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 107) Follow up to response to Staff #3, and the attached letter regarding "funding of consent fees". Please provide a document which shows a) a list of consent fees by party and amount which has been agreed to, and, b) a list of parties to which consent fees will likely be due and an estimated contingency amount for each one.

Response) Big Rivers anticipates that the consent fees it pays will go to creditors. To date, no specific agreement has been reached with Big Rivers' creditors on consent fees to be paid. Those consent fees will be disclosed when Big Rivers files its application for approval of its financing arrangements.

Witness) C. William Blackburn

Item 108) Please refer to the following summarized directly from the Response to Staff #8:

WKEC Additions to Big Rivers Production Plant
Incept of Lease of December 31, 2007

1998 & 1999			$	5,827,500	
	2000		$	15,431,026	
	2001		$	13,192,912	
	2002		$	6,506,458	
	2003	$ 94,650,068			Total
		$ (64,567,905)			SCR-Wilson
			$	30,082.163	Net
	2004		$	35,952,180	
	2005		$	16,057,651	
	2006		$	43,536,818	
	2007		$	21,364,023	
			$	187,950,731	

Source: Response to OAG #8

Response) N/A, see AG's Supplemental Request Item 109.

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Item 109) Please explain and discuss the reasons why additions for the period 2003 – 2007 are markedly higher than for the period 1998 - 2002.

Response) The reasons why additions are higher is predominantly the SCRs and other NO_x control equipment added to Big Rivers and the Station Two units.

Witness) C. William Blackburn
E.ON

Item 110) Please refer to the Response to Staff #18. State at what point in time it will be known to Big Rivers that the Internal Revenue Service concurs with and accepts the assumed split of consideration for federal income tax purposes.

Response) Big Rivers has not and does not plan to ask for an IRS ruling in this matter.

Witness) C. William Blackburn
Counsel

Item 111) Please refer to the Response to Staff #21, where it states "through 2010, the 60 year life per the Unwind Model serves to approximate the depreciable life".

Response) N/A, see AG's Supplemental Request Item112.

Item 112) Looking to 2011 (three years in the future) what factors will modify this "60 year life"?

Response) In a depreciation study, the following factors would most likely have the largest impact:

1. The projected remaining economic life of each generating asset.
2. Capital additions since the last depreciation study.
3. Historical operating conditions of each unit.
4. Maintenance and operating practices.
5. Analysis of external and environmental factors affecting plant useful lives.
6. Current depreciation reserves.

Witness) C. William Blackburn

Item 113) What percentage change is anticipated to this "60 year life", and what direction (increase or decrease)?

Response) It is impossible for Big Rivers to estimate a percentage change in the "60 year life" cycle that a new depreciation study could produce. Please see Big Rivers' response to the Commission Staff's Supplemental Data Request Item 11.

Witness) C. William Blackburn

Item 114) Please refer to the Response to Staff #22, where it is stated "...APM provided a statistical study..." Provide a complete identification and discussion of assumptions utilized in making that statistical study.

Response) The assumptions were developed, and are provided below, by APM for Big Rivers.

Power Prices

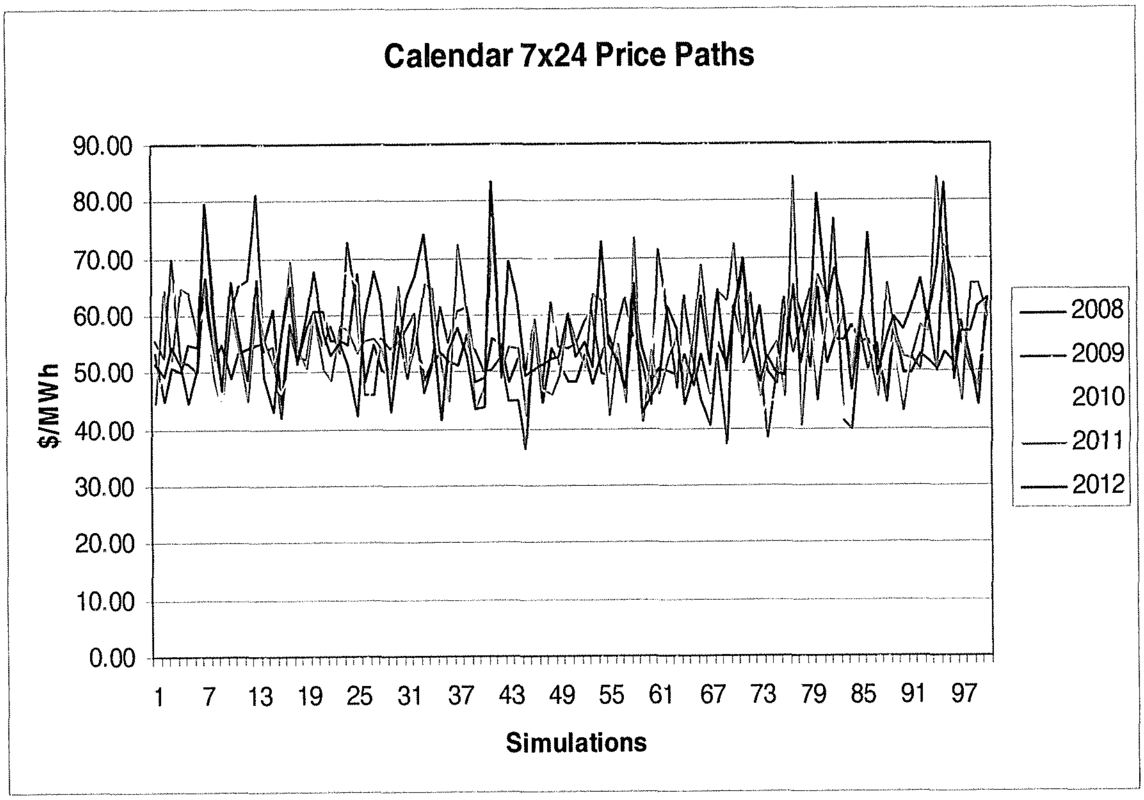
The mean prices shown in the spreadsheet are from Cinergy Hub broker quotes, which are tracked by ACES Power Marketing's mark-to-market group. This represents the price level at which forward block transactions can be executed on the given trade day.

- 2008 - $53.65
- 2009 - $54.70
- 2010 - $55.81
- 2011 - $56.47
- 2012 - $56.94

Statistical Simulation

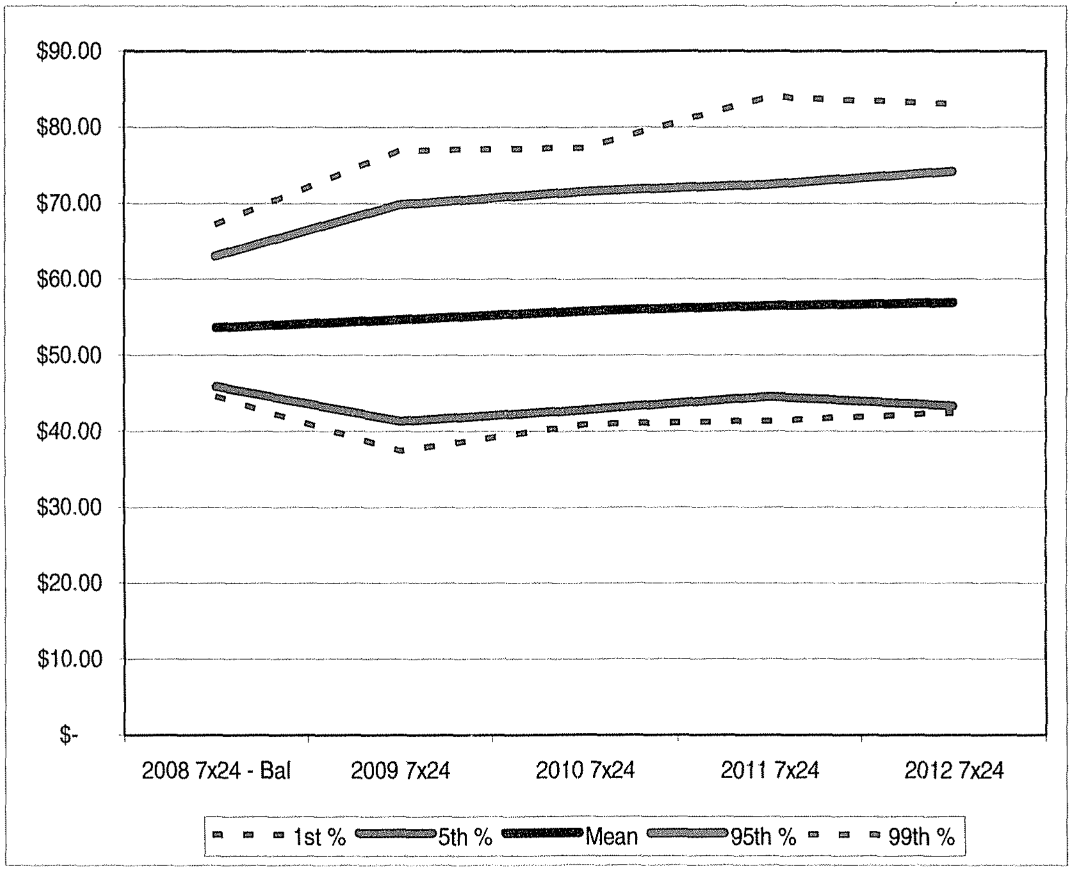
Cinergy HUB was used as the basis for market pricing in the Big River portfolio. A distribution of possible prices is reflected in annual price distributions shown in the spreadsheet. These distributions were derived from traded market products, Cinergy HUB forward price quotes and implied volatilities. These data items are recorded by APM's mark-to-market group. The model utilizes a Monte-Carlo simulation to create 100 possible price paths such that over the course of all simulations the mean price equals the quoted forward prices shown above. The range of prices simulated allows for options valued in the model to equal the quoted option prices on the day of the analysis.

The graph below shows the 100 calendar 7x24 simulations for each year.



The table and chart below show the statistical range. Percentiles are simply the sorted simulation results from low (1st %) to high (99th %).

Output Name	1st %	5th %	Mean	95th %	99th %
2008 7x24 - Bal	$ 44.57	$ 45.94	$ 53.65	$ 63.09	$ 67.17
2009 7x24	$ 37.41	$ 41.34	$ 54.70	$ 69.86	$ 76.94
2010 7x24	$ 40.98	$ 42.86	$ 55.81	$ 71.60	$ 77.32
2011 7x24	$ 41.39	$ 44.60	$ 56.47	$ 72.49	$ 83.98
2012 7x24	$ 42.46	$ 43.38	$ 56.94	$ 74.24	$ 83.08



Witness) C. William Blackburn

Item 115) Please refer to the Response to Staff #30, regarding contract with Southwire.

a. Does the Big Rivers/Kenergy contract proposal contain proposed rates above or equal to the large industrial class figures reflected in the Unwind Model?

b. At what point in time does Big Rivers/Kenergy expect agreement to be reached with Southwire?

Response) a. The contract proposal from Big Rivers/Kenergy to Southwire Rod & Cable contains rates equal to the large industrial class reflected in the Unwind Model.

b. Big Rivers/Kenergy expects to reach agreement with Southwire Rod & Cable prior to closing the Unwind Transaction.

Witness) C. William Blackburn

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Item 116) Please refer to the Response of OAG #5. Outside of a desire to have financing alternatives, identify and explain each and every other condition or circumstance that is contributing to Big Rivers' exploration of the indicated alternative long-term financing scenario, e.g., difficulties in obtaining previously planned financing, unfavorable credit market conditions, etc.

Response) The sole reason driving Big Rivers to explore financing alternatives is the unsettled condition in the credit market and the extremely wide credit spreads.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
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Item 117) Please refer to the Response of OAG #1, regarding "continuing disputes" with E.ON. Provide a description of the subject matter of each such dispute, and the approximate time of the dispute.

Response) The issues referred to in AG Initial Request Item 1 were disputes over energy imbalance charges and energy scheduling. The first of those were brought to the attention of Big Rivers in May of 2003 with the second shortly thereafter. They remain unresolved and would be considered settled upon the closing of the Unwind.

Witness) Michael H. Core

Item 118) Please refer to the Response of OAG #18, which attachment is dated April 25, 2007.

a. Provide any documents or analysis from Goldman Sachs (or other investment banking advisors) subsequent to that date whose topics include deterioration of credit market conditions related to sub-prime mortgage and other developments.

b. Update the table on page 5 to reflect current credit market conditions.

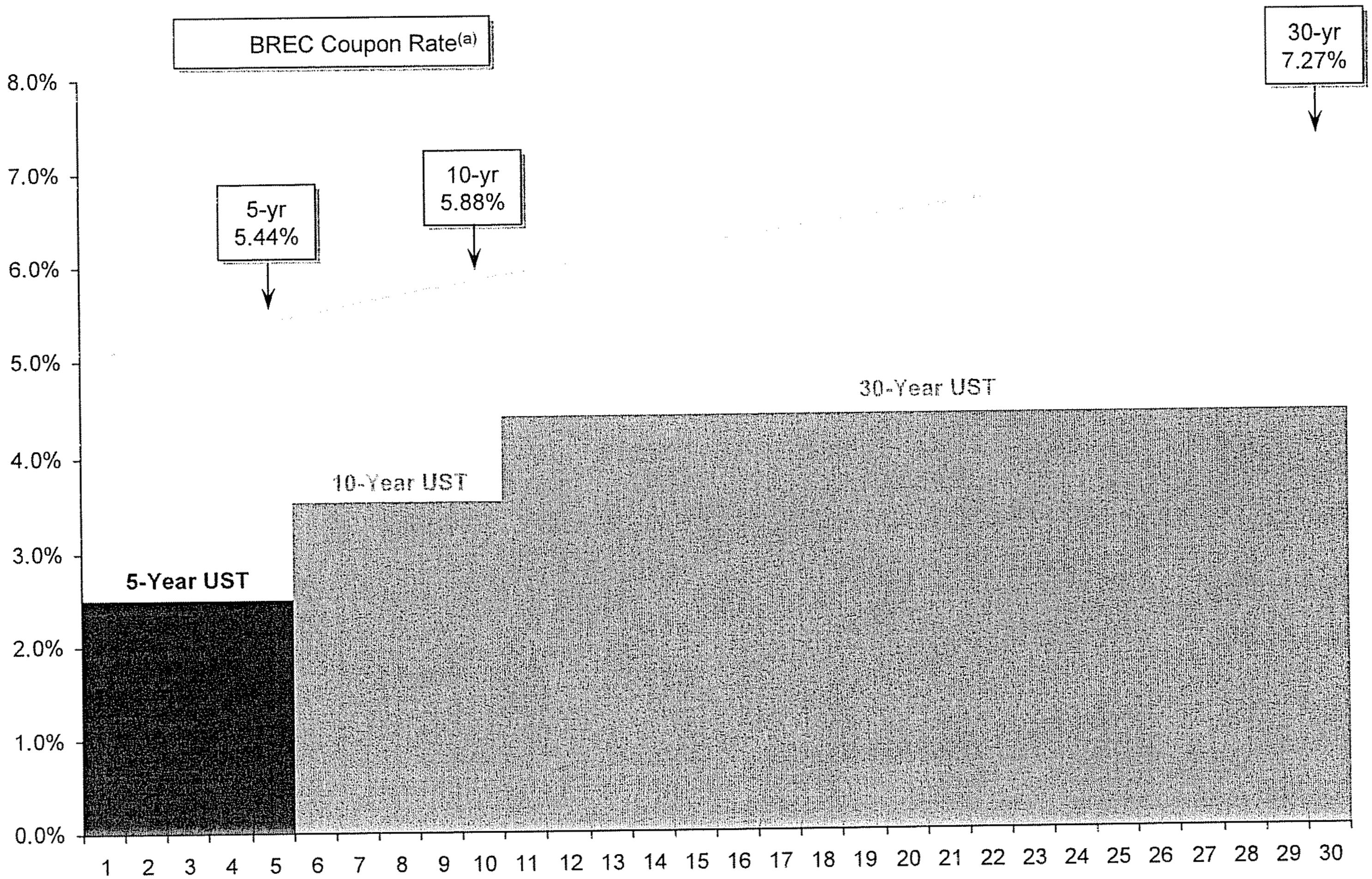
Response) a. Goldman Sachs has not provided Big Rivers with any written information on the credit markets relative to the sub-prime mortgage market.

b. Please refer to the attached table which reflects current credit market conditions.

Witness) C. William Blackburn

Goldman Sachs

Indicative Big Rivers borrowing rates with underlying benchmark US Treasury rates.



(a) As of 3/3/2008

Note: Due to increased volatility in the debt capital markets, these rates are our best estimates and are subject to change

Item 119) Please refer to the Response of OAG #41. Provide a summary of outcomes and action steps and associated timelines/milestones from the "scheduled meetings".

Response) The meetings scheduled for March 5, 2008 with Standard & Poors and Moody's have been postponed. Big Rivers will inform the parties of record when these meetings have been rescheduled, the outcome of the meetings, any action steps required, and the timeline to receive the ratings.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST
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March 6, 2008

Item 120) Please refer to Big Rivers' Power Point presentation, "Discussion of Unwind Financial Model" dated January 2008. Please update this presentation to incorporate revised data from the 2.14.08 version of the Unwind Model as provided to the parties, where the newer version changes the data in the original presentation.

Response) Please see the attached updated presentation of the Financial Model to include the 2.14.08 data.

Witness) C. William Blackburn

Discussion of Unwind Financial Model

Consistent with 2.14.08 Version

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

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C. Appendices

A. Key Measures and Outcomes

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

A. Key Measures and Outcomes

1a. Target Earnings and Coverage Ratios - Times Interest Earned (TIER) ($M, unless otherwise indicated)

The financial model, via the terms of the Smelter Agreements, revolves around maintaining a target earnings level, and hence TIER

		2008*	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Earnings	10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4
2	Interest & Related **	40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
3	Adjust. Per Smelter Agreeme	(1.0)	(1.5)	0.9	(1.7)	(1.7)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(2.5)	(2.7)	(2.8)
4	Total	49.6	73.8	73.7	73.5	73.4	73.1	72.7	72.5	72.3	71.9	71.7	71.4	71.2	70.9	70.8	70.3
5	Interest & Related **	40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
6	Contract TIER	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24
7																	
8	Short Term-Int./ Fees	0.3	0.4	0.4	0.4	0.5	0.5	0.4	0.4	0.5	0.5	0.5	0.5	0.6	0.6	0.7	0.5
9	Income Tax	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
10																	
11	RUS TIER	1.27	1.27	1.23	1.27	1.27	1.27	1.27	1.28	1.28	1.28	1.28	1.28	1.29	1.29	1.29	1.29
12	Conventional TIER	1.27	1.27	1.22	1.27	1.27	1.28	1.28	1.29	1.29	1.29	1.29	1.29	1.30	1.30	1.30	1.31

* Partial year

** Includes Sale-Leaseback Interest

Proforma worksheet, line 290

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

A. Key Measures and Outcomes

1b. Target Earnings and Coverage Ratios – Debt Service Coverage ($M, unless otherwise indicated)

		2008*	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Cash Available for Debt Service																
2	Receipts less Disbursements	84.6	88.0	77.5	69.2	77.9	89.8	102.0	102.7	103.3	111.9	116.9	116.2	116.5	116.4	113.5	114.8
3	Economic Reserve	5.5	12.5	19.1	20.4	24.2	4.5	-	-	-	-	-	-	-	-	-	-
4	Taxes	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.5)	(0.6)
5	Net	90.2	100.5	96.6	89.5	102.1	94.2	101.7	102.3	102.9	111.5	116.4	115.7	116.0	115.8	113.0	114.2
6	Plus Sale-Leaseback Interest	8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
7	Total	99.1	113.8	110.5	104.0	117.1	109.9	118.0	119.3	120.6	130.0	135.9	136.0	137.3	138.2	136.5	138.9
8	Divided by																
9	Interest Expenditures	27.2	39.9	38.8	37.7	36.5	35.3	34.0	32.5	31.1	29.5	27.8	26.1	24.2	22.2	20.2	18.1
10	Scheduled Principal	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
11	Plus Sale-Leasback Interest	8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
12	Total Debt Service	48.0	71.7	72.3	72.9	73.5	74.1	74.7	75.4	76.2	77.0	77.8	78.7	79.7	80.8	81.9	83.1
13																	
14	*DSCR*	2.06	1.59	1.53	1.43	1.59	1.48	1.58	1.58	1:58	1.69	1.75	1.73	1.72	1.71	1.67	1.67

* Partial year

Proforma worksheet, line 320

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

A. Key Measures and Outcomes

2a. Member Rates – Base Derivations

Base Rates remain at current levels through 2010

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rural																
Load Factor (%)	60%	60%	60%	60%	60%	60%	60%	61%	61%	61%	61%	61%	61%	61%	61%	61%
Demand ($/ KW-mo.)	7.4	7.4	7.4	7.5	7.5	7.5	7.5	7.6	7.6	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Energy ($/ MWH)	20.4	20.4	20.4	20.8	20.8	20.8	20.8	21.0	21.0	23.1	23.1	23.1	23.1	23.1	23.1	23.1
Base ($/MWh)	37.2	37.2	37.2	37.9	37.9	37.9	37.8	38.2	38.2	42.0	41.9	41.9	41.9	41.9	41.8	41.8
MRDA ($/ MWh)	(1.1)	(1.1)	(1.1)	(1.1)	(1.0)	(1.0)	(1.0)	(1.0)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.8)	(0.8)	(0.8)
Net ($/ MWh)	36.1	36.1	36.1	36.9	36.9	36.9	36.9	37.2	37.2	41.0	41.0	41.0	41.0	41.0	41.0	41.0
Large Industrial																
Load Factor (%)	78%	79%	79%	79%	78%	79%	79%	79%	78%	79%	79%	79%	78%	79%	79%	79%
Demand ($/ KW-mo.)	10.2	10.2	10.2	10.4	10.4	10.4	10.4	10.5	10.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
Energy ($/ MWH)	13.7	13.7	13.7	14.0	14.0	14.0	14.0	14.1	14.1	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Base ($/MWh)	31.5	31.4	31.4	32.0	32.0	32.0	32.0	32.3	32.4	35.6	35.6	35.6	35.6	35.6	35.6	35.6
MRDA ($/ MWh)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)
Net ($/ MWh)	30.6	30.5	30.5	31.1	31.2	31.2	31.2	31.5	31.6	34.8	34.8	34.8	34.9	34.9	34.9	34.9
Blend	34.4	34.4	34.4	35.1	35.1	35.1	35.1	35.4	35.4	39.1	39.1	39.0	39.0	39.0	39.0	39.0

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

A. Key Measures and Outcomes

2b. Blended Member Rates ($/ MWh)

Member cost of riders are offset through 2012, with FAC significantly offset by Surcredit through whole period

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Member Non-Smelters																
1	Base (Net of MDA)	34.4	34.4	34.4	35.1	35.1	35.1	35.1	35.4	35.4	39.1	39.1	39.0	39.0	39.0	39.0	39.0
2	Regulatory Account	-	-	-	-	-	0.2	0.2	0.2	0.5	0.5	0.5	0.9	0.9	0.9	1.3	1.3
3	FAC	5.9	5.8	7.1	7.6	7.8	8.3	9.0	9.0	9.4	9.4	9.8	9.6	10.1	10.3	10.4	10.4
4	Env. Surcharge	0.5	0.8	2.7	2.6	2.9	2.9	3.0	4.1	4.2	4.1	4.3	4.2	4.5	4.6	4.6	4.8
5	Surcredit	(4.0)	(3.0)	(3.9)	(3.8)	(4.3)	(4.2)	(4.1)	(4.0)	(3.9)	(4.5)	(4.4)	(4.3)	(4.2)	(4.1)	(4.0)	(4.0)
6	Rebate:																
7	Accrued *	(0.2)	(0.5)	(0.9)	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Realized	-	(0.2)	(0.5)	(0.9)	-	-	-	-	-	-	-	-	-	-	-	-
9	MRSM	(2.4)	(3.6)	(5.3)	(5.5)	(6.4)	(1.2)	-	-	-	-	-	-	-	-	-	-
10	Effective Rate - Cash	34.4	34.4	34.4	35.1	35.1	41.1	43.2	44.8	45.6	48.7	49.2	49.5	50.3	50.7	51.4	51.6

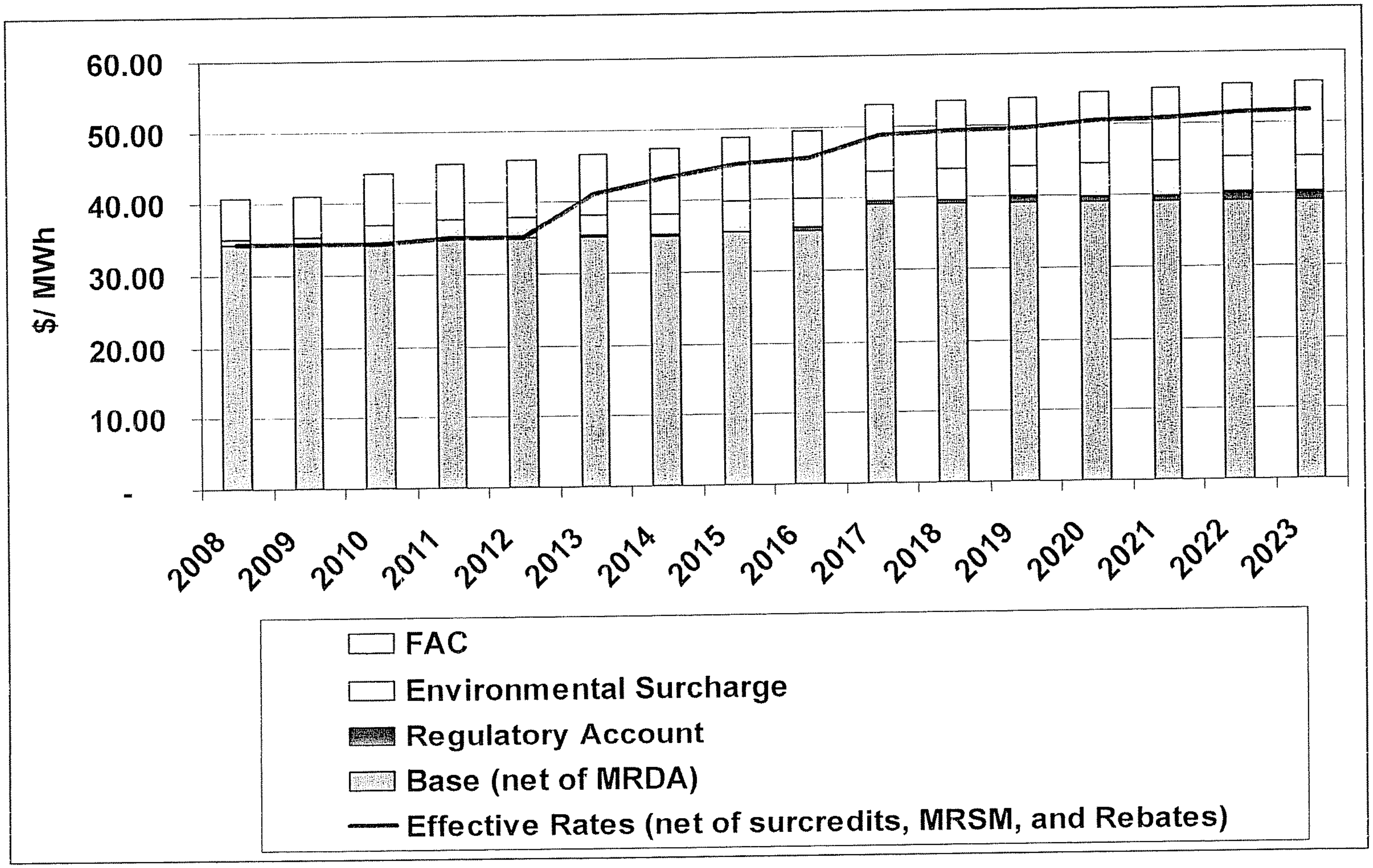
* Accrual basis; rebates actually paid in follwing year

Member Rates Cash Method Worksheet, line 50

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

A. Key Measures and Outcomes

2c. Blended Member Rates ($/ MWh)



Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

A. Key Measures and Outcomes

3a. Smelter Rates ($/ MWh)

Smelters share certain rate components with Members: FAC, Environmental Surcharge, Rebate, and via Regulatory Account, PPA…

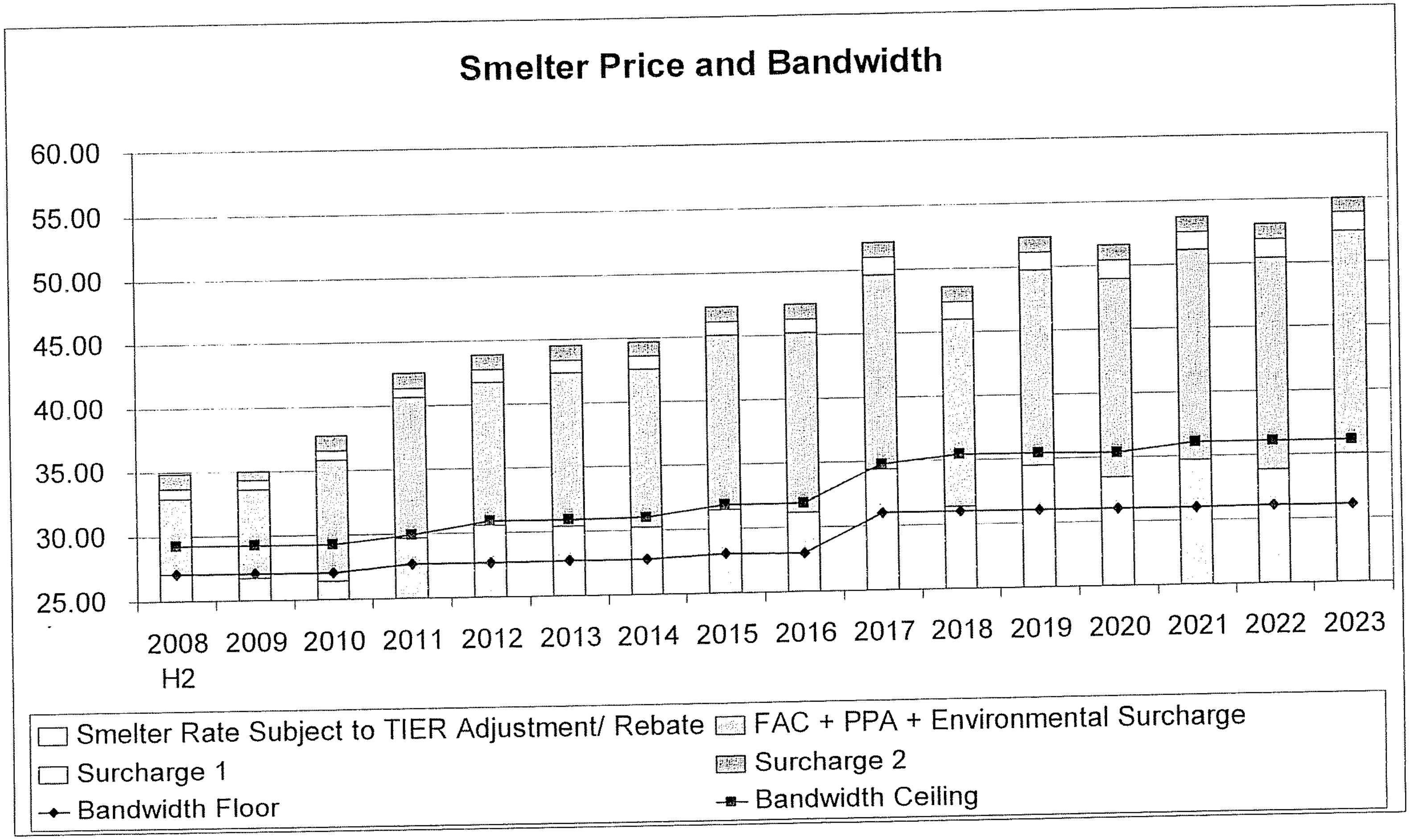
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Smelters																
1	Lg. Indus. Rate @	27.1	27.1	27.1	27.7	27.7	27.7	27.7	28.0	28.0	30.9	30.9	31.0	30.9	31.0	31.0	31.0
2	Addl. Smelt. Charge	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
3	Base	27.3	27.3	27.3	27.9	27.9	28.0	28.0	28.3	28.3	31.2	31.2	31.2	31.2	31.2	31.2	31.3
4	TIER Adjustment	-	-	-	1.8	2.6	2.4	2.3	3.2	2.9	3.1	0.2	3.2	2.2	3.5	2.5	3.7
5	FAC	5.9	5.8	7.1	7.6	7.8	8.3	9.0	9.0	9.4	9.4	9.8	9.6	10.1	10.3	10.4	10.4
6	Env. Surcharge	0.5	0.8	2.7	2.6	2.9	2.9	3.0	4.1	4.2	4.1	4.3	4.2	4.5	4.6	4.6	4.8
7	PPA	(0.5)	0.0	(0.4)	0.7	0.5	0.8	0.3	0.6	0.5	1.7	0.6	1.5	1.1	1.5	1.7	2.2
8	Surcharge	1.9	1.4	1.9	1.9	2.2	2.2	2.2	2.2	2.2	2.6	2.6	2.6	2.6	2.6	2.6	2.6
9	Rebate (accrued)	(0.2)	(0.5)	(0.9)	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Effective Rate	34.8	34.9	37.7	42.5	43.9	44.6	44.7	47.3	47.4	52.2	48.6	52.4	51.6	53.7	53.1	55.1

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

A. Key Measures and Outcomes

3b. Smelter Rates ($/ MWh) - Bandwidth

...but uniquely pay the TIER Adjustment and other items



Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

A. Key Measures and Outcomes

3c. Smelter Rates ($/ MWh)

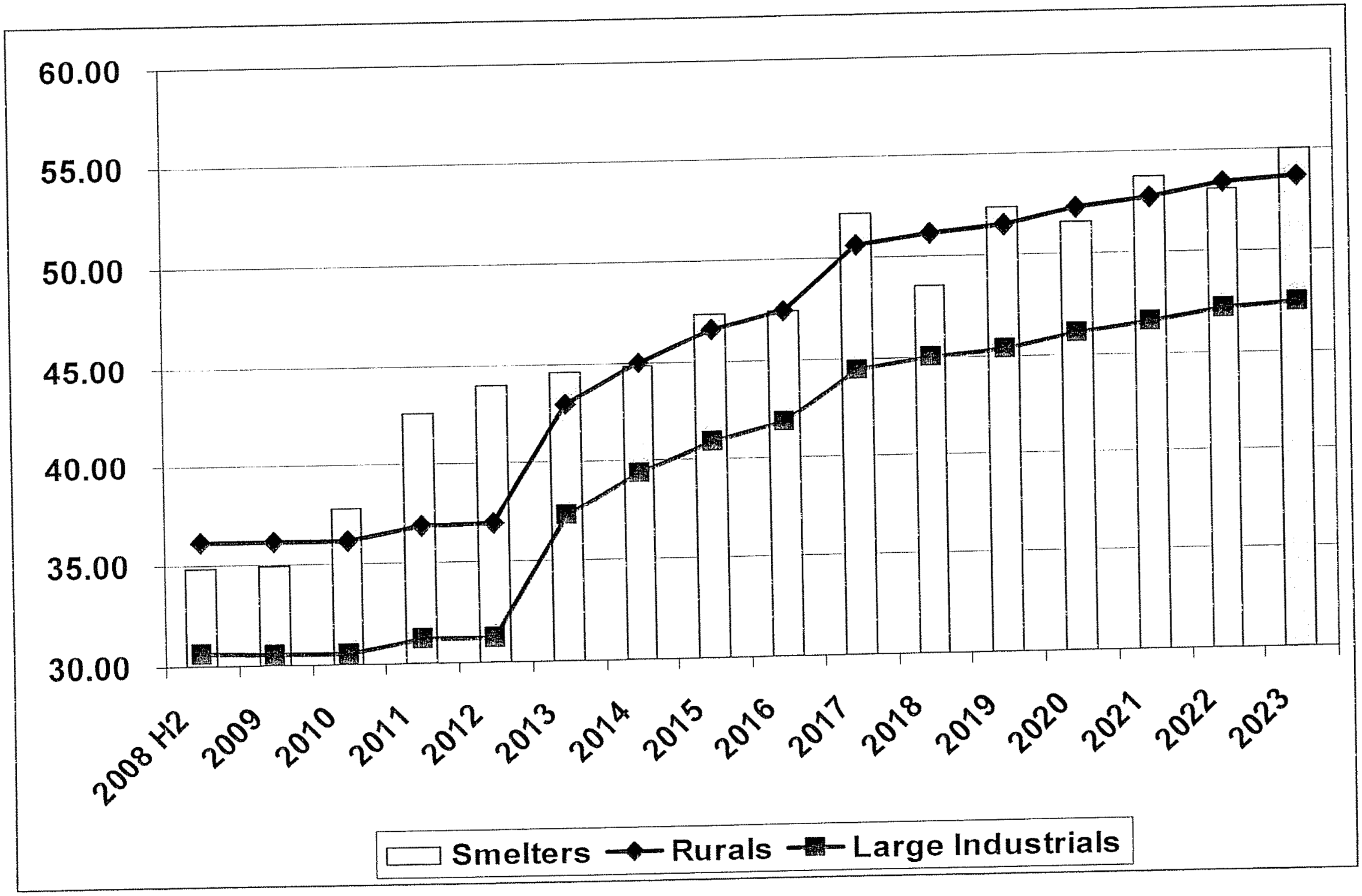
Overall, Smelters pay on average $/ 4.66MWh in excess of Large Industrial Rate (adjusted to 98% load factor) plus other rate components common to Smelters and Members:

	Avg. $/ MWh
Large Industrial Rate @ 98% LF+FAC+PPA+ES-Rebate	42.13
Increment:	
Margin	0.25
TIER Adjustment Charge	2.13
Surcharge 1	1.11
Surcharge 2	1.17
Total	4.66
Effective Smelter Rate	46.78

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

A. Key Measures and Outcomes

4. Comparative Rates ($/ MWh)



Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

A. Key Measures and Outcomes

5. Balance Sheet
($M, unless otherwise indicated)

Growing equity leaves room for future financing

Balance Sheet	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Assets																
Net Utility Plant	1,035	1,074	1,095	1,107	1,115	1,105	1,097	1,087	1,076	1,053	1,035	1,016	995	974	951	929
Sale-Leaseback	200	201	209	218	226	235	244	255	266	277	290	303	318	333	350	368
Cash & Investments	138	102	80	53	41	40	44	48	53	64	74	82	92	99	104	109
Transition Reserve	36	38	39	41	43	44	46	48	50	52	55	57	60	62	65	68
MRSM	72	62	46	27	4	-	-	-	-	-	-	-	-	-	-	-
Receivables, Inventori	138	138	143	148	150	160	162	165	166	175	173	177	179	183	188	194
Assets	1,618	1,615	1,612	1,594	1,580	1,585	1,593	1,603	1,611	1,622	1,627	1,636	1,643	1,652	1,658	1,667
Liabilities & Equities																
Equities	387	403	417	433	448	464	480	496	512	529	545	561	577	593	610	626
Sale-Leaseback	241	240	246	252	258	265	272	279	288	297	307	319	331	344	358	373
Debt	850	838	825	811	797	782	766	749	731	712	692	671	649	625	600	574
Payables & Other	139	134	125	98	76	74	75	78	79	84	82	86	86	90	90	94
Liabilities & Equities	1,618	1,615	1,612	1,594	1,580	1,585	1,593	1,603	1,611	1,622	1,627	1,636	1,643	1,652	1,658	1,667
Equity/ Assets	24%	25%	26%	27%	28%	29%	30%	31%	32%	33%	33%	34%	35%	36%	37%	38%

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

A. Key Measures and Outcomes

6. Cash Balances
($M, unless otherwise indicated)

Cash on hand + line of credit exceeds 4 months operating costs in any year

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Average Cash Balance	167	157	129	107	89	84	87	93	100	110	123	134	145	156	165	173
2	Line of Credit	67	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
3	Total	234	257	229	207	189	184	187	193	200	210	223	234	245	256	265	273
4	Total Operating Expense	294	439	451	477	481	494	501	518	524	554	538	558	561	582	583	602
5	Days Cash on Hand:																
6	Including Line of Credit	291	213	186	158	143	136	136	136	139	138	151	153	159	161	166	165
7	Excluding Line of Credit	207	130	105	82	68	62	63	66	70	72	83	88	94	98	104	105

B. Assumptions

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

B. Assumptions

1a. Transaction Economics - Unwind Compensation

Immediate impact on Big Rivers' financial statements

	$ Millions
Cash	301.5
Residual Value Payment	150.4
LG&E Rental Income Advance	11.4
Fuel Inventory & Other	55.0
Settlement Promissory Note	16.0
Coleman Scrubber	97.5
SO2 Allowances & Other	10.9
Expense Unamortized Mktg Payment/ Settlement Note	(15.7)
Assurances Agreement Payment	(4.3)
Total	622.7

Income Statement (Proforma worksheet, line 205) → Total

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

B. Assumptions

1b. Transaction Economics – Cash Flow

Transaction cash flow reduces debt and enhances liquidity

Balance Sheet (Proforma worksheet, lines 221 + 222 + 223)

Accounts established for exclusive Member benefit

	$ Millions
Cash Balances Pre-Transaction	134.9
Transaction Proceeds	301.5
Debt Reduction	(195.8)
Misc. Transaction	(5.6)
Net Flow to Unrestricted Cash	100.1
Cash Balances Post-Transaction	235.0
Less Funding of Member Rate Stabilization Account	(75.0)
Less Funding of Member Transition Reserve	(35.0)
Cash Balances	125.0

B. Assumptions

2a. Debt Reduction – RUS Note

RUS Note reduced with transaction proceeds + new issuance

Proforma worksheet lines 347 + 354 →

Proforma worksheet line 368 →

	$ Millions
Sources of Funds	
Net Transaction Proceeds	195.8
Net New Issuance Proceeds	263.5
Total	459.3
Uses of Funds	
Reduce RUS New Note (GAAP Basis)	440.7
Adjustment to Stated Basis	1.8
Reduce RUS New Note (Stated Basis)	442.4
Accrued Interest	7.2
Transaction Costs	9.6
Total	459.3

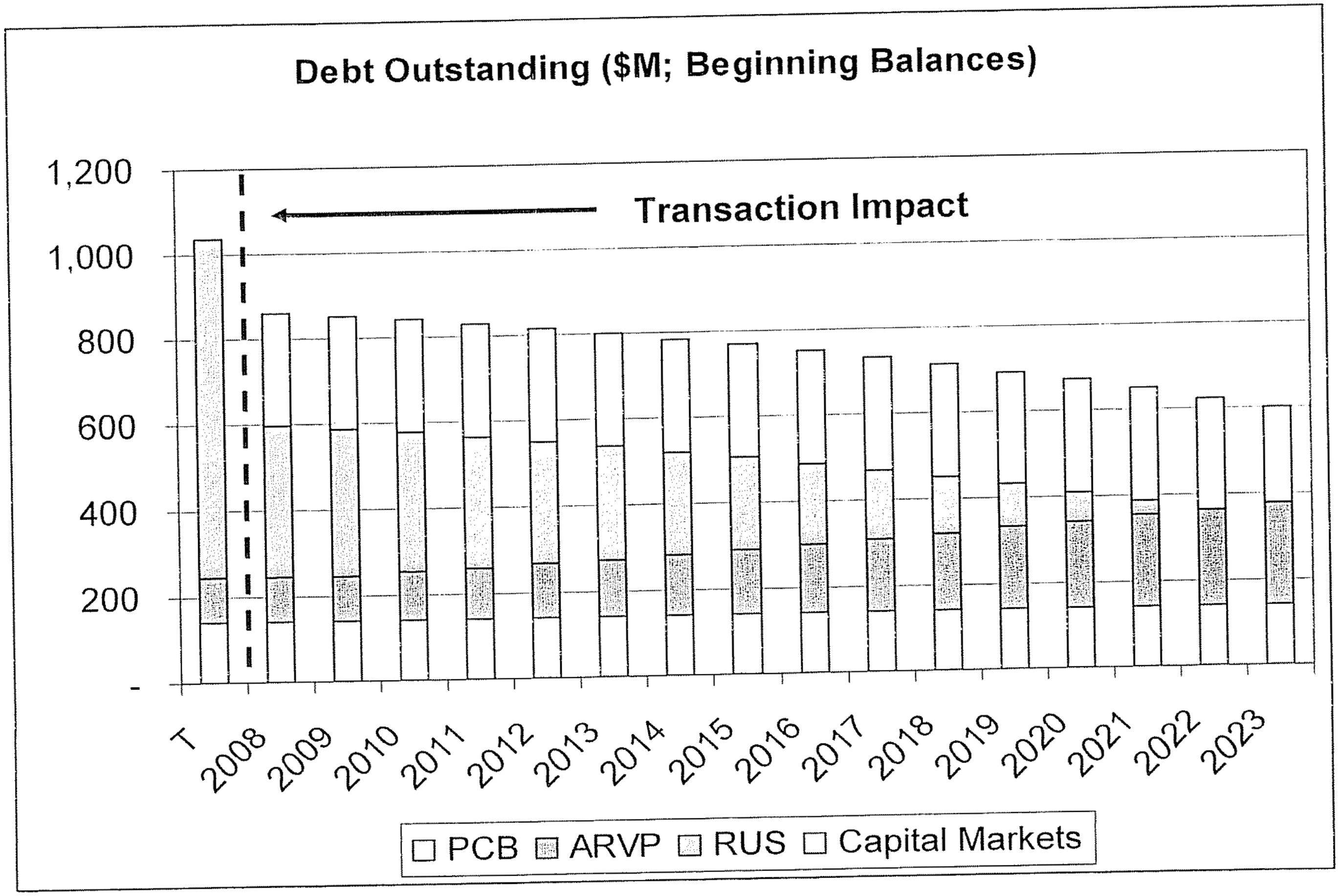
Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

B. Assumptions

2b. Ongoing Financing

- *RUS Note paid down by current maturity of 2021*
- *Capital Markets, PCB and ARVP Refinancing in 2023 amortize through 2038*

See Proforma worksheet lines 343 - 392



B. Assumptions

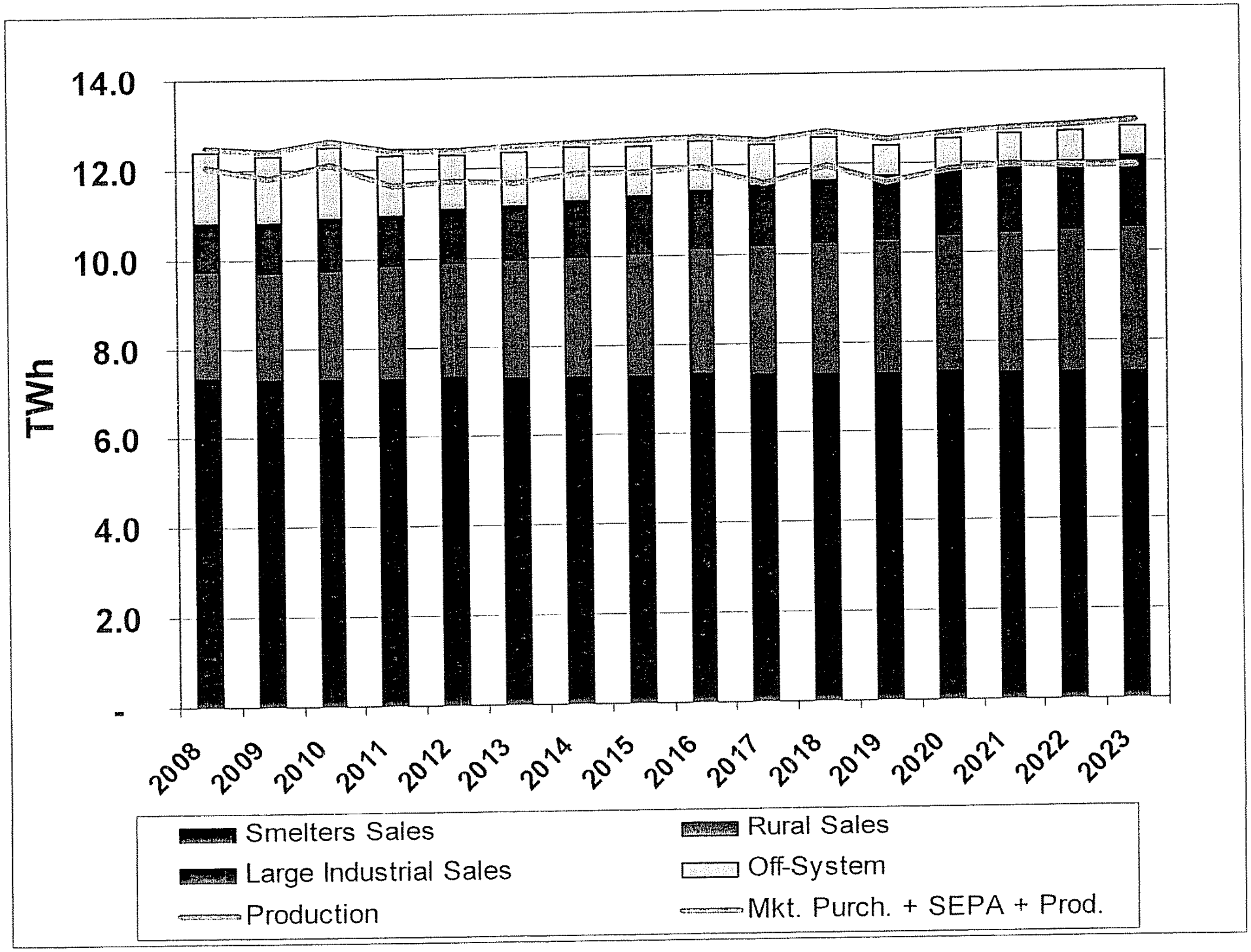
3a. Production and Variable Costs – Energy Balance (Annualized in 2008)

- *Driven by Production Cost Model*
- *Increase in Member Sales displace Market Sales over time*

See:

Proforma worksheet lines 1 – 13

FAC PPA Env Sur worksheet lines 1 and 2



Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

B. Assumptions

3b. Production and Variable Costs – Market Sales

See Pro Forma Worksheet, lines 11, 99, and 109)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
TWh	1.06	1.49	1.61	1.32	1.21	1.20	1.17	1.12	1.08	0.92	0.99	0.70	0.72	0.75	0.68	0.70
Rates ($/ MWh)	48.40	51.34	49.47	50.22	48.34	51.48	51.92	53.69	52.59	53.75	54.70	57.55	57.70	56.11	59.94	59.12
$Millions	51.4	76.7	79.8	66.3	58.5	61.7	60.8	60.0	56.9	49.2	54.0	40.0	41.4	42.0	41.0	41.4

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

B. Assumptions

3c. Production and Variable Costs – Fuel (see Fuel Inventory Worksheet)

Projected fuel costs average $1.88/ MMbtu, sourced from Production Cost Model

	T	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fuel Purchases ($/mmbtu)	1.48	1.48	1.50	1.64	1.70	1.71	1.81	1.82	1.84	1.88	1.92	1.90	1.92	1.95	1.97	1.99	2.01
Coal Consumed (000s of Gbtus)	0.0	89.9	131.5	134.0	129.1	129.4	128.1	130.5	130.5	131.2	127.3	131.6	127.3	130.4	131.3	130.7	131.1
Volumes Fuel Inventory (000s of Gbtus)																	
BB	0.0	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1
Fuel Purchased	0.0	89.9	131.5	134.0	129.1	129.4	128.1	130.5	130.5	131.2	127.3	131.6	127.3	130.4	131.3	130.7	131.1
WKE Additions	37.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Consumed	0.0	(89.9)	(131.5)	(134.0)	(129.1)	(129.4)	(128.1)	(130.5)	(130.5)	(131.2)	(127.3)	(131.6)	(127.3)	(130.4)	(131.3)	(130.7)	(131.1)
EB	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1
$Millions																	
BB	0.0	55.0	55.0	55.8	61.0	63.0	63.6	67.1	67.7	68.2	69.7	71.1	70.6	71.2	72.4	73.1	73.6
Fuel Purchased	0.0	133.3	197.7	220.4	219.2	221.7	231.6	238.1	239.8	246.5	244.0	250.5	244.3	254.5	258.8	259.6	263.0
WKE Additions	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Expensed	0.0	(133.3)	(197.0)	(215.2)	(217.2)	(221.2)	(228.1)	(237.6)	(239.3)	(245.0)	(242.6)	(250.9)	(243.7)	(253.3)	(258.1)	(259.0)	(262.3)
EB	55.0	55.0	55.8	61.0	63.0	63.6	67.1	67.7	68.2	69.7	71.1	70.6	71.2	72.4	73.1	73.6	74.4
$/ MWh Sales		16.62	16.56	17.77	18.31	18.53	19.03	19.71	19.72	20.13	20.17	20.47	20.35	20.83	21.02	21.10	21.16
FAC Base ($/ MWh)		10.72	10.72	10.72	10.72	10.72	10.72	10.72	10.72	10.72	10.72	10.72	10.72	10.72	10.72	10.72	10.72
FAC ($/ MWh)		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44

B. Assumptions

3d. Production and Variable Costs - Power Purchases (see Inputs Worksheet, lines 23, 24, 43, 45, 310)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
TWh																
Market	0.13	0.29	0.19	0.46	0.38	0.54	0.37	0.42	0.42	0.72	0.47	0.66	0.53	0.55	0.62	0.71
SEPA	0.17	0.30	0.31	0.31	0.30	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
Total	0.30	0.59	0.50	0.77	0.68	0.81	0.64	0.69	0.69	0.99	0.74	0.93	0.80	0.82	0.89	0.98
Rates ($/MWh)																
Market	47.55	53.53	53.88	51.18	48.73	43.89	46.92	48.93	48.57	49.27	46.27	48.71	52.10	59.38	55.96	59.64
SEPA	22.44	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
Blend	33.40	37.52	34.63	39.75	39.69	39.01	39.78	41.51	41.24	43.97	40.58	43.70	45.14	50.19	48.52	52.08
$M																
Market	6.2	15.3	10.4	23.7	18.6	23.9	17.6	20.7	20.3	35.4	21.8	32.2	27.6	32.8	34.9	42.4
SEPA	3.8	6.8	6.8	6.8	8.6	7.7	7.9	7.9	7.9	8.0	8.1	8.3	8.3	8.4	8.4	8.6
Total	10.0	22.1	17.3	30.5	27.2	31.6	25.5	28.7	28.3	43.3	29.9	40.6	35.9	41.2	43.3	51.0
Pmts. to Henderson	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Income State	10.2	22.4	17.6	30.8	27.5	31.9	25.8	29.0	28.6	43.7	30.3	40.9	36.2	41.5	43.7	51.3

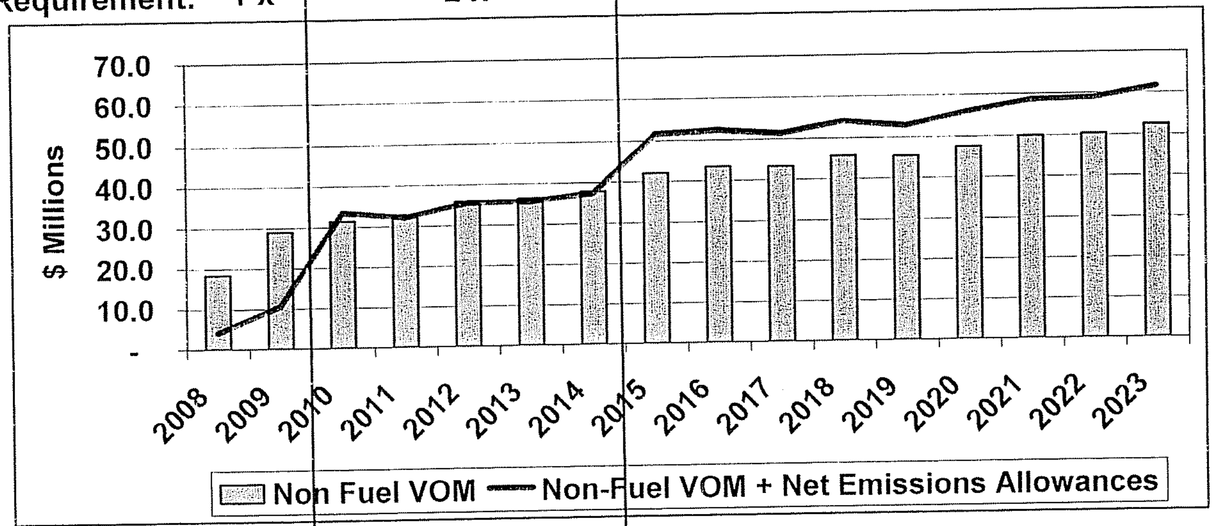
Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

B. Assumptions

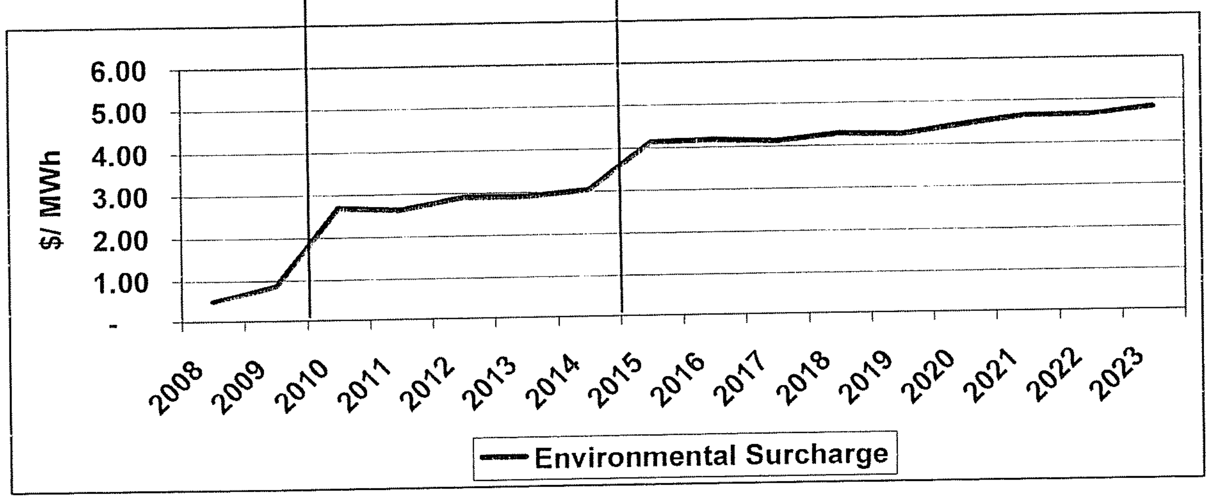
3e. Production and Variable Costs - Environmental Costs

SO2 Allowance Requirement: 1 x | 2 x | 2.86 x

- *Environmental Costs ($M)*



- *Environmental Surcharge ($/ MWh)*



Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

B. Assumptions

3f. Production and Variable Costs - Environmental Costs (see Inputs Worksheet, lines 32 – 39, 47, 48)

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Non-Fuel Variable O&M**																
2	Net Production (TWh)	8.1	11.8	12.1	11.6	11.7	11.6	11.9	11.9	12.0	11.6	12.0	11.6	11.9	11.9	11.9	11.9
1	Total SO2/ Nox/ SO3																
2	$/ MWh	2.27	2.45	2.60	2.83	3.07	3.13	3.19	3.53	3.62	3.74	3.81	3.92	4.01	4.18	4.23	4.40
3	$M	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
4																	
5	**Emissions Allowances**																
6	SO2																
7	Emissions (000 Tons)	14.0	18.8	19.9	18.8	19.4	18.3	19.3	19.1	19.5	18.1	19.5	18.8	19.4	19.2	19.5	19.1
8	Allowances (000 Tons)	32.7	49.0	24.5	24.5	24.5	24.5	24.5	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
9	Net Requirement (000 Tons)	(18.6)	(30.2)	(4.6)	(5.7)	(5.1)	(6.2)	(5.2)	1.9	2.4	1.0	2.4	1.6	2.2	2.1	2.3	2.0
10	SO2 Allowances ($/ton)	778	853	881	818	792	747	787	907	759	618	357	146	137	134	111	105
11	$M	(14.5)	(25.7)	(4.1)	(4.6)	(4.1)	(4.6)	(4.1)	1.8	1.8	0.6	0.9	0.2	0.3	0.3	0.3	0.2
12	Nox																
13	Emissions (000 Tons)	4.9	13.6	13.6	12.9	12.9	13.1	13.0	13.1	13.0	13.0	13.1	12.8	13.2	13.2	12.9	13.3
14	Allowances (000 Tons)	4.7	11.1	11.1	11.1	11.1	11.1	11.1	8.9	8.9	8.5	8.3	8.2	7.9	7.7	7.5	7.4
15	Net Requirement (000 Tons)	0.3	2.5	2.5	1.8	1.8	2.0	1.9	4.2	4.0	4.5	4.8	4.7	5.2	5.5	5.4	5.9
16	SO2 Allowances ($/ton)	763	2,847	2,409	2,155	1,985	1,900	1,909	1,869	1,748	1,625	1,569	1,510	1,521	1,523	1,525	1,527
17	$M	0.2	7.2	6.1	4.0	3.6	3.8	3.7	7.8	7.1	7.4	7.5	7.0	7.9	8.3	8.3	9.0
18	Total ($M)	(14.3)	(18.5)	2.0	(0.7)	(0.4)	(0.8)	(0.4)	9.5	8.9	7.9	8.3	7.3	8.2	8.6	8.6	9.2
19																	
20	**Total ($M)**	4.1	10.4	33.4	32.2	35.5	35.6	37.5	51.5	52.2	51.2	53.9	52.6	55.8	58.5	58.9	61.6
21																	
22	**TWh Sales**	8.28	12.29	12.49	12.29	12.29	12.35	12.41	12.45	12.52	12.43	12.59	12.40	12.53	12.64	12.67	12.78
23																	
24	**Env. Surcharge ($M)**	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.16	4.12	4.28	4.25	4.45	4.63	4.65	4.82

B. Assumptions

4a. Fixed Operating Costs – Production O&M
(see Production – Fixed Worksheet, lines 29 - 53)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Production - Labor	30.0	43.4	45.1	46.9	48.6	50.1	51.3	52.3	53.3	54.3	55.7	57.4	59.1	60.8	62.7	64.6
Production - Non-Labor																
Baseline	29.2	37.0	41.1	41.9	39.7	50.3	41.9	53.4	45.5	47.1	53.9	54.3	54.6	60.4	53.1	67.8
Plant Maintenance	2.2	3.7	2.1	2.6	2.0	1.5	1.1	5.4	1.3	6.5	1.4	2.4	2.0	2.6	2.2	2.8
Turbine/ Generator Overhauls	2.8	9.2	-	9.3	10.5	-	7.0	-	6.7	19.8	-	13.5	5.9	7.8	8.4	-
Total $M	34.2	49.8	43.2	53.8	52.1	51.8	50.0	58.7	53.5	73.5	55.2	70.2	62.5	70.9	63.7	70.6
Total $M	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

B. Assumptions

4b. Fixed Operating Costs – Transmission O&M (see Production- Fixed Worksheet, lines 18 - 27)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Transmission - Labor	3.8	5.9	6.1	6.2	6.4	6.6	6.8	7.0	7.2	7.5	7.7	7.9	8.2	8.4	8.7	8.9
Transmission - Non-Labor																
Baseline	1.1	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.5
Upgrades	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5
Total $M	1.3	2.0	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.5	2.5	2.6	2.7	2.8	2.9	3.0
Total $M	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

B. Assumptions

4c. Fixed Operating Costs – Administrative & General
(see Production- Fixed Worksheet, lines 1 - 6)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
A&G - Labor	7.7	11.0	11.3	11.6	12.0	12.3	12.7	13.1	13.5	13.9	14.3	14.7	15.2	15.6	16.1	16.6
A&G - Non-Labor																
Baseline	6.5	10.0	10.3	10.6	10.9	11.2	11.6	11.9	12.3	12.6	13.0	13.4	13.8	14.2	14.6	15.1
Intellectual Property	3.7	4.0	2.6	2.8	2.5	2.6	3.0	2.7	2.8	3.2	3.0	3.1	3.5	3.2	3.3	3.8
Total	10.2	14.0	12.9	13.3	13.4	13.8	14.5	14.6	15.1	15.9	16.0	16.5	17.3	17.5	18.0	18.9
Total $M	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

B. Assumptions

5. Depreciation and Amortization (see Capex & Depreciation Worksheet)

			Existing Depreciation Study			Transitional Depreciation						Long Run Depreciation						
		T	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Total Utility Plant (Including CWIP)**																	
2	Beginning Balance	1,780	1,878	1,924	2,001	2,060	2,117	2,172	2,208	2,246	2,285	2,323	2,364	2,411	2,459	2,505	2,553	2,601
3	Capitalization																	
4	Coleman Scrubber	97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Capital Expenditures	-	37	76	59	56	54	36	37	37	38	40	46	47	45	47	47	49
6	Capitalized Interest	-	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
7	Change in CWIP	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Ending Balance	1,878	1,924	2,001	2,060	2,117	2,172	2,208	2,246	2,285	2,323	2,364	2,411	2,459	2,505	2,553	2,601	2,650
9																		
10	**Depreciation and Amortization**																	
11	Beginning Balance	870	870	894	931	970	1,015	1,061	1,108	1,154	1,203	1,252	1,316	1,381	1,447	1,515	1,584	1,654
12	Annual Depreciation and Amort	-	24	38	39	45	46	46	47	48	50	64	65	66	68	69	70	72
13	Ending Balance	870	894	931	970	1,015	1,061	1,108	1,154	1,203	1,252	1,316	1,381	1,447	1,515	1,584	1,654	1,726
14																		
15	**Years Depreciation ((Line 2 + Line 8)/ 2)/ Line 12**			52	52	46	46	47	48	47	47	37	37	37	37	37	37	37

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

B. Assumptions

6. Income Taxes (see Income Taxes Worksheet)

	T	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Taxable Transaction	55.8																
Transition Reserve																	
BB	-	35.0	36.0	37.5	39.2	40.8	42.6	44.4	46.3	48.3	50.3	52.5	54.7	57.1	59.5	62.1	64.7
Interest Earnings	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
EB	35.0	36.0	37.5	39.2	40.8	42.6	44.4	46.3	48.3	50.3	52.5	54.7	57.1	59.5	62.1	64.7	67.5
Taxable Income Before NOLs	55.8	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
Regular NOLs	55.8	1.0	1.5	1.6	1.7	1.7	0.0	-	-	-	-	-	-	-	-	-	-
Taxable Income	-	-	-	-	-	-	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
Book Tax @ 35%	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
AMT Tax/ (Offset)	1.1	0.0	0.0	0.0	0.0	0.0	(0.6)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Taxes Paid	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6

B. Assumptions

7. Capital Expenditures (see Capex & Depreciation Worksheet)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capital Expenditures ($M)																
Generation	14.6	32.5	23.7	28.8	30.1	30.4	31.3	32.2	33.2	34.2	35.2	36.2	37.3	38.5	39.6	40.8
Extraordinary Generation	7.6	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
Transmission	6.2	9.6	9.2	4.4	5.9	0.5	0.4	0.5	1.6	2.8	3.4	3.5	3.6	3.7	3.8	3.9
Transmission Upgrades	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
A&G	0.9	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0
IT & Other	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
Total Capital Expenditures	37.5	76.0	58.6	56.3	53.9	35.5	37.5	37.3	37.8	40.0	45.7	47.1	45.1	47.4	46.9	48.8

C. Appendices

C. Appendices

1. Example TIER Adjustment/ (Rebate) Calculation

		2009			2011		
		Rebate is shared			*TIER Adjustment applies to Smelters only*		
		Before Adjust.	TIER Adjust./ (Rebate)	After Adjust.	Before Adjust.	TIER Adjust./ (Rebate)	After Adjust.
1	**TWh**						
2	Members		3.50			3.67	
3	Smelters		7.30			7.30	
4	**Revenues/ MWh**		(0.54)			1.77	
4	**Revenues/ MWh**						
5	**Revenues**						
6	Members	121.0	(1.9)	119.1	132.2	-	132.2
7	Smelters	258.9	(3.9)	254.9	297.5	12.9	310.4
8	Other	102.6	-	102.6	72.0	-	72.0
9	Total	482.5	(5.8)	476.6	501.7	12.9	514.6
10	**Expenses**	473.3	-	473.3	519.1	-	519.1
11	**Economic Res./ MRSM**	12.5	-	12.5	20.4	-	20.4
12	**Net Income**	21.7	(5.8)	15.8	3.0	12.9	15.9
13	**Adjustment Per Smelter Agreements**	-	(1.5)	(1.5)	-	(1.7)	(1.7)
14	**Total**	21.7	(7.4)	14.3	3.0	11.2	14.2
15							
16	**Interest & Related**	59.6	-	59.6	59.3	-	59.3
17	**TIER**	1.36	(0.12)	1.24	1.05	0.19	1.24

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

C. Appendices

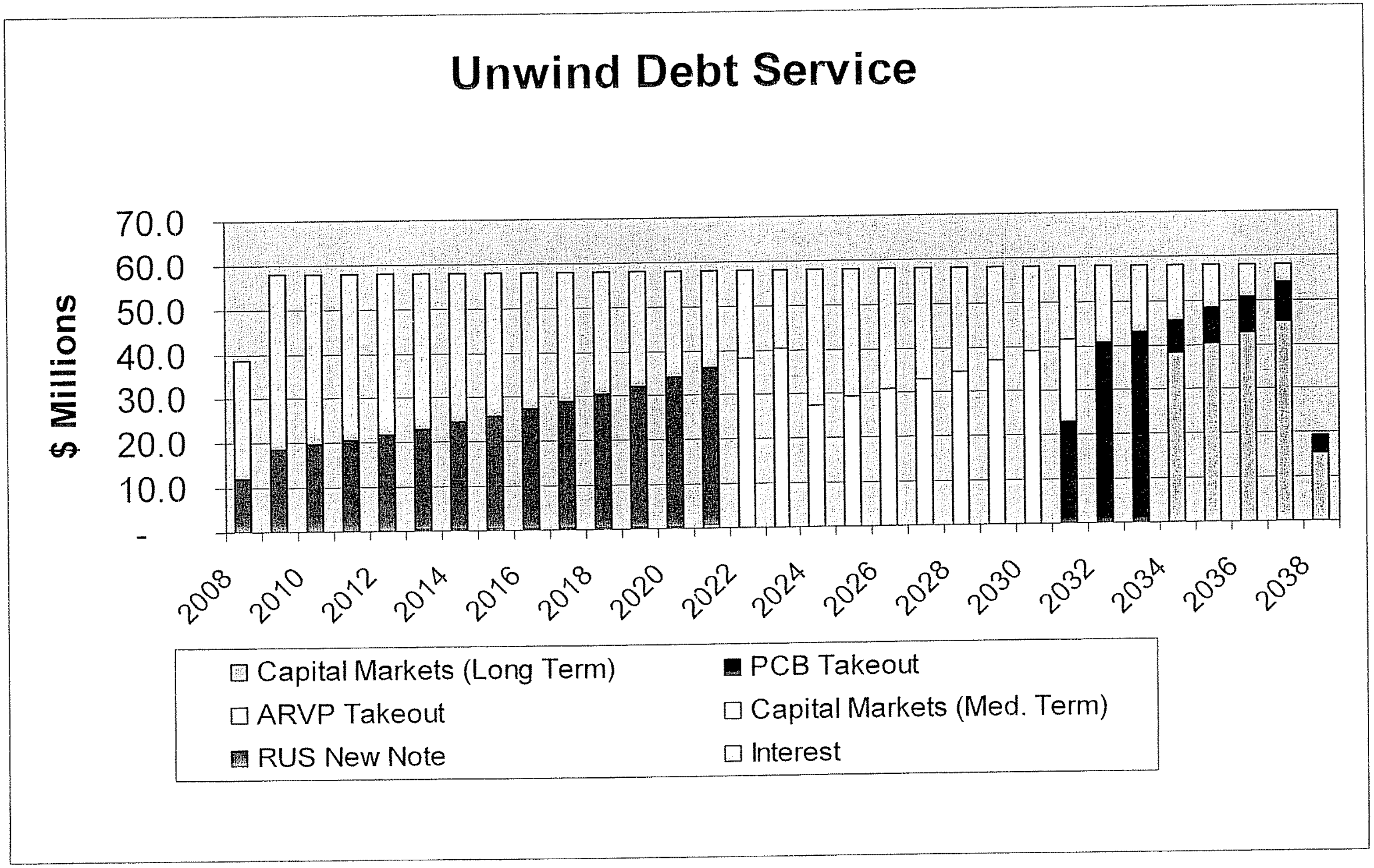
2. Transaction Impact on Balance Sheet - Detail

	Pre-Trans.	Changes				Post-Trans.
		1	2	3	4	
		Trans-action	Tax & Other	Debt Restruc.	Fund Member Reserves	
Balance Sheet (M$)						
Net Utility Plant	923	97	-	-	-	1,021
Sale-Leaseback Investments	195	-	-	-	-	195
Cash & Investments						
Transition Reserve	-	-	-	-	35	35
Economic Reserve	-	-	-	-	75	75
Unrestricted	135	297	(1)	(196)	(110)	125
Receivables, Inventories & Other	53	50	1	11	-	116
Assets	1,307	445	(0)	(184)	-	1,567
Equities	(171)	623	-	-	(75)	377
Sale-Leaseback Obligation & Unamortized Gain	239	-	-	-	-	239
Debt						
RUS New Note	791	-	-	(441)	-	351
Capital Markets	-	-	-	263	-	263
Other	260	(16)	-	-	-	244
Total	1,051	(16)	-	(177)	-	858
Payables & Other	188	(162)	(0)	(7)	75	94
Equities & Liabilities	1,307	445	(0)	(184)	-	1,567
Equity/ Assets	-13.1%					24.0%

Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

C. Appendices

3. 30-Year Debt Service



Discussion of Unwind Financial Model, (Consistent with 2.14.08 Version)

C. Appendices

4. Regulatory Account Detail

#		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Purchased Power Cost not Included in Member Rates	(1.26)	0.17	(1.33)	2.69	1.72	3.11	1.20	2.23	2.09	7.32	2.69	6.70	5.01	6.93	7.83	10.72
1	**EXPENSE DEFERRAL METHOD**																
2																	
3	**Income Statement (Change in Regulatory Account)**																
4	1. Deferral																
5	Power Purchase Expense																
6	Debit	1.26	-	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Credit	-	(0.17)	-	(2.69)	(1.72)	(3.11)	(1.20)	(2.23)	(2.09)	(7.32)	(2.69)	(6.70)	(5.01)	(6.93)	(7.83)	(10.72)
8	Total	1.26	(0.17)	1.33	(2.69)	(1.72)	(3.11)	(1.20)	(2.23)	(2.09)	(7.32)	(2.69)	(6.70)	(5.01)	(6.93)	(7.83)	(10.72)
9																	
10	2. Recognition of Prior Year Balance (Set to Start in 2013)																
11	Credit Member Revenue (Charge to Members)						0.66	0.66	0.66	2.18	2.18	2.18	4.03	4.03	4.03	6.21	6.21
12	Debit Power Purchase Expense						0.66	0.66	0.66	2.18	2.18	2.18	4.03	4.03	4.03	6.21	6.21
13																	
14	Net Income	(1.26)	0.17	(1.33)	2.69	1.72	3.11	1.20	2.23	2.09	7.32	2.69	6.70	5.01	6.93	7.83	10.72
15																	
16	**Balance Sheet**																
17	Assets																
18	Cash						0.66	1.33	1.99	4.17	6.35	8.52	12.56	16.59	20.62	26.83	33.04
19	Regulatory Asset	-	-	-	0.27	1.99	4.43	4.97	6.53	6.44	11.58	12.10	14.76	15.74	18.63	20.25	24.76
20	Total	-	-	-	0.27	1.99	5.10	6.30	8.52	10.61	17.93	20.62	27.32	32.33	39.26	47.08	57.80
21																	
22	Liabilities & Equity																
23	Equity	(1.26)	(1.10)	(2.42)	0.27	1.99	5.10	6.30	8.52	10.61	17.93	20.62	27.32	32.33	39.26	47.08	57.80
24	Regulatory Liability	1.26	1.10	2.42	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total	-	-	-	0.27	1.99	5.10	6.30	8.52	10.61	17.93	20.62	27.32	32.33	39.26	47.08	57.80

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 121) Please refer to Sections 9.2.1 of the (claimed confidential) Stone and Webster report, the table on page 66 attached to the Smelters' Response to OAG #3, and the table provided in response to Staff #43.

a. Please provide documents which show a reconciliation of the "SO_2 allowances held" on the two tables.

b. For the table on page 66, please provide documents which show the division of these allowances between E.ON and Big Rivers.

Response) a. The basis for Big Rivers' response to Staff #43 was to present the annual SO_2 allowance allocation, emissions, and remaining (or excess), if any, allowances that would be sold after the end of each year. In other words, Big Rivers has modeled no beginning "bank" of allowances rolling from one year over to the next, except for the 14,000 allowances to be contractually provided by E.ON after Closing.

The table "A" below shows the annual SO_2 allowance allocations by plant that Big Rivers has assumed going forward. In 2010 and again in 2015 the allowance "surrender rate" back to EPA to cover one ton of SO_2 emissions increases: 2.0 allowances for 1.0 ton emitted in 2010 and then 2.86 allowances for 1.0 ton emitted in 2015.

Big Rivers is unable to identify how the table on page 66 of the Stone and Webster report was compiled.

b. The contractual division of SO_2 allowances between Big Rivers and E.ON occurs only in the year of Closing and is described on the attached Schedule from the Termination Agreement, Amendment #1 (Application, Tab 3, Volume 2 of 10, page 620 of 622). The amount of allowances to be divided between each party will depend upon the actual month of Closing. In addition to the SO_2 allowances Big Rivers will be allocated each year by the EPA, per the Termination Agreement Big Rivers will also receive from E.ON a one-time "payment" of 14,000 banked SO_2 allowances.

A	**2008 allocation**	**2009 allocation**	**2010 - 2023 allocation**
C-1	4,854	4,854	4,854
C-2	5,536	5,536	5,536
C-3	5,324	5,324	5,324
Sub	**15,714**	**15,714**	**15,714**
G-1	5,294	5,294	5,294
G-2	6,378	6,378	6,378
Sub	**11,672**	**11,672**	**11,672**
H-1	5,758	5,758	5,758
H-2	5,936	5,936	5,936
Sub	**11,694**	**11,694**	**11,694**
R-1	942	942	942
R-CT	0	0	0
Sub	**942**	**942**	**942**
W-1	**12,465**	**12,465**	**12,465**
total	**52,487**	**52,487**	**52,487**

Witness) David A. Spainhoward

Schedule 8.2

LEASED GENERATOR SO_2 ALLOWANCES

Closing Year Month	SO_2 Allowances
January, 2008	5,069
February	4,632
March	1,349
April	2,741
May	2,747
June	2,811
July	4,839
August	4,940
September	2,594
October	3,047
November	2,957
December	3,067

The allowance amounts set forth above do not include SO_2 Allowances allotted to Station Two.

Item 122) Please refer to the response to OAG #43, where it states "Here are some examples of possible issues that could cause the need for more funds: 1. Major Capital Expenditures as defined in the Lease Agreement."

a. Identify and quantify the estimated capital cost to E.ON, and Big Rivers' estimated share of that capital cost under the Lease Agreement, by year through 2017, for each referenced "Major Capital Expenditure as defined in the Lease Agreement".

b. Provide documents which show Big Rivers' Members' contributions to Big Rivers' capital investment over the past three years, over and above retained margins or patronage capital.

Response) a. The defined term "Major Capital Expenditures" referenced in Big Rivers' response to the Attorney General's first data request, Item 43 is properly "Major Capital Repairs." Please see attached definition of Major Capital Repairs, Exhibit F to Third Amendment to New Participation Agreement dated July 15, 1998. There have been no such costs to date and, by the very nature of events that produce costs that qualify as "Major Capital Repairs," Big Rivers cannot forecast the incurrence of such costs. And should there be costs associated with Major Capital Repairs, looking at the complexity of that definition one can easily see the potential for a dispute over the responsibility for those costs.

b. There have been none. During the last three years, Big Rivers' Members have only made contributions to Big Rivers in the form of patronage capital.

Witness) David Spainhoward
C. William Blackburn

EXHIBIT F
TO THIRD AMENDMENT

Major Capital Repairs Definition

"Major Capital Repairs" shall mean the Non-Incremental Capital Costs (including without limitation, such costs as are included in a permitted deviation from an Annual Capital Budget that are required to be funded by Big Rivers and any LG&E Party as contemplated in Section 7.5 of the Lease or, in the case of Henderson Non-Incremental Capital Costs, Section 9.10(d) of the Station Two Agreement) associated with inspection of, repairs (including parts and labor) to and/or replacements of a retirement unit in accordance with the Capitalization Guidelines for, any Steam Turbine-Generator Set, Flue Gas Desulfurization Unit (Scrubber) or Boiler during any scheduled maintenance outage or forced outage (as defined by NERC) (i) which are not recovered through insurance (exclusive of required deductibles and LG&E Self Insurance Proceeds, which shall be the sole responsibility of the LG&E Parties) or any warranty, (ii) which are not the result of the negligence or willful misconduct of any of the LG&E Parties or any of their Affiliates, successors or assigns or any of their respective officers, directors, employees, consultants or agents, or any breach or default by any of the LG&E Parties or any of their Affiliates, successors or assigns under any of the Operative Documents, and (iii) (A) with respect to any forced outage of any Steam Turbine-Generator Set, which exceed 1.5 times the amount of Non-Incremental Capital Costs (or costs incurred by Big Rivers prior to the Closing which would have been considered Non-Incremental Capital Costs had they been incurred after the Closing) associated with inspection of, repairs (including parts and labor) to and/or replacements of a retirement unit in accordance with the Capitalization Guidelines for, that Steam Turbine-Generator Set during the last scheduled maintenance outage (including the last scheduled outage prior to the Closing) for that Steam Turbine-Generator Set, (B) with respect to any scheduled maintenance outage of any Steam Turbine-Generator Set, which exceed 1.5 times the amount of Non-Incremental Capital Costs (or costs incurred by Big Rivers prior to the Closing which would have been considered Non-Incremental Capital Costs had they been incurred after the Closing) associated with inspection of, repairs (including parts and labor) to and/or replacements of a retirement unit in accordance with the Capitalization Guidelines for, that Steam Turbine-Generator Set during the last scheduled maintenance outage (including the last scheduled outage prior to the Closing) for that Steam Turbine-Generator Set, (C) with respect to any forced outage of any Scrubber or Boiler, which exceed 1.5 times the amount of Non-Incremental Capital Costs (or costs incurred by Big Rivers prior to the Closing which would have been considered Non-Incremental Capital Costs had they been incurred after the Closing) associated with inspection of, repairs (including parts and labor) to and/or replacements of a retirement unit in accordance with the Capitalization Guidelines for, that Scrubber or Boiler during the last scheduled maintenance outage (including the last scheduled outage prior to the Closing) for that Scrubber or Boiler, and (D) with respect to any scheduled maintenance outage of any Scrubber or Boiler, which exceed 1.5 times the amount of Non-Incremental Capital Costs (or costs incurred by Big Rivers prior to the Closing which would have been considered Non-Incremental Capital Costs had they been incurred after the Closing) associated with inspection of, repairs (including parts and labor) to and/or replacements of a retirement unit in accordance with the Capitalization Guidelines for, that Scrubber or Boiler during the last scheduled maintenance outage (including the last outage prior to the Closing) for that Scrubber or Boiler; provided, that the 1.5 times multiplier is based on scheduled outage frequencies of eighteen months for each Scrubber and Boiler and six years for each Steam Turbine-Generator Set and, in the event the LG&E Parties apply different scheduled outage frequencies, the multiplier shall be changed to the product of (i) 1.5 and (ii) a fraction, the numerator of which is the scheduled outage frequency applied by the LG&E Parties and the denominator of which is eighteen months with respect to any Scrubber or Boiler and six years with respect to any Steam Turbine-Generator Set. For purposes of this definition, the Non-Incremental Capital Costs from the last scheduled maintenance outage shall be deemed to be the actual amount of those costs plus an inflation factor equal to 2.25 percent of those costs compounding during each Year (or portion thereof) from that last scheduled maintenance outage through and including the date on which the Major Capital Repairs calculation is to be determined (i.e. the date on which the equipment that is the subject of the most recent outage is brought back on line). For purposes of this definition, (i) a "Steam Turbine-Generator Set" shall be deemed to consist only of the steam turbine, turbine valves, generator, exciter, voltage regulator, turbine control systems, turbine-generator hydraulic systems, condensing cooling water systems, and electric equipment and its related protective equipment associated with the delivery of electricity to any Point of Delivery (whether or not such electricity is for delivery to Big Rivers), but excluding "Step-Up Facilities" as defined in the Transformer Operation and Maintenance Agreement (as defined in the Transmission Services and Interconnection Agreement), (ii) a "Scrubber" shall be deemed to consist only of the gas path components from the scrubber inlet damper and duct through the scrubber outlet damper, recycle pumps and piping, mist eliminator wash system, reaction tanks, and scrubber control system, and (iii) a "Boiler" shall be deemed to consist only of the gas path components from the burners through the air preheaters including the soot blowers, feed water system and boiler controls. Each LG&E Party shall use its commercially reasonable efforts to collect under any relevant insurance policies or warranties of which it is aware reimbursement for any relevant Non-Incremental Capital Costs or Henderson Non-Incremental Capital Costs that are for Major Capital Repairs or Henderson Major Capital Repairs, respectively. The relevant LG&E Parties (or their respective successors or permitted assigns) will use all amounts delivered by Big Rivers to them for Major Capital Repairs solely for Capital Assets or Station Two Improvements.

Item 123) Please refer to the Response to OAG #43, where it states "Current unresolved issues with E.ON already exist".

a. Identify and describe each such unresolved issue with E.ON.

b. Provide documents which show the financial impacts to Big Rivers of each such unresolved issue.

Response) a. Please see response to AG Supplemental Request Item 117.

b. The documents estimating the potential range of financial impacts on Big Rivers of these unresolved disputes are privileged attorney-client communications and attorney work product which are protected from discovery. That information is highly confidential to ongoing legal disputes that are suspended during the process to implement the Unwind Transaction.

Witness) C. William Blackburn
Counsel

Item 124) Please refer to the Response to OAG #45. Please provide the complete set of Base Power Rate Adjustment calculations performed per the Agreement prior to February 1, 2004, the resulting indicated adjustments.

Response) The complete set of Base Power Rate Adjustments calculations completed prior to February 1, 2004 is attached. The results were below the threshold for an adjustment to base rates in the contract.

Witness) C. William Blackburn

File 110.7.12.1

Big Rivers Electric Corporation

Base Power Rate Adjustment Calculations
JAWS Provision of PPA
Prepared 12/17/03

Coal Index January 1997	1.2800	Labor Index 1997	1.3523
Coal Index (Average Jan-Jul 2003)	1.2476	Labor Index 2002	1.4609

$$Qn = 9.52x+7.25y+3.23$$

x = Ratio of the value of Coal Index at January 1 of year n to the value at January 1 of the seventh preceding year.

y = Ratio of the value of Labor Index at January 1 of year n to the value at January 1 of the seventh preceding year.

2004 Adjustment

(A) If Q2004 is less than 16.69, then set F2004 = Q2004 / 16.69

(B) If Q2004 is greater than 35.32, then set F2004 = Q2004 / 35.32

(C) If neither determination (1) or (2) is made, then set F2004 = 1.0

(D) The adjusted rate for Base Power, P'n for each year from 2004 through 2010 shall be determined as P'n = Pn * F2004

Q2004 = =9.52*(D11/D10)+7.25*(H11/H10)+3.23 20.34126

F2004 = 1.0

	Base Rate	F2004	Adjusted Base Rate
2004	19.317	1.0	19.317
2005	19.417	1.0	19.417
2006	19.517	1.0	19.517
2007	19.717	1.0	19.717
2008	20.017	1.0	20.017
2009	20.327	1.0	20.327
2010	20.627	1.0	20.627

Big Rivers Electric Corporation

Base Power Rate Adjustment Calculations
JAWS Provision of PPA
Prepared 12/17/03

WHAT IF - SCENARIO
ASSUMING COAL & LABOR INDEX INCREASED BY 100%

Coal Index January 1997	1.2800	Labor Index 1997	1.3523
Coal Index (Assum 100% increase)	2.56	Labor Index (Assum 100% increase)	2.7046

$$Qn = 9.52x+7.25y+3.23$$

x = Ratio of the value of Coal Index at January 1 of year n to the value at January 1 of the seventh preceding year.

y = Ratio of the value of Labor Index at January 1 of year n to the value at January 1 of the seventh preceding year.

2004 Adjustment

(A) If Q2004 is less than 16.69, then set F2004 = Q2004 / 16.69

(B) If Q2004 is greater than 35.32, then set F2004 = Q2004 / 35.32

(C) If neither determination (1) or (2) is made, then set F2004 = 1.0

(D) The adjusted rate for Base Power, P'n for each year from 2004 through 2010 shall be determined as P'n = Pn * F2004

Q2004 = =9.52*(D11/D10)+7.25*(H11/H10)+3.23 36.77

F2004 = =(F38/35.32) 1.041053228

	Base Rate	F2004	Adjusted Base Rate
2004	19.317	1.041	20.11
2005	19.417	1.041	20.21
2006	19.517	1.041	20.32
2007	19.717	1.041	20.53
2008	20.017	1.041	20.84
2009	20.327	1.041	21.16
2010	20.627	1.041	21.47

Big Rivers Electric Corporation

Base Power Rate Adjustment Calculations
JAWS Provision of PPA
Prepared 12/17/03

WHAT IF - SCENARIO
ASSUMING COAL & LABOR INDEX INCREASED BY 200%

Coal Index January 1997	1.2800	Labor Index 1997	1.3523
Coal Index (Assum 200% increase)	3.84	Labor Index (Assum 200% increa:	4.0569

$$Qn = 9.52x+7.25y+3.23$$

x = Ratio of the value of Coal Index at January 1 of year n to the value at January 1 of the seventh preceding year.

y = Ratio of the value of Labor Index at January 1 of year n to the value at January 1 of the seventh preceding year.

2004 Adjustment

(A) If Q2004 is less than 16.69, then set F2004 = Q2004 / 16.69

(B) If Q2004 is greater than 35.32, then set F2004 = Q2004 / 35.32

(C) If neither determination (1) or (2) is made, then set F2004 = 1.0

(D) The adjusted rate for Base Power, P'n for each year from 2004 through 2010 shall be determined as P'n = Pn * F2004

Q2004 = =9.52*(D11/D10)+7.25*(H11/H10)+3.23 53.54

F2004 = =(F38/35.32) 1.51585504

	Base Rate	F2004	Adjusted Base Rate
2004	19.317	1.516	29.28
2005	19.417	1.516	29.43
2006	19.517	1.516	29.58
2007	19.717	1.516	29.89
2008	20.017	1.516	30.34
2009	20.327	1.516	30.81
2010	20.627	1.516	31.27

Table 4.2. Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, January 2001 through July 2003

Period	Coal[1]				Petroleum[2]				Natural Gas[3]		All Fossil Fuels
	Receipts	Average Cost		Avg. Sulfur	Receipts	Average Cost		Avg. Sulfur	Receipts	Average Cost	Average Cost
	(1000 tons)	(cents/ 10^6 Btu)	(dollars/ ton)	%	(1000 barrels)	(cents/ 10^6 Btu)	(dollars/ barrel)	%	(1000 Mcf)	(cents/ 10^6 Btu)	(cents/ 10^6 Btu)
2001											
January	67,470	122.33	24 73	.92	17,891	457 74	28.61	1 10	134,549	920.74	214.12
February	57,397	123 88	25.10	.98	10,225	441.42	27 71	1.24	114,039	694.66	189.05
March	64,359	122 63	24 64	.88	10,242	401.07	25 18	1.33	141,653	573 82	178 28
April	60,277	123 94	24 73	.85	10,740	388.63	24.55	1.33	178,222	563.74	191 91
May	68,369	124 47	25.02	.89	13,424	378 61	24.00	1.42	203,724	514.15	186 33
June	63,667	124 78	25.04	.89	12,107	369.68	23.17	1 36	212,536	425.10	178.34
July	65,920	122.50	24.42	.86	12,169	349 15	22.12	1.49	282,929	374.31	176.41
August	67,986	123.28	24.71	.90	10,049	331.23	20.84	1.67	277,039	355.79	169 55
September	57,998	123.44	24.53	.86	8,454	316.00	19.73	1.85	207,491	295.47	156.39
October	64,442	121.00	24.15	.90	5,906	287.54	18.00	1.66	165,688	271.49	142.20
November	59,551	123.68	25.00	.89	7,019	268.78	16.85	1.51	111,201	324.05	145 11
December	65,380	122.04	24.11	.87	6,390	256.08	15 92	1.62	123,295	307.63	141.71
Total	**762,815**	**123.15**	**24.68**	**.89**	**124,618**	**369.27**	**23.20**	**1.42**	**2,152,366**	**448.65**	**173.04**
2002											
January	60,026	121.90	24.72	.92	5,098	237 49	14 78	1.86	98,478	321 17	139.56
February	56,544	123.99	25 33	93	2,927	231.50	14.27	1 87	97,866	296 98	139 15
March	57,216	121.13	24.75	.91	4,661	258.29	15.98	2.05	118,372	343.22	144.45
April	51,499	121.11	24.61	86	7,289	324.42	20 29	1.56	120,934	379 77	155 12
May	51,574	121 37	24.60	.84	7,706	332.79	21.02	1.59	130,691	378.29	157 78
June	51,965	121.61	24.59	.82	7,328	340.56	21.55	1.37	165,341	357.90	161 25
July	60,607	120.77	24.51	84	6,093	316.63	19.84	1 77	205,575	343.64	157.61
August	61,386	123.36	25.20	.87	8,770	326.12	20 46	1 82	205,148	338 41	160 47
September	58,245	123 03	25.09	.86	5,124	320 10	19.88	1.75	165,108	367.62	157.31
October	62,424	122 41	24.87	.87	8,479	359 67	22.42	1.71	134,776	414.73	158 74
November	60,260	122.22	24.85	.87	6,276	369 51	23.20	1 44	95,352	428.91	151.78
December	56,000	118 43	23.64	85	7,443	372.34	23.31	1.68	103,009	471.47	157.18
Total	**687,747**	**121.81**	**24.74**	**.87**	**77,194**	**325.13**	**20.35**	**1.68**	**1,640,650**	**367.02**	**153.50**
2003											
January	58,692	123.26	25.11	1.06	6,520	402.30	25.03	1 77	99,142	530.69	161.04
February	52,743	123.31	25.59	1.02	12,012	445 83	28.12	80	85,983	620 80	177.65
March	55,723	123.78	25 27	91	13,329	517 90	32.67	1.19	93,978	728.35	193 44
April	51,776	129.11	26 84	.93	7,444	411 25	25.75	1.48	101,409	545.13	175.34
May	57,238	124.23	25 07	.88	5,031	374 03	23.10	2.01	119,546	556.46	171.00
June	60,249	125 27	25.63	.93	6,172	359.76	22.27	1.95	115,604	615 26	173.94
July	58,794	124 60	25.13	.86	9,332	429.82	27.10	1.56	154,338	556 54	186.42
Total	**395,216**	**124.76**	**25.50**	**.94**	**59,841**	**435.76**	**27.32**	**1.42**	**770,001**	**589.14**	**177.04**
Year to Date											
2001	**447,458**	**123.49**	**24.81**	**.89**	**86,799**	**400.68**	**25.22**	**1.31**	**1,267,651**	**541.25**	**187.74**
2002	**389,431**	**121.70**	**24.73**	**.88**	**41,102**	**303.12**	**18.98**	**1.68**	**937,257**	**348.35**	**150.66**
2003	**395,216**	**124.76**	**25.50**	**.94**	**59,841**	**435.76**	**27.32**	**1.42**	**770,001**	**589.14**	**177.04**
Rolling 12 Months Ending in July											
2002	**704,788**	**122.13**	**24.63**	**.88**	**78,921**	**300.09**	**18.79**	**1.67**	**1,821,971**	**332.26**	**151.09**
2003	**693,531**	**123.56**	**25.18**	**.91**	**95,933**	**403.64**	**25.28**	**1.52**	**1,473,394**	**494.76**	**168.48**

[1] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.

[2] Distillate fuel oil, residual fuel oil, jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.

[3] Natural gas, including a small amount of supplemental gaseous fuels.

Notes: •See Glossary for definitions.•Data for 2002 are preliminary; data for 2001 are final •Totals may not equal sum of components because of independent rounding. •Due to restructuring of the electric power industry, electric utilities are selling/transferring plants to the Independent Power Producer sector. This will affect comparisons of current and historical data.•Mcf = thousand cubic feet.•Monetary values are expressed in nominal terms.

Sources: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Cost and Quality of Fuels for Electric Plants Report."

Table 26. U.S. Electric Utility Receipts of and Average Cost for Fossil Fuels, 1987 Through January 1997

Period	Coal [1]		Petroleum				Gas		All Fossil Fuels [2]
			Heavy Oil [3]		Total				
	Receipts (thousand short tons)	Cost (cents/ 10^6 Btu)	Receipts (thousand barrels)	Cost (cents/ 10^6 Btu)	Receipts (thousand barrels)	Cost (cents/ 10^6 Btu)	Receipts (thousand Mcf)	Cost (cents/ 10^6 Btu)	Cost (cents/ 10^6 Btu)
1987	721,298	150.6	187,300	297.6	194,578	301.1	2,605,191	224.0	170.5
1988	727,775	146.6	230,234	240.5	236,924	243.9	2,362,721	226.3	164.3
1989	753,217	144.5	237,668	284.6	246,422	289.3	2,472,506	235.5	167.5
1990	786,627	145.5	202,281	331.9	209,350	338.4	2,490,979	232.1	168.9
1991	769,923	144.7	163,106	246.5	169,625	254.8	2,630,818	215.3	160.3
1992	775,963	141.2	138,537	247.5	144,390	255.1	2,637,678	232.8	159.0
1993	769,152	138.5	141,719	236.2	147,902	243.3	2,574,523	256.0	159.5
1994	831,929	135.5	135,184	240.9	142,940	248.8	2,863,904	223.0	152.6
1995									
January	70,206	133.1	5,565	273.1	6,113	282.7	188,545	209.2	145.4
February	65,789	133.5	6,150	256.2	6,535	263.1	163,665	197.1	143.7
March	69,059	133.8	5,040	258.9	5,448	267.4	233,533	189.0	144.3
April	66,167	133.7	2,849	266.2	3,221	280.3	222,256	194.5	144.1
May	68,564	133.7	5,864	279.0	6,213	285.8	245,676	202.1	147.3
June	64,543	133.3	8,476	274.3	9,083	282.0	281,987	202.8	150.4
July	67,734	130.4	8,367	250.8	8,838	257.2	376,158	186.1	146.1
August	73,242	130.9	9,284	237.0	10,029	247.7	424,284	179.4	145.1
September	70,938	131.8	9,036	234.7	9,432	241.3	302,928	189.5	145.1
October	70,140	129.6	5,555	242.5	6,060	253.8	228,644	204.1	142.6
November	70,196	130.2	4,773	250.5	5,414	268.8	189,641	218.9	143.3
December	70,281	127.7	7,259	295.8	7,905	305.7	166,010	255.3	146.1
Total	**826,860**	**131.8**	**78,216**	**258.6**	**84,292**	**267.9**	**3,023,327**	**198.4**	**145.3**
1996 [4]									
January	67,852	129.1	13,855	332.4	14,540	337.1	155,022	281.0	155.5
February	66,620	129.3	6,099	282.5	7,021	300.6	131,688	294.7	148.5
March	69,921	130.2	9,031	285.2	9,595	296.8	149,233	268.4	149.0
April	70,361	130.8	8,263	309.7	8,724	319.0	160,918	264.6	150.0
May	72,158	130.7	5,882	304.4	6,437	317.6	251,461	247.6	151.8
June	69,677	129.2	8,825	277.0	9,508	288.2	285,271	255.1	155.1
July	75,178	127.8	10,793	276.6	11,380	284.4	346,295	263.9	158.2
August	78,545	127.7	10,484	282.5	10,971	290.6	346,542	250.7	154.6
September	72,730	127.5	5,538	293.6	5,926	307.1	269,988	219.1	145.3
October	75,756	128.9	5,675	331.9	6,407	354.7	217,115	233.8	146.6
November	71,375	127.9	6,382	333.3	7,159	354.4	162,258	301.9	151.0
December	72,525	127.6	8,098	338.1	8,961	355.2	128,870	393.1	156.1
Total	**862,701**	**128.9**	**98,926**	**303.4**	**106,629**	**315.7**	**2,604,663**	**264.1**	**151.9**
1997 [4]									
January	71,900	128.0	8,811	305.7	9,652	321.0	133,193	405.8	157.5
Total	**71,900**	**128.0**	**8,811**	**305.7**	**9,652**	**321.0**	**133,193**	**405.8**	**157.5**
Year-to-Date									
1997 [4]	**71,900**	**128.0**	**8,811**	**305.7**	**9,652**	**321.0**	**133,193**	**405.8**	**157.5**
1996 [4]	**67,852**	**129.1**	**13,855**	**332.4**	**14,540**	**337.1**	**155,022**	**281.0**	**155.5**
1995	**70,206**	**133.1**	**5,565**	**273.1**	**6,113**	**282.7**	**188,545**	**209.2**	**145.4**

[1] Includes lignite, bituminous coal, subbituminous coal, and anthracite

[2] The weighted average for all fossil fuels includes both heavy oil and light oil (Fuel Oil No. 2, kerosene, and jet fuel) prices. Data do not include petroleum coke

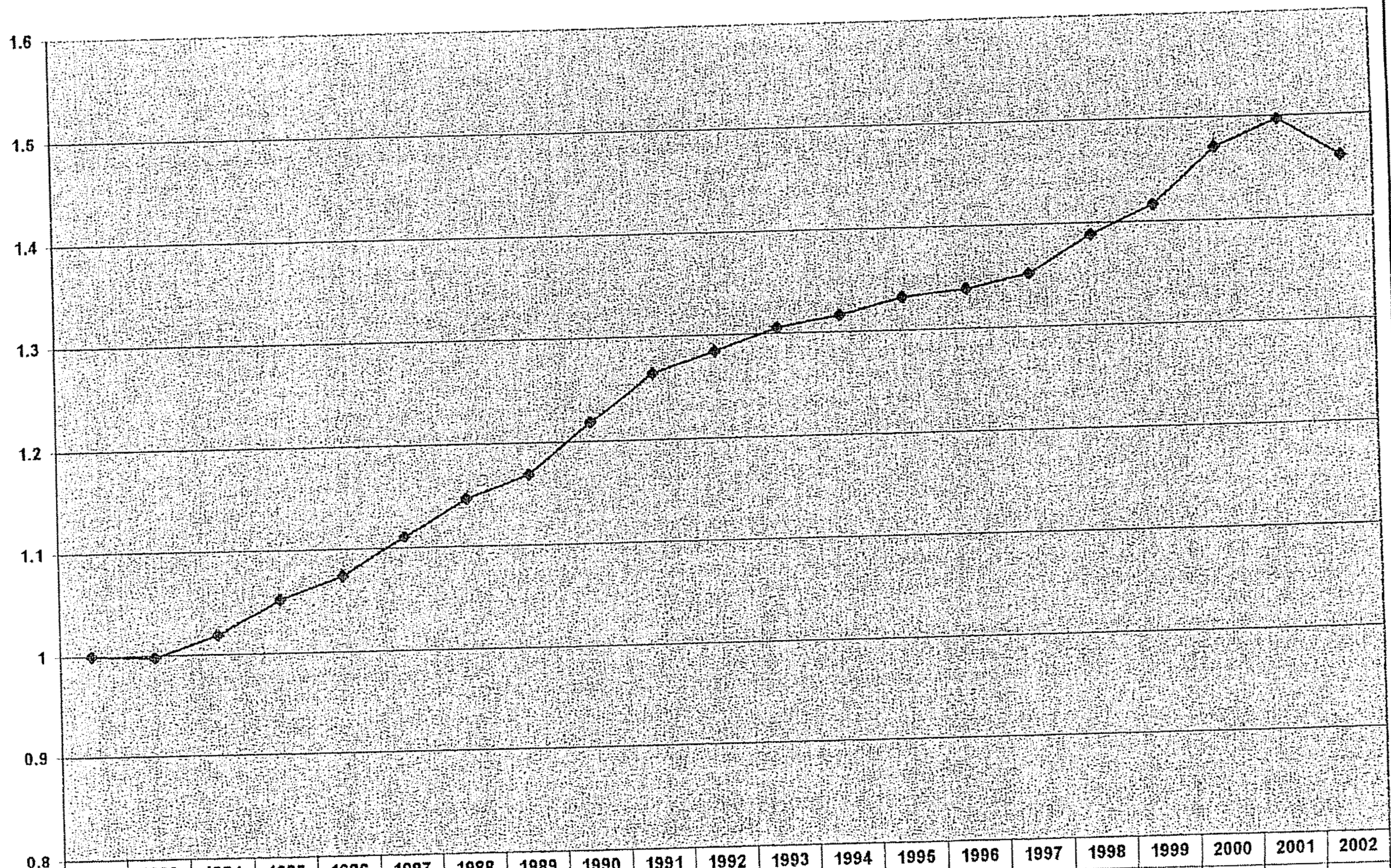
[3] Heavy oil includes Fuel Oil Nos. 4, 5, and 6, and topped crude fuel oil

[4] Data for 1997 are preliminary. Data for 1996 are final

Notes: •Totals may not equal sum of components because of independent rounding. •As of 1991, data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. •Data for 1987-1990 are for steam-electric plants with a generator nameplate capacity of 50 or more megawatts. •Mcf=thousand cubic feet. •Monetary values are expressed in nominal terms

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," and predecessor forms.

Labor Indices



	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Labor Indices	1	0.998	1.019	1.0526	1.0747	1.1112	1.1468	1.1686	1.2188	1.2639	1.2841	1.306	1.3164	1.3322	1.3389	1.3523	1.3888	1.4166	1.4718	1.4968	1.4609