2	18.3	8.5	8.4	8.4	8.3	8.3	9.1	10.1	11.0	12.0	12.9	13.9
47	A&G			17.3	17.8	18.3	18.9	19.5	20.0	20.6	21.3	21.9	22.6	23.2	23.9	24.6	25.4	26.1
48	RVP			-	-	-	-	-	-	-	-	-	-	-	-	-	-	376.6
49	Purchase of Production Inventory			-	-	-	-	-	-	-	-	-	-	-	-	-	-	80.1
50	Other			28.5	7.6	27.8	23.5	26.1	22.6	27.3	28.8	29.2	31.2	32.2	34.7	38.0	39.1	39.4
51	Total			182.8	165.5	212.4	232.5	220.9	220.9	228.8	234.2	237.6	244.3	250.0	257.6	265.1	269.0	730.6
52	*BREC Share of Capital Expenditures*			24.5	18.4	13.6	13.3	8.2	7.9	8.4	9.5	11.1	11.7	13.3	12.3	12.8	13.0	13.5
53	*Debt Service*																	
54	New Borrowing			-	-	-	-	-	-	-	-	-	-	-	-	-	-	(480.7)
55	Principal Repayment (incl. ARVP)			39.2	41.0	51.1	72.0	70.8	71.2	69.3	75.1	76.9	80.8	83.0	81.8	56.9	84.5	205.7
56	Interest			52.9	48.7	44.3	41.1	39.5	35.2	31.2	27.2	22.8	18.5	14.5	10.5	6.0	3.4	-
57	Total			92.1	89.7	95.5	113.1	110.3	106.4	100.6	102.3	99.7	99.3	97.5	92.3	62.8	88.0	(275.0)
58	*PMCC Lease Buyout*																	
59	Termination Payment (net)		(214.0)															
60	GIC		92.6															
61	B Loan		(0.3)															
62	Net		(121.7)															
63	PMCC Loan		12.4	(13.0)														
64	*Net Cash Flow*		(109.3)	(4.8)	10.9	10.5	0.3	7.1	6.4	4.9	11.3	10.1	4.5	0.5	14.8	37.3	9.9	(88.3)
65	*Ending Balance*		37.9	33.1	44.0	54.5	54.8	61.9	68.3	73.2	84.5	94.6	99.0	99.5	114.3	151.6	161.5	73.2

Existing Transaction/ Arbitrage Case

Income Statement and Balance Sheet

	PMCC Lease Buyout @ 12/31/08	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Income Statement																
Revenues																
Members		149.1	132.9	168.0	176.5	167.4	171.0	175.0	189.4	193.6	197.6	202.0	218.4	223.0	227.5	232.0
Arbitrage		100.9	94.4	79.6	74.0	70.7	62.0	58.9	55.4	52.0	49.0	46.2	41.8	37.8	33.9	30.2
Other		37.9	38.1	41.5	68.8	66.7	67.2	67.7	71.9	72.7	73.6	74.4	79.4	81.4	85.4	91.3
Total		287.9	265.4	289.1	319.4	304.8	300.2	301.6	316.7	318.3	320.2	322.6	339.5	342.2	346.8	353.5
Expenses																
Base Purchases		106.8	108.3	132.4	142.0	144.3	146.6	148.9	151.3	153.7	156.1	158.6	161.1	163.7	166.2	168.8
SEPA Purchases		6.8	6.8	6.8	7.6	7.8	7.9	7.9	7.9	7.9	8.1	8.3	8.3	8.3	8.3	8.5
Market Purchases and Related		23.3	24.9	26.9	40.5	23.4	23.8	24.1	24.9	24.9	26.2	27.6	29.6	30.4	29.9	31.1
A&G		17.3	17.8	18.3	18.9	19.5	20.0	20.6	21.3	21.9	22.6	23.2	23.9	24.6	25.4	26.1
Interest		59.9	55.2	53.0	50.0	46.7	42.5	39.4	35.6	31.9	28.0	25.2	21.2	17.6	16.5	14.0
Other		32.7	24.3	36.2	31.3	29.3	29.4	33.5	34.2	35.2	36.9	37.6	38.7	43.0	44.1	44.8
Total		246.9	237.4	273.7	290.4	270.8	270.3	274.5	275.2	275.5	278.0	280.6	282.8	287.8	290.4	293.3
Net Margin		40.9	28.0	15.4	29.0	34.0	29.9	27.1	41.5	42.7	42.2	42.0	56.7	54.4	56.4	60.1
Balance Sheet																
Assets																
Net Utility Plant	913	955	964	967	951	942	925	908	889	872	857	845	830	814	798	782
Sale-Leaseback Investments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cash & Investments	38	33	44	55	55	62	68	73	84	95	99	100	114	152	162	73
Receivables & Other	132	129	124	119	115	109	103	97	92	86	81	75	72	67	62	137
Assets	1,083	1,118	1,131	1,140	1,120	1,113	1,096	1,078	1,065	1,053	1,037	1,020	1,016	1,032	1,021	993
Liabilities & Equities																
Equities	(135)	(94)	(66)	(51)	(22)	12	42	69	111	153	196	238	294	349	405	465
Sale-Leaseback Obligation & Unamorti	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt	1,040	994	960	915	850	787	723	662	595	527	456	383	312	266	193	481
RVP/ Lease Advance	153	191	200	232	244	269	286	302	315	328	341	355	365	373	378	0
Payables & Other	27	27	38	43	48	46	45	45	45	44	44	45	45	45	45	46
Liabilities & Equities	1,083	1,118	1,131	1,140	1,120	1,113	1,096	1,078	1,065	1,053	1,037	1,020	1,016	1,032	1,021	993

EXHIBIT 101

SUPPLEMENTAL DIRECT TESTIMONY OF BURNS E. MERCER

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2007-00455

SUPPLEMENTAL TESTIMONY OF BURNS E. MERCER

ON BEHALF OF
APPLICANTS

OCTOBER 2008

SUPPLEMENTAL TESTIMONY OF
BURNS E. MERCER

I. INTRODUCTION

Q. Please state your name.

A. My name is Burns E. Mercer.

Q. Are you the same Burns E. Mercer who previously submitted direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your supplemental testimony in this proceeding?

A. The purpose of my supplemental testimony is to provide an update to the Kentucky Public Service Commission ("Commission") on the views of the Member Distribution Cooperatives ("Members") of Big Rivers Electric Corporation ("Big Rivers"), including Meade County Rural Electric Cooperative Corporation, Kenergy Corp., and Jackson Purchase Electric Corporation, concerning certain developments relating to the Unwind

Transaction for which Big Rivers is seeking approval in this proceeding. Specifically, I testify to the Members' continued support for the Unwind Transaction.

II. <u>BIG RIVERS' MEMBERS CONTINUE TO SUPPORT THE UNWIND TRANSACTION</u>.

Q. Are you familiar with the arrangements under which Big Rivers has terminated its leveraged lease transactions of undivided interests in Plants Green and Wilson with a subsidiary of Philip Morris Capital Corporation ("PMCC")?

A. Yes, I am aware that in order to address complications resulting from a downgrade in the claims paying ability of Ambac Assurance Corporation, Big Rivers agreed to terminate the PMCC lease transactions pursuant to a buy-out structure involving financial contributions from Big Rivers and other entities ("PMCC Buyout").

Q. Are you familiar with the arrangements involved in the termination of Big Rivers' leveraged lease transactions involving Bank of America Leasing ("BoA") in June 2008 (the "BoA Buyout")?

A. *Yes. I am familiar with the BoA Buyout.*

Q. Have you reviewed the revised financial model presented by Big Rivers showing the effects of the Unwind Transaction, incorporating the PMCC Buyout, the BoA Buyout, and other changes to the Unwind Transaction since the original version of the Unwind Financial Model was filed on December 28, 2007?

A. Yes, I have reviewed the revised Unwind Financial Model (Exhibit 79) and am familiar with the projected results, as they are presented in Mr. Blackburn's testimony, Exhibit 78, including the projected rates for Big Rivers' Members.

Q. In light of the foregoing developments, do the Members continue to support the Unwind Transaction?

A. Yes, the Members have not changed their positions supporting the Unwind Transaction. The Members believe that the Unwind Transaction continues to present the prospect of multiple benefits for the Members and for Big Rivers, as I explained in my previous testimony in this proceeding, Exhibit 26. Nothing that has occurred since I submitted my previous testimony has changed the views of the Members concerning the desirability of expeditious Commission approval of the Unwind Transaction.

Q. Are the Members familiar with Big Rivers' proposal to "feather" the use of the Economic Reserve to the Members until the Economic Reserve is exhausted?

A. Yes. The Member CEOs and boards are familiar with the proposal to feather use of the Economic Reserve through the Member Rate Stability Mechanism, described in the Supplemental Direct Testimony of William Steven Seelye, Exhibit 101, and I have seen the graduated rate slope presented in Exhibit WSS-17. The feathered rate slope approach for Member rates from the effective date of the tariff until the Economic Reserve is exhausted (estimated in Big Rivers' Unwind Financial Model to be during 2013) is an acceptable approach to Big Rivers' Members. Of course, the Members also understand that the Unwind Transaction contemplates that Big Rivers will file for a general tariff review to be effective no earlier than January 1, 2010.

Q. Does this conclude your testimony at this time?

A. Yes.

VERIFICATION

I verify, state, and affirm that the foregoing testimony is true and correct to the best of my knowledge and belief.

Burns Mercer

Burns Mercer

COMMONWEALTH OF KENTUCKY)
COUNTY OF Henderson)

Subscribed and sworn to before me by Burns Mercer on this the 7th day of October, 2008.

Paula Mitchell

Notary Public, Ky. State at Large
My commission expires: 1-12-09

EXHIBIT 102

SUPPLEMENTAL DIRECT TESTIMONY OF MICHAEL H. CORE

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2007-00455

SUPPLEMENTAL DIRECT TESTIMONY OF MICHAEL H. CORE

ON BEHALF OF
APPLICANTS

OCTOBER 2008

SUPPLEMENTAL DIRECT TESTIMONY OF
MICHAEL H. CORE

I. INTRODUCTION

Q. Please state your name, address and position with Big Rivers Electric Corporation ("Big Rivers").

A. My name is Michael H. Core. My business address is 201 Third Street, Henderson, Kentucky, 42419. I am the President and Chief Executive Officer of Big Rivers.

Q. Are you the same Michael H. Core who previously submitted direct and rebuttal testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your supplemental direct testimony in this proceeding?

A. The purpose of my supplemental direct testimony is to provide an overview concerning certain developments that have occurred with respect to the proposed unwind ("Unwind Transaction") of the 1998 transactions between

Big Rivers and E.ON U.S. LLC ("E.ON") (formerly LG&E Energy Corp.) and certain E.ON affiliates approved by the Kentucky Public Service Commission ("Commission") in Case Nos. 97-204 and 98-265 ("1998 Transactions").

First, I summarize how the Ambac Assurance Corporation ("Ambac") credit downgrade resulted in Big Rivers agreeing to terminate its leveraged lease transactions with respect to undivided interests in Plants Green and Wilson with a subsidiary of Philip Morris Capital Corporation ("PMCC") ("Lease Transactions") through a buyout ("PMCC Buyout"). I further describe an amendment to the Transaction Termination Agreement ("Termination Agreement") among Big Rivers, LG&E Energy Marketing Inc. ("LEM") and Western Kentucky Energy Corp. ("WKEC") that has been entered into since I provided rebuttal testimony in this proceeding.

I also present a supplemental analysis of benefits and costs to Big Rivers and its cooperative member systems ("Members") associated with the Unwind Transaction reflecting these developments, and I recap the history of Big Rivers' rates over the past ten years.

In addition, I provide an overview of the status of negotiations concerning the resumption by Big Rivers of the rights and responsibilities under pre-1998 contracts ("Station Two Contracts") between Big Rivers, the City of

Henderson, Kentucky (the "City") and the City of Henderson Utility Commission doing business as Henderson Municipal Power & Light ("HMP&L") (collectively, "Henderson") concerning the City's Station Two generating facility ("Station Two"). Finally, I explain that time is of the essence with respect to implementation of the Unwind Transaction, and urge the Commission to act expeditiously to approve the transaction.

Q. The Application Supplement is a large filing. Does this indicate that there are extensive and complex changes to the Application?

A. No. In reality, most of the material included in the Application Supplement merely updates previously filed information with minor conforming changes resulting from the PMCC Buyout. The Commission should not be put off by the volume of the filing. The substance is straightforward and actually streamlines Big Rivers' financial position.

II. OVERVIEW OF RECENT DEVELOPMENTS

Q. Please describe why Big Rivers sought postponement of the hearing in this proceeding in June 2008.

A. Big Rivers and E.ON sought postponement of the hearing in order to negotiate a resolution to address the effect on the Lease Transactions of the downgrade by Moody's Investor Services to its rating of Ambac's creditworthiness. This downgrade event was independent of and unrelated to Big Rivers' request for approval of the Unwind Transaction. Big Rivers would have had to act to resolve the Ambac downgrade even if there had been no proposed Unwind Transaction. However, the Unwind Transaction could not go forward with the uncertainty created by the Ambac downgrade. As C. William Blackburn explains in greater detail in his Third Supplemental Direct Testimony, Exhibit 78, Ambac insured certain default swaps that Big Rivers was using to satisfy contractual collateral requirements under the Lease Transactions. The Ambac downgrade caused these swaps to no longer qualify as collateral, and raised the possibility of Big Rivers being found in default unless it could either replace the non-qualifying swaps or come to some other arrangement.

Q. Has Big Rivers been able to resolve this issue?

A. Yes. Big Rivers has resolved the issues relating to Ambac's financial downgrade by agreeing to terminate the Lease Transactions with PMCC under a negotiated buyout structure, with financial contributions being made by Big Rivers, E.ON, and PMCC. Big Rivers considered a variety of alternatives to address the effect of the Ambac downgrade, but concluded that a negotiated buyout with PMCC would present the best means of preserving satisfactory economics for the Unwind Transaction.

Q. Has Big Rivers revised the Unwind Financial Model to reflect the PMCC Buyout?

A. Yes. I discuss the results of the revised financial model below, in my review of the benefits and costs of the Unwind Transaction.

Q. Has there been a further amendment to the Termination Agreement since you last testified in this proceeding?

A. Big Rivers, LEM, and WKEC have entered into a further amendment to the Termination Agreement that is being submitted with this supplement to its Application in this proceeding. This amendment, entitled Third Amendment to Transaction Termination Agreement, is included as Exhibit 80, and is discussed in the Supplemental Testimony of Paul W. Thompson, Exhibit 91.

III. UPDATED ASSESSMENT OF THE BENEFITS OF THE UNWIND TRANSACTION

Q. Have recent developments affected your evaluation of the benefits and costs of the Unwind Transaction to Big Rivers and its Members?

A. Yes, although I continue to believe that the anticipated benefits of the Unwind Transaction significantly outweigh the potential costs. The non-monetary benefits that I described in my direct testimony, such as needed financing flexibility for Big Rivers and the new power supply arrangements with the aluminum smelters, have not changed at all, and neither have many of the financial benefits that I previously described. The financial model that Big Rivers has used to evaluate the benefits and risks of the Unwind Transaction has been revised, however, to reflect the effect of the PMCC Buyout (as discussed above) and other developments, as described in greater detail by Mr. Blackburn in Exhibit 78.

Q. How has the Unwind Financial Model been changed?

A. Although Mr. Blackburn and Mr. Mudge describe the changes to the Unwind Financial Model in greater detail in their testimony at Exhibit 78 and Exhibit 98, respectively, the changes are generally of three kinds. First, Big Rivers has updated the Unwind Financial Model to reflect updated cost data for contract labor, to reflect new projected fuel oil prices and other unit startup costs, to incorporate increased materials costs, and to implement WKEC workplan updates. Second, Big Rivers has performed a new run of the Production Cost Model (Exhibit 97) using updated regional assumptions to reflect more current wholesale power markets. And third, Big Rivers has implemented the terms of the resolution of the PMCC Buyout, including Big Rivers' estimated $60.9 million share of those costs, and the updated balance schedule to the RUS Note.

Q. How is the PMCC Buyout related to the Unwind Transaction?

A. The problem which the PMCC Buyout sought to resolve, the Ambac credit downgrade's effects on the PMCC Lease Transaction, is wholly unrelated to the Unwind Transaction. Big Rivers would have needed to resolve this financial issue whether or not the Unwind Transaction occurred. But the terms of the PMCC Buyout are themselves integrated with the Unwind Transaction – E.ON's agreement to pay an estimated $60.9 million of the costs of that PMCC Buyout is provided as a direct incentive to close the Unwind Transaction, and the payment will not be provided if the Unwind Transaction does not close.

Q. What are the effects of the Buyouts on the updated Unwind Financial Model?

A. The updated Unwind Financial Model indicates that the BoA Buyout and the PMCC Buyout will cause an increase in projected rates estimated to be $0.39/MWh on a weighted average basis for the Non-Smelter Members and $0.27/MWh on a weighted average basis for the Smelters, each measured over the 15 year period modeled. *See* Exhibit RSM-3 to the Supplemental Testimony of Robert S. Mudge, Exhibit 98. However, I further note that the PMCC Buyout provides a number of benefits on its own. The PMCC Buyout:

1. Eliminates Big Rivers' obligation to replace Ambac in the PMCC Lease Transactions in light of Ambac's credit downgrade – an obligation that would be very difficult to fulfill;
2. Removes the risk of additional problems that may result from further Ambac downgrades;
3. Simplifies Big Rivers' creditor structure by reducing the number of creditors;
4. Simplifies Big Rivers' ability to obtain consents, as it required consents from PMCC, Ambac, and the RUS. The PMCC Buyout removes PMCC, CoBank and CFC from the picture, and ultimately Ambac will be removed when the pollution control bonds are refunded;

5. Maintains Big Rivers' credit metrics necessary for obtaining an investment grade credit rating, metrics which are still excellent; and

6 Involves a contribution by E.ON in the amount of 50 percent of Big Rivers' buyout cost as discussed in Mr. Blackburn's Third Supplemental Direct Testimony.

Q. What is the effect of all the changes to the updated Unwind Financial Model (*not only* the Buyouts) on rates from the June 2008 Unwind Financial Model?

A. Rates to the Non-Smelter Members and Smelters show increases as a result of the changes to the Unwind Financial Model. Overall (inclusive of all costs including those related to the BoA Buyout and the PMCC Buyout), these increases amount to a weighted average increase of $1.38/MWh for the Non-Smelter Members and $1.49/MWh for the Smelters over the term of the period modeled. *See* Supplemental Direct Testimony of Robert S. Mudge, Exhibit 98, pages 13-14. However, the increased rates to the Non-Smelter Members continue to be tempered by the Economic Reserve of $157 million. And Big Rivers' rates still remain amongst the lowest wholesale rates in the region.

Q. What is the effect of the revised Unwind Financial Model on Big Rivers' balance sheet?

A. In my direct testimony I presented Exhibit MHC-1, a financial analysis of the Unwind Transaction Profile as of December 12, 2007. Attached to this Supplement Direct Testimony is Exhibit MHC-2, an updated Unwind Transaction Profile comparing Big Rivers' pre-1998 balance sheet, its current balance sheet, and the projected post-closing balance sheet. The financial benefits of the Unwind Transaction are clear.

Q. Does Big Rivers still intend to pursue an investment grade credit rating?

A. Yes. Big Rivers' financial metrics remain strong for pursuing an investment grade credit rating, and Big Rivers intends to do so.

Q. Is Big Rivers still committed to completing the Unwind Transaction?

A. Yes. The overall advantages of the Unwind Transaction for Big Rivers and its Members remain the same as presented in my Direct Testimony, Exhibit 14.

Q. Mr. Core, at an informal conference Big Rivers was asked to provide a schedule showing its rates in recent history. Has such a schedule been prepared by you or at your direction?

A. Yes. Please see my Exhibit MHC-3, which presents a table showing average revenue per MWh for Big Rivers' rural customers and large industrial customers as well as an average revenue for the period 1998 through 2008.

Q. Is this rate history relevant to consideration of the Unwind Transaction?

A. Yes. If the Unwind Transaction is implemented, Big Rivers' prices to its Members, both for rural and large industrial customers, will increase. In some years these increases may appear significant. But these increases would appear very differently had they been implemented beginning in 1998 over a longer term. Since 1998, energy prices have increased across the board as have the electricity prices of virtually all electric utilities. Even now, if Big Rivers' Members' rates increase as a result of the Unwind Transaction their rates will remain competitive, and they still will have enjoyed an extended period of stable, low prices.

Finally, the rates in the Unwind Financial Model are not meant to be actual proposed rates, and Big Rivers is not requesting approval for specific future rate increases. The Unwind Financial Model is meant merely to be a decision model and to demonstrate the financial viability of Big Rivers under the Unwind Transaction given a set of reasonable, best-estimate assumptions.

Q. Have Big Rivers' negotiations with the parties to the Unwind Transaction been at arms-length, with all consideration for the transaction or value given or promised by or to Big Rivers or its agents fully disclosed to the Commission and the parties?

A. Yes.

IV. STATUS OF NEGOTIATIONS REGARDING STATION TWO

Q. Has there been a final resolution among Big Rivers, E.ON, and Henderson concerning the effect of the Unwind Transaction on the existing Station Two arrangements?

A. No. The parties are continuing to negotiate towards termination of the Station Two arrangements that were entered into as part of the 1998 Transactions, and resumption by Big Rivers of its rights and responsibilities with respect to Station Two, consistent with the underlying contracts among Big Rivers, the City, and the City of Henderson Utility Commission concerning Station Two ("Station Two Contracts") which were executed and approved by the Commission in the 1970s. However, the parties have yet to achieve final resolution of the issues involved. As David A. Spainhoward explains in his supplemental testimony, Exhibit 99, draft agreements necessary to effectuate this resolution have been presented to, but not yet executed by, the City and the City of Henderson Utility Commission.

Q. Do you anticipate that the parties will come to terms and agree to resumption by Big Rivers of its rights and responsibilities with respect to Station Two?

A. Yes, I believe that the parties will finalize the necessary agreements and provide for Big Rivers to resume its pre-1998 role with respect to Station Two. The parties, including both Board chairs, have met numerous times in attempts to negotiate a resolution of the many issues relating to Station Two, and I am confident that the outstanding issues will be resolved.

Q. Is termination of the existing Station Two arrangements a condition for the Unwind Transaction to close?

A. It is, pursuant to Subsection 10.2(q) of the Termination Agreement.

Q. Is Big Rivers seeking any Commission approvals with respect to Station Two at this time?

A. Yes. As explained in greater detail by Mr. Spainhoward, Big Rivers is submitting five unexecuted agreements to the Commission as part of its Application Supplement in this proceeding. Although certain of these agreements are being provided to the Commission solely for informational purposes, Big Rivers is requesting that the Commission approve the remaining agreements in their current, unexecuted forms. To the extent that any of these agreements is modified in a material fashion, Big Rivers will of course file the modified agreement(s) with the Commission and seek renewed approval of the agreement(s) as modified.

V. <u>NEED FOR EXPEDITIOUS COMMISSION APPROVAL</u>

Q. Do you continue to recommend that the Commission approve the Unwind Transaction, including the modifications presented in your Application Supplement?

A. Yes, I continue to recommend Commission approval, without reservation. I continue to believe that the Unwind Transaction will provide Big Rivers with flexibility to finance and manage growth, enhance the long-term viability of the aluminum smelters served by Big Rivers ("Smelters"), benefit the economy of Western Kentucky, and create a win-win future for Big Rivers' Members, E.ON and the Smelters.

Q. Is there need for the Commission to act expeditiously on the Application?

A. I believe that there is. The Unwind Transaction has been years in the making, and the parties have achieved a negotiated resolution of many complicated issues. It is important that the Unwind Transaction be approved as soon as is feasible, in order to preserve the delicate balance that has been achieved. The parties already have spent much time and labor to resolve issues that arose just prior to the scheduled commencement of the hearing in this proceeding, and the passage of time presents the possibility of other developments that could result in further delay. Accordingly, I urge the Commission to act expeditiously to approve the Application, as supplemented, so that the Unwind Transaction may go forward promptly and the resulting benefits may be secured for Big Rivers and the other interested parties.

Q. Does this conclude your testimony at this time?

A. Yes.

Unwind Transaction Profile, 10/4/08

		1997	2008		
		Audited Financials	***Pre Unwind + Lease Buyouts***	***Unwind + Lease Buyouts***	***Post Unwind + Lease Buyouts***
1	**Balance Sheet (M$)**				
2	Net Utility Plant	914	912	99	1,011
3	Sale-Leaseback Investments	-	197	(197)	-
4	Cash & Investments				
5	Transition Reserve		-	35	35
6	Economic Reserve		-	157	157
7	Unrestricted	21	146	(21)	125
8	Receivables, Inventories & Other	61	53	40	93
9	Assets	996	1,308	112	1,420
10					
11	Equities	(293)	(139)	511	372
12	Sale-Leaseback Obligation & Unamortized Gain	-	240	(240)	-
13	RUS Debt		765	(140)	626
14	Other Debt	1,256	262	(16)	246
15	Payables & Other	33	179	(3)	176
16	Equities & Liabilities	996	1,308	112	1,420
17					
18	**Equity/ Assets**	-29%	-11%		26%

EXHIBIT MHC-2

Exhibit MHC-3

RATE HISTORY

YEAR	RURAL	LARGE INDUSTRIALS	WEIGHTED AVERAGE
1998	36.72	30.70	34.11
1999	36.44	30.47	33.78
2000	36.25	30.12	33.58
2001	35.27	30.59	33.44
2002	35.38	31.22	33.97
2003	34.99	31.15	33.78
2004	35.06	30.31	33.55
2005	35.26	30.70	33.89
2006	35.58	30.67	34.11
2007	35.22	30.96	34.04
2008	35.30	30.74	34.03

VERIFICATION

I verify, state, and affirm that the foregoing testimony is true and correct to the best of my knowledge and belief.

Michael H. Core

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Michael H. Core on this the 7th day of October, 2008.

Paula Mitchell
Notary Public, Ky. State at Large
My Commission Expires 1-12-09

EXHIBIT 103

SUPPLEMENTAL DIRECT TESTIMONY OF WILLIAM STEVEN SEELYE

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2007-00455

SUPPLEMENTAL DIRECT TESTIMONY OF WILLIAM STEVEN SEELYE

ON BEHALF OF
APPLICANTS

OCTOBER 2008

SUPPLEMENTAL DIRECT TESTIMONY OF WILLIAM STEVEN SEELYE

I. OVERVIEW OF TESTIMONY

Q. Please state your name and business address.

A. My name is William Steven Seelye, and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky providing consulting and educational services in the areas of utility regulatory analysis, revenue requirements support, cost of service, rate design and economic analysis.

Q. Are you the same William Steven Seelye who earlier provided testimony in these proceedings?

A. I am. I filed my direct testimony as Exhibit 25 to the original Application filed on December 28, 2007.

Q. Why are you presenting this Supplemental Direct Testimony?

A. I am presenting this Supplemental Direct Testimony in order to sponsor certain changes to the Member Rate Stability Mechanism ("MRSM") which I originally sponsored in Exhibit 25 at pages 27-32. I am sponsoring the revised MRSM tariff language attached as Exhibit WSS-16.

Q. Is Big Rivers changing the method by which the MRSM will be used to draw down amounts in the Economic Reserve?

A. Yes.

Q. Why is Big Rivers changing the MRSM?

A. Originally, as presented in the Application and described in my Direct Testimony, Exhibit 25 at pp. 27-32, the MRSM provided for the use of the Economic Reserve as a rate credit to offset in each month the total dollar amount of fuel adjustment charges ("FAC") and Environmental

Surcharge charges billed to Members in that month to the extent such total dollar amounts were not already offset by the Unwind Surcredits and any Rebate Adjustments in that month. This proposed use of the MRSM left existing rates to the Non-Smelter Members effectively unchanged until exhaustion of the the Economic Reserve. In consideration of the well-established ratemaking principle of gradualism, Big Rivers proposes to modify the MRSM to alter the speed at which the Economic Reserve will be drawn down and thereby "feather" the effect of anticipated FAC and Environmental Surcharge Expenses on the Non-Smelter Member rates until the Economic Reserve is exhausted and the full amounts of the FAC and Environmental Surcharge are applied without credit. The revised MRSM tariff also reflects the increase in the level of the Economic Reserve from $75 million to $157 million.

Q. Can you explain what you mean by incorporating "gradualism" or "feathering" of the use of the Economic Reserve?

A. Yes. Incorporating "gradualism" or "feathering" simply refers to the process of smoothing the transition between existing rates with all FAC and Environmental Surcharge increases offset by the Economic Reserve to the existing rates with all FAC and Environmental

Surcharge increases included after the exhaustion of the Economic Reserve. Absent some sort of gradualism, there potentially will be an abrupt rate transition at the time the Economic Reserve is exhausted and there is no offset to the FAC and Environmental Surcharge costs that are then included in the Non-Smelter Member rates other than the Unwind Surcredit and any Rebate Adjustment in that month. Consistent with the ratemaking principle of gradualism, Big Rivers over a course of years will use the MRSM to reduce the rate of drawdown of the Economic Reserve so that the rate increases seen by its Members will be less extreme once the Economic Reserve is exhausted.

The positive effect of incorporating gradualism to smooth Non-Smelter Member Rates can be shown quite effectively graphically. Attached as Exhibit WSS-17, I include a chart graphically comparing use of the MRSM to draw down the Economic Reserve against all FAC and Environmental Surcharge charges without gradualism as compared to a use of the MRSM that smooths the drawdown of the Economic Reserve by leaving some amount of FAC and Environmental Surcharge charges as adjustments to Non-Smelter Rates without full offset. As can be seen from this exhibit, through feathering the Non-

Smelter Member rates more smoothly increase without as large a spike at the exhaustion of the Economic Reserve.

Q. Do Big Rivers' Members support the concept of gradualism?

A. I am informed that they do. They recognize that existing rates will be altered by FAC and Environmental Surcharge costs in years to come and that the Non-Smelter Members will receive a contribution of the full $157 million of the Economic Reserve at whatever rate that amount is distributed through the MRSM. Incorporating a "feathering" approach to more gradually reduce the Economic Reserve's offset of the total amount of potential FAC and Environmental Surcharge cost increases to existing Non-Smelter Member rates serves to smooth the rate transition that inevitably will occur once the Economic Reserve is exhausted. Accordingly, the Members are in agreement that smoothing the drawdown of the Economic Reserve is preferable to a stark rate transition at the exhaustion of the Economic Reserve. *See* Exhibit 102, Supplemental Testimony of Burns E. Mercer.

Q. How does Big Rivers propose to change the MRSM to incorporate gradualism regarding the drawdown of the Economic Reserve use?

A. During the first 12 months after the effective date of the tariff (*i.e.*, calendar year 2009, assuming a December 31, 2008 closing), Big Rivers proposes to leave the MRSM as was previously proposed. Thus, in those initial twelve months the Economic Reserve will be used in each month to offset the total amount of FAC and Environmental Surcharge charges not otherwise offset by the Unwind Surcredit or a Rebate Adjustment in that month. Thus, for the first 12 months of the tariff Member rates will remain level.

During months 13 through 24 after the effective date of the tariff (*i.e.*, calendar year 2010), the Economic Reserve will offset most of the total amount of FAC and Environmental Surcharge increases in each month not otherwise offset by the Unwind Surcredit or a Rebate Adjustment, but not the total difference. Instead, the monthly withdrawal from the Economic Reserve will be reduced by $0.002/kWH multiplied by the Non-Smelter sales for the month. The revised MRSM tariff defines this amount as an Expense Mitigation Adjustment.

Similarly, during months 25 through 36 after the effective date of the tariff (*i.e.*, 2011), the Expense Mitigation Adjustment increases to an amount equal to $0.004/kWh multiplied by the Non-Smelter Member sales in each month. And in months 37 through 48 after the effective date of the tariff (*i.e.*, in 2012), the Expense Mitigation Adjustment increases to an amount equal to $0.006/kWh multiplied by the Non-Smelter Member sales in each month. After month 48, the Expense Mitigation Adjustment terminates and the Economic Reserve will be used in each month to offset the net cost increases until the Economic Reserve is fully exhausted. In essence, the Non-Smelter Members will gradually begin to bear the cost increases associated with the FAC and the Environmental Surcharge cost increases, thus "feathering" the Economic Reserve application by smoothing rates to the Non-Smelter Members and mitigating the large step up that would occur when the Economic Reserve is completely depleted.

Q. Could you provide an example of how the revised MRSM would operate in 2010 (months 13 through 24 after closing)?

A. Yes. Using the same example incorporated in my Direct Testimony at page 29 (which would reflect how the MRSM would operate in 2009 when no Expense Mitigation Adjustment would apply), suppose that (i) the FAC amount billed to a Member for non-Smelter sales is $10,150, (ii) the Environmental Surcharge billed to a Member for non-Smelter sales is $20,200, and (iii) the Unwind Surcredit received is $5,000. Under prior operation of the MRSM, the Member's MRSM adjustment for the month would have been a credit of $25,350 (or $10,150 +$20,200 -$5,000 = $25,350). Assume further that the product of the Member's non-Smelter sales is $10,000 ($0.002/kWh multiplied by non-Smelter sales of 5,000,000 kWh). This $10,000 would then be the calculated Expense Mitigation Adjustment for that month. Under the revised MRSM the Member's MRSM adjustment for the month would be a credit of $15,350. In other words, the MRSM of $15,350 would offset the FAC charge of $10,150, plus the Environmental Surcharge of $20,200, less the Unwind Surcredit of $5,000 and less the Expense Mitigation Adjustment of $10,000. I should point out that the figures used in this example were developed simply to illustrate how the MRSM will be determined and in no way represent amounts that will likely occur.

Q. How would the above example change were it to occur in 2011 (months 25 through 36 after closing)?

A. In 2011, the Expense Mitigation Adjustment would be calculated to be $20,000 ($0.004/kWh multiplied by sales of 5,000,000 kWh). The MRSM thus would credit $5,350 to offset the FAC and Environmental Surcharge ($10,150 + $20,200 - $5,000 - $20,000).

Q. And how would the same example change were it to occur in 2012 (months 37 through 48 after closing)?

A. In 2012, the Expense Mitigation Adjustment would be calculated to be $30,000 ($0.006/kWh multiplied by sales of 5,000,000 kWh). Because the Member Expense Adjustment of $30,000 would exceed the $25,350 calculated amount of the FAC plus the Environmental Surcharge less the Unwind Surcredit, no amounts would be credited to the Member from the Economic Reserve in that month and the Member would bear the full cost of the FAC and Environmental Surcharge. However, because the Unwind Surcredit separately would be flowed through that rider, the Member would still receive that credit.

Q. Mr. Seelye, does this conclude your testimony at this time?

A. Yes, it does.

Exhibit WSS-16

MEMBER RATE STABILITY MECHANISM (MRSM)

APPLICABILITY:

Applicable in all territory served by Big Rivers" Member Cooperatives.

AVAILABILITY:

Available pursuant to Section A.7. of this tariff for electric service provided by Big Rivers to its Member Rural Electric Cooperatives for all Rural Delivery Points and Large Industrial Customer Delivery Points, served under Rate Schedule C.4.d, and Rate Schedule C.7, respectively.

DEFINITIONS:

"Members" are Jackson Purchase Energy Corporation, Kenergy Corp. ("Kenergy"), and Meade County Rural Electric Cooperative Corporation.

"Smelters" are the aluminum reduction facilities of Alcan Primary Products Corporation and Century Aluminum of Kentucky General Partnership, as further described under the Wholesale Smelter Agreements.

"Smelter Agreements" are the two Wholesale Electric Service Agreements each dated as of October ___, 2008, between Big Rivers and Kenergy with respect to service by Kenergy to a Smelter.

MEMBER RATE STABILITY MECHANISM (MRSM)

Big Rivers will establish an Economic Reserve of $157 million, plus any additional amounts that may be added at the time of closing the unwind arrangement with E.ON, which will be used to offset the effect of billing the FAC and Environmental Surcharge to non-Smelter sales, after taking into account the credits received from the Unwind Surcredit and the Rebate Adjustment. The Economic Reserve will be established as a stand-alone investment account, accruing interest. The MRSM will draw on the Economic Reserve to mitigate the monthly impacts of the FAC and Environmental Surcharge on each non-Smelter Member's bill, net of the credits received under the Unwind Surcredit and Rebate Adjustment. Each month the MRSM will mitigate the dollar impact of billings under the FAC and Environmental Surcharge *less* the total dollar amounts received under the Unwind Surcredit, *less* a monthly pro-rata portion of any lump sum rebates provided under the Rebate Adjustment, and *less* the Expense Mitigation Adjustment (EMA) which is defined below.

The amount of the MRSM credit provided to each member system during a month will each equal (i) the total dollar amount of FAC charges billed to the member during the month, *plus* (ii) the total dollar amount of Environmental Surcharge charges billed to the member during the month, *less* (iii) the total dollar amount of the Unwind Surcredits credited to the member during the month, *less* (iv) one-twelfth (1/12) of any rebates provided under the Rebate Adjustment during the current month or during any of the 11 preceding months, *less* (v) the total dollar amount of the Expense Mitigation Adjustment (EMA) charged to the member during the month; provided that the amounts subtracted in items (iii), (iv) and (v) cannot exceed the total of items (i) and (ii), in which case the monthly MRSM adjustment would be zero.

Expense MITIGATION FACTOR (EMF) AND ADJUSTMENT (EMA)

The EMF shall be the following:

i. $0.000 per kWh for the first twelve (12) months following the effective date of this tariff;

ii. $0.002 per kWh for months 13 through 24 following the effective date of this tariff;

iii. $0.004 per kWh for months 25 through 36 following the effective date of this tariff; and

iv. $0.006 per kWh for months 37 through 48 following the effective date of this tariff.

The EMA for the month shall be the EMF multiplied by the S(m) which is the jurisdictional sales for the current expense month. The EMF and EMA will expire after month 48 following the effective date of this tariff.

If any portion of FAC or Environmental Surcharge costs are transferred to base rates, or if any portion of the FAC costs are transferred from base rates to the FAC, then the MRSM will account for any effect of such transfers so that the Members will not see any impact on their bills, either positive or negative, of such transfers.

The MRSM shall be no longer applicable and shall be terminated once the Economic Reserve is exhausted. During the last month of the MRSM, the amount remaining in the Economic Reserve will be prorated to each member on the basis of the total FAC and Environmental Surcharge charges applicable to non-Smelter sales less credits under the Unwind Surcredits, less monthly prorated amounts under the Rebate Adjustment and less the Expense Mitigation Adjustment as applicable.

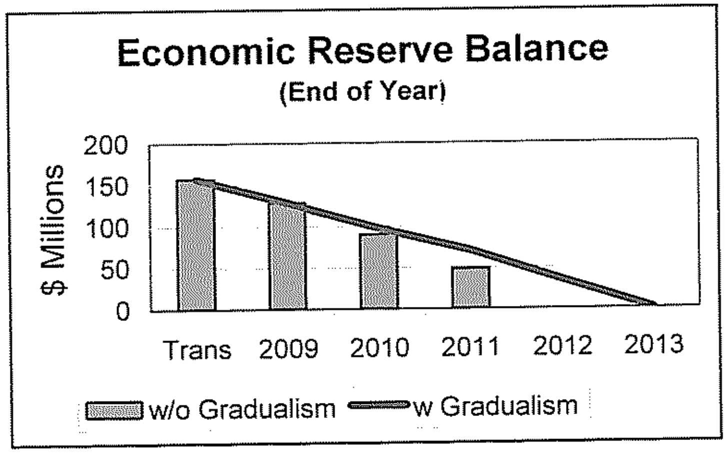
Exhibit WSS-17

Economic Reserve Analysis

(based on Unwind Presentation Draft 10_04_08.xls)

More gradual draws on Economic Reserve (red lines below) buffer what would otherwise be 40% rate increase in 2013

	Trans	2009	2010	2011	2012	2013
Impact on Economic Reserve Balance ($M; EOY)						
With Gradualism	157	128	97	70	34	-
Without Gradualism	157	128	90	48	-	-
Impact on Non-Smelter Member Rates ($/ MWh)						
With Gradualism		35.45	37.42	39.29	41.26	44.14
% Change			6%	5%	5%	7%
Without Gradualism		35.45	35.42	35.29	38.25	53.42
% Change			0%	0%	8%	40%



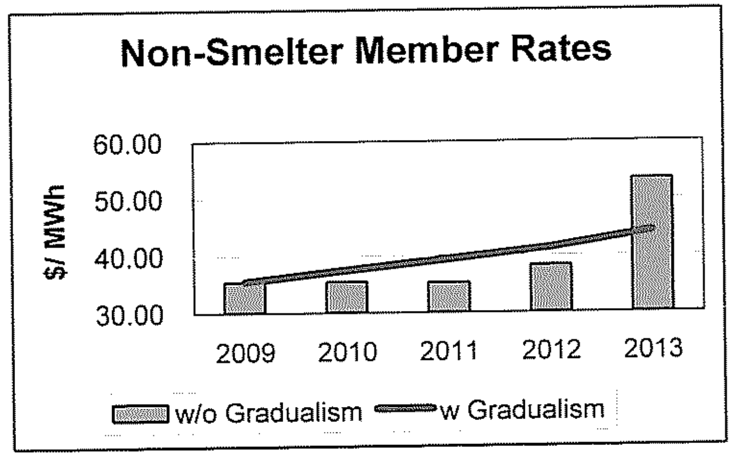


Exhibit WSS-17

EXHIBIT 104

SUPPLEMENTAL DIRECT TESTIMONY OF MARK A. BAILEY

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2007-00455

SUPPLEMENTAL DIRECT TESTIMONY OF MARK A. BAILEY

ON BEHALF OF
APPLICANTS

OCTOBER 2008

SUPPLEMENTAL DIRECT TESTIMONY OF MARK A. BAILEY

I. INTRODUCTION

Q. Please state your name, address and position with Big Rivers Electric Corporation ("Big Rivers").

A. My name is Mark A. Bailey. My business address is 201 Third Street, Henderson, Kentucky, 42419. I am the Executive Vice President and Chief Operating Officer of Big Rivers.

Q. Are you the same Mark A. Bailey who previously submitted Direct and Rebuttal testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Supplemental Direct Testimony in this proceeding?

A. The purpose of my Supplemental Direct Testimony is to address certain developments that have occurred with respect to the proposed unwind ("Unwind Transaction") of the 1998 transactions between Big Rivers and

E.ON U.S. LLC ("E.ON") (formerly LG&E Energy Corp.) and certain E.ON affiliates approved by the Kentucky Public Service Commission ("Commission") in Case Nos. 97-204 and 98-265 ("1998 Transactions").

First, I describe the status of Big Rivers' ongoing conduct of due diligence with respect to the Big Rivers-owned generating facilities that currently are leased to, and operated by, Western Kentucky Energy Corp. ("WKEC"), and that will once again be operated by Big Rivers upon closing of the Unwind Transaction. As I explain below, Big Rivers is abiding by the commitments it has made with respect to its conduct of due diligence, and will continue to do so. I then provide an update concerning Big Rivers' transition to resuming operational control of the generating facilities. I demonstrate that Big Rivers is continuing to ensure that it will have the personnel and arrangements in place to guarantee a seamless transition when Big Rivers resumes operational control of the facilities, including the necessary arrangements for the provision of information technology ("IT") services and generation dispatch services.

II. <u>DUE DILIGENCE</u>

Q. Is Big Rivers continuing to conduct due diligence with respect to the generating facilities and sites?

A. Yes, Big Rivers is continuing to engage in due diligence, and will continue to do so up to the closing of the Unwind Transaction. In a May 29, 2008 memorandum to the Big Rivers Board of Directors, I explained that although I had become comfortable with the plant situation at that time, I recognized that a number of conditions remained to be met before the closing of the Unwind Transaction – and before I would be fully satisfied that the due diligence portion of the closing conditions under the Transaction Termination Agreement ("Termination Agreement") among Big Rivers, LG&E Energy Marketing Inc. and WKEC had been satisfied. Big Rivers has continued to conduct due diligence to ensure that all such closing conditions have been satisfied. *See* Exhibit MAB-8 (Big Rivers' March 6, 2008 Responses to the Attorney General's Supplemental Request, Item 88; Big Rivers' May 30, 2008 Updated Responses to Data Requests, Tab 13; Big Rivers' June 24, 2008 Updated Responses to Data Requests, Item 1).

Q. Are there issues that remain to be resolved before Big Rivers can conclude that the closing requirements concerning the condition of the plants have been satisfied?

A. Yes, there are. In his Supplemental Direct Testimony, Exhibit 99, David A. Spainhoward at Exhibit DAS-2 presents a list of certain due diligence closing conditions and Big Rivers' understanding of how those conditions are expected to be satisfied. Big Rivers is continuing to pursue resolution of the outstanding issues with E.ON, consistent with its reaffirmed commitment at the June 19, 2008 informal conference in this proceeding that it would "finalize its due diligence on the generating facilities and sites using all resources available to it."

Q. Big Rivers also committed to filing a report with the Commission within 120 days after closing the Unwind Transaction concerning resolution of the Big Rivers conditions to closing. Does Big Rivers stand by this commitment?

A. Absolutely. As reaffirmed at the June 19 conference, Big Rivers will file a report with the Commission within 120 days after closing, "stating that all Big Rivers conditions to the closing of the Unwind Transaction have been satisfied or waived, and if waived, the terms on which waiver was granted." This includes conditions relating to due diligence, but all other Big Rivers conditions to closing as well.

Q. In your Direct Testimony, you described a Production Work Plan that Big Rivers had developed for operating the generating facilities

following closing of the Unwind Transaction. Have there been changes to this plan?

A. Yes. Big Rivers has recently updated its three-year Production Work Plan covering the years 2009 through 2011. A copy of the revised Production Work Plan is included as Exhibit 105. A summary of the major changes included in the updated plan from the previous Production Work Plan covering the years 2008 through 2010 is included in Exhibit MAB-9. These changes have been incorporated in Big Rivers' revised Unwind Financial Model, which is presented as Exhibit 79 and is described more fully in the Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78.

Q. You also explained in your Direct Testimony that Bob Berry will become Vice President and Chief Production Officer for Big Rivers. Will Mr. Berry be available at the hearing in this proceeding?

A. Yes, Mr. Berry will be available at the hearing to respond to any questions addressed to his overall responsibility for operation and maintenance of Big Rivers' generating fleet. As I noted in my direct testimony, Mr. Berry has over 27 years of experience with Big Rivers and WKEC. He recently managed operations at Green/Reid/Station Two and has previously worked at the Coleman Plant, and thus is well suited to provide information to the Commission in this area.

III. UPDATE ON TRANSITION

Q. In your Direct Testimony, you identified the Big Rivers management team that will be in place after closing of the Unwind Transaction. Have there been any changes to that team since you submitted your Direct Testimony?

A. No, there have not been any changes to the post-closing management team.

Q. Has Big Rivers named managers for the individual generating facilities?

A. Yes. Jim Garrett, who is currently plant manager of the Coleman Plant, is transfering to the Sebree Station, replacing Bob Berry. Kenny Stewart, currently the Wilson Plant manager, has elected to retire. Ron Gregory has been promoted to plant manager at the Wilson Plant by WKEC, and will become Big Rivers' Wilson Plant manager. Pat Waldeck, currently production manager and interim plant manager at the Coleman Plant, will become Big Rivers' Coleman Plant manager. A list of the managers and their individual experiences is attached as Exhibit MAB-10.

Q. Do you have any updates concerning the status of Big Rivers' efforts to hire current WKEC employees to continue with Big Rivers?

A. I have one update, concerning Big Rivers' offers to "exempt" – *i.e.*, non-bargaining – employees of WKEC. Big Rivers had offered positions to 150 of these employees, and 149 accepted Big Rivers' offers to continue with Big Rivers, including all of the plant managers. However, as I noted previously, one of the plant managers subsequently elected to retire, so Big Rivers currently expects 148 of the exempt employees to stay on with Big Rivers when it resumes operational control of the generating facilities.

Q. What about the bargaining unit employees?

A. It is Big Rivers' intent to offer to hire all bargaining unit employees. We expect most, if not all, to continue working with Big Rivers.

Q. Do you have a current estimate of the number of employees Big Rivers will have after the closing of the Unwind Transaction?

A. Yes. We plan to have approximately 623 employees post-closing, down slightly from the 630 employees I estimated in my Direct Testimony. This is because, as I discuss below, we are outsourcing our IT and generation dispatch services.

Q. In your Direct Testimony, you explained that Big Rivers was exploring alternatives for obtaining IT and generation dispatch services upon the expiration of certain transitional arrangements with WKEC. Has Big Rivers contracted for IT services?

A. Yes. As I explained in my Direct Testimony, WKEC will provide certain information technology services to Big Rivers for up to eighteen months following the closing of the Unwind Transaction, pursuant to the Information Technology Support Services Agreement. By the end of that eighteen month period, Big Rivers must have fully transitioned to its long-term information technology solution. Big Rivers has worked with Black & Veatch Corporation ("Black & Veatch") to determine the best options with respect to the IT function. As a result of this effort, Big Rivers has decided to purchase and implement various modules of Oracle's e-Business Suite Software, and has negotiated an agreement with Oracle to purchase the software at a cost of $1.4 million, with an annual maintenance fee of $300,000. Big Rivers also has finalized agreements with EDS to configure and implement the software at a cost of $7.3 million, and to provide certain IT services (application management, help desk, desktop support, network and data center) for eight years following the closing of the Unwind Transaction, at an annual cost of $2.3 million. The revised Unwind Financial Model includes all expected IT costs.

Q. How did Big Rivers select Oracle as the software solutions provider?

A. E.ON has established a WKEC "quasi"-current state environment for post-unwind Big Rivers (including Oracle, Maximo, PeopleSoft and Volts software) under the Information Technology Support Services Agreement. Pending transition to its long-term solution, Big Rivers will be operating on two IT systems, the current WKEC system and the current Big Rivers system. Big Rivers' long-term solution due diligence process involved both Big Rivers and WKEC business area and technical staff, and included site visits and vendor demonstrations. Big Rivers evaluated multiple options, including legacy native, Oracle, SAP and Maximo, on both a quantitative and qualitative basis. Qualitative scoring included critical criteria such as business functionality, business processes, technical requirements, strategic fit, vendor viability and migration strategy. Oracle Release 12 was the clear winner.

Q. How did Big Rivers select EDS to be its IT services provider over other options, such as having the services provided in-house?

A. Big Rivers solicited interest from three large outsourcers (EDS, IBM and Capgemini) to configure and implement 20 modules of Oracle Release 12 and provide the services I identified above. EDS alone responded favorably to Big Rivers' request. After twelve months of negotiations, an agreement between Big Rivers and EDS was finalized on June 30, 2008, generally to become effective upon the closing date of the Unwind Transaction. While on the surface it appears that the EDS option (as compared to the in-house option) carries a 9% cost premium (absent any risk premium), when considered from a risk management perspective, Big Rivers concluded that the deep and broad resources of EDS more than compensate for the in-house option risk. Transitioning to Oracle Release 12 will be a monumental undertaking for Big Rivers. Big Rivers has no backstop beyond the eighteen month period during which E.ON will be providing certain IT services, and thus believes that outsourcing these IT services to EDS is the best solution.

Q. Has Big Rivers likewise contracted for generation dispatch services?

A. Yes, Big Rivers has contracted with ACES Power Marketing ("APM") to provide generation dispatch services to Big Rivers following expiration of its transitional arrangement with WKEC. APM is a national energy risk management and transaction execution company of which Big Rivers is a member-owner, along with numerous other cooperatives. APM already provides power marketing and risk management services to Big Rivers, and Big Rivers believes that there will be synergies in having APM also perform generation dispatch.

Q. Does this conclude your testimony at this time?

A. Yes.

Exhibit MAB-8

ITEM 88

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
March 6, 2008

Item 88) Please reference the Response to HMP&L 1-7. When does Big Rivers anticipate it will complete its due diligence review of the facilities?

Response) Big Rivers will complete its due diligence review of the generating facilities at or near the time of the transaction closing. Big Rivers intends to continue its due diligence between now and that time. For instance, Section 10.3 of the Transaction Termination Agreement sets forth several closing conditions which are intended to assure Big Rivers that the conditions of the plants are acceptable at the closing; such as, 10.3 (w) No Damage to Generating Plants; (ff) No Forced Outage at Generating Plants; etc.

Due diligence requests for information are continuously sent to WKEC and when responses are received, they are reviewed by Big Rivers' staff and/or counsel, and/or Big Rivers' consultants. Big Rivers has positioned one person at each plant site to monitor the plant operations and maintenance. It is important that Big Rivers be satisfied with the condition of the plants at closing. Section 10.3 (dd) of the Transaction Termination Agreement (Condition of Generating Plants) states, "Solely in the reasonable judgment of Big Rivers, each Generating Plant shall be in all material respects in good condition and state of repair, ordinary wear and tear excepted, consistent with Prudent Utility Practice." Big Rivers will only close the transaction if this and other closing conditions are met. There will be no single final due diligence report which will make that determination. Big Rivers' executive team and its advisors will make that determination, based on almost constant due diligence which has previously taken place as well as future due diligence that will continue to take place until the closing.

Witness) Mark A. Bailey
David A. Spainhoward

ITEM 13

Item 88) Provide any and all internal E. ON documents which address the subject of existing agreements which are the subject of the "Unwind Transaction" and "Termination Transaction", including any financial analyses and strategic analyses.

Response) Big Rivers files this supplement to its response to Item 88 of the Attorney General's Supplemental Request for Information in response to requests by the Attorney General and the Commission Staff for more information regarding the generating plant and plant site due diligence Big Rivers is performing in anticipation of the Unwind Transaction closing. For the convenience of the Commission and the parties, Big Rivers has assembled in this supplemental response references to most of the information on its due diligence that has been filed in the record in this matter. This Supplemental Response also relates to Draft Settlement Concept No. 1 presented at the May 15, 2008, Informal Conference in this matter.

Big Rivers believes that its knowledge of the condition of its owned-leased and previously operated plants at the closing of the Unwind Transaction will be substantially greater than the knowledge of facility conditions most utilities would have upon the acquisition of generating plants. The due diligence conducted by Big Rivers on its generating units and sites did not commence at the time the Unwind Transaction began to appear viable. Big Rivers constructed those units and operated them until 1998. It employs persons who have institutional history and memory regarding the condition of those units through 1998. Robert Berry, the person who will be the Vice President and Chief Production Officer of Big Rivers after the Unwind Transaction closing is a former Big Rivers employee, and the current plant manager of the Green/Reid/Station Two operations. Testimony of Mark Bailey, Application Exhibit 5, page 8. "Almost every Western Kentucky-based employee of WKEC will [also] become an employee of Big Rivers, including the plant managers and personnel, most of whom were employees of Big Rivers prior to 1998, bringing with them a thorough knowledge of the operation of the Big Rivers' generating stations and Station Two." Application, pages 32 and 33.

Since 1998, subsidiaries of E.ON have had the obligation to operate and maintain the generating units owned by Big Rivers, or operated by Big Rivers under agreements with Henderson. Application, p. 8. During that period, WKEC has made millions of dollars of capital improvements to the plants under budgets reviewed, investigated and contributed to by Big Rivers in connection with the budgeting and cost-sharing processes established under the 1998 Transaction agreements. See Big Rivers' Response to Item 141 of Attorney General Initial Request for Information, Big Rivers' Response to Item 8 of Commission Staff Initial Request for Information and E.ON Entities' Response to Item 8 of Commission Staff Initial Request for Information.

Big Rivers also engaged Stanley Consultants Inc. ("Stanley") in 2000 to begin making an annual review of generating plant condition, including physical inspection of the plants, review of plant inspection reports prepared by vendors and consultants and review of plant operating and performance data. Beginning in 2006, when Big Rivers thought a closing of the Unwind Transaction might be imminent, Stanley's reports to Big Rivers were condensed to data that could be included in an annual report in the future without the expense of preparing a full report should the Unwind not occur. Stanley's role changed somewhat from outage visits and once a year on-site walk-down, to having two full-time people who are stationed on-site. The Stanley reports, which have been reviewed by Big Rivers as part of its due diligence, are filed in the record. Big Rivers' Response to Item 51 of the Commission Staff's Initial Information Requests.

Big Rivers has made additional, in-depth due diligence of generating plant condition a priority in the terms of the Termination Agreement itself (Application, Exhibit 3), in part because there are no warranties in the Termination Agreement by the E.ON entities regarding plant condition that extend beyond the Unwind Transaction closing. For example, Big Rivers required warranties and representations from the E.ON parties regarding environmental conditions (Section 11.1(k)), correctness of diligence materials (Section 11.1(l)) and the obligation to deliver diligence materials (Section 11.1(m)).

The Termination Agreement deals with a number of issues that would not have been known to Big Rivers but for its ongoing diligence efforts prior to the date the Termination Agreement was negotiated. For example, the closing conditions expressly require resolution or satisfaction before closing of issues related to: the Station Two H1 boiler event (Section 10.3(l)); gypsum facilities removal (Section 10.3(cc)); status of gypsum offtake agreement (Section 10.3(hh)); and cleaning of Wilson ponds (Section 10.3(jj)). The closing conditions also protect Big Rivers from the implications of due diligence problems that Big Rivers discovers prior to closing, such as: casualty damage to the generating plants (Section 10.3(w)); environmental conditions (Section 10.3(y)); condition of generating plants (Section 10.3(dd)); testing of generating plant capability (Section 10.3(ee), and see also Section 12.7); forced outages (Section 10.3(ff)); requirements that WKEC comply with its own operating plans, including expenditures (Section 10.3(ii), and see also Section 12.2); compliance of plants with reliability standards (Section 10.3(ll)); and unresolved disputes (Section 10.3(mm))
The Termination Agreement specifically provides the methodology for certain due diligence issues, such as determination of the quantities and value of inventory and personal property (Article 4), receiving notice of forced outages prior to closing (Section 12.2(b)) and procedures to address noncompliance by WKEC with its operating plan (Section 12.5(c)). Article 15 of the Termination Agreement contains extensive terms regarding an environmental audit and environmental indemnities, which cover subjects for which due diligence is difficult.

Big Rivers' representatives have made hundreds of due diligence requests of the E.ON Entities. Each due diligence request is separately tracked, and the product of the request is placed on a Big Rivers FTP site, where those who need access to the information can retrieve it.

Big Rivers and others have filed in this proceeding in response to information requests a number of items Big Rivers has considered in connection with its due diligence. Big Rivers has filed a copy of 74 different reports and studies (under a Petition for

Confidential Treatment) that it has produced or collected with respect to the generating facilities and sites. Big Rivers' Response to Item 6 of Henderson's Initial Data Request. The Stanley reports have been filed, as noted above. The Smelters have filed the Stone & Webster report, which Big Rivers has also considered (Big Rivers' Response to Item 83 of Attorney General's Second Request for Information), although neither Big Rivers nor the Smelters consider the Stone & Webster report to be a "work plan" for Big Rivers going forward. Rebuttal Testimony of Henry Fayne, page 4. Although not filed in this case, and protected by confidentiality agreements, Big Rivers has also reviewed engineering reports produced by Henderson regarding the Station Two units. Information on the recent operation performance of the units regarding heat rate, net capacity factor, equivalent availability factor and equivalent forced outage rate are filed with Big Rivers' Response to Item 3 of the Commission Staff's Second Supplemental Information Request.

As Big Rivers has explained in its responses to information requests in this proceeding, due diligence is a process, not an end in itself. See the rebuttal testimonies of Mark Bailey, pages 2-5 (due diligence efforts of Big Rivers are more than adequate), and Michael Core, pages 5-7 (due diligence is a process; a single, comprehensive "due diligence report" not contemplated or required); see also Big Rivers' Response to Items 109 and 110 of the Attorney General's Initial Request for Information, and to Item 88 of Attorney General's Supplemental Request for Information. The components of Big Rivers' due diligence plan include: (i) inspection of O&M records at each site; (ii) engineering evaluation of condition of plants by Big Rivers and Stanley Consultants; (iii) review E.ON's operating plans; and (iv) physical test of operating capability of the generating facilities to be conducted prior to closing. Big Rivers' Response to Item 1 of the Commission Staff's Initial Request for Information.

With respect to the due diligence process at the generating plants and sites, since 2005, Big Rivers has employed a person whose duties include visiting each generating plant each week to monitor the condition of the plant and the performance by WKEC of its obligations under the existing transaction. After the Termination Agreement was signed in March of 2007, Big Rivers added two Stanley employees/consultants to this task, assigning one person full-time to each of the generating plant sites. These persons became part of the Termination Agreement Execution Team ("TAE"). In addition to their preexisting duties, members of the TAE track performance by Big Rivers and the E.ON entities of their respective obligations under the Termination Agreement. This includes monitoring the condition of the generating plants so that Big Rivers' management can determine on the date of closing whether, "[s]olely in the reasonable judgment of Big Rivers, each Generating Plant shall be in all material respects in good condition and state of repair, ordinary wear and tear excepted, consistent with Prudent Utility Practice." Termination Agreement, Section 10.3(dd). In the Termination Agreement Big Rivers obtained expanded rights to have these representatives present in the plants performing due diligence activities prior to closing. Termination Agreement, Section 12.2(a).

The TAE team members report at least weekly to a supervisor, who tracks compliance with the Termination Agreement on a Gaant chart, and reports any due diligence issues to a Big Rivers vice president. Issues are evaluated and, as deemed appropriate, an issue could be put on a list for resolution with the E.ON entities pursuant to a closing condition, or added to the Production Work Plan for correction after closing. Any material issues with the condition of a generating plant will be resolved before closing, which could include a revision to the Production Work Plan with the cost of resolution appropriately reflected in the Unwind Financial Model. Issues that arise may also be reviewed by other Big Rivers employees, and Big Rivers' consultants and counsel as appropriate. Big Rivers' Response to Items 127, 131 and 133 of Attorney General's Initial Request for Information.

The Big Rivers Production Work Plan, filed in response to Item 1 of the Commission Staff's Second Supplemental Request for Information, has been included in the Unwind Financial Model, and will allow Big Rivers to meet the generation and reliability levels anticipated by the Unwind Financial Model. Big Rivers' Response to Commission Staff's Second Supplemental Request, Item 2 and Item 92 of Attorney General's Supplemental Request for Information. This includes capital expenditures for environmental compliance that are anticipated and included in the Unwind Financial Model. Big Rivers' Response to Item 5 of the Commission Staff's Second Supplemental Request for Information. Some of the items in the Big Rivers Production Work Plan and capital budget were not and are currently not in the WKEC capital budget. Testimony of Mark Bailey, Application Exhibit 5, page 16; Big Rivers' Response to Item 94 of Attorney General's Supplemental Request for Information. The projections in the Production Work Plan are consistent with the projections in the Unwind Financial Model. Big Rivers' Response to Item 2 of Commission Staff's Second Supplemental Request for Information. In addition to assessing the physical condition of plants, Big Rivers has also performed economic modeling on the reliability of Reid I, and included the results in the Unwind Financial Model. Big Rivers' Response to Item 96 of Attorney General's Supplemental Request for Information.

Ultimate management responsibility for evaluation of any generating plant and site due diligence issues rests with Mark Bailey, who will succeed Michael Core as president and CEO of Big Rivers at some point after the Unwind Transaction closing. Mr. Bailey is an electrical engineer with over 34 years of experience in the utility industry, including 10 years in coal-fired generating plants. He is the person who will have responsibility for operating Big Rivers post-closing, and for securing the funds to correct any issues with the generating plants that are not resolved prior to closing and included in the Production Work Plan at closing. He accordingly has an intense interest in detecting and resolving any generating plant condition issues prior to closing.

Big Rivers has not planned to generate a "due diligence report," as such. Big Rivers' Response to Item 51 of the Commission Staff's Initial Request for Information. Mr. Bailey, however, has previously and as recently as on May 16, 2008, reported to the Big Rivers board of directors verbally and in a follow-up memorandum on his current satisfaction that Big Rivers will be taking back generating plants that, in the end, are in appropriate condition to perform as anticipated under the Unwind Financial Model. A copy of his memorandum to the Big Rivers board of directors on this subject dated May 29, 2008, is attached. Big Rivers will also create a post-closing memorandum on disposition of closing conditions, including those related to the condition of the generating plants. Rebuttal Testimony of Michael Core, page 12.

The Smelters have also expressed their comfort with the plans of Big Rivers for operating and maintaining the generating units. Response of Smelters to Item 4 of Attorney General's Supplemental Request for Information. Their consultant on the condition of the generating units, Stone & Webster, concluded that Big Rivers' system is in "reasonable condition, and capable of performing on a reliable basis, consistent with industry standards." *Id.* Ultimately, however, a determination of whether the plants are in all material respects in good condition and state of repair is a business judgment only Big Rivers can make.

Witness) Mark A. Bailey

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MEMORANDUM

TO: Big Rivers' Board of Directors

FROM: Mark Bailey MB

DATE: May 29, 2008

SUBJECT: Condition of Big Rivers' Generating Plants

I am writing in follow-up to various conversations we have had over the past several years, including at the most recent May 16, 2008 board meeting, regarding the condition of Big Rivers' generating plants. As Big Rivers' President & CEO-Elect, I recognize that following the "unwind," I will be ultimately accountable and responsible to see that the company safely delivers low-cost, reliable power to its members. Based on my engineering education along with 34 years engineering and management experience in the electric utility industry including many years involving various operation and maintenance management assignments at a number of AEP power plants, I further recognize that reliable, low-cost generating facilities are the key to fulfilling that responsibility.

Because of their importance, I have paid close attention to our power plants, both while I was CEO of Kenergy as well as after joining Big Rivers last June as Executive Vice President. As you know, Big Rivers has utilized Stanley Consultants to monitor the plant conditions since the early 2000s through the present. We also have employees assigned to the plants to observe plant operations and maintenance and regularly communicate with local plant management. These individuals regularly review plant conditions and maintenance work that is performed, and also monitor plant budgets and expenditures.

I have examined the various reports produced by Stanley as well as reports prepared by Henderson Municipal Power & Light's engineering consultants. In addition, I have reviewed the Stone & Webster draft and final reports produced for the aluminum smelters as part of their due diligence of the "unwind" transaction. In general, it has been my observation that many of the items documented in many of these reports should have very little impact on the ability of the plants to produce low-cost, reliable electricity. I have also found that when major areas of concern have arisen, as they do in facilities as complex as generating stations, WKE addressed them in an effective manner.

In addition to these activities, I have examined the historical operating performance of the units. You may recall I have said on numerous occasions, both while I was with Kenergy as well as after joining Big Rivers, that based on my experience, a generating unit's performance will deteriorate rather quickly (e.g., 3–5 years) if it is not adequately maintained. In studying WKE expenditures since it began operating the units, I have found that base annual gross (including HMP&L's share of Station Two) capital and O&M expenditures have steadily increased from approximately $36.5 million in 1999 to nearly $65 million in 2007; a 78 percent increase which is nearly triple the rate of inflation (CPI) over that period. Given this information, combined with the fact that the Big Rivers' units are still performing well after ten years of WKE oversight, it is difficult to conclude they have not been adequately maintained. I have also recently walked down all the units and spoken with local plant management about the condition and operation and maintenance of the facilities, and am comfortable with what I have seen and heard.

As you know, Bob Berry, currently the plant manager of the Reid-Green plant and a 27-year veteran of both Big Rivers and WKE, who has also worked in various maintenance and management positions at the Coleman Plant, will assume the position of Vice President of Power Production following the "unwind." Since Bob has agreed to re-join Big Rivers in this capacity, I have worked closely with him and am quite comfortable with his knowledge, experience and management philosophy. Together, we have worked with the current Big Rivers' personnel who have primary plant monitoring responsibilities to develop a Production Work Plan which Bob and I believe will enable Big Rivers to safely meet the generation and reliability levels included in the "unwind" financial model.

Based on the activities described earlier as well as my experience with generating facilities of various design, size and age including some with similar characteristics as the Big Rivers' units, I am comfortable with the current condition of the generating facilities with the exception of the Coleman Unit 1 low pressure (LP) turbine rotor which is currently undergoing repairs found necessary during its regularly scheduled routine outage. Assuming that turbine is properly repaired, demonstrates it can operate normally and generate its rated output following its return to service prior to close of the "unwind" transaction, I will be comfortable with it as well.

Even though I am presently comfortable with the plant situation, there are still a number of conditions that must be met between now and the "unwind' closing before I will be completely satisfied that the plant due diligence portion of the Termination Agreement closing conditions are satisfied. For example, the plants must continue to operate without any significant abnormalities arising between now and the closing that would impact their ability to reliably generate at their rated levels and at their predicted cost profile. In addition, WKE must complete the 2008 Production Work Plan scheduled to occur up to closing and spend the budgeted funds necessary to complete that work. The units must also demonstrate their ability to operate at their rated output under normal conditions for eight continuous hours. Other due diligence items found, if any, will also need to be addressed to Big Rivers' satisfaction. If these conditions are not met, then WKE will either need to make satisfactory corrections similar to what I described earlier in the case of the Coleman 1 LP turbine and/or agree to other remedies which will permit Big Rivers to satisfactorily correct the deficiencies post-close and recover any modeled revenue lost in the process.

In closing, I want to reiterate a point noted earlier. Power plants are complex facilities with many things that can go wrong which will occasionally occur even in the best-managed operations. While Big Rivers' plant management plans to rely heavily on condition- based maintenance practices designed to detect, predict, and permit correction of major problem areas before they occur to minimize significant unplanned situations, they will still likely happen occasionally as they have in the past. If the "unwind" proceeds and these unexpected situations arise, Big Rivers will be much stronger financially and thus much better positioned to deal with them than we are at present.

I hope you find this information helpful in understanding how I have become and why I am currently comfortable with the plant conditions and also in understanding what must occur between now and closing for the plant portions of the Termination Agreement closing conditions to be satisfied.

c: Burns Mercer
Kelly Nuckols
Sandy Novick

ITEM 1

BIG RIVERS ELECTRIC CORPORATION'S
UPDATE TO RESPONSE TO THE ATTORNEY GENERAL'S
SUPPLEMENTAL REQUEST FOR INFORMATION
PSC CASE NO. 2007-00455
(June 24, 2008)

Item 88) Provide any and all internal E. ON documents which address the subject of existing agreements which are the subject of the "Unwind Transaction" and "Termination Transaction", including any financial analyses and strategic analyses.

Response) Big Rivers files this supplement to its response to Item 88 of the Attorney General's Supplemental Request for Information in response to requests by the Attorney General and the Commission Staff for more information regarding the generating plant and plant site due diligence Big Rivers is performing in anticipation of the Unwind Transaction closing. This Supplemental Response relates to Draft Settlement Concept No.15 presented at the June 14, 2008, Informal Conference in this matter. Refer also to Tab 13 of Big Rivers' May 30, 2008 filing. Specifically, the attached document was prepared to provide additional information to the Public Service Commission concerning follow-up action taken or planned in response to the Stanley Consultants report dated April 2007 entitled "Analysis of WKE Outages". The Stanley recommendations can be found in the Executive Summary of that report on pages vi through x.

Witness) Mark A. Bailey
Robert Berry

Responses to Recommendations in April 2007 Stanley Consultants Report Entitled "Analysis of WKE Outages"
June 24, 2008

Coleman Unit 1

1. Identify the cause of wet bottom tube leaks and take corrective action.

   Big Rivers' Response:

   The tubes in question were original to the unit and had been in service for approximately 39 years. During the unit's 2008 spring outage which is currently in progress, all lower slope tubes were replaced from the lower water wall header to the water wall transition line.

2. The cause of the unit trip on June 5, 2004 due to No. 4 turbine bearing vibration should be identified. Determine if future actions are required.

   Big Rivers' Response:

   The unit was returning to service from a planned outage and during start-up when the turbine was being brought to normal operating speed, the turbine developed an internal rub causing a bow in the rotor resulting in higher than normal vibration on bearing number 4. The unit was removed from service and the turbine placed on turning gear to allow the rotor to straighten and return to normal condition. No further action was required and the unit was returned to service. The turbine generator is currently undergoing a complete overhaul/inspection described in item 4 which follows.

3. Due to the installation of the AOFA systems in 2004 on Coleman Unit 1 boiler fire-side tube corrosion or erosion could have detrimental impacts. Implement a regular program of mapping boiler tube thickness to monitor.

   Big Rivers' Response:

   WKE currently utilizes a Computerized Maintenance Management System (CMMS) to manage boiler mapping. Within the CMMS, a job plan is established to monitor boiler fire-side tube corrosion or erosion impacts. This job plan includes: scaffolding of the boiler, non-destructive examination (NDE) of boiler tubes, visual inspections, collecting tube samples, and metallurgical analysis as part of each 3-year scheduled maintenance outage. This activity is also included in the Big Rivers' Production Work Plan.

4. Plan for Coleman Unit 1 turbine generator overhaul.

   Big Rivers' Response:

   The Coleman Unit 1 turbine generator inspection is currently in progress with a scheduled completion date of July 19, 2008. The following is a partial list identifying major items addressed during this outage: replacement of L-0 (last row of turbine blades before the steam exhausts to the condenser), L-1 (next to last row), and L-2 (2nd from last row) rows of LP turbine blades on both the generator and turbine ends of the turbine rotor, total generator inspection and electrical testing per the original equipment manufacturer (OEM) recommendations, generator exciter refurbishment, replacement of HP-IP (high pressure – intermediate pressure) stub shaft extension with new ruggedized rotor, turbine throttle valve modification for positive seating, complete inspection of HP & IP turbine rotor, shells, and turbine valve inspection.

Coleman Unit 2

1. Since the upper and lower reheater has been replaced recently, the cause of the reheater leaks noted in 2004 should be identified and corrective action taken.

   Big Rivers' Response:

   Coleman Unit 2 experienced two reheat tube leaks in 2004. Both leaks were a result of sootblower (steam blown into the boiler against the tubes to remove ash accumulation) erosion. This issue was corrected by installing tube shields in the sootblower lane to protect the tubes from erosion. Coleman Unit 2 did not experience any reheat tube leaks in 2005 or 2006.

2. Identify the cause of wet bottom tube leaks. Determine if future repairs are required.

   Big Rivers' Response:

   The tubes in question are original to the unit and have (had) been in service for approximately 38 years. During the unit's 2007 spring outage, non-destructive examination (NDE) inspections were performed and 35 (of abnormally thin-walled tubes) of the 270 lower slope tubes were replaced from the lower header to outside the affected area as a result of this inspection.

3. Due to the installation of the AOFA systems in 2004 on Coleman Unit 2 boiler fire-side tube corrosion or erosion could have detrimental impacts. Implement a regular program of mapping boiler tube thickness to monitor.

 <u>Big Rivers' Response:</u>

 As described earlier in response to a similar recommendation for Coleman Unit 1, WKE currently utilizes a Computerized Maintenance Management System (CMMS) to manage boiler mapping. Within the CMMS, a job plan is established to monitor boiler fire-side tube corrosion or erosion impacts. This job plan includes: scaffolding of the boiler, NDE of boiler tubes, visual inspections, tube samples, and metallurgical analysis as part of each 3-year scheduled maintenance outage. This activity is also included in the Big Rivers' Production Work Plan.

Coleman Unit 3

1. New superheater tubes were installed in 2003. The cause of the superheater tube leaks since 2003 appear to have been evaluated in a Sheppard T. Powell report dated March 6, 2007. The Sheppard T. Powell report dated March 6, 2007 stated "...A portion of the tube has been submitted for alloy identification...." Obtain alloy identification report from Sheppard T. Powell.

 <u>Big Rivers' Response:</u>

 New Secondary superheater tubes were installed on this unit in 2003. The referenced Sheppard T. Powell (S.T.P.) report involved a primary superheater tube sample which was sent for analysis, not the secondary superheater tubes installed in 2003. On March 20, 2007, the station received the S.T.P. report confirming the tube composition is consistent with SA210 (designation number developed by the American Society for Testing and Materials (ASTM) which describes the mechanical properties of steel boiler tubing). This is consistent with the boiler design. A detailed boiler tube sampling program is included in the Big Rivers' Production Work Plan.

2. Stanley Consultants has insufficient information to determine if all necessary repairs and/or replacement items were performed during the fall 2006 turbine generator unplanned overhaul. In preparation for the next planned turbine generator overhaul, obtain list of spare parts, repair and/or replacement items as required.

 <u>Big Rivers' Response:</u>

 The Coleman Unit 3 turbine generator is currently operating within the original equipment manufacturer (OEM) specifications. Station personnel

have reviewed reports from the OEM related to the C3 turbine generator recommendations and will have spare parts, repairs, and replacement items as required for the planned outage currently scheduled for 2012. These items are included in the Big Rivers' long term plan.

3. Due to the installation of the AOFA systems in 2004 on Coleman Unit 3 boiler fire-side tube corrosion or erosion could have detrimental impacts. Implement a regular program of mapping boiler tube thickness to monitor.

<u>Big Rivers' Response:</u>

As described in previous responses within this document to similar recommendations, WKE currently utilizes a Computerized Maintenance Management System (CMMS) to manage boiler mapping. Within the CMMS, a job plan is established to monitor boiler fire-side tube corrosion or erosion impacts. This job plan includes: scaffolding of the boiler, non-destructive examination (NDE) of boiler tubes, visual inspections, tube samples, and metallurgical analysis as part of each 3-year scheduled maintenance outage. This activity is also included in the Big Rivers' Production Work Plan.

Green Unit 1

1. Plan for overlay welding or laser cladding of furnace walls to address furnace wall corrosion due to the delayed combustion characteristics of the coal re-burn system which generate higher levels of hydrogen sulfide (H2S) resulting in higher corrosion rates of the furnace walls. Investigate the possibility of relocation of IR sootblowers or additional IR sootblowers to reduce fireside deposits and combustion tuning to reduce flame impingement.

<u>Big Rivers' Response:</u>

Weld overlay (boiler tubes with extra material welded over them) was installed on the furnace east and west walls during the spring 2007 scheduled outage. An area, 95 feet high by 35 feet wide was overlaid with Alloy 33 (ASTM designation) corrosion resistant material. Water wall mapping revealed no loss of tube metal on the north or the south Walls. Ultrasonic testing will be performed again during the 2010 scheduled outage. An additional $2.6 million is included in the Big Rivers' Production Work Plan to apply additional weld overlay during the 2010 planned outage if testing results indicate it is needed. There are no plans to move the IR sootblowers. General Electric Energy Environmental Research (GE EER), the original equipment manufacturer (OEM) for the Re-burn/OFA (over fire air) system, completed combustion tuning in April of 2008.

2. Green Unit 1 has not been chemically cleaned since 1997. The analysis of both water wall tube samples removed by Babcock & Wilcox during the fall 2004 outage revealed internal deposit weight densities of 21 grams per square foot (gms/ft2) and 24 gms/ft2. The third-party inspection report states "...chemical cleaning should be performed when deposit weight densities reach 12 gm/ft2..." It is expected that Green Unit 1 requires cleaning at this time.

   Big Rivers' Response:

   Boiler chemical cleaning is performed using a condition-based approach rather than a time-based approach. The Green Unit 1 boiler tube sample analysis report by Sheppard T. Powell (S.T.P.) and Associates dated February 23, 2004 confirmed the boiler needs chemical cleaning. The Big Rivers' Production Work Plan includes chemical cleaning the Green Unit 1 boiler during the 2010 scheduled outage.

Green Unit 2

1. Monitor the condition of 2005 overlay welding of furnace walls to address furnace wall corrosion due to the delayed combustion characteristics of the coal re-burn system which generate higher levels of hydrogen sulfide (H_2S) resulting in higher corrosion rates of the furnace walls. Investigate the possibility of relocation of IR sootblowers or additional IR sootblowers to reduce fireside deposits and combustion tuning to reduce flame impingement.

   Big Rivers' Response:

   During the spring 2008 scheduled outage, water wall tube mapping was conducted to monitor the effectiveness of the water wall tube weld overlay that was installed in 2005. An area 35 feet wide by 85 feet high on both the east and west furnace side walls are weld overlaid with Inconel 622 (ASTM designation) corrosion-resistant material. Ultrasonic testing showed no metal loss in the weld overlay area or on the north and south burner walls. Ultrasonic testing will be conducted again during the 2009 scheduled outage and $2 million is included in the Big Rivers' Production Work Plan for additional weld overlay if the testing indicates it is needed. There are no plans to move the IR soot blowers. General Electric Energy Environmental Research (GE EER), the original equipment manufacturer (OEM) for the Re-burn/OAF (over fire air) system, completed combustion tuning in April of 2008.

2. Green Unit 2 has not been chemically cleaned since 1990. The David N. French Metallurgist 2005 analysis of a water wall tube sample revealed a deposit weight

density of 15 gms/ft2. This third-party inspection report indicated the water wall tube was considered clean and a chemical clean was not needed at this time. This contradicts the Babcock & Wilcox recommendation of performing a chemical clean when deposit weight densities reach 12 gm/ft2. The Green Unit 2 spring 2005 outage work order (WO5079905 indicates Green Unit 2 was to be chemically cleaned during the spring 2005 outage. Verify Green Unit 2 was chemically cleaned during the 2005 spring outage.

Big Rivers' Response:

Boiler chemical cleaning is performed using a condition-based approach rather than a time-based approach. A tube sample analysis report (number 05-070) performed by Dr. David N. French (metallurgist whom WKE uses to evaluate tube sample deposits) suggests chemical cleaning of the boiler should be considered when the deposit weight density reaches 25 grams/ft2. Per Dr. French's' recommendation, the chemical cleaning was deferred until the next scheduled outage. The Big Rivers' Production Work plan includes chemical cleaning of the Green Unit 2 boiler during the 2009 scheduled outage.

HMPL Unit 1

1. New high temperature reheater tubes were installed in 1999, the cause of the high temperature reheater tube leak that occurred in 2006 should be identified and corrective action taken.

Big Rivers' Response:

According to the metallurgical analysis performed by Dr. David N. French (metallurgist whom WKE uses to evaluate tube sample deposits) and a Riley Power report (number 202302) dated June 6, 2008, the Henderson Unit 1 high-temp reheater tubes are failing due to thinning as a result of coal ash corrosion. The tubes have initial evidence of creep in the form of oxide cracking on the ID (inside diameter). While not in the current Big Rivers' Production Work Plan, current plans are to replace the high-temp reheat tubes at an estimated cost of $1.8 million during the scheduled spring outage of 2009.

Funding for this project will come from other planned projects that are not of as high a priority (e.g. deferred projects); from budgeted funds that might not entirely be needed to complete planned projects (e.g. over-budgeted projects); or by adding to the budget later if it is determined that there are no budgeted lower priority projects that can be deferred or enough money left over from under-budgeted completed projects.

As demonstrated in Big Rivers' response to the Attorney General's Supplemental Request for Information, items 94 and 95, even if the entire $1.8 million is added to the Financial Forecast, the rate impact of this change for both the non-smelter members and the smelters would be minimal.

2. Review the January 29, 2007 root cause analysis report. Determine if any future repairs are required as a result of the most recent thermal event.

Big Rivers' Response

A total of fourteen tube samples were removed and sent to David N. French (metallurgist whom WKE uses to evaluate tube samples) to determine if any significant damage had occurred. These included four samples on the east wall, four samples on the west wall, and six samples from the south wall were removed at elevations 492' 10" and 512' 10" within the boiler. The final report was received from the laboratory on Thursday February 8, 2007; the conclusions of this report are as follows.

- **There was no evidence of metallurgical degradation of the sample water wall tubes resulting from the coolant disruption.**
- **Typical microstructures were observed in the tubing, as for new SA-178 Gr.C (ASTM designation).**
- **There has been no significant loss of expected life of the boiler tubes from the low water event.**
- **Some inside diameter (ID) corrosion pitting was observed but deemed superficial.**
- **Deposit weight density was measured on a sample from each of the three walls, and the measurements showed the waterside to be clean. Even with the high temperature excursion, the tubes have not been oxidized on the waterside.**

HMPL Unit 2

1. Verify the high temperature reheater is being replaced during fall 2007 outage. If not accomplished during the fall 2007 outage, confirm the high temperature reheater is on the spring 2008 outage schedule.

Big Rivers' Response:

The H-2 high-temp reheater was replaced in October of 2007.

Reid Unit

1. The cause of the superheater tube leaks should be identified and corrective action

taken.

<u>Big Rivers' Response:</u>

Tube sample analysis concludes the Reid Unit 1 primary superheater is approaching the end of its useful life. Due to changes in environmental regulations such as CAIR, 316b, NOx, PM 2.5 and mercury, Big Rivers has in its 2009 Production Work Plan to evaluate the spending levels needed to maintain the future reliability of the Reid unit.

2. The cause of the water wall tube leaks should be identified and corrective action taken.

<u>Big Rivers' Response:</u>

Reid Unit 1 experienced numerous tube leaks on the lower water wall header tube stubs. These tubes experienced thinning due to exposure in the corrosive area of the boiler bottom ash hopper seal water. The lower water wall header stubs were replaced in the spring of 2004 which eliminated the water wall leaks associated with the thinning tube stubs.

Wilson Unit

1. The IMR metallurgical report dated June 16, 2006 states "...superheater Tube #1... a moderately dirty deposit density of 41.4 gm/ft2 was measured from internal deposits, which indicates that the tube would benefit from internal cleaning." Perform recommendations from metallurgical report. Continue annual submission of superheater tube samples for metallurgical review.

<u>Big Rivers' Response:</u>

Tube samples were collected from the platens and finishing superheater sections during the spring 2008 outage. The samples were sent to Dr. David N. French, (metallurgist whom WKE uses to evaluate tube sample deposits) for analysis. The reports from both the platens and the finishing tube samples indicated there was a very thin oxide layer and the internal condition was reported to be good. The Big Rivers' Production Work Plan includes the replacement of the Wilson superheater tubes during the fall 2009 outage.

2. The Wilson unit has not been chemically cleaned since 1997. The most recent metallurgical report Stanley Consultants has received to date from BREC is dated June 16, 2006 and prepared by IMR Metallurgical Services. This third-party inspection report stated "Waterside deposits/scale on the inside surfaces of the tubing were measured in accordance with ASTM D3483, Test Method A. The

measured value recorded from superheater tube was a maximum of 41.4 g/ft2, while the values recorded from the water wall tubing were "cleaner" with a maximum deposit of 13.95 g/ft2. The values recorded are a combination of oxide scale and/or internal deposition." The need to perform a chemical clean of this unit should be verified.

Big Rivers' Response:

Boiler chemical cleaning is performed on a condition-based approach rather than a time-based approach. During the 2008 spring outage, tube samples were collected and sent to Sheppard T. Powell for analysis. The report from the north wall tube sample has been received and indicated that no chemical cleaning is needed at this time. The report from the south wall tube sample analysis is still pending. The Big Rivers' Production Work Plan contains plans to chemical clean the Wilson unit during the fall 2009 outage since an earlier report (prior to the 2008 sample reports) indicated the unit was borderline concerning the need for chemical cleaning and the outage length was such that the cleaning could be accommodated without extending the outage length.

3. Review the future Wilson outage work lists and post work documentation related to the turbine generator incident to assure the recommended repairs and inspections as a result of the loss of lube oil event are completed.

   Big Rivers' Response:

   Remote continuous vibration monitoring is performed on the main turbine/ generator. The data has not indicated any serious problems. The Big Rivers' Production Work Plan includes a high pressure-intermediate pressure (HP/IP) turbine/generator inspection for 2009. A complete evaluation will be performed on the HP/IP rotor at this time. Appropriate corrective actions will be based upon the findings of this evaluation.

All Units

1. Boiler Tube Leaks:
   a) A comprehensive assessment should be performed to determine the root cause of boiler tube failures. An investigation of all aspects of boiler operation, leading to a tube failure to fully understand the cause should be performed. For example, boiler water treatment, so scale, foaming, corrosion, caustic embrittlement, and turbine blade deposition can be avoided or minimized. Water chemistry, outage, and maintenance records should be requested to aid in root cause analyses of corrosion and deposit problems.

Big Rivers' Response:

In addition to the Computerized Maintenance Management System (CMMS) to manage boiler tube mapping described previously, Big Rivers will implement a formal root cause analysis process for all tube leak outages. The person identified to fill the newly created (within the Big Rivers post-unwind organization) Manager of Maintenance Services will work with staff at each plant to implement and monitor this process. The process will include metallurgical analysis of failed tubes and an adjacent tube in the same area.

b) The rate of damage and the effects of water and steam chemistry on erosion/corrosion, boiler tube corrosion, turbine blade pitting and cracking, feedwater heater and condenser tube corrosion, etc., should be identified and lead to planned outages and equipment repairs or replacement.

Big Rivers' Response:

Drum inspections, internal condenser inspections, boiler tube samples and turbine inspections conducted on all units in the Big Rivers' system indicate there have been no problems related to water chemistry. Regular monitoring of these areas will continue so that in the event water chemistry becomes an issue, it can be addressed promptly.

c) Physical evidence in all tube failures should be analyzed. High velocities occur during a tube leak that will remove deposits in the leaking or ruptured tube. Therefore, it is recommended that a tube similar to a tube which has failed, in the same area, be removed for proper analysis.

Big Rivers' Response:

When the cause of a boiler tube failure is not readily determined, Big Rivers plans to send the tube failure along with a tube in the adjacent area to either Sheppard T. Powell and Associates or Dr. David N. French (metallurgist whom WKE uses to analyze tube samples) for analysis including life assessment and deposit composition. This will continue to be a part of the root cause analysis process.

d) As tube failures occur, they should be tracked and any patterns analyzed for similarity. A better assessment of the causes of the tube leaks could be performed if there was more information on where these leaks occurred. Mapping of the tube leaks would show how close the tube leaks are to any sootblowers or other equipment that may have caused abrasion to the inside of the tubes. Failures should be used to determine the locations for the next set of tube samples. In addition, there is a need to sample for external attack such as reducing atmosphere, sulfur attack and erosion wear patterns.

<u>**Big Rivers' Response:**</u>

All stations track tube failures detailing the location of the leak(s), tube material, size of tube and thickness, date of repair, length of repair and estimated cause of failure. In the future, Big Rivers plans that the analysis process will include a composite drawing identifying the location of each failure.

e) The boiler water treatment program should be audited for compliance with the recommended EPRI guidelines and/or plant chemical vendor guidelines.

<u>**Big Rivers' Response:**</u>

The boiler water treatment plan being utilized by Western Kentucky Energy which is planned to be continued under Big Rivers is the program recommended by Dave Cline with Sheppard T. Powell and Associates. Sheppard T. Powell's staff was instrumental in formulating the EPRI Boiler Treatment guidelines. All stations are following the EPRI guidelines.

f) A continuous and consistent program of sampling boiler, economizer, superheater and reheater tubes should be implemented.

<u>**Big Rivers' Response:**</u>

As a result of the Boiler Condition Assessment team work, during each scheduled outage the CMMS system (described in earlier responses) automatically generates a work order for boiler tube samples to be taken from the water walls, nose arch, superheater, economizer and reheat sections of each unit's boiler. The tube samples are sent to either Sheppard T. Powell and Associates or Dr. David N. French (metallurgist whom WKE uses for tube analysis) for analysis including life assessment and deposit composition.

g) An annual review of the recorded boiler operating temperatures and pressures, as compared to design parameters, should be performed.

<u>**Big Rivers' Response:**</u>

Each station's Performance Engineer and Production Manager perform a routine daily evaluation of the parameters listed in this recommendation. In addition to the station's efforts, Coleman and Green

station both have a standing performance monitoring contract with Black and Veatch to continuously monitor station operating parameters, including operating temperatures and pressures. The Wilson plant will also utilize Black and Veatch for performance monitoring after Big Rivers resumes operation and HMP&L Station Two will do so when the new system controls are installed in 2010 which will accommodate this activity.

2. BREC should consider having a BREC plant transition site representative at all of the BREC stations. This site representative would require access to maintenance records, operating logs, performance reports, and other pertinent information.

<u>Big Rivers' Response:</u>

Big Rivers currently has a representative at each location and they have access to all pertinent information.

Exhibit MAB-9

Explanation of Increases in the 2009 – 2011 Production Work Plan
Compared to the 2008 – 2010 Production Work Plan

The Operation and Maintenance expenses (O&M) in the 2009 – 2011 Production Work Plan increased a total of $7.3 million dollars compared to the 2008 – 2010 Production Work Plan. The plan over plan changes in the Production Work Plan is captured in five primary categories.

1) Contractor Rates; The existing maintenance contract expires in December of 2008 and budgetary quotes indicate a 15% increase in labor rates associated with the maintenance contracts. This equates to approximately $4.1M over the three year plan.

2) Cost of Materials; We are experiencing a significant increase in materials due to increased steel prices. We are also experiencing large increases in chemical costs which are needed to maintain boiler and cooling water chemistry, and significant increases in dredging and industrial cleaning contracts due to rising diesel fuel cost. This equates to approximately $2.9M over the three-year plan.

3) Scope of Work; Outage inspections completed during the 2008 outage cycle has identified the need for additional work that was not included in the 2008 – 2010 Production Work Plan. This additional work is primarily in the FGD (scrubber) at Sebree and the Boiler and Fuel handling areas at Coleman. The total scope of work increase over the three year plan is $4.6M.

4) Diesel/Gas Prices; Diesel and gasoline prices have increased approximately $900k in the 2009 -2011 Production Work Plan compared to the 2008 – 2010 Production Work Plan. The diesel and gas is used in the heavy (mostly coal handling) equipment at the plant sites.

5) Catalyst Management Plan; The catalyst regeneration and replacement was considered O&M in the 2008 – 2010 Production Work Plan; however, after further review it was determined to follow the WKE capitalization policy and capitalize these items. The catalyst regeneration and replacement is now considered a capital expense in the 2009 – 2011 Production Work Plan. This reduced the O&M expense by approximately $5.4M, thus the total net O&M increase to the Production Work Plan is $7.3M over the three year period.

The 2009 – 2011 capital budgets increased $12.2M compared to the previous plan. This increase is due to the timing of the Wilson FGD (scrubber) repairs. In the 2008 – 2010 Production Work Plan the Wilson FGD repair project was spread equally over a four year period. The 2009 – 2011 Production Work Plan aligns the necessary repairs with the outage schedule. A more detailed repair plan for the Wilson FGD has required most of the repair work to be completed during the scheduled outages and less work during the non-outage years. Over a four year time period (2009 through 2012) the net increase to the capital budget is $2.6M which is due to the capitalization of the catalyst regeneration and replacement. The table below reflects the capital increases/decreases by year.

Year	2008 - 2010 Capital Plan		2009 - 2011 Capital Plan		Plan over Plan Variance	
2009	$	53,791,816	$	64,894,651	$	(11,102,835)
2010	$	44,602,914	$	38,029,726	$	6,573,188
2011	$	49,223,817	$	56,909,547	$	(7,685,730)
2012	$	43,636,516	$	34,082,833	$	9,553,683
Total	**$**	**191,255,063**	**$**	**193,916,757**	**$**	**(2,661,694)**

Non-Labor O&M Variance Explanations from prior Model

2009	Coleman	Wilson	Green	R/SII	Total
Contractor Rates	-	65,000	65,000	7,000	137,000
Cost of Materials	595,000	160,830	192,400	188,057	1,136,287
Fuel/Gas Prices	140,000	-	60,000	94,000	294,000
Scope of Work	726,000	31,000	739,140	220,000	1,716,140
Catalyst Moved to Capital	-	(1,700,000)	-	-	(1,700,000)
Other	-	-	(19,908)	71,101	51,193
Total Increase/(Decrease)	1,461,000	(1,443,170)	1,036,632	580,158	1,634,620

2010	Coleman	Wilson	Green	R/SII	Total
Contractor Rates	849,326	198,785	736,711	-	1,784,822
Cost of Materials	547,000	251,560	177,900	50,112	1,026,572
Fuel/Gas Prices	145,000	32,257	30,000	93,000	300,257
Scope of Work	473,000	28,200	559,240	106,000	1,166,440
Catalyst Moved to Capital	-	(1,400,000)	-	-	(1,400,000)
Other	-	-	(10,950)	77,986	67,036
Total Increase/(Decrease)	2,014,326	(889,198)	1,492,901	327,098	2,945,127

2011	Coleman	Wilson	Green	R/SII	Total
Contractor Rates	1,066,000	470,135	643,845	2,244	2,182,224
Cost of Materials	274,000	232,000	116,900	138,523	761,423
Fuel/Gas Prices	145,000	-	24,000	92,963	261,963
Scope of Work	1,082,000	39,000	522,340	91,206	1,734,546
Catalyst Moved to Capital	-	(1,820,000)	-	(512,593)	(2,332,593)
Other	-	-	(17,093)	83,339	66,246
Total Increase/(Decrease)	2,567,000	(1,078,865)	1,289,992	(104,318)	2,673,809

Exhibit MAB-10

Experience of Big Rivers' Plant Managers

Jim Garrett

Jim Garrett is currently the Plant Manager of the Sebree facility and a 25 year veteran with Big Rivers and WKEC. Jim has held various positions within Big Rivers and WKEC, such as plant manager, project manager over large capital projects, maintenance manager and superintendent of maintenance. Prior to joining Big Rivers, Jim was employed by the Tennessee Valley Authority from 1978 to 1983 as a machinist and supervisor.

Pat Waldeck

Pat Waldeck is currently the interim Plant Manager of the Coleman facility and a 38 year veteran with Big Rivers and WKEC. Pat has held various positions within Big Rivers and WKEC, such as production manager and construction / start-up coordinator at both the Wilson and Green facilities. From 1998 to 2003, Pat was employed by Covanta Energy as the plant manager of the Quezon facility in Quezon, Philippines.

Ron Gregory

Ron is currently the Plant Manager of the Wilson facility and a 32-year veteran with Big Rivers and WKEC. Ron has held various positions within Big Rivers and WKEC, such as maintenance manager, supervisor of maintenance, maintenance planner and maintenance supervisor.

VERIFICATION

I verify, state, and affirm that the foregoing testimony is true and correct to the best of my knowledge and belief.

Mark A. Bailey

Mark A. Bailey

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark A. Bailey on this the 7th day of October, 2008.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires 1-12-09

EXHIBIT 105

UPDATED BIG RIVERS WORK PLAN

(LOCATED IN SEPARATE BOOK)

EXHIBIT 106

BIG RIVERS RUS FORM 12