BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S OCTOBER 24, 2008
SUPPLEMENTAL REQUEST FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
November 7, 2008

Item 11) Please update responses to all previous data requests from the Office of Attorney General with any additional responsive documents and information since the date of the last response to such data requests. If no update exists for a specific question, the responses indicating that fact can be grouped in a joint response.

Response) In response to this request, Big Rivers has updated the following responses of the Attorney General:

Tab A - Attorney General's Initial Request Item 65
Tab B - Attorney General's Initial Request Item 67
Tab C - Attorney General's Initial Request Item 85
Tab D - Attorney General's Initial Request Item 107
Tab E - Attorney General's Initial Request Item 116
Tab F - Attorney General's Initial Request Item 117
Tab G - Attorney General's Initial Request Item 127
Tab H - Attorney General's Initial Request Item 129
Tab I - Attorney General's Initial Request Item 131
Tab J - Attorney General's Initial Request Item 132
Tab K - Attorney General's Supplemental Request Item 82
Tab L - Attorney General's Supplemental Request Item 87
Tab M - Attorney General's Supplemental Request Item 94
Tab N - Attorney General's Supplemental Request Item 95
Tab O - Attorney General's Supplemental Request Item 99
Tab P - Attorney General's Supplemental Request Item 100
Tab Q - Attorney General's Supplemental Request Item 107

Big Rivers believes that there are no other updates necessary at this time.

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Item 65) Please reference the testimony of David A. Spainhoward, page 16, lines 7-12, regarding purchase of NO_x allowances. Provide work papers and associated supporting documents to support these estimates[d] net costs.

Response) The attachment to Big Rivers' response to the Attorney General's Initial Request for Information No. 65 concerning NO_x allowances is updated and attached.

Witness) David A. Spainhoward

Emissions & Allowance Summary

Nominal dollars

	2009	2010	2011	2012
NOx Price forecast	$ 700	$ 650	$ 2,120	$ 1,951
Yearly beginning NOx allowance inventory x1000	0.000	0.000	0.000	0.000
Total system NOx tons emitted x1000	5.248	5.212	13.779	13.672
System NOx Emissions allocation to City x1000	0.107	0.107	0.290	0.301
BREC NOx tons emitted net City x1000	5.141	5.105	13.489	13.371
yearly allocation of NOx allowances from EPA x1000	4.799	4.799	11.398	11.398
EPA NOx allowances allocation to City x1000	0.147	0.147	0.330	0.341
BREC allocation of NOx allowances net of City x1000	4.652	4.652	11.068	11.057
yearly BREC NOx allowances sold/(purchased) net City x1000	(0.489)	(0.453)	(2.421)	(2.314)
Yearly ending NOx allowance inventory x1000	0.000	0.000	0.000	0.000
BREC NOx allowances Sales/(purchases)	($342,300)	($294,450)	($5,132,520)	($4,514,614)

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Item 67) Please reference the testimony of Michael H. Core, page 7, where it states the higher rates paid by the Smelters under the new agreement "will add approximately $327 million in present value..." Provide documents and detailed supporting workpapers (in electronic spreadsheet format with formulas intact) that show the derivation and calculations to reach this $327 million figure.

Response) Per the calculation shown below, the overall present value contribution of the Smelters is virtually unchanged since the first response to question 67. The number is arrived at by calculating the amount of payments from the Smelters that exceed what would be collected from Big Rivers' large industrial tariff at a 98% load factor, discounted at a rate of 5.75%.

As shown in the attached spread sheet, the difference consists of 1) the Smelter payment of 25 cents over the large industrial tariff, 2) the cost of the TIER Adjustment and 3) surcharges that flow back to the Members. Key changes since the first response to question 67 are:

- Unwind close at 12/31/08 instead of 4/30/08, and thus removal of Smelter contribution amounts for the last 8 months of 2008;

- Offset to Smelter "Surcharge 2" (Retail Service Agreements 4.11 (b) and (c)) in the amount of $200,000 per month for 96 months;

- Increased costs to the Smelters via the TIER Adjustment.

The reduced Smelter contribution via the Surcharge is slightly more than offset by the increased Smelter contribution via the TIER adjustment, such that the current present value contribution by the Smelters is $327.9 million.

Witness) Robert S. Mudge

		Contract Reference (Smelter Retail Agreements)	Total	PV	Wtd. Avg.	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	$/ MWH																			
2	Large Industrial Rate @ 98% LF+FAC+PPA+ES-Rebate				46.62	41.29	41.16	45.58	47.97	50.20	42.91	43.52	43.74	48.07	47.39	48.53	48.49	49.62	49.95	50.94
3	Increment:																			
4	Margin	1.1.20 (Alcan)/ 1.1.19 (Century)			0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
5	TIER Adjustment Charge	4.7			2.40	-	-	1.79	2.25	1.59	1.64	2.78	2.59	3.55	0.54	3.67	2.97	4.30	3.53	4.75
6	Surcharge 1	4.11 (a)			1.12	0.70	0.70	0.70	1.00	1.00	1.00	1.00	1.00	1.40	1.40	1.40	1.39	1.40	1.40	1.40
7	Surcharge 2	4.11 (b) and (c)			1.02	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	1.20	1.20	1.20	1.20	1.20	1.20	1.20
8	Total				4.80	1.82	1.82	3.62	4.37	3.71	3.76	4.90	4.71	6.40	3.38	6.52	5.81	7.15	6.37	7.60
9	Effective Smelter Rate				51.42	43.11	42.98	49.19	52.33	53.92	46.67	48.42	48.44	54.47	50.77	55.05	54.30	56.77	56.32	58.53
10																				
11	Smelter TWh					7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
12	$M																			
13	Increment:																			
14	Margin		27.4	18.5		1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
15	TIER Adjustment		262.5	157.1		-	-	13.1	16.4	11.6	12.0	20.3	18.9	25.9	3.9	26.8	21.7	31.4	25.7	34.7
16	Surcharges		235.3	152.2		11.5	11.5	11.5	13.7	13.7	13.7	13.7	13.7	18.9	18.9	18.9	19.0	18.9	18.9	18.9
17	Total		525.2	327.9		13.3	13.3	26.4	32.0	27.1	27.4	35.8	34.4	46.7	24.7	47.6	42.5	52.2	46.5	55.4

BIG RIVERS ELECTRIC CORPORATION'S
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Item 85) Provide the complete joint application and supporting documentation for the parties' waiver from the Federal Trade Commission under the Hart-Scott-Rodino Antitrust Improvements Act ("HSR Filing"). If the filing has not yet been made, please state when it is anticipated the HSR filing will be made.

a. If the HSR filing has not yet been made, provide each document that is being considered for inclusion when the filing is made.

Response) Based upon a projected closing of February 26, 2008, Big Rivers expects to make its HSR Filing in mid-December, 2008. Big Rivers will file the HSR filing when it is complete, but objects to filing an incomplete draft of this voluminous document on grounds of relevancy.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
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Item 107) Please reference the Application at page 17, paragraph 33. Describe the negotiations to date with Henderson. In the description include dates, people involved, and all matters discussed.

Response) Please see attached spreadsheet providing a list of meetings with Henderson from December 2007 to present.

Witness) David A. Spainhoward
Mark A. Bailey

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SCHEDULE OF MEETINGS
WITH HENDERSON MUNICIPAL POWER & LIGHT

Date	**Attendees**	**Matters Discussed**
12/17/2007	Mike Core, David Spainhoward, Sandy Novick, Mark Bailey, Mayor Tom Davis, Co. Judge Executive Sandy Watkins, Community Leaders John Sights and John Logan	status of unwind negotiations with HP&L
2/25/2008	Mike Core, David Spainhoward, Mark Bailey, Gary Quick, Wayne Thompson, Paul Thompson, David Sinclair, Ralph Bowling, Allan Eyre, Pam Schneider	Unwind
2/28/2008	Mark Bailey, David Spainhoward, Dr. Smith, Gary Quick, Scott Miller, and perhaps others	Unwind
3/6/2008	Gov. Steve Beshear, Senator Dorsey Ridley, Co. Judge Executive Sandy Watkins, Dr. William Smith, Gary Quick, Paul Thompson, Mike Core, Mark Bailey	Unwind
3/19/2008	Mark Bailey, Bill Blackburn, David Spainhoward, E.ON & HMP&L people	Unwind
5/9/2008	Governor's representatives, David Spainhoward, Mike Core, William Denton, Mark Bailey, Paul Thompson, David Sinclair, George Siemens, Gary Quick, Dr. William Smith, Senator Dorsey Ridley	Unwind negotiations
6/11/2008	David Spainhoward, Mark Bailey, Gary Quick, Wayne Thompson, CB West, Paul Thompson, David Sinclair, Bob Ferdon by phone	Unwind
6/27/2008	Mayor Tom Davis, Commissioners Mike Farmer, Robby Mills, Jim White, Paul Kuerzi, Mike Core, David Spainhoward, Mark Bailey, Pam Schneider, Chuck Stinnett & Ron Jenkins (The Gleaner), Co. Judge Executive Sandy Watkins came late, not sure if he was there during the actual meeting	Specially-called Henderson City Commission meeting to pass a resolution in support of HMP&L
8/1/2008	Dr. William Smith (HMP&L Board Chair), Bill Denton (Big Rivers' Board Chair)	Unwind

8/15/2008	William Denton, Mark Bailey, Gary Quick, Dr. William Smith	Unwind
9/2/2008	Dr. William Smith (HMP&L Board Chair), William Denton (Big Rivers' Board Chair)	Unwind
9/25/2008	Mark Bailey, Gary Quick	Unwind
10/7/2008	Paul Thompson, Wayne Thompson, Gary Quick, Mark Bailey	Unwind
10/30/2008	Paul Kuerzi (Henderson City Commissioner), Mark Bailey	Unwind

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Item 116) For each year 2008-2013, please provide the computed rate of return on rate base inherent in the financial model projections (Exhibit 8).

Response) Attached is an update of the calculation of projected returns on rate base for the years 2009-2014.

Witness) C. William Blackburn

ATTACHMENT TO AG INITIAL REQUEST ITEM 116

	2009	2010	2011	2012	2013
Approximate Rate Base ($M, Beginning of Period)					
Total Utility Plant in Service	1,882	1,987	2,039	2,103	2,146
Accumulated Depreciation & Amortization	(887)	(921)	(957)	(1,001)	(1,047)
Net Plant	995	1,066	1,082	1,102	1,099
Return on Rate Base ($M, unless otherwise indicated)					
Net Margins	14	13	13	14	13
Plus Finance Related Expenses:					
Interest Expense (Incl. Financing Fees and Restructuring Cost	53	49	48	51	48
Net Sale-Leaseback	-	-	-	-	-
Total	67	62	61	65	61
Percent	6.7%	5.8%	5.6%	5.9%	5.6%

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Item 117) Assuming the 2008 capital structure projected in the financial model (Exhibit 8), please provided Big Rivers' current weighted average cost of capital, showing computations and the cost attributed to each source of capital.

Response) The attached schedule updates the cost of capital computation for the 12 months ended December 31, 2009 based on the latest Unwind Financial Model.[1]

Witness) C. William Blackburn

[1] Note that the one-time expensing of $3.85 million in unamortized AMBAC credit enhancement costs relating to the Pollution Control Bonds is excluded from Interest on Long Term Debt in that year.

Cost of Capital is calculated as follows:

$$\frac{\text{Interest on Long Term Debt}}{\text{Average Principal Balance}} \text{ plus } \frac{\text{Depreciation \& Amortization + Property Taxes + Property Insurance}}{\text{Average Gross Plant in Service}}$$

2009 Cost of Capital	
$53.1/$868.3	5.67%
($34.4+$2.9+$4)/$1934.5	2.13%
Total	7.81%

2009	
Interest on Long Term Debt	$ 49.3
Depreciation & Amortizaton	$ 34.4
Property Taxes	$ 2.9
Property Insurance	$ 4.0
Average Principal Balance 12/31/09*	$ 868.3
Average Gross Plant in Service 12/31/09**	$ 1,934.5

Calculation of average principal balance:	
balance @ 12/31/08	$ 871.7
balance @ 12/31/09	$ 864.8
total	$ 1,736.5
total divided by 2	$ 868.3

Calculation of average gross plant in service	
balance @ 12/31/08	$ 1,882.3
balance @ 12/31/09	$ 1,986.7
total	$ 3,869.0
total divided by 2	$ 1,934.5

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Item 127) Provide reference Exhibit 37/Independent Auditors' Annual Opinion states at page 10, paragraph VII that "WKEC will make required capital improvements to the facilities to comply with a new law or change to existing law ("Incremental Capital Costs")...." Provide the current view and estimation of such "Incremental Capital Costs" for:

a) The next five years; and

b) The next ten years, by type/function of capital cost.

Response) a) Over the next five years (2009-2013) the following "Incremental Capital Costs" are anticipated:

1. Catalyst replacement/regeneration for the selective catalytic reduction (SCR) systems at the Wilson and HMP&L Station Two stations (approx. $12.7 million);

2. Stack monitors for mercury emissions for Wilson, Coleman, Green, Reid, and HMP&L station Two stations (approx. $2.0 million);

3. SO3-abatement equipment at Wilson Station (approx. $3.36 million);

4. Boilers' tube corrosion protection installed on Coleman & Green Station units resulting from NOx reduction equipment installed in response to SIP Call (approx. $10.85 million).

b) Over the succeeding five years (2014-2018) Big Rivers presently has no "Incremental Capital Costs" planned other than additional ongoing catalyst

replacement/regeneration for Wilson and HMP&L Station Two (approx. $12.1 million). However, Big Rivers will be monitoring changes in environmental regulations and will modify its environmental compliance plan accordingly.

Witness) David Spainhoward

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Item 129) Provide copies of the three Distribution Cooperatives financial annual reports for 2005 to present.

Response) Attached to this response is the Jackson Purchase Energy Corporation 2007 annual report, which was not available when this item was originally answered.

Witness) C. William Blackburn

JPEC

Your Touchstone Energy® Partner
The power of human connections

2007 Annual Report

Welcome...

Welcome To The 2007 Annual Report. In The pages That Follow you will find information about your electric company. In addition, you will find a look ahead for The remainder of 2008 and into 2009.

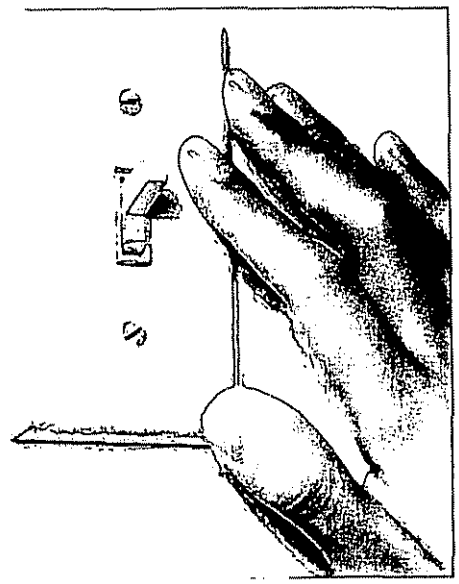
G. Kelly Nuckols
President/CEO

From gasoline prices to *natural gas, the cost of* energy is on the rise. These increases have begun to affect Jackson Purchase Energy members and the rate you pay for electricity. Even though you will see a small increase soon, JPEC members will still pay some of the lowest rates in the country. JPEC has not had a rate increase in more than ten years. In fact, JPEC has lowered electric rates by more than 10% in the last 10 years. Even after JPEC's new rates are in place, you will still be paying less than you were ten years ago.

In late 2007, JPEC emphasized energy saving in the company's member newsletter, in bill messages and at JPEnergy.com. It continues to be the company's goal to help you save money by reducing your energy consumption. Just because JPEC's rates are increasing doesn't mean members' bills have to rise. By reducing energy consumption, consumers should be able to offset the small increase. JPEC's staff and customer service representatives are energy experts and want to be your source of information concerning ways to reduce your energy consumption.

Many forces are at work pushing energy costs up. For petroleum products, these forces include rapidly growing worldwide demand for oil, political and military turmoil in several oil-producing areas and natural disasters disrupting oil delivery and refining facilities. In the electric industry, these forces include appropriate, but highly expensive, environmental enhancements to power plants as well as increased demand and tightening supplies. Further, significant changes to how energy is bought and sold on the wholesale market, and the cost of materials used, has driven up costs.

In 2007, JPEC used nearly 75,000 gallons of fuel in the trucks that install new equipment, repair existing equipment and respond to service interruptions. With an increase of $1.00 per gallon, which today seems small, JPEC's day-to-day operational cost increased by $75,000. The organization is working to reduce fuel requirements and encourage greater efficiency. For example, employees are doing a better job of turning off trucks at job sites when they are not in use.



The costs of basic building materials continue to skyrocket with no end in sight. The price of metals such as steel, copper and aluminum, which are used in transformers, meters, lines, and other items, are at record highs. The cost of copper is up nearly 300% and is so valuable, thieves are stealing wire from vacant homes or homes under construction. JPEC has experienced some instances of copper ground wires being stolen from poles in the company's service area. The practice is not only illegal but also very dangerous -- and not only for the thief. Missing ground wires can create safety hazards for the public as well. JPEC is working closely with area law enforcement officials to prevent this dangerous practice.

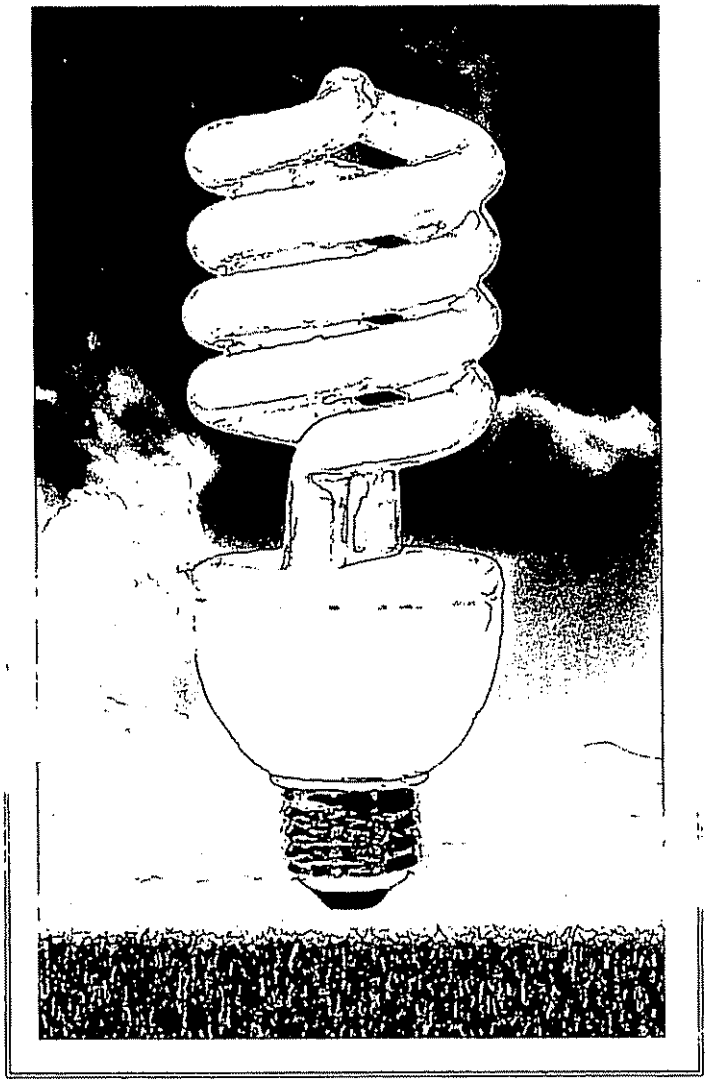
As your cooperative looks into the future, additional forces will put more upward pressure on electric prices. JPEC will continue to control costs and use innovative methods to keep rate increases at bay. However, the biggest threat to controlling those costs stems from environmental concerns. Carbon dioxide emissions from coal power plants have been singled out as a leading cause of global climate change, and efforts are underway to reduce these emissions even further. Of course, those efforts come at a cost. The debate has moved out of the realm of science and into emotion and politics. Political solutions to what should be an objective, scientific issue are now in play in Washington and several states. It's critical not only for the environment, but also for our nation's economy and well-being that political solutions take into account the impact on people who will ultimately bear the costs of whatever laws may be passed. JPEC and our cooperative family will work hard to ensure the political debate is well-informed and that elected officials understand the impact to the common citizen.

There are answers beyond politics that can do much to reduce carbon dioxide and save money. The simplest and most cost-effective solution is to use energy wisely. This is nothing new for JPEC. Your cooperative has been a champion of energy efficiency and conservation since the first line was energized more than 70 years ago, and that commitment continues today.

A few examples of being energy wise (without dramatically changing lifestyle) include changing regular light bulbs to compact fluorescent bulbs, turning off lights when a room is unoccupied, and making sure homes and businesses are well insulated.

In the following pages, you'll read more about specific activities and achievements from the past year such as new green power options for members and customer service enhancements. The report will highlight the reliability of the system and plans for the future. JPEC continues to stress employee and member safety with high-voltage demonstrations to area school students and other groups, such as volunteer fire departments and first responders.

The information in this report is for you, JPEC's owners. As a member of a cooperative, you are an owner and have an equity position in the company. It always is JPEC's goal to keep member-owners well informed. If you have questions about anything you read in the following pages or questions about something that is not highlighted in the report, please contact a customer service representative.



Last year alone, JPEC distributed nearly 10,000 compact fluorescent light bulbs to help members curb their energy use and reduce their own costs.

Tracy Bensley

VP Engineering & Operations

Jackson Purchase Energy's staff and management work hard to provide members with safe, reliable electric service. Maybe more important are the efforts JPEC makes to keep that reliable electric service affordable.

The Engineering and Operations Department is ultimately responsible for getting power to your door. That includes constructing new lines and maintaining existing lines and substations. In addition to the obvious, there are many efforts made to keep the lights on and many members are not aware of those efforts. There is a lot behind the line that leads to your house, from constant analysis of the electric system to the never-ending cycle of maintenance. And, all those efforts have a cost associated with them.

Over the last four years, JPEC has invested nearly $1 million a year to clear right-of-way and trim trees. Maintaining right-of-way is the most significant part of JPEC's efforts to keep electric service reliable.

More than $900,000 each year is spent in system maintenance efforts, which includes servicing existing equipment and making repairs to existing power lines. Maintaining existing power lines and equipment is an essential part of making sure power is there when you need it.

In addition to the maintenance of right-of-way and power lines, JPEC spends more than $1 million annually in system replacements and improvements. Our system improvement projects ensure that we are maintaining a good working system by replacing out-of-date lines and equipment with new ones. An example of this is replacing old and brittle copper wire that breaks easily with new aluminum wire that will be more reliable during ice and wind storms.

The costs associated with providing service to members, obviously, has a direct impact on electric rates. JPEC continues to weigh the costs of providing reliable service with the costs that members will have to pay when the monthly electric bill arrives. With proper budgeting and smart choices the investment in the system will continue to pay benefits.

JPEC makes choices similar to members' own household budgets by deciding what has to be done, what needs to be done and what can wait to be done. The company is always looking for ways to control expenses just like members. Because of this mindset, JPEC continues to offer members ways to control their own expenses. Last year alone, JPEC distributed nearly 10,000 compact fluorescent light bulbs to help members curb their energy use and reduce their own costs.

Izell White

VP Human Resources & Member Relations

Jackson Purchase Energy employs more than 80 full- and part-time staff members dedicated to providing quality service at the most affordable rates possible While members are the company's primary responsibility, JPEC also has a responsibility to the company's employees The Human Resources Department fulfills this responsibility

Part of that responsibility is to ensure employees are kept informed of the latest advancements within their field of expertise Therefore, employee training is a big part of the department's efforts For the last several years, training for JPEC employees has been increased However, the company has been able to do so with little increase in costs By harnessing the power of the Internet and technology in general, employees have gained valuable knowledge and training through online courses This increases productivity as employees can move through the training at their own pace and when time allows Further, the traditional cost of training, such as paying an instructor or traveling to a training session, is eliminated

As part of employment, JPEC offers a competitive benefits package designed to increase employee retention and to attract qualified candidates The administration of those benefits is conducted under the umbrella of Human Resources There are many legal requirements, both state and federal, that the company is required to abide by in regards to benefit packages

Again, by utilizing technology, many of these efforts have been streamlined For example, employees now register for benefit packages online This gives employees more accountability for benefits selections

In addition to current employee issues, the Human Resources Department is responsible for recruiting new employees Recruitment has become a challenge in recent years due to a higher turnover rate as retirements grow, as well as a potential labor shortage for skilled labor such as line workers The department has been working with the Kentucky Department of Labor and Kentucky's Workforce Development group to ensure the employment pool meets the future needs of the company

Finally, the increase in retirements has necessitated an increased focus on succession planning Led by Human Resources, each department has completed a comprehensive succession plan for managers and supervisors The best-qualified candidates for management positions often times come from current employees With succession planning, departments can identify those employees and focus training and education efforts to give those employees a clear career path

Member Relations

Member Relations continues to bring added value to your cooperative membership. Each year as part of Jackson Purchase Energy's Power To Students Campaign, the company gives high school juniors the opportunity to travel to Frankfort, KY and then Washington D C to learn more about our government. In addition, JPEC awards six $1,000 scholarships to high school seniors planning to attend a Kentucky college or university.

Another part of the Power to Students Campaign is JPEC's support of Newspapers in Education. This program delivers newspapers to middle school students one day a week to be used for current events studies, reading and more. JPEC has been a part of the Newspapers in Education program for nearly 10 years and hundreds of thousands of newspapers have been delivered to nearly every school in the region.

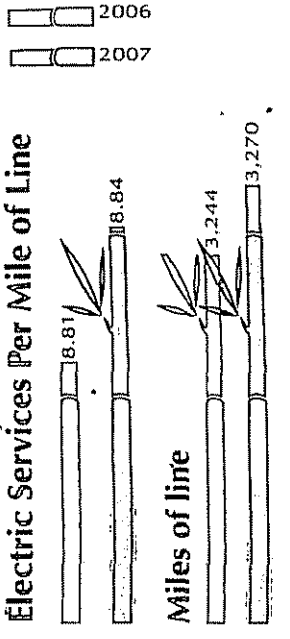
JPEC's commitment to schools and education doesn't stop there. The company provides safety presentations and science demonstrations to schools throughout the year, and hosts school tours.

Being a good corporate citizen by giving back to the communities served by JPEC is one of the seven cooperative principles that guide the business everyday. To that end, JPEC has again helped support many community-based and non-profit organizations. JPEC's support of these groups gives cooperative members an opportunity to benefit from the services offered by these organizations.

For example, JPEC supports the Carson Center's Class Act Series. The series produces shows specifically for school-aged children. Shows provide history lessons, science lessons and expose children to the arts. More than 20,000 students from 130 schools have attended a show at the Carson Center as part of the Class Act Series. Our sponsorship enables the Center to offer students this opportunity at about $2 per child.

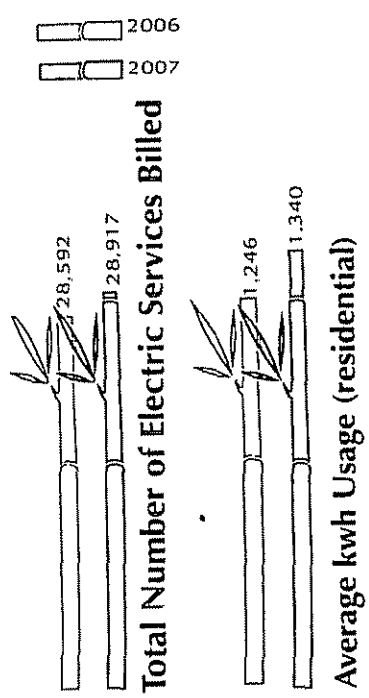
Similarly, for several years JPEC has supported efforts of the Paducah Symphony Orchestra. Our support has allowed the symphony to supply free concert tickets to students across the region. Music education in schools has diminished over the last several years and the Paducah Symphony has been able to pick up the slack with their free student ticket program as well as by sending ensemble groups to perform at area schools. These programs would not be possible without the support of corporate gifts from businesses like JPEC.

In addition to supporting non-profit organizations, Member Relations also is responsible for communications to JPEC members. Information for members is delivered by way of the company's monthly newsletter, on JPEC's website at JPEnergy.com, as well as through modest advertising efforts. Much of the information disseminated to members in the past year has revolved around energy efficiency. As the energy experts, JPEC is committed to providing answers to members' energy related questions. Further, after JPEC announced a small rate increase, the company took the next step by telling customers, through the newsletter and advertising, how they can reduce energy use and negate the increase in rates. Education efforts will continue in the coming year with an even larger focus in the company's online efforts at JPEnergy.com.



Chuck Williamson

VP Finance & Accounting



Jackson Purchase Energy's Finance and Accounting Department includes accountants, financial analysts and customer service representatives The Finance and Accounting Department oversees the day-to-day financial health of the organization as well as customer service representatives who establish service for new customers, process current members' payments and answer questions relating to members' electric service

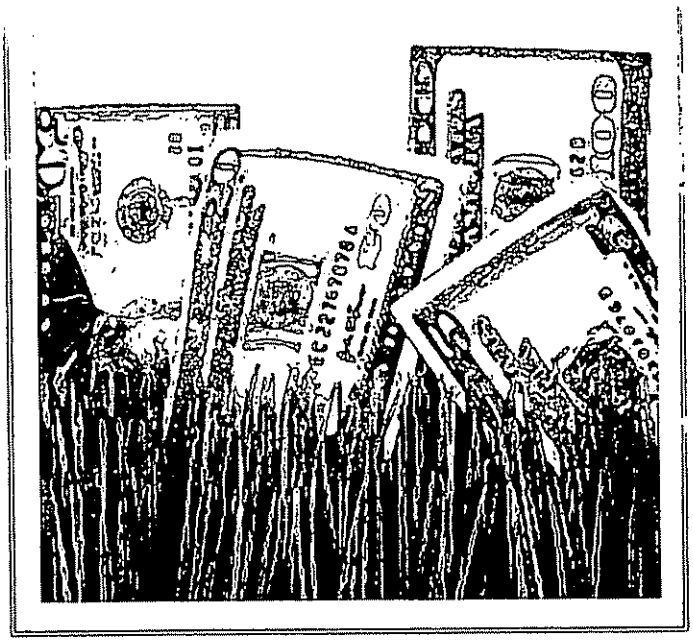
In 2007, customer service training was again the focus Because of the ever-changing industry, it is important that JPEC's customer service representatives are well versed in all aspects of the electric energy business For example, last year, JPEC filed a request with the Kentucky Public Service Commission to allow members to purchase a portion of their electricity from generation that was fueled by a renewable "green" source Big Rivers Electric, JPEC's wholesale power supplier, has contracted with an energy producer who is using waste wood products to produce renewable electricity The electricity is more expensive to produce; therefore, members who purchase renewable power presently must pay a premium Customer service representatives must be able to explain this option to members as well as make sure the customer's account is properly noted

Last summer, JPEC began a pilot project in the Burna area to read meters electronically The Automated Meter Information project is still in the testing phase It is likely JPEC will deploy AMI meters to the entire electric system over the next few years The pilot project has been led by engineering and customer service By including both customer service and engineering, the organization will be able to get a clear picture on how the technology works, as well as how it interfaces with JPEC's billing system

In another inter-departmental, cooperative effort, the Customer Service Department sits on the Emergency Response Task Force Planning Committee This group constantly reviews and critiques JPEC's response to outages and then tweaks the system to ensure members are restored service as soon as possible

Also in 2007, JPEC was again awarded Safety Accreditation The Customer Service Department, along with every other department in the company, helped make sure JPEC is one of the safest cooperatives in the state Safety accreditation is important not only because the company wants to keep employees and members safe, but also because safety accredited cooperatives are eligible for certain insurance reductions Safety accreditation is a win for members and JPEC alike

The number of members using JPEC's website, JPEnergy.com, continues to increase, as well as the number of members using bank draft and the internet to pay their electric bills Members can look at payment history, review energy use, make a one-time payment, and more at JPEnergy.com These customer service features reduce calls to the company's customer service representatives giving them an opportunity to spend more time with members that call for energy advice or other services



safety accredited cooperatives are eligible for certain insurance reductions

2006
2007
12,508
12,619
4,655
4,720
5,795
5,867
2,326
2,350
507
514
2,799
2,817
McCracken
Marshall
Livingston
Graves
Carlisle
Ballard
ELECTRIC SERVICES BY COUNTY

2007 FINANCIAL STATEMENT

STATEMENT OF OPERATIONS
FOR THE YEAR ENDING DECEMBER 31, 2007

Operating Revenue and Patronage Capital	**$40,365,878**
Cost of Purchased Power	25,264,491
System Operation & Maintenance	5,301,144
Depreciation	3,433,896
Taxes/Other	43,167
Interest Expense	2,697,030
Other Deductions	3,403,959
Total Cost of Electric Service	**$40,143,687**
Patronage Capital & Operating Margins	222,191
Total Non-Operating Margins	464,067
Other Capital Credits and Patronage Dividends	133,805
Total Patronage Capital or Margin	**$820,063**

STATEMENT OF ASSETS, LIABILITIES & MEMBER EQUITIES
AS OF DECEMBER 31, 2007

ASSETS	
Total Utility Plant	$113,200,271
Less Depreciation	(34,096,756)
Net Utility Plant Book Value	79,103,515
Investments in Associations, Organizations, Special Funds & Other Investments	2,297,745
Cash & Reserves	275,781
Owed to JPEC on Accounts & Notes	2,329,056
Material in Inventory	1,642,580
Expenses Paid in Advance	430,173
Other Deferred Debts	1,133,309
Other Current and Accrued Assets	1,681,546
Total Assets	**$88,893,705**
LIABILITIES & MEMBER EQUITIES	
Consumer Deposits	$1,409,622
Membership and Other Equities	34,759,030
Long-Term Debt	46,768,664
Short-Term Notes Payable	800,000
Operating Provisions	1,555,510
Accounts Payable	2,860,116
Other Current and Accrued Liabilities	502,253
Deferred Credits & Noncurrent Liabilities	238,510
Total Liabilities & Member Equities	**$88,893,705**

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BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST FOR
INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
(Original Response February 14, 2008)
November 7, 2008

Item 131) Regarding the "Environmental Matters" and "significant financial impacts on the use of fossil fuels for power generation" referenced in the Big Rivers 2005 Annual Report to Members (Exhibit 41), please provide the current best estimates of costs to Big Rivers broken down by fiscal year and capital versus operating expense associated with compliance with:

a. The EPA's Clean Air Mercury Rule (CAMR);

b. The EPA's Clean Air Interstate Rule (CAIR);

c. Performance goals of the Clean Water Act Section 316(b);

d. Regulation of carbon dioxide as a pollutant under the Clean Air Act; and,

e. Any other state or federal rules likely to cause additional cost in order to meet pollution standards or otherwise comply with those rules.

Response) a. Over the next five years (2009-2013) the following costs for CAMR are anticipated:

1) Stack monitors for mercury emissions for Wilson, Coleman, Green, Reid, and HMP&L Station Two stations (approximately $2.0 million);

2) No operating expenses for CAMR are planned other than servicing the stack monitors;

3) Over the succeeding years Big Rivers presently has no other capital costs or operating expenses planned for CAMR. However, Big Rivers will be monitoring changes in environmental regulations and will modify its environmental compliance plan accordingly.

b. Over the next five years (2009-2013) the following costs for CAIR are anticipated:

1) Catalyst replacement/regeneration for the selective catalyst reduction (SCR) systems at the Wilson and HMP&L Station Two stations (approximately $12.7 million);

2) See the attachment for anticipated annual variable operating expenses for CAIR;

3) Boiler tube corrosion protection installed on Coleman Station & Green Station units resulting from NOx reduction equipment installed in response to SIP Call (approximately $10.85 million);

4) Over the succeeding years Big Rivers anticipates SO2 scrubber waste disposal variable costs to increase due to the Green/HMP&L Station Two on-site special waste landfill to reach its capacity and the waste will have to be hauled elsewhere (farther away). The financial model includes costs for the expected increase;

5) Over the succeeding years Big Rivers presently has no other capital costs planned for CAIR. However, Big Rivers will be monitoring changes in environmental regulations and will modify its environmental compliance plan accordingly;

6) Operation of the CAIR-related NOx removal equipment increases the parasitic load at each plant thus reducing the available net generation output (Mwhrs). Mr. Blackburn addresses the net available generation in Big Rivers response to the Commision Staff's supplemental data request Number 6. The net capacity for each unit is shown in the Updated Production Cost Model filed in October as Exhibit 97.

c. Over the next five years (2009-2013), no costs for "316(b)" are anticipated:

1) No capital or operating expenses are anticipated by Big Rivers for "316(b)";

2) Over the succeeding years Big Rivers presently has no other capital costs for operating expenses planned for "316(b)". However, Big Rivers will be monitoring changes in environmental regulations and will modify its environmental compliance plan accordingly.

d. Over the next five years (2009-2013), no costs for carbon dioxide (CO2) capture are anticipated:

1) No capital or operating expenses are anticipated by Big Rivers for CO2;

2) Over the succeeding years Big Rivers presently has no other capital costs or operating expenses planned for CO2 regulations. However, Big

Rivers will be monitoring changes in environmental regulations and will modify its environmental compliance plan accordingly.

e. Over the next five years (2009-2013), no costs for "Ozone Attainment" or Regional Haze are anticipated:

1) No capital or operating expenses are anticipated by Big Rivers for "Ozone Attainment" or Regional Haze;

2) Over the succeeding years Big Rivers presently has no other capital costs or operating expenses planned for "Ozone Attainment" or Regional Haze regulations. However, Big Rivers will be monitoring changes in environmental regulations and will modify its environmental compliance plan accordingly.

Witness) David A. Spainhoward

Year	2009-model	2010-model	2011-model	2012-model	2013-model
	Coal	Coal	OTAG-coal	OTAG-coal	OTAG-coal
Net Generation (MWhr)	3,434,877	3,457,502	3,427,339	3,342,456	3,482,825
Net Avg MW's					
Net Average Heat Rate (BTU/kWh)					
SO2 lb/mmBTU inlet					
Average Service Hours					
Percent SO2 removal					
Limestone					
TPY limestone	210,669	211,967	211,477	208,669	218,150
Cost per Ton of Reagent	$15.75	$16.30	$16.87	$17.33	$17.81
Cost of Reagent	$3,318,034	$3,455,058	$3,567,620	$3,616,242	$3,885,243
Gypsum sales					
Tons	278,193	289,682	299,119	303,196	325,749
Cost per Ton	($1.25)	($1.25)	($1.25)	($1.25)	($1.25)
Cost	($347,741)	($362,102)	($373,899)	($378,995)	($407,187)
Fly Ash					
Tons of Disposal	182,778	184,349	183,699	181,136	189,455
Cost per Ton of Disposal	$4.01	$4.14	$4.29	$4.41	$4.53
Cost of Disposal	$732,938	$763,206	$788,071	$798,811	$858,232
Bottom Ash					
Tons of Disposal	45,695	46,088	45,925	45,284	47,364
Cost per Ton of Disposal	$4.01	$4.14	$4.29	$4.41	$4.53
Cost of Disposal	$183,236	$190,803	$197,019	$199,704	$214,560
Off-Spec Gypsum disppsal					
Tons of Disposal	24,437	24,647	24,560	24,218	25,330
Cost per Ton of Disposal	$4.01	$4.14	$4.29	$4.41	$4.53
Cost of Disposal	$97,992	$102,039	$105,363	$106,799	$114,744
Di-Basic Acid					
Pounds of Reagent	0	0	0	0	0
Cost per Pound of Reagent	$0.70	$0.70	$0.72	$0.74	$0.76
Cost of Di-Basic Acid	$0	$0	$0	$0	$0
SO2 and ash $/Mwhr	**$1.16**	**$1.20**	**$1.25**	**$1.30**	**$1.34**
Total /Year	$3,984,459	$4,149,004	$4,284,174	$4,342,563	$4,665,592
Sulfur					
MWhr per Gals	0	0	0	0	0
Gallons of Sulfur	0	0	0	0	0
Cost/gallon of Sulfur	$3.75	$3.85	$3.96	$4.07	$4.18
Cost of Sulfur	$0	$0	$0	$0	$0
Ammonia					
NH3 Lbs/ MWhr	*0.0000*	*0.0000*	0.0000	0.0000	0.0000
Tons of Ammonia	0	0	0	0	0
Cost / Ton of Ammonia	$800.00	$900.00	$931.50	$957.12	$983.44
Cost of Ammonia	$0	$0	$0	$0	$0
Lime Hydrate (for SO_3)					
TPD	0	0	0	0	0
Tons of Lime Hydrate	0	0	0	0	0
Cost/ton of Lime Hydrate	$130.00	$135.00	$139.73	$143.57	$147.52
Cost of Lime Hydrate	$0	$0	$0	$0	$0
NOx Sub-Total	$0	$0	$0	$0	$0
Total /Year	$3,984,459	$4,149,004	$4,284,174	$4,342,563	$4,665,592
Total $/Mwhr	**$1.16**	**$1.20**	**$1.25**	**$1.28**	**$1.32**

Green Station non-fuel variable O&M

Attachment 1

(in nominal dollars)

Year	2009-model	2010-model	2011-model	2012-model	2013-model
	pet coke	Coal	OTAG-coal	OTAG-coal	OTAG-coal
Net Generation (MWhr)	3,668,755	3,672,767	3,554,020	3,689,862	3,690,343
Net Avg MW's					
Net Average Heat Rate (BTU/kWh)					
SO2 lb/mmBTU inlet					
Average Service Hours					
Percent SO2 removal					
Lime					
TPY lime	143,777	140,954	135,609	140,638	140,705
Cost per Ton of Reagent	$78.74	$86.61	$95.28	$97.90	$100.59
Cost of Reagent	$11,321,016	$12,208,006	$12,920,785	$13,768,444	$14,153,558
Sludge Disposal					
Tons	598,005	626,945	645,616	669,867	670,947
Cost per Ton	$2.10	$2.16	$2.22	$2.28	$2.34
Cost	$1,255,811	$1,354,201	$1,433,267	$1,527,296	$1,570,016
Fly Ash					
Tons of Disposal	156,702	164,286	169,179	175,533	175,816
Cost per Ton of Disposal	$2.10	$2.16	$2.22	$2.28	$2.34
Cost of Disposal	$329,075	$354,858	$375,576	$400,216	$411,410
Bottom Ash					
Tons of Disposal	39,176	41,071	42,294	43,883	43,953
Cost per Ton of Disposal	$2.10	$2.16	$2.22	$2.28	$2.34
Cost of Disposal	$82,269	$88,713	$93,893	$100,053	$102,851
Fixation Lime					
Tons of Disposal	12,830	11,572	12,103	12,552	12,557
Cost per Ton of Disposal	$92.00	$110.00	$111.32	$114.38	$117.53
Cost of Disposal	$1,180,385	$1,272,936	$1,347,258	$1,435,644	$1,475,800
Di-Basic Acid					
Pounds of Reagent	0	0	0	0	0
Cost per Pound of Reagent	$0.70	$0.70	$0.72	$0.74	$0.76
Cost of Di-Basic Acid	$0	$0	$0	$0	$0
SO2 and ash $/Mwhr	**$3.86**	**$4.16**	**$4.55**	**$4.67**	**$4.80**
Total /Year	$14,168,556	$15,278,714	$16,170,780	$17,231,652	$17,713,635
Sulfur					
MWhr per Gals	0.00	0.00	0.00	0.00	0.00
Gallons of Sulfur	0	0	0	0	0
Cost/gallon of Sulfur	$3.75	$3.85	$3.96	$4.07	$4.18
Cost of Sulfur	$0	$0	$0	$0	$0
Ammonia					
NH3 Lbs/ MWhr	0.0000	0.0000	0.0000	0.0000	0.0000
Tons of Ammonia	0	0	0	0	0
Cost / Ton of Ammonia	$800.00	$900.00	$931.50	$957.12	$983.44
Cost of Ammonia	$0	$0	$0	$0	$0
Lime Hydrate (for SO_3)					
TPD	0.00	0.00	0.00	0.00	0.00
Tons of Lime Hydrate	0	0	0	0	0
Cost/ton of Lime Hydrate	$130	$135.00	$139.73	$143.57	$147.52
Cost of Lime Hydrate	$0	$0	$0	$0	$0
NOx Sub-Total	$0	$0	$0	$0	$0
Total /Year	$14,168,556	$15,278,714	$16,170,780	$17,231,652	$17,713,635
Total $/Mwhr	**$3.86**	**$4.16**	**$4.55**	**$4.67**	**$4.80**

HMP&L Station non-fuel variable O&M

Attachment 1

(in nominal dollars-net of City)

Year	2009-model	2010-model	2011-model	2012-model	2013-model
	coal	coal	OTAG-coal	OTAG-coal	OTAG-coal
Net Generation (MWhr)	2,398,272	2,400,491	2,306,741	2,289,309	2,399,461
Net Avg MW's					
Net Average Heat Rate (BTU/kWh)					
SO2 lb/mmBTU inlet					
Average Service Hours					
Percent SO2 removal					
Lime					
TPY lime	65,182	65,286	61,611	61,193	64,141
Cost per Ton of Reagent	$78.74	$86.32	$99.27	$102.00	$104.80
Cost of Reagent	$5,132,407	$5,635,515	$6,116,128	$6,241,694	$6,721,992
Sludge Disposal					
Tons	268,411	268,576	302,568	300,654	315,487
Cost per Ton	$2.10	$2.16	$2.22	$2.28	$2.34
Cost	$563,664	$580,124	$671,701	$685,491	$738,239
Fly Ash					
Tons of Disposal	72,317	72,434	81,521	81,005	85,001
Cost per Ton of Disposal	$2.10	$2.16	$2.22	$2.28	$2.34
Cost of Disposal	$151,867	$156,456	$180,976	$184,691	$198,903
Bottom Ash					
Tons of Disposal	18,080	18,109	20,380	20,251	21,250
Cost per Ton of Disposal	$2.10	$2.16	$2.22	$2.28	$2.34
Cost of Disposal	$37,968	$39,115	$45,244	$46,173	$49,726
Flue Gas Lime					
Tons of Disposal	5,792	5,801	5,759	5,721	5,996
Cost per Ton of Disposal	$92.00	$103.57	$110.26	$113.29	$116.41
Cost of Disposal	$532,854	$600,831	$635,042	$648,080	$697,950
Di-Basic Acid					
Pounds of Reagent	0	0	0	0	0
Cost per Pound of Reagent	$0.70	$0.70	$0.72	$0.74	$0.76
Cost of Di-Basic Acid	$0	$0	$0	$0	$0
SO2 and ash $/Mwhr	**$2.68**	**$2.92**	**$3.32**	**$3.41**	**$3.50**
Total /Year	$6,418,760	$7,012,043	$7,649,091	$7,806,129	$8,406,809
Sulfur					
MWhr per Gals	5,698.94	5,698.94	5,698.94	5,698.94	5,698.94
Gallons of Sulfur	185	195	422	419	439
Cost/ton of Sulfur	$510.00	$550.00	$600.00	$616.50	$633.45
Cost of Sulfur	$94,314	$107,059	$252,998	$258,192	$278,060
Ammonia					
NH3 Lbs/ MWhr	1.7719	1.7719	1.7719	1.7719	1.7719
Tons of Ammonia	934	983	2,070	2,056	2,155
Cost / Ton of Ammonia	$750.00	$825.00	$907.50	$932.46	$958.10
Cost of Ammonia	$700,281	$810,810	$1,878,498	$1,917,064	$2,064,582
Lime Hydrate (for SO_3)					
TPD	0.00	0.00	0.00	0.00	0.00
Tons of Lime Hydrate	0	0	0	0	0
Cost/ton of Lime Hydrate	$130.00	$135.00	$139.73	$143.57	$147.52
Cost of Lime Hydrate	$0	$0	$0	$0	$0
NOx Sub-Total	$794,596	$917,869	$2,131,496	$2,175,256	$2,342,642
Total /Year	$7,213,356	$7,929,912	$9,780,587	$9,981,385	$10,749,451
Total $/Mwhr	**$3.01**	**$3.30**	**$4.24**	**$4.36**	**$4.48**

Year	2009-model	2010-model	2011-model	2012-model	2013-model
	petcoke	petcoke	OTAG-petcoke	OTAG-coal	OTAG-coal
Net Generation (MWhr)	3,018,776	3,432,875	3,140,591	3,317,450	3,161,215
Net Avg MW's					
Net Average Heat Rate (BTU/kWh)					
SO2 lb/mmBTU inlet					
Average Service Hours					
Percent SO2 removal					
Limestone					
TPY limestone	200,604	227,662	219,467	212,503	187,988
Cost per Ton of Reagent	$15.93	$16.32	$16.89	$17.36	$17.83
Cost of Reagent	$3,195,622	$3,715,440	$3,706,799	$3,689,053	$3,351,826
Sludge Disposal					
Tons	358,723	407,109	393,613	380,138	336,721
Cost per Ton	$2.10	$2.16	$2.22	$2.28	$2.34
Cost	$753,319	$879,354	$873,820	$866,715	$787,927
Fly Ash					
Tons of Disposal	98,233	111,483	107,787	119,403	126,816
Cost per Ton of Disposal	$2.10	$2.16	$2.22	$2.28	$2.34
Cost of Disposal	$206,289	$240,802	$239,287	$272,240	$296,750
Bottom Ash					
Tons of Disposal	24,558	27,871	26,947	29,851	31,704
Cost per Ton of Disposal	$2.10	$2.16	$2.22	$2.28	$2.34
Cost of Disposal	$51,572	$60,201	$59,822	$68,060	$74,187
Fixation Lime					
Tons of Disposal	3,200	3,280	6,133	6,789	6,019
Cost per Ton of Disposal	$100.00	$110.00	$121.00	$124.33	$127.75
Cost of Disposal	$319,969	$360,836	$742,072	$844,023	$768,927
Di-Basic Acid					
Pounds of Reagent	1,722,534	1,958,841	1,901,783	1,838,216	1,697,472
Cost per Pound of Reagent	$0.70	$0.70	$0.72	$0.74	$0.76
Cost of Di-Basic Acid	$1,205,774	$1,371,189	$1,369,284	$1,360,280	$1,290,079
	5474683.971	6326819.91	6691974.575	6760070.737	6198758.733
SO2 and ash $/Mwhr	**$1.90**	**$1.93**	**$2.23**	**$2.14**	**$2.08**
Total /Year	$5,732,545	$6,627,823	$6,991,083	$7,100,370	$6,569,696
Sulfur					
MWhr per Gals	190.69	190.69	190.69	190.69	190.69
Gallons of Sulfur	15,637	17,762	17,023	17,399	16,744
Cost/gallon of Sulfur	$3.75	$3.85	$3.96	$4.07	$4.18
Cost of Sulfur	$58,640	$68,383	$67,411	$70,815	$69,989
Ammonia					
NH3 Lbs/ MWhr	1.8337	1.8337	1.8337	1.8337	1.8337
Tons of Ammonia	1,355	1,389	2,699	3,042	2,926
Cost / Ton of Ammonia	$800.00	$900.00	$931.50	$957.12	$983.44
Cost of Ammonia	$1,084,118	$1,250,369	$2,514,283	$2,911,541	$2,877,592
Lime Hydrate (for SO_3)					
TPD	25.00	25.00	25.00	25.00	25.00
Tons of Lime Hydrate	3,666	3,758	7,910	8,229	7,915
Cost/ton of Lime Hydrate	$130.00	$135.00	$139.73	$143.57	$147.52
Cost of Lime Hydrate	$476,553	$507,354	$1,105,220	$1,181,412	$1,167,636
NOx Sub-Total	$1,619,310	$1,826,106	$3,686,913	$4,163,767	$4,115,217
Total /Year	$7,351,855	$8,453,928	$10,677,996	$11,264,138	$10,684,913
Total $/Mwhr	**$2.44**	**$2.46**	**$3.40**	**$3.40**	**$3.38**

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST FOR
INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
(Original Response February 14, 2008)
November 7, 2008

Item 132) Provide documents compiled or written by national associations of which Big Rivers is a member (e.g., NRECA, National Rural Electric Environmental Association) which address potential costs of electric generating company compliance with current and future regulations pertaining to the environment, pollution and/or air/water quality, since January 2005, that are in Big Rivers' possession or available to it as an association member.

Response) Big Rivers supplements its original response to file the additional information attached hereto.

Witness) Michael H. Core
Counsel

NRECA

ENVIRONMENTAL BULLETIN

March 18, 2008

What's Inside This Issue

CLEAN AIR ACT

- **EPA SETS STRICTER AMBIENT AIR STANDARDS FOR OZONE**: New primary and secondary standards are equal in form and level at 0.075 parts per million
- **PEABODY COAL-FIRED PLANT TO PROCEED**: Environmental groups have exhausted all legal appeals
- **NEW JERSEY APPEALS NSR RECORDKEEPING RULE**: State argues regulations are lax

CLIMATE CHANGE

- **DESERET CASE COULD DETERMINE IF CO2 EMISSIONS ARE PART OF PERMITTING DECISION**: EPA may have to consider greenhouse gas emissions when granting permits to new power plants
- **EPA DENIES CALIFORNIA WAIVER REQUEST**: EPA determines that separate California's standards are not necessary
- **GROUPS ALLEGE UNREASONABLE DELAY BY EPA**: EPA criticized for not moving forward on rulemaking finding an endangerment to public health and welfare
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- **RURAL UTILITIES SERVICE AFFIRMS ADMINISTRATION STANCE ON BASELOAD LOANS**: RUS denying loans to co-ops because of uncertainties in funding

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- **GROUPS SUE TO HALT EAST KENTUCKY PLANT CONSTRUCTION**: Complaint alleges RUS failed to properly conduct its environmental assessment
- **EPA APPOINTS MEMBERS OF NEW AGRICULTURAL ADVISORY COMMITTEE**: Committee set up to advise EPA on issues that affect farms, ranches and rural communities

Clean Air Act

EPA SETS STRICTER AMBIENT AIR STANDARDS FOR OZONE

On March 12, 2008, EPA announced it is tightening the National Ambient Air Quality Standards (NAAQS) for ground-level ozone. The agency is setting the primary and secondary standards equal in form and level at 0.075 parts per million, replacing the existing standards of 0.08 ppm that were set in 1997. Because of rounding, the existing standards encompass ozone levels as high as 0.084 ppm.

In announcing the new ozone standards, Administrator Johnson also stated that he will be sending Congress four principles to guide legislative changes to the Clean Air Act (CAA) including that the CAA be revised to allow decision-makers to consider benefits, costs, risk tradeoffs, and feasibility in making decisions about how to clean the air, something the agency is currently not allowed to do when revising NAAQS. While various environmental organizations and some states were quick to criticize EPA for not making the standards even more stringent, industry has pointed out that the large uncertainty in the scientific evidence does not justify the new standards and the cost of attaining them will be huge – making the new rule among the most expensive federal rules ever issued. In addition to the high costs of likely new requirements for utilities to add more emission reduction equipment, counties designated as "nonattainment" face serious repercussions such as immediate impacts on new transportation projects, restrictions on industry expansion within those counties, and new permitting requirements and delays.

Along with revising the NAAQS for ozone, EPA also is changing the Air Quality Index (AQI) to reflect the new primary standard. The AQI is EPA's color-coded tool designed for use by state and local authorities to inform the public about daily air pollution levels in their communities. While the agency notes that significant progress has been made in reducing ground-level ozone across the country with ozone levels having dropped 21 percent since 1980 and improvements expected to continue, revising the AQI to reflect the new standard likely will lead to a greater number of bad ozone-day alerts being generated. Information, including EPA's press release, Fact Sheet, maps of new and existing nonattainment areas, and a pre-publication version of the new ozone rule are available on the EPA website by clicking here. For additional information, contact Bill Wemhoff at (703) 907-5824 or at bill.wemhoff@nreca.coop.

PEABODY COAL-FIRED PLANT TO PROCEED

On March 3, 2008, Peabody Energy Corp. announced that it has achieved a "final and unappealable" air permit for the construction of a 1,600-megawatt, coal-fired electric power plant in Southern Illinois. The plant had been vigorously opposed by a coalition of Illinois environmental groups including the Sierra Club. Peabody officials said the environmental groups had exhausted all available legal channels for opposing the permit. The environmental groups had initially challenged the permit with EPA's Environmental Appeals Board (EAB). When the EAB denied a petition to overturn the permit, the groups filed a lawsuit. The appellate court declined to second-guess the EAB and upheld the permit. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

NEW JERSEY APPEALS NSR RECORDKEEPING RULE

On February 19, 2008, New Jersey filed a petition in a federal appeals court challenging EPA's recently revised NSR recordkeeping requirements for power plants and other industrial facilities, arguing that the regulations are too lax and would inhibit state regulators from determining whether plants should have to upgrade their pollution controls (*New Jersey v. EPA,* D.C. Cir., docket number unavailable, 2/19/08). The state argues that without more rigorous recordkeeping requirements, state regulators cannot know whether emissions are increasing at factories and coal-fired power plants covered by the rules. The EPA final rule, published December 21, 2007, gives covered facilities flexibility in determining whether they need to keep detailed records of increased air emissions under the NSR program. For more information, contact Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

Climate Change

DESERET CASE COULD DETERMINE IF CO2 EMISSIONS ARE PART OF PERMITTING DECISION

A case before EPA's Environmental Appeals Board (EAB) involving Deseret Power Electric Cooperative could result in the agency's having to consider greenhouse gas (GHG) emissions when granting permits to new power plants. The EAB agreed in 2007 to review a permit granted by EPA Region 8 for a new coal-fired generating unit at Deseret's plant near Bonanza, Utah. The permit did not require any controls on CO_2. After EPA granted the permit, the Sierra Club petitioned the EAB to review the permit, stating that EPA was required by the Clean Air Act to consider the new generator's CO_2 emissions before granting a permit under the Clean Air Act's prevention of significant deterioration (PSD) program. Under PSD, new and modified major sources are required to install best available control technology (BACT) pollution controls if they cause an emissions increase. A favorable decision by the EAB would mean that EPA would have to require all new and reconstructed coal-fired power plants to minimize their CO_2 emissions. In a brief filed January 31, 2008, the Sierra Club said EPA is required to set BACT requirements because the Supreme Court ruled in 2007 that CO_2 is a pollutant under the Clean Air Act. NRECA will be filing an amicus brief with the EAB supporting EPA and Deseret. For more information, contact Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

EPA DENIES CALIFORNIA WAIVER REQUEST

On March 6, 2008, EPA published its final *Notice of Decision* in the *Federal Register* denying California's request for a waiver under Section 209 of the CAA to implement greenhouse gas controls on new motor vehicles (73 *Fed. Reg.* 12156). For a copy of the notice, click here. In its notice, EPA said California "does not need its greenhouse gas standards for new motor vehicles to meet compelling and extraordinary conditions," a criterion for a waiver for state motor vehicle emission standards under Section 209. When announcing EPA's decision in December 2007, Administrator Johnson noted that federal energy legislation recently signed by President Bush includes a new federal fuel economy

standard of 35 miles per gallon. He said this legislation would result in nearly equivalent GHG emission reductions as the California standards and would also avoid a confusing patchwork of regulations. In response to EPA's December 2007 announcement, California and several other states filed suit in January seeking to overturn the agency's decision.

The denial of the California waiver petition is significant because two federal courts (the U.S. District Court for the District of Vermont and the U.S. District Court for the Eastern District of California) conditionally upheld the California standards (noting that EPA needed to grant the pending waiver request), and indicated in those decisions that the California standards would become federal standards under the Clean Air Act if the waiver was granted. Prevention of Significant Deterioration (PSD) requirements apply to any regulated pollutant under the Clean Air Act and had the waiver request been granted, states and environmental groups would have argued that the grant of the waiver triggered PSD for all major sources of CO_2 and the other greenhouse gases, including power plants. The denial is also important because granting the waiver could have been considered an implicit finding of "endangerment" by EPA. A finding that greenhouse gases and CO_2 endanger public health or welfare has consequences for stationary sources under numerous provisions of the Clean Air Act. For additional information, contact Bill Wemhoff at (703) 907-5824 or at bill.wemhoff@nreca.coop.

GROUPS ALLEGE UNREASONABLE DELAY BY EPA

On January 23, 2008, several environmental groups sent a letter to EPA alleging that the agency has unreasonably delayed acting on the Supreme Court's remand in *Massachusetts v. EPA*. In particular, the letter criticized EPA for not having moved forward on a rulemaking finding an endangerment to public health and welfare from greenhouse gas (GHG) emissions. The letter asked EPA to respond with regard to its plans on the remand by February 27, 2008, and set forth the organizations' intent "to take action to enforce the Supreme Court's remand and the D.C. Circuit's mandate." The letter also stated that it "serves as formal notice pursuant to Section 304(a) & (b) of the Clean Air Act of the groups' intent to bring an action to challenge EPA's unreasonable delay in acting on the pending rulemaking petition" at issue in *Massachusetts v. EPA*. Several states and the cities of Baltimore and New York sent a similar letter, but without the specific notice of intent to sue. For a copy of the environmental groups' letter on Cooperative.com, click here.

On February 27, 2008, EPA answered the above letters stating that it does not have a time frame for complying with the Supreme Court decision requiring it to establish GHG emissions limits for vehicles or to explain why it is not doing so. EPA further maintained that it has expended considerable effort to develop draft regulations in response to the Supreme Court decision. However, the agency is delaying action on a rulemaking to consider the effect of energy legislation enacted late in 2007 that increased automobile fuel economy. Massachusetts Attorney General Martha Coakley and the Sierra Club issued statements the next day saying they will take EPA to court to enforce the Supreme Court decision, but they did not say when they would do so. For a copy of EPA's response on Cooperative.com, click here. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

ENERGY AND COMMERCE COMMITTEE RELEASES NEW WHITE PAPER ON CLIMATE CHANGE

The House Energy and Commerce Committee released a third climate change white paper as part of its process to develop a comprehensive record prior to drafting legislation. According to the white paper, where an economy-wide federal cap and trade program exists, states should not be allowed to establish more stringent cap and trade programs. Such programs could result in higher costs and would probably not decrease national greenhouse gas emissions. State, local, and tribal greenhouse gas (GHG) reduction programs, however, could be beneficial if they were to impact sectors outside the scope of a federal cap and trade program. For instance, changes in building codes could lower GHGs and augment a federal program. Also, a federal cap and trade program could be maximized where state, local, and tribal governments implement uniform recordkeeping and monitoring activities. For a copy of the white paper, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

EPA REPORTS LIEBERMAN-WARNER COSTS HIGH

Lieberman-Warner climate legislation (S. 2191) will cost more than twice that of climate bills by Bingaman-Specter or McCain-Lieberman, reducing economic growth from 1 to 3.8 percent by 2030, equivalent to $238 billion to $938 billion annually, according to EPA. The report, *EPA Analysis of the Lieberman-Warner Climate Security Act of 2008*, projects that CO_2 will cost between $46 and $83 per ton in 2030, with the electricity sector making the greatest emission reductions and electricity prices increasing 44 percent. The analysis includes aggressive technology assumptions, with the result that almost all fossil electricity generation is capturing and storing CO_2 emissions by 2035. If CCS remains expensive, costs increase. EPA found that the use of domestic and international offsets substantially reduce the cost of the bill. In terms of emission reductions, Lieberman-Warner reduces emissions 56 percent lower than current levels in 2050. EPA will release a revised analysis by June that will include the effects of the Energy Independence and Security Act, enacted in December 2007, such as new automobile fuel-economy standards and larger mandates for renewable fuel and energy efficient household appliances. The Energy Information Administration is due to release its analysis of S. 2191 shortly. For a copy of the EPA analysis, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

RGGI ANNOUNCES RULES FOR CO2 ALLOWANCE AUCTION

The Regional Greenhouse Gas Initiative (RGGI) for a cap-and-trade program on the power sector has released the design elements for its auctions, the nation's first for a mandatory CO_2 emissions reduction program. Ten RGGI states from Maryland to Maine will auction nearly the entire annual regional emissions budget, approximately 188 million tons of CO_2. The states have agreed to participate in uniform regional auctions for the allowances that each state will be offering for sale. Key design elements include:

- All market participants will be eligible to participate in the initial auction, provided they meet qualification requirements, which will include a provision of financial security. Flexibility will be retained to limit participant eligibility in subsequent auctions. There will be a total limit for the number of allowances that entities may

purchase in a single auction, equivalent to 25 percent of the allowances offered for sale in any single auction.

- A reserve price of $1.86 per allowance will apply to the first auction. After the first auction, a reserve price will be in effect that is the higher of $1.86 per allowance, as adjusted annually from 2009 onward based on the Consumer Price Index, or 80 percent of the current market price of the particular RGGI allowance vintage being auctioned.
- Any unsold allowances will be made available for sale in future auctions in which a reserve price based on the current market price is being used. In 2012, the states will decide whether to retire any unsold allowances from the first compliance period, or to offer these allowances for sale in subsequent auctions during the second compliance period.

The first compliance period for RGGI program will begin January 1, 2009. Because several states have not yet approved the auction rules through legislation or regulation, the design elements are not final. For a copy of the rules, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

EPA GREENHOUSE GAS REPORTING RULEMAKING

EPA is developing a national mandatory greenhouse gas (GHG) reporting rule, as directed in the Consolidated Appropriations Act, 2008 (H.R. 2764; Public Law 110-161) enacted in December 2007. EPA is on a very aggressive timetable to meet the congressional deadlines of publishing a proposed rule by September 2008 and a final rule by June 2009. The objective for the reporting program is to provide data that will inform and support development of national climate policy. The program will cover six GHGs: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). EPA will include emissions from both upstream production (fuel and chemical producers and importers) and downstream emissions (e.g., power plants, iron, steel, and cement manufacturers). Areas of flexibility include emission thresholds and the frequency of reporting. In addition, EPA has the discretion to use existing reporting requirements for electric generating units under Section 821 of the CAA. Importantly, this rulemaking is classified as data collection; it is not a regulatory action that would make GHGs regulated pollutants. While reporting on CO_2 emissions from electric generation units could remain unchanged from current requirements, cooperatives may have to consider reporting CO_2 emissions from other sources such as vehicle fleets and other gases such as SF_6. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

CITIZENS GROUP SUES MICHIGAN OVER FAILURE TO REGULATE COAL-FIRED PLANT FOR CO2

On January 29, 2008, Citizens for Environmental Inquiry filed a lawsuit against the Michigan Department of Environmental Quality (DEQ), seeking to force the department to regulate CO_2 emissions from coal-fired power plants (*Citizens for Environmental Inquiry v. Department of Environmental Quality,* Mich. Cir. Ct., No. 08-114 AW, *complaint filed 1/29/08*). The group had asked the DEQ to put in place, or explain why it could not put in place, rules governing emissions after the U.S. Supreme Court ruling in *Massachusetts v.*

EPA. The DEQ said the agency is waiting for EPA to develop its guidelines before starting the state rulemaking process. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

GROUP TAKES MULTIPLE ACTIONS TO PROTECT ENDANGERED SPECIES

On February 7, 2007, the Center for Biological Diversity (CBD) field a petition with the U.S. Department of Interior, Fish and Wildlife Service (FWS), claiming the Pacific walrus, a species dependent on arctic sea ice for support in foraging, resting, and raising calves, should be listed as threatened or endangered under the Endangered Species Act (ESA) because global warming is disrupting their habitat. For a copy of the petition and other information about CBD, click here.

On February 27, 2008, the CBD filed a lawsuit in the U.S. District Court for the District of Columbia, seeking to speed up ESA evaluations on 10 species of penguin whose habitat is allegedly shrinking as the planet warms. The FWS said last summer that an endangered species listing "may be warranted" for the 10 penguin species in South America, Southern Africa and Antarctica. The agency missed a November 2007 deadline for deciding whether the species qualify and proposing a listing.

On March 10, 2008, CBD joined with two other groups to file a lawsuit against the Department of the Interior for missing a legal deadline to issue a final decision on whether to list the polar bear under the ESA (*Center for Biological Diversity v. Kempthorne,* N.D. Cal., No. 08-1339, 3/10/08). The lawsuit seeks a court order compelling the Bush administration to issue the final decision on the polar bear immediately. In an interesting twist on the issue, several days before the filing of the lawsuit, the Congress of Racial Equality, one of the nation's major civil rights organizations, promised to sue the Bush Administration if it lists the polar bear as threatened under the ESA because such a listing will drive up energy prices and hurt America's working poor more than any other element of society. For further information about these actions, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop, or Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

ALASKAN VILLAGE SUES ENERGY COMPANIES OVER EROSION LINKED TO CLIMATE CHANGE

On February 26, 2008, an Inuit Eskimo coastal village in northwestern Alaska sued 24 major oil and energy companies for allegedly causing the global warming that has resulted in severe erosion in the village (*Native Village of Kivalina v. ExxonMobil Corp.*, N.D. Cal., No. cv-08-1138, 2/26/08). The lawsuit charges the companies with emitting large amounts of carbon gases and, in some cases, conspiring to cast public doubt on the seriousness of emissions-caused global warming. The defendants were selected according to the amounts of carbon emissions they produce. Kivalina, home to about 400 people, is one of the Alaska coastal villages most imperiled by rapid erosion that is accelerated by a lack of sea ice and thawing permafrost on shore. The complaint relies on federal and state laws regarding public and private nuisances. It seeks to have the defendants pay the cost of relocating Kivalina, which the U.S. Army Corps of Engineers has estimated would cost $100 million to $400 million. Other eroding Alaska villages could likely join in the

lawsuit, with the aim of securing the money to relocate. ExxonMobil in particular was singled out in the lawsuit as a company that used "disinformation tactics," promoting friendly advocates to work as scientific representatives even though their work has not been peer-reviewed. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

BANK OF AMERICA FOLLOWS TREND TO ASSESS CARBON EMISSIONS IN UTILITY FINANCING

Following an emerging financial industry trend, Bank of America will start assessing CO_2 emissions impact costs in risk formulas for underwriting electric utilities. Bank officials said they will consider carbon emissions a liability in utility financing because greenhouse gas regulation is inevitable. The bank said it favors a market-based trading system regulated by the federal government. Since there are no federal carbon emission regulations, the bank will estimate liability costs at $20 to $40 per ton of CO_2. As previously reported, Citigroup, JPMorgan Chase and Morgan Stanley announced an agreement to adopt carbon principles and set standard guidelines for funding construction and modification of coal-based power plants in an effort to reduce financial risk. The banks said the new guidelines are intended to encourage utilities to lower CO_2 emissions and invest in renewable energy and low-emission technologies. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

CBO SAYS CARBON TAX 'MOST EFFICIENT' CLIMATE CHANGE OPTION

The Congressional Budget Office (CBO) has issued a report favoring a carbon tax as the most efficient method to address global warming. CBO's report states that a carbon tax would limit economic costs and provide industry certainty while achieving environmental benefits. The report requested by Senate Energy Committee Chairman Jeff Bingaman (D-NM) found a carbon tax would provide climate benefits five times greater than three proposed cap-and-trade regulatory policies with no provisions to limit economic costs. A carbon tax would provide an incentive to reduce emissions while the costs were low and continue to lower emissions as costs rise, the report stated. Cap-and-trade plans reviewed include Chairman Bingaman's bill (S. 1766) with a "safety valve" to limit how much industry must spend to comply. CBO found S. 1766 would be the best cap-and-trade alternative to imposing a carbon tax because it would prevent price spikes and keep emission reduction costs from surpassing expected benefits. The study did not include the costly Lieberman-Warner cap-and-trade bill (S. 2191), which lacks a safety valve, that the full Senate will consider. Sen. James Inhofe (R-OK), Senate Environment Committee ranking member and climate legislation critic, said CBO's study supports his position in favor of a carbon tax. For a copy of the report, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

TEN STATES SEEK FRAUD PROTECTION FOR CARBON OFFSET MARKET FROM THE FTC

On January 25, 2008, California Attorney General Edmund Brown Jr., along with nine other state attorneys general, sent a letter to the Federal Trade Commission (FTC) recommending tighter guidelines for businesses that sell carbon emission offset credits. These credits represent environmental projects that reduce greenhouse gas (GHG)

emissions elsewhere in the environment, allowing businesses to purchase these credits to offset their own emissions. Brown and other attorneys general are requesting that the FTC develop a clearer definition of what qualifies as a carbon offset, and conduct more thorough research into consumers' understanding of the offset market. As previously reported, with the market for carbon offsets expected to reach $100 million annually in the United States within the next four years, the FTC recently requested public comments by January 25, 2008, on regulation of this market. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

EPA PRESENTATION ON REGULATION OF GREENHOUSE GASES

On January 31, 2008, Peter Tsirigotas of EPA's Office of Air Quality Planning and Standards gave a presentation at the agency's Clean Air Act Advisory Committee meeting., which addresses EPA's authority to regulate greenhouse gases under the Clean Air Act. For a copy of the presentation on Cooperative.com, click here. For additional information, contact Bill Wemhoff at (703) 907-5824 or at bill.wemhoff@nreca.coop, or Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

WYOMING ENACTS TWO BILLS ON CARBON CAPTURE, SEQUESTRATION

On March 4, 2008, Wyoming Gov. Dave Freudenthal (D) signed two bills establishing what he called a "groundbreaking" regulatory framework for carbon capture and sequestration (H.B. 89, H.B. 90). The bills position Wyoming as the first state to set up a comprehensive system for regulating long-term carbon capture and storage (CCS). The bills give the state Department of Environmental Quality the authority to regulate the long-term storage of CO_2, and sets up permitting requirements as defined by department rules. The bills also recognize that surface owners control the underground pore spaces where CO_2 could be stored long term. For a copy of H.B. 89, click here. For a copy of H.B. 90, click here. At this time, 31 other states are contemplating some sort of legislation, but none of them would be as comprehensive as the Wyoming laws. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

EPA HOLDS SECOND PUBLIC WORKSHOP ON REGULATING UNDERGROUND STORAGE OF CO2

On February 26-27, 2008, EPA held the second Public Workshop on CO_2 Geologic Sequestration. NRECA prepared a summary of the break-out workshop that addressed financial assurance for long-term care and monitoring of CO2 injection wells. For a copy of the summary on Cooperative.com, click here. Summaries prepared by staff from other utilities should be available soon. For workshop presentations on EPA's website, click here. In July 2008, EPA is planning to propose a rule regulating geologic sequestration of CO_2 that will be part of the agency's Underground Injection Control program. For additional information please contact Jim Stine at james.stine@nreca.coop or 703-907-5739.

EPA RAISES GREENHOUSE GASES IN IMPACT STATEMENT FOR NEVADA COAL-FIRED PLANT

EPA is raising questions about a draft environmental impact statement for a proposed $1.2 billion coal-fired power plant on U.S. Bureau of Land Management (BLM) land in southern Nevada, including whether greenhouse gas (GHG) emissions from the plant have

been adequately addressed. The comments by EPA, dated December 14, 2007, on a BLM draft impact statement recommend further analysis of other options for generating power such as advanced coal-generating technology or renewable sources such as wind and solar. EPA's comments mark an emerging agency trend to more carefully watch GHG emissions from power plants. BLM will now consider those comments, along with others, as it develops final impact statement. Completion of the document is expected sometime this summer. For a copy of EPA's comments, click here. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

GROUPS PETITION TO INCLUDE CLIMATE CHANGE IN NEPA REVIEWS

On February 28, 2008, three environmental groups petitioned the White House Council on Environmental Quality (CEQ) to amend National Environmental Policy Act (NEPA) regulations to require that climate change be addressed in environmental studies for federal projects. The petition proposes several amendments to the regulations in which climate change and its effects are included among the factors to be considered when preparing environmental assessments or environmental impact statements. The groups also want CEQ to issue new guidance to all federal agencies "explaining that NEPA and existing CEQ regulations require that agencies address climate change." The petition also requests that CEQ address climate change specifically by preparing a comprehensive handbook for officials to use when preparing NEPA documents. For a copy of the petition, click here. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

FUND LEADERS, MANAGERS APPROVE PLAN FOR CONSIDERING CLIMATE IN INVESTMENTS

On February 14, 2008, a group of pension fund leaders, foundation heads, and financial asset managers adopted a nine-point action plan to consider climate change as a factor in investment decisions. The plan with 49 signatories representing some $1.75 trillion in assets is aimed at boosting investments in energy efficiency and new technologies, while also raising the level of scrutiny of the possible long-term risks of carbon-intensive investments. The nine points of the plan include:

- Requiring the consideration of climate risks and opportunities in investment decisions;
- Investing in companies developing and deploying clean technologies;
- Improving energy performance of real estate portfolios and investments;
- Urging comprehensive corporate responses to climate risks;
- Assisting investors with information and guidance to evaluate corporate climate risks;
- Expanding company scrutiny and collaboration by investors, analysts, and other financial professionals;
- Pushing the Securities and Exchange Commission (SEC) to require disclosure of material risk from climate factors in corporate securities filings;
- Encouraging companies and investors to back government action on climate policy; and
- Supporting policies to maximize energy efficiency.

More information, including the action plan text, is available by clicking here. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

INVESTORS FILE RECORD NUMBER OF CLIMATE CHANGE RESOLUTIONS WITH U.S. COMPANIES

Leading U.S. investors announced on March 6, 2008, that they have filed a record 54 global warming shareholder resolutions with U.S. firms, including electric power companies, which face far-reaching business impacts from climate change. The resolutions are nearly double the number filed just two years ago. Resolutions are already getting action from companies. Fourteen of the 54 resolutions were withdrawn by investors after the companies agreed to disclose potential impacts from emerging climate regulations and strategies for reducing greenhouse gas emissions including Allegheny Energy, Alliant Energy, Dominion Resources and Southern Co. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

CLIMATE NOTES

The February 15, 2008 edition of *Climate Notes* is available on Cooperative.com by clicking here. The March 3, 2008 edition of *Climate Notes* is available on Cooperative.com by clicking here.

Clean Water Act

UWAG UPDATE LETTER

Hunton & Williams, counsel to UWAG, periodically prepares a non-confidential version of the Update Memo that is sent to all UWAG members to keep them abreast of the various water issues they are working on at the federal level. It address important issues including the Section 316(b) lawsuits and appeals to the Supreme Court, EPA's on-going study of wastewater discharges from power plants as part of the agency's plans to update the industry's effluent guidelines, and wetland developments. If you wish to discuss any of the issues in the UWAG memo, please contact Jim Stine at james.stine@nreca.coop or 703-907-5739.

Waste Issues

NRECA SUBMITS COMMENTS ON EPA's COAL ASH NODA

EPA published a notice of data availability (NODA) on August 29, 2007 (72 *Fed. Reg.* 49714), that addressed disposal of coal combustion products (CCP) in landfills and surface impoundments. EPA's publication contained several reports and a great deal of technical information pertaining to the safety and protection provided by existing CCP management activities at coal-fired power plants. EPA is considering whether current regulations are protective enough, or if it needs to write new federal regulations. Environmental groups are pressing hard for much stricter regulation of ash management practices or even an out-right ban. Protecting the ability of G&Ts to continue economical generation of electricity from coal is a top NRECA priority. With support from USWAG, on February 11, 2008, NRECA prepared comments and a template that helped several individual cooperatives to submit their own comments. For a copy of NRECA's comments on cooperative.com, click here. For a copy of USWAG's February 11, 2008 comments on Cooperative.com, click here. For a copy

of the appendix to USWAG's comments on Cooperative.com, click here. For additional information, please contact Jim Stine at james.stine@nreca.coop or 703-907-5739.

Energy

RURAL UTILITIES SERVICE AFFIRMS ADMINISTRATION STANCE ON BASELOAD LOANS

Jim Newby, Assistant Administrator of the Rural Utilities Service (RUS), recently stated that the agency will not issue any loans for new plant construction in 2008 and is unlikely to do so in 2009. The announcement comes after several cooperatives have either been denied RUS loans or have withdrawn RUS loan applications in recent months. Newby cited a 30 percent price increase for new generation as one reason for the denials, and the anti-loan stance as another. Newby also acknowledged that the agency hopes to resolve its concerns about increased risk and resume loans at some point after 2009. NRECA CEO Glenn English told the media that RUS and the Administration were exhibiting some of the same nervousness seen in private financial markets over the potential effects of climate change legislation. Mr. English also noted that many lawmakers are solely focused on reducing the amount of CO_2 emissions and do not yet have a plan for getting "from here to there." At the time of the loan suspension, at least four cooperatives were lined up for loans totaling $1.3 billion for projects in Kentucky, Illinois, Arkansas and Missouri. A project in Montana was denied funding last month, and two more were recently withdrawn in Wyoming and Missouri. For more information, contact John Holt at (703) 907-5805 or at john.holt@nreca.coop.

LATEST CREB ALLOCATIONS INCLUDE 26 ELECTRIC COOPERATIVE PROJECTS – BACKLOG REMAINS

The latest Clean Renewable Energy Bond (CREB) allocations include 26 electric cooperative projects in 13 states totaling $143.47 million, about a third of all project requests. Cooperative projects receiving allocations spanned most of the eligible technologies: wind, solar, hydropower, open-loop biomass and landfill gas. Allocations were between $30,000 and $30 million. This round is the second of CREB allocations under a funding extension Congress approved in 2006 after overwhelming response to the initial allocations left a significant project backlog. Again, cooperative response to the program leaves a significant backlog in projects seeking funding. During initial CREB allocations in 2007, electric cooperatives received $300 million, 55 percent of project requests. NRECA is working with key members of Congress for another CREB program and Production Tax Credit extension in 2008. For a list of the allocations on Cooperative.com, click here. For more information, contact Susan Pettit at (703) 907-5822 or susan.pettit@nreca.coop.

TAX CREDIT EXTENSION FOR CLEAN ENERGY TECHNOLOGY INVESTMENTS REINTRODUCED

On February 14, 2008, despite failed efforts in the Senate in 2007, Sens. Amy Klobuchar (D-Minn.), Olympia Snowe (R-Maine), and Maria Cantwell (D-Wash.) reintroduced legislation (S. 2642) that would extend expiring tax credits for the production of energy-

efficient technologies and would be funded by repealing tax credits for major oil and gas producers. The bill also would provide longer-term extensions of tax incentives of five years for the development of new wind power technologies, solar energy producers, and other "clean technology" energy businesses. For a copy of the Senate bill, click here. The tax incentives are set to expire at the end of this year. Like last year, Republicans and the White House do not support the repeal of the manufacturing deduction for major oil and gas producers, a provision that would raise nearly $10 billion to offset the costs of the tax credits. Another package of energy-related tax incentives is slated for consideration in the House. H.R. 3221 would use tax credits to encourage the production and use of cleaner forms of energy while offsetting those incentives with a denial of the Section 199 manufacturing deduction to certain oil and gas producers. For a copy of the House bill, click here. For more information, contact Susan Pettit at (703) 907-5822 or susan.pettit@nreca.coop.

Other

GROUPS SUE TO HALT EAST KENTUCKY PLANT CONSTRUCTION

On March 3, 2008, three environmental groups sued the Rural Utilities Service (RUS) to halt construction of an East Kentucky Power Cooperative plant that the groups say is unnecessary and harmful to the environment. The groups claim the RUS failed to properly conduct an environmental assessment of East Kentucky Power's plans to build a new coal-fired plant and transmission lines at its J.K. Smith power station in Clark County. The groups maintain that environmental studies on the two projects should be done together instead of separately. The transmission line study already has been completed. Their separation, the groups say, violates the National Environmental Policy Act's requirement that related proposals be analyzed as a group. The co-op successfully fought off similar challenges of its plans during Public Service Commission hearings over the past year. Last month, the environmental groups issued a report saying East Kentucky could meet its growing power needs by using a combination of energy efficiency and renewable energy programs. For a copy of the complaint in the lawsuit on Cooperative.com, click here. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

EPA APPOINTS MEMBERS OF NEW AGRICULTURAL ADVISORY COMMITTEE

On February 21, 2008, the EPA Administrator appointed 30 people to serve on the agency's newly formed Farm, Ranch, and Rural Communities Advisory Committee. The committee will advise the Administrator on agricultural issues that affect farms, ranches, and rural communities. The committee also will address the challenges of meeting growing demand for renewable fuels and curbing waste from concentrated animal feeding operations. The committee is holding its first meeting March 13-14, 2008, D.C., where it is looking at how EPA's policies and regulations on climate change and renewable energy will affect the agriculture community, and how the agriculture industry can play a significant role in the nation's ability to reduce its greenhouse gas emissions and its dependence on oil imports. The committee is also being asked to develop an environmental strategy to manage waste

from livestock operations that considers both regulatory and voluntary approaches, and that provides tools for producers to improve environmental performance. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

Produced by the NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
Environmental Affairs Unit, Editor Richard Robinson

The Environmental Bulletin is provided free of charge to all NRECA members upon request
Prior editions and referenced documents are posted to the Cooperative.com web site at:
https://www.cooperative.com/environmental/resources/EnvironmentalBulletin/EnvironmentalBulletin.htm

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National Rural Electric Cooperative Association
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NRECA

ENVIRONMENTAL BULLETIN

April 16, 2008

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Clean Air Act

COURT ISSUES MANDATE ON CAMR DECISION/EPA AND UARG FILE FOR REVIEW

In a surprise move, on March 14, 2008, the U.S. Court of Appeals for the D.C. Circuit granted a request by environmental petitioners for an expedited issuance of the mandate vacating the Clean Air Mercury Rule (CAMR). Although the court issued its opinion earlier to vacate the rule, CAMR remained in effect until the mandate was issued. The court's action was unexpected because the court normally does not issue a mandate to vacate a rule until the deadline for filing appeals has passed. In this case, environmental organizations were anxious to have the mandate issued early so they could challenge units undergoing permit applications. They will seek to have states set mercury limits on these facilities through case-by-case Maximum Achievable Control Technology (MACT) reviews. As a result of issuing the mandate, CAMR, including the mercury monitoring provisions, is now void in its entirety.

On March 24, 2008, EPA and UARG filed separate petitions for review by the full court of the three-judge panel's decision to vacate CAMR. The full court should decide within the next few weeks whether to accept the appeal. If the court decides not to hear the case, and if the Supreme Court is either not asked to review the decision, or if asked, declines to review it, EPA will need to begin a rulemaking under the MACT provisions. One cannot predict what standards will emerge from a MACT rulemaking because many important policy questions would need to be resolved by EPA, and because of the likelihood that the vast bulk of any EGU MACT rulemaking will be left to the next administration.

While it waits to learn of the full court's decision, EPA is preparing guidance for states to use regarding how to assess mercury controls at new power plants. The absence of an EPA rule has created problems for states reviewing permit applications. The guidance will address whether EPA agrees that case-by-case MACT requirements under Section 112(g) are now in effect and, if so, how the requirements should be applied. The fate of state mercury programs that set more stringent requirements than CAMR is more complex and will be addressed later. Many of them have yet to receive final EPA approval and nearly all of them rely on mercury monitoring provisions vacated in CAMR. For additional information, contact Bill Wemhoff at (703) 907-5824 or at bill.wemhoff@nreca.coop.

STATES FAIL TO SUBMIT APPROVABLE OZONE EMISSION PLANS

Several states are facing possible EPA sanctions because of their failure to submit plans to attain the agency's 1997 national ozone air quality standards. According to a March 24, 2008 *Federal Register* notice (73 *Fed. Reg.* 15416), California, New York, Illinois, Ohio, Indiana, Virginia, Wisconsin, New Hampshire, Rhode Island, Vermont and Maine have not completed acceptable state implementation plans (SIPs) to show how they will attain the 1997 standards. For a copy of the notice, click here. On March 27, 2008, EPA also issued a *Federal Register* notice (73 *Fed. Reg.* 16205), finding that many additional states had submitted incomplete versions of their plans. For a copy of the notice, click here.

The CAA establishes specific consequences if EPA finds that a state failed to submit a SIP, or, regarding a submitted SIP, EPA determines it is incomplete or disapproves it. If a state fails to submit a satisfactory SIP within 18 months, EPA may impose sanctions requiring new or modified sources to offset double the amount of their emissions exceedance. If the state fails to submit a satisfactory SIP within two years, the state may lose federal highway funds and EPA will also impose federal implementation plans for ozone attainment. The failure of the states to submit approvable SIPs to meet the 1997 standards underscores the difficulty states may face when developing plans to meet EPA's new standards announced on March 12, 2008. The agency significantly tightened the 1997 standards from 0.08 ppm to 0.075 ppm throwing many new areas into nonattainment. For additional information, contact Bill Wemhoff at (703) 907-5824 or at bill.wemhoff@nreca.coop.

EPA DESIGNATES 13 COMMUNITIES IN ATTAINMENT OF 8-HOUR OZONE STANDARD

On April 2, 2008, EPA published a notice in the *Federal Register*, designating 13 areas participating in early action compacts (EACs) to be in attainment of the eight-hour ozone standard (73 *Fed. Reg.* 17,897). The EAC areas agreed to reduce ground-level ozone emissions earlier than the Clean Air Act required and to demonstrate attainment with the 8-hour ozone NAAQS by December 31, 2007. The communities being given the designation are Washington County/Hagerstown in Maryland; Fayetteville, the Greensboro area, and the Hickory-Morganton-Lenoir area in North Carolina; Greenville-Spartanburg-Anderson in South Carolina; the Chattanooga area, the Johnson City-Kingsport-Bristol area, and the Nashville area in Tennessee; the San Antonio area in Texas; Frederick County/Winchester and Roanoke in Virginia; and Berkeley and Jefferson Counties in West Virginia. In exchange for early compliance, EPA gives EAC participants greater flexibility to choose locally tailored emissions control measures rather than more conventional ones required of most nonattainment areas. EPA also agreed to revoke the one-hour standard for each of the 13 early compact areas one year after final attainment designations take effect April 15, 2008. For a copy of the *Federal Register* notice, click here. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

EPA AMENDS HAZARDOUS WASTE COMBUSTORS EMISSIONS STANDARDS

On April 8, 2008, EPA published a Clean Air Act final rule in the *Federal Register* (73 *Fed. Reg.* 18,970) that clarifies several compliance and monitoring provisions from the October 2005 rulemaking designed to reduce emissions of hazardous air pollutants (NESHAPS). The emissions standards affect about 267 hazardous waste-burning sources including industrial, commercial, or institutional boilers and process heaters (which may affect some co-ops). The revised rule corrects typographical errors, and amends timelines to reflect the accurate dates and time frames associated with compliance activities, and makes the rule easier to understand and use. Some other amendments are more substantive. The revisions are effective immediately, and the final rule does not change the October 14, 2008 compliance date established by the October 2005 final rule. For a copy of the rule, click here. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

Climate Change

DESERET G&T IS AT CENTER OF DEBATE TO REGULATE GREENHOUSE GAS EMISSIONS UNDER AIR ACT

Deseret Power Electric Cooperative's attempt to build a small commercial waste coal combustion generator (110 MW) is receiving national attention as its Clean Air Act construction permit (PSD) reaches the EPA appeals board (EAB). The Sierra Club challenged EPA Region 8-issued federal PSD permit issued last year for failing to consider CO_2 emissions in its required best available control technology (BACT) analysis. Over a dozen groups with national interests have filed briefs in support of or in opposition to the EPA-issued permit. Oral arguments in Washington have been scheduled for May 29, 2008. Essentially, the arguments to include CO_2 BACT are two-fold. Either a CO_2 monitoring provision added during the 1990 Clean Air Act legislative debates requires CO_2 BACT because it became a "regulated pollutant" in 1990, or the Supreme Court decision in *Massachusetts v EPA* issued late April resulted in CO_2 becoming a "regulated pollutant" for BACT purposes at that time. The EAB decision is likely to be appealed to the courts. For a copy of Deseret's brief on Cooperative.com, click here. For a copy of NRECA's brief supporting EPA and Deseret on Cooperative.com, click here. For a copy of UARG's brief supporting EPA and Deseret on Cooperative.com, click here. For more information, contact Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

KANSAS GOVERNOR VETOES LEGISLATION ALLOWING EXPANSION OF SUNFLOWER PLANT

On March 21, 2008, Kansas Gov. Kathleen Sebelius (D) vetoed a bill that would have allowed the addition of two coal-fired generating units at the Sunflower Electric Power Corp. plant in western Kansas. Instead of allowing the expansion of Sunflower's project with two new 700-megawatt units, Sebelius said she supported pursuing other, more promising, energy and economic development alternatives. The bill, in effect, sought to overturn an October 2007 decision by the state's health and environment secretary to deny an air quality permit to Sunflower over concerns about greenhouse gas emissions from the new units. The governor said the bill went beyond this specific project by stripping emergency powers from the state in the air quality permitting process and prohibiting the consideration of any standards beyond the federal Clean Air Act. Both houses of the Kansas legislature are now attempting to override the governor's veto. For a copy of the bill, click here. For a copy of the governor's veto message, click here. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop, or Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

EPA ADMINISTRATOR OUTLINES RESPONSE TO *MASSACHUSETTS V. EPA* DECISION

On March 27, 2008, EPA Administrator Johnson sent letters to several key members of Congress outlining his intended approach to respond to the Supreme Court's decision, *Massachusetts v. EPA*. On April 2, 2007, the Court held that EPA has authority under the CAA to regulate CO_2 and other greenhouse gases (GHGs) from new motor vehicles. In the letters, the Administrator said he would issue an Advance Notice of Propose Rulemaking (ANPR) on all aspects of how CO_2 and other GHGs should and/or could be regulated under

the CAA. The letter explains that regulation of motor vehicles under the CAA would entail much more than automobiles (e.g., the triggering of PSD requirements affecting many stationary sources including numerous small businesses currently not subject to controls). The Administrator said that it is better to examine the entirety of the situation rather than act on automobiles without considering the ramifications. He does not give a timeline for when the ANPR will be released but it is expected later this spring. For a copy of Administrator Johnson's letter to John Dingell (D-MI) and Joe Barton (R-TX) on Cooperative.com, click here.

Because it had been a year since the Supreme Court's decision, on April 2, 2008, twelve states and several environmental groups fled suit in the U.S. Court of Appeals, D.C. Circuit, seeking to force EPA to issue a decision within 60 days on whether GHG emissions from motor vehicles endanger the public health or welfare. The petitioners claim that EPA has "unreasonably" delayed issuing a formal endangerment determination. For a copy of the petition filed by states and environmental groups on April 2, 2008, click here. On the same day, Sens. Dianne Feinstein (D-Calif.) and Olympia Snowe (R-Maine) introduced a bill that would require EPA to issue such a finding. The bill (S. 2806) also would require that EPA reconsider its decision denying California a CAA waiver to enforce stricter emissions standards for vehicles. For a copy of the bill, click here. For additional information, contact Bill Wemhoff at (703) 907-5824 or at bill.wemhoff@nreca.coop.

THE CLIMATE REGISTRY FINALIZES REPORTING PROTOCOL

The Climate Registry, a state-based initiative to report greenhouse gas (GHG) emissions in facilitation of regional climate programs, released the final version of its General Reporting Protocol. The protocol, which outlines requirements for the voluntary reporting scheme, includes policy guidelines, technical guidelines, and methodologies for quantifying emissions. Reporters that sign on with the registry must track their direct and indirect emissions of six GHGs—carbon dioxide, methane, nitrous oxide, perfluorocarbons, hydrofluorocarbons, and sulfur hexafluoride—from each facility in North America. All reporters must obtain third party verification annually to ensure the accuracy of the data. Currently, 39 states, the District of Columbia, three Canadian provinces, three tribes, and one Mexican state are members of the Climate Registry. Founding reporters, those that join the registry by May 1, 2008, include Great River Energy and Wolverine Power Cooperative. For a copy of the Climate Registry's General Reporting Protocol, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

GORE LAUNCHES $300 MILLION CLIMATE AD CAMPAIGN

Former Vice President Al Gore has rolled out an advocacy campaign that is aimed to mobilize Americans to rally for aggressive reductions in greenhouse gas emissions, and tilt public opinion on climate change in an optimistic direction. While avoiding specific recommendations on solutions, the "We" campaign employs online organizing and action alerts. The ad's tone is designed to make people feel positive about the potential to fix climate change, and to increase public consciousness. This campaign is one of the most ambitious and costly in U.S. history. Private contributors have already donated $150 million of the $300 million that is needed to fund the campaign for the next three years.

This ad is airing on major broadcast shows such as *American Idol*, the *Today Show* and *Good Morning America*, as well as online. To view the campaign, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

WAXMAN, MARKEY INTRODUCE BILL TO CONTROL NEW COAL-POWERED PLANT EMISSIONS

On March 11, 2008, Reps. Ed Markey (D-MA) and Henry Waxman (D-CA) teamed up to release the "Moratorium on Uncontrolled Power Plants Act" (HR 5575). This bill would prohibit both states and EPA from issuing permits for the construction of new coal-fired power plants unless the plants sequester and store 85 percent of their annual CO_2 emissions. Also, the bill would prohibit plants that receive permits before the bill's passage, but which are built afterward and without the mandated technology, from receiving free or discounted emissions allowances once a greenhouse gas cap-and-trade bill is implemented. Technology that captures and permanently stores 85 percent CO_2 emissions has yet to be implemented on a scale large enough to be used for a power plant, so the bill requires beyond what can currently be done. Additionally, the bill signals to House Speaker Nancy Pelosi (D-CA) that these two senior members of the House Energy and Commerce Committee will oppose Chairman John Dingell (D-MI) if he advances more moderate climate change legislation. For a copy of the bill, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

HOUSE COMMITTEE REVIEWS CAA AUTHORITIES OVER GHGS

At an April 10, 2008 House Energy and Air Quality Subcommittee hearing, Energy and Commerce Committee Chairman John Dingell (D-MI) took issue with the Supreme Court decision in *Massachusetts v. EPA* that gives the EPA authority under the Clean Air Act (CAA) to issue climate-related regulations. EPA testified to a list of potential areas for CAA regulation including limits on tailpipe emissions and fuels, new source review permits and a broad new National Ambient Air Quality Standard that measures greenhouse gas concentrations in all 50 states. Chairman Dingell has predicted there would be a "glorious mess" if EPA is allowed to implement emissions rules under existing provisions of the CAA without comprehensive legislation on the issue. His tone at the hearing took on a new sense of urgency as he appealed to lawmakers skeptical of mandatory emission curbs to support legislation that would amend the CAA and improve implementation of a carbon control scheme. House committee staff is drafting a comprehensive cap-and-trade bill that seeks to reduce U.S. emissions 60 percent to 80 percent by 2050. Chairman Dingell has said he would try to produce the bill for comment by mid-April, but he has not gone any further in stating his legislative plans. Industry lobbyists believe the House will wait to address climate legislation until the Senate considers the Lieberman-Warner climate bill, S. 2191, currently scheduled for floor debate June 2, 2008. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

DOE TO ISSUE TWO LOAN GUARANTEE SOLICITATIONS

The Department of Energy has announced that it plans to issue loan guarantee solicitations this summer for up to $38.5 billion. The first solicitation will come no later than June 2008 for efficiency, renewable energy and electric transmission projects (up to $10 billion); nuclear power facilities (up to $18.5 billion); and uranium enrichment projects (up to $2

billion). The second solicitation, which will be issued later in the summer, will be for advanced fossil energy projects (up to $8 billion). Prior to the issuance of the $10 billion solicitation for projects in the efficiency, renewable energy and electric transmission areas, DOE intends to issue a Request for Information to solicit input concerning areas of particular technology focus and interest in these areas. Selection criteria under these solicitations will focus on the avoidance of emissions of greenhouse gas emissions and other air pollutants; the speed at which technologies can be commercialized; cost-saving potential for consumers; the prospect of repayment; and the potential for long-lasting success of these technologies in the marketplace. The upcoming solicitations will be the second and third under the program, which some lawmakers say the agency has been slow to get off the ground. The agency is planning to receive full applications from 16 projects as a result of the first solicitation, issued in 2006. The projects include integrated gasification combined cycle power plants, solar energy projects, cellulosic ethanol plants and others. For more information on DOE's loan guarantee program, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

GREENING THE VATICAN

The Catholic Church and environmentalists have found common ground on the issue of climate change. Pope Benedict XVI last month added polluting the earth to the Catholic list of sins. Presenting climate change as a moral issue, he warned that environmental neglect hurts the poor and vulnerable. The pope's efforts are resonating throughout the Catholic community as schools, universities and churches adopt green practices and participate in environmental activism. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

SEALS TO BE REVIEWED FOR LISTING AFTER LAWSUIT THREATENED

On March 21, 2008, the Center for Biological Diversity (CBD) served notice of its intent to sue the National Marine Fisheries Service (NMFS) over its failure within 90 days to review the ribbon seal, a marine mammal whose sea-ice habitat is becoming scarce as its climate warms, for possible listing under the Endangered Species Act (ESA). The CBD had submitted a petition December 20, 2007, to have the ribbon seal listed as threatened or endangered. Subsequently, on March 26, 2008, the NMFS announced that it had launched a status review to determine whether the ribbon seals should be protected under the ESA because of the effects of climate change. In addition, the agency said it will conduct similar status reviews of the three other species of ice-dependent seals living in northern Alaska waters--spotted, bearded, and ringed seals. The CBD is one of the groups that petitioned for listing of the polar bear and subsequently sued over the U.S. Fish and Wildlife Service's failure to announce such a listing. The organization has also petitioned for ESA listing of another ice-dependent sea mammal, the Pacific walrus. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

CLIMATE NOTES

The March 17, 2008 edition of *Climate Notes* is available on Cooperative.com by clicking here. The March 26, 2008 edition of *Climate Notes* is available on Cooperative.com by clicking here.

Clean Water Act

COURT OVERTURNS DEFINITION OF "NAVIGABLE WATER"

On March 31, 2008, the U.S. District Court for the District of Columbia ruled on a case brought by the American Petroleum Institute ("API") and others challenging the definition of "navigable waters" in EPA's 2002 Spill Prevention, Control, and Countermeasure ("SPCC") Rule (*American Petroleum Institute v. Johnson,* No. 02-2247 and *Marathon Oil Company v. Johnson,* No. 02-2254). For a copy of the opinion, click here. The court held that the definition of "navigable waters" in the 2002 SPCC Rule violated the federal Administrative Procedure Act because the agency did not offer a "clear, cogent and reasoned explanation" for the new "broad definition," and because the explanation the agency did provide "failed to come to grips with" the reasoning of the United States Supreme Court in *Solid Waste Agency of N. Cook County v. U.S. Army Corps of Engr's,* 531 U.S. 159 (2001) ("SWANCC"). The court vacated and remanded the new regulatory definition in the 2002 SPCC Rule back to the agency, which means that the definition of "navigable waters" in the 1973 SPCC Rule still provides the operative definition for all SPCC programs. EPA is determining whether to appeal the decision. For the purposes of their SPCC programs, many co-ops tend to use a broad interpretation of "navigable waters" and, to be on the safe side, tend to assume even the smallest water course could be a navigable water. For additional information please contact Jim Stine at james.stine@nreca.coop or 703-907-5739.

EPA PUBLISHES DRAFT WATER PROGRAM STRATEGY FOR RESPONDING TO CLIMATE CHANGE

EPA recently published a draft strategy that describes the potential effects of climate change on clean water, drinking water, and ocean protection programs, and outlines EPA actions to respond. The strategy is based on the findings of the Intergovernmental Panel on Climate Change (IPCC). It accepts as given what it calls the "scientific consensus" that we can expect rising sea levels, changes in ocean chemistry, warmer water, new patterns of rainfall, and more intense storms. It then proposes 46 specific "key actions" that the National Water Program will take to respond to these changes. The key actions, listed in summary fashion in Appendix 2 of the Strategy, are a remarkably broad list of goals, including improving energy efficiency at water and wastewater facilities, promoting water conservation, promoting "green" buildings, developing regulations for and studies of sequestering CO_2, assessing the risks of waterborne disease, expanding emergency response planning, sponsoring climate research, educating the public on climate change, and making EPA organizational adjustments. EPA has invited comment but, since the document is so broad and at the "30,000 foot" strategic level, neither UWAG nor NRECA are likely to comment. The strategy can be found by clicking here. For additional information, please contact Jim Stine at james.stine@nreca.coop or 703-907-5739.

TMDL KNOWLEDGEBASE CLEARINGHOUSE

Virginia Tech's Center for Total Maximum Daily Load (TMDL) and Watershed Studies has developed an online database to house selected TMDL-related information and documents in one location. The searchable clearinghouse contains three types of resources:

(1) TMDL guidance documents, (2) reviews and summaries of TMDL-related technical and trade literature, and (3) state-by-state summaries of TMDL programs. State summaries are updated regularly for all 50 states and include the approach and methodology used to develop TMDLs in that state. In total, about 500 documents are available within this database, which was funded, in part, by an EPA grant. The TMDL Knowledgebase Clearinghouse can be accessed via the Center's website by clicking here. For additional information, please contact Jim Stine at james.stine@nreca.coop or 703-907-5739.

EPA, ARMY CORPS ISSUE FINAL RULE TO MITIGATE LOSS OF WETLANDS, STREAMS

EPA and the U.S. Army Corps of Engineers released a final rule March 31, 2008, that sets standards to mitigate the loss of wetlands and associated aquatic resources. EPA said the rule under Section 404 of the Clean Water Act improves the planning, implementation, and management of compensatory mitigation projects designed to restore aquatic resources that are affected when activities like construction, mining, and farming disturb a half-acre or more of wetlands. EPA has said that this rule is the "most important advancement of the wetlands program" since the U.S. adopted a "no-net-loss" policy toward wetlands in 1989. According to EPA, the final rule also provides one set of regulations for compensatory mitigation instead of the numerous, separate guidance documents currently in use. Under the rule, all compensation projects must have mitigation plans that include the same 12 fundamental components. Among other things, these components include objectives, site selection criteria, site protection instruments like conservation easements, a mitigation work plan, and a maintenance plan. The final compensatory mitigation rule has not yet been published in the *Federal Register*. The text of the final rule and other information is available by clicking here. For additional information, please contact Jim Stine at james.stine@nreca.coop or 703-907-5739.

UWAG UPDATE LETTER

The March 17, 2008 *Environmental Bulletin* contained an article on the periodic update memo prepared by Hunton & Williams, counsel to UWAG, to keep UWAG members abreast of various water issues they are working on at the federal level. The memo, dated February 8, 2008, addresses important issues including the Section 316(b) lawsuits and appeals to the Supreme Court, EPA's on-going study of wastewater discharges from power plants as part of the agency's plans to update the industry's effluent guidelines, and wetland developments. The memo was inadvertently left off the March 17, 2008 *Environmental Bulletin*. For a copy of the update memo on Cooperative.com, click here. For more information, please contact Jim Stine at james.stine@nreca.coop or 703-907-5739.

Energy

RENEWABLE ENERGY CREDITS BILL INTRODUCED

On April 3, 2008, Sens. Maria Cantwell (D-Wash.) and John Ensign (R-Nev.) introduced a $6 billion tax bill (number not available) that includes a one-year extension of a renewable energy production tax credit. The Clean Energy Tax Stimulus Act of 2008, cosponsored originally by six Democrats and 14 Republicans, represents another attempt by Senate

Democrats to secure quick passage of renewable energy tax credits that expire at the end of 2008. The bill would extend for one year through 2009 and expand by $400 million the $1.2 billion provision that rural cooperatives and public power utilities can issue Clean Renewable Energy Bonds to reduce the cost of renewable energy investments. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

Other

EPA REQUESTS HELP FROM AG COMMITTEE ON POLICIES AFFECTING FARMS

On March 13, 2008, EPA Deputy Administrator Marcus Peacock told the agency's new Farm, Ranch, and Rural Communities Advisory Committee (FRRCC), at its first meeting, that it will help EPA make policy decisions that affect farms, ranches, and the rural way of life. The FRRCC will address three initial topics:

1. The role of agriculture in reducing greenhouse gas (GHG) emissions. The agricultural industry as both a source of and a sink for GHG emissions has a significant role in cutting oil imports through the development of renewable energy sources.
2. An environmental strategy for livestock operations.
3. Communication issues.

For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

Produced by the NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
Environmental Affairs Unit, Editor Richard Robinson

The Environmental Bulletin is provided free of charge to all NRECA members upon request.
Prior editions and referenced documents are posted to the Cooperative.com web site at:
https://www.cooperative.com/environmental/resources/EnvironmentalBulletin/EnvironmentalBulletin.htm

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NRECA

ENVIRONMENTAL BULLETIN

May 22, 2008

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Clean Air Act

EPA SETS GUIDELINES FOR IMPLEMENTING NSR STANDARDS FOR FINE PARTICLES

On May 8, 2008, EPA issued a final rule clarifying requirements for enforcement of the NSR program for fine particulate matter ($PM_{2.5}$) emissions. The rule defines a major emissions source as one that emits 250 tons per year with the exception of 28 source categories that will constitute a major emitter at 100 tons per year. The rule also sets NSR significant emissions rates at 10 tons of $PM_{2.5}$ per year, 40 tons of SO_2 per year, 40 tons of NOx per year, and 40 tons of organic volatile compounds per year, if regulated. The rule also allows emitters to trade emissions between states and regions but not within in a given nonattainment area. The rule does not initially require states to account for gases that could condense to form particles. For the text of the rule and a fact sheet, click here. For more information, contact Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

UARG COMMENTS ON EPA'S ISA FOR OXIDES OF NITROGEN

On May 5, 2008, UARG submitted comments on EPA's Second External Review Draft of its Integrated Science Assessment (ISA) for Oxides of Nitrogen -- Health Criteria, March 2008. In its comments, UARG said the second draft of the ISA is an improvement but there remain significant flaws that the agency must address before it will satisfy the CAA legal standard applicable to "air quality criteria." UARG said in many areas the draft fails to present EPA's evaluation of the relevant science, opting instead to simply describe various studies, and then pronounce conclusions. In other areas where the agency does include analyses, an undefined and vague framework for reaching causality determinations is used and serious mistakes are made. For a copy of UARG's comments on Cooperative.com, click here. For more information, contact Bill Wemhoff at (703) 907-5824 or at bill.wemhoff@nreca.coop.

EPA SETTLES LAWSUIT WITH COKE MANUFACTURERS OVER RULES FOR POWER PLANTS

On April 11, 2008, EPA announced settlement of a lawsuit in the *Federal Register* filed by coke manufacturers challenging new emissions standards for fossil fuel-fired electric power plants (*Coke Oven Environmental Task Force v. EPA,* D.C. Cir., No. 06-1131). The industry filed the lawsuit after the agency finalized new monitoring and emissions requirements for PM, SO_2, and NOx for new fossil fuel-fired electric power plants in June 2007. The industry claimed that coke oven gas does not produce as much PM or NOx emissions as coal, which is how it is currently classified. As part of the settlement, EPA will issue a direct final rule or a proposed rule by May 31, 2008, clarifying the emissions monitoring standards and relieving coke oven gas-powered boilers and plants from the burden of monitoring PM and NOx emissions, but that the plants would continue to monitor for SO_2 under proposed amendments offered by the coke oven gas industry. Under the rule, new plants or older facilities that are significantly upgraded would have to meet the new emissions and monitoring standards. EPA has until November 30, 2008, to take final action on the rulemaking. Currently, there are only 18 coke plants in the U.S. that could potentially use coke oven gas, but there are some new facilities under construction that could have to meet the new emissions standards. For a copy of the *Federal Register*

notice (73 *Fed. Reg.* 19838), click here. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

UARG FILES COMMENTS ON MANE-VU VISIBILITY PROJECTIONS DRAFT REPORT

On April 25, 2008, UARG filed comments in response to the Mid-Atlantic/Northeast Visibility Union's (MANE-VU) April 4, 2008 email invitation, asking stakeholders to comment on its 2018 Visibility Projections Draft Report. The draft report describes the process that MANE-VU used to assess the impact by 2018 if:

1. The electric generating units (EGUs) in the MANE-VU, Midwest Regional Planning Organization (MPRO), and the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) regions implemented the emissions reductions required by CAIR;
2. The states in those regions also implemented additional reductions from non-EGU sources including best available retrofit technology (BART); and
3. Certain emissions reductions occur from EGUs in Canada.

Most importantly, the draft report concludes that, using MANE-VU's analysis, all MANE-VU sites are projected to meet or exceed the uniform rate of progress goal for 2018. UARG comments that this conclusion agrees with that of the other regional planning organizations (RPOs) in the eastern half of the U.S. Therefore, UARG contends that states in this area should develop SIPs that reflect compliance with CAIR levels for EGUs, and do not require any additional reductions by EGUs. If the three eastern RPOs (MANE-VU, VISTAS and MPRO) agree with this conclusion, then no co-op plants in those states would have to go "beyond CAIR" in meeting their states' regional haze SIPs. For a copy of UARG's comments on Cooperative.com, click here. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

EPA PROPOSES NSPS FOR COAL PROCESSING PLANTS

On April 28, 2008, EPA proposed revisions to NSPS Subpart Y, which affects coal processing and conveying equipment (breakers, crushers, screens, conveyor belts), coal storage systems, and coal transfer or loading systems at new, modified and reconstructed units (73 *Fed. Reg.* 22901). This rule may be significant for those co-ops that own or operate such equipment or systems. Under a consent decree with the Sierra Club, the EPA Administrator must sign the final rule by April 16, 2009. Environmentalists who are targeting emissions from all aspects of coal power production are likely to oppose the proposal. The proposed rule addresses:

- Subcategorization;
- Thermal dryers;
- Coal processing and conveying equipment (including breakers and crushers), coal storage systems, and transfer and loading systems;
- Compliance and emissions monitoring;
- Modified and reconstructed conveyors;
- The definition of "coal storage system;" and
- Regulation of nonmetallic minerals.

UARG will prepare comments on these proposed revisions, which are due June 12, 2008. For a copy of the proposal, click here. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

Climate Change

NRECA PROVIDES CONSTRUCTIVE SUGGESTIONS TO LIEBERMAN AND WARNER ON CLIMATE BILL

On May 9, 2008, NRECA sent a letter to Sens. Joseph Lieberman (I-CT) and John Warner (R-VA) urging them to improve their climate change cap-and-trade legislation before bringing it to the floor in June. The letter included making the caps and timelines more realistic, including an economic safety valve, and minimizing the use of an auction for cooperative emission allowances, in addition to outlining some more detailed concerns NRECA has identified with the bill. Several key senators have pledged to work with NRECA on the Lieberman-Warner climate bill, including some who have cosponsored the legislation and now have increasingly become concerned with its complexity and cost. This will not be the only opportunity to provide suggestions to improve the bill. For a copy of the letter, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

PRESIDENT BUSH OUTLINES NEW US CLIMATE GOALS

On April 16, 2008, prior to the latest U.S.-led meeting to establish a post-Kyoto, international climate change regime, President Bush announced a new national goal of stopping the growth of greenhouse gas emissions by 2025. Saying, "We've got to do more in the power generation sector," he laid out a goal of having power plant emissions peak over the next 10 years to 15 years, and then decline. Bush emphasized his opposition to higher taxes and harm to the economy and said solutions should focus on technology. He also noted, with disapproval, that some environmental activists want to use the Clean Air Act to regulate CO_2. Calling the current package of technology tax incentives "a complicated mix," he called for a single incentive program that is technology-neutral and long-lasting. For a fact sheet on the policy, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

EIA PROJECTS SENATE CLIMATE BILL WILL RAISE ENERGY COSTS

According to the Energy Information Administration (EIA) in April 2008, the Lieberman-Warner climate bill (S. 2191) will raise energy prices and decrease average annual household consumption—a measure of economic welfare—between $160 and $310 in 2015, and $300 and $790 by 2030 (2007 dollars). Electricity prices under S. 2191 would rise between 11 percent and 64 percent under the various technology scenarios modeled. Under a core case where nuclear and coal with carbon capture and storage (CCS) are available in the timeframes of the bill's emission reduction requirements, 533 gigawatts (GW) of new capacity would be added by 2030 in contrast to 264 GW of projected capacity additions without S. 2191. New generation would be dominated by nuclear power, 268 GW, while coal generation would lag, 64 GW of new coal with CCS capacity offset by retirements and reduced utilization. The bulk of emission reductions are

projected to come from electricity generation under all scenarios. Proponents of S. 2191 claimed the EIA analysis showed that it would not cause significant harm to the economy, while opponents focused on projected increases to gasoline prices of anywhere from 41 cents to over a dollar by 2030. For a copy of the EIA analysis, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

KANSAS LEGISLATURE AGAIN FAILS TO OVERRIDE GOVERNOR'S VETO OF BILL ON SUNFLOWER UNITS

On May 1, 2008, the Kansas House failed for a second time to override Gov. Kathleen Sebelius's (D) veto of legislation that would have allowed Sunflower Electric Power Corporation to build two coal-fired generating units in western Kansas. The vote in favor of overriding Sebelius's veto of the bill was 80-45, four votes shy of the necessary two-thirds majority. The bill also would have prevented the state agency from using its emergency powers to impose restrictions on future sources of emissions. Leaders of the Republican-controlled legislature are considering a variety of other ways to provide support for the project. For the full text of the bill and a summary on the web site of the Kansas legislature, click here. For more information, contact Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

ENDANGERMENT CASE

A federal district court in California on March 28, 2008, on a motion to dismiss, threw out a labor rights organization's request to force EPA to immediately decide whether greenhouse gases endanger public health (*San Francisco Chapter of A. Philip Randolph Institute, et al. v. EPA, et al.*). The court said the group's request "is so far afield from notions of comity and propriety that it need not be seriously considered." This decision is potentially damaging for environmentalists who are asking a federal appeals court to compel EPA to quickly issue a climate endangerment finding pursuant to the Supreme Court case of *Massachusetts v. EPA*. The labor rights organization sued EPA and the Bay Area Air Quality Management District last September attempting to stop the permitting process for a proposed power plant. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

DEPARTMENT OF INTERIOR LISTS POLAR BEAR AS "THREATENED SPECIES"

On May 14, 2008, Secretary of Interior Dirk Kempthorne announced that he is listing the polar bear as a "threatened species" under the Endangered Species Act (ESA). According to the Secretary, the loss of habitat because of the decline in sea ice puts polar bears at risk of becoming endangered in the foreseeable future, the standard established by the ESA for designating a threatened species. In his comments, Secretary Kempthorne reiterated President Bush's statement last month that the ESA was never intended to regulate global climate change. Kempthorne promised the following actions:

- Importantly, the Director of the U.S. Fish & Wildlife Service will issue guidance to staff that the best scientific data available today cannot make a causal connection between harm to listed species or their habitats and greenhouse gas emissions from a specific facility, resource development project or government action. The Department will issue an official legal opinion further clarifying these points. The guidance and

legal opinion will hopefully provide an acceptable argument for cooperatives seeking to permit power plants that they do not have to consult with the U.S. Fish & Wildlife Service pursuant to the ESA regarding any harm to polar bears.

- The Department will propose common sense modifications to the existing ESA regulatory language to prevent abuse of this listing to erect a back-door climate policy outside the normal system of political accountability.
- The U.S. Fish and Wildlife Service is proposing a 4(d) rule that states that if an activity is permissible under the stricter standards of the Marine Mammal Protection Act (MMPA), it is also permissible under the ESA with respect to the polar bear. This rule, effective immediately, will, the Secretary stated, ensure the protection of the bear while allowing the U.S. to continue to develop its natural resources in the arctic region in an environmentally sound way.

For copies of Secretary Kempthorne's remarks, the MMPA Section 4(d) rule, the guidance from the Director of the U.S. Fish & Wildlife Service and other materials on the Department of Interior web site, click here. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

GOVERNORS PROTEST FEDERAL VEHICLE GREENHOUSE GAS EMISSIONS PLAN

On April 24, 2008, California Governor Arnold Schwarzenegger and 11 other governors sent a letter to President Bush protesting a federal proposal to limit California's right to regulate greenhouse gas (GHG) emissions from vehicles. The letter came after the National Highway Traffic Safety Administration (NHTSA) issued a 417-page Notice of Proposed Rulemaking (NOPR) on April 22, 2008, proposing a set of fuel-efficiency standards, including a provision that would override California laws that set limits on carbon emissions from cars. NHTSA is taking comment on its NOPR until May 28, 2008. In 2007, two federal district courts ruled in Vermont and California that the GHG motor vehicle emission standards adopted by those states are not preempted under the Energy Policy and Conservation Act. The governors also sent letters to the Senate and House leadership complaining about the NHTSA action. For a copy of the letter to President Bush by Gov. Schwarzenegger and its accompanying press release, click here. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

EPA WILL NOT REGULATE REFINERY EMISSIONS UNDER NEW SOURCE PERFORMANCE STANDARDS

On April 30, 2008, EPA, in response to comments that urged the agency to include greenhouse gas (GHG) emission standards in the NSPS for petroleum refineries, declined to adopt any such standards at this time. EPA explained its position, stating that (1) it has no legal obligation to promulgate GHG emission standards under Section 111 of the CAA at this time; and (2) it is reasonable not to adopt any such standards in this rulemaking, but instead to consider more broadly the issue of possible Section 111 regulation in the agency's upcoming advance notice of proposed rulemaking (ANPR) on potential Clean Air Act regulation of GHG emissions. EPA was under court order to complete the review for petroleum refineries and to issue revised standards by April 30, 2008. EPA also said regulating GHGs under the refinery standards would automatically trigger NSR

requirements for thousands of stationary sources including power plants. For a copy of the refinery standards, click here. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

CCS ALLIANCE SUBMITS COMMENTS ON STATE OF WASHINGTON PROPOSAL

On April 18, 2008, the CCS Alliance, established to encourage deployment of carbon, capture and sequestration (CCS) technologies, and of which NRECA is member, submitted comments to the State of Washington on its proposed rules on CCS. This proposal is the first attempt by any state to regulate these activities, and the Alliance filed comments because of the potential of these rules to become a model for other states. The Alliance found a number of problems with the proposed rules including that the proposal:

- If finalized, will make it more difficult to build or upgrade fossil-fired power plants in the state,
- Treats sequestered CO_2 as a waste rather than a commodity,
- Requires permanent sequestration for 1,000 years,
- Will lead to plant shutdown in all cases of extended sequestration site noncompliance,
- Does not exclude liability under other environmental laws, and
- Provides no defined post-closure period of financial responsibility.

For a copy of the comments on Cooperative.com, click here. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

DOE TO PROVIDE FUNDING FOR CCS PROJECTS

On May 6, 2008, the Department of Energy (DOE) announced that it will give grants to the West Coast and Midwest Regional Carbon Sequestration Projects that will total $126.6 million. Industry partners will provide $56.6 million in cost-shared funds. The money will be used to conduct large-scale carbon capture and sequestration (CCS) tests in Ohio and California to demonstrate that capturing CO_2 emissions, compressing them, and storing them in the ground is a safe, permanent, and viable way to reduce CO_2 emissions into the atmosphere. For additional information on DOE's web site, click here. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

CALIFORNIA CONSUMER ADVOCATES OPPOSE UTILITY-FUNDED CLIMATE STUDIES

A California consumer advocacy group is planning to challenge the legality of a plan by state energy regulators to increase electricity rates to fund climate change research and technology development. The California dispute may provide other state and federal officials lessons about how certain climate change programs can be paid for in the coming years. A key issue, expected eventually to be addressed by other state regulators as well as federal officials, is to what degree utilities can raise rates to implement GHG-reduction programs. At issue is a plan approved April 10, 2008, by the California Public Utilities Commission to create the California Institute for Climate Solutions, which will fund research, development and commercialization of technologies to reduce GHG emissions in the electricity and natural gas sectors. The plan includes a slight increase in electricity rates for customers of the state's investor owned utilities, which serve about two-thirds of the

California population. A ratepayer advocacy organization, The Utility Reform Network (TURN), contends CPUC is not authorized to raise electricity rates on its own to fund in-house programs, and plans to appeal the CPUC decision. For more information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

CLIMATE NOTES

The April 21, 2008 edition of *Climate Notes* is available on Cooperative.com by clicking here. The May 2, 2008 edition of *Climate Notes* is available on Cooperative.com by clicking here.

Clean Water Act

SUPREME COURT AGREES TO HEAR INDUSTRY LAWSUIT ON SECTION 316(b) COOLING WATER INTAKE RULE

When the Second Circuit rejected EPA's final Phase II, 316(b) rules, one of the most important agency decisions the judge objected to was the use of a cost-benefit analysis to determine Best Technology Available (BTA) for minimizing environmental harm. EPA has long considered cooling towers to be a leading candidate for BTA, and if costs are not an issue, towers will almost certainly be declared BTA in many circumstances. Cost-benefit analysis is such an important issue that the utility industry asked the Supreme Court to review the circuit court decision. One IOU estimated it would cost one billion dollars to retrofit cooling towers on an existing 2-unit nuclear power plant. Twelve co-op G&T's have plants that could be affected because they use once-through cooling water or cooling lakes.

Three petitions asking for Supreme Court review were filed by Entergy Corp., PSEG and by UWAG on behalf of it members, including NRECA. The three separate petitions were filed in November 2007, challenging the U.S. Court of Appeals for the Second Circuit decision. The Supreme Court agreed to hear the case, consolidated the three petitions and limited them to one issue: "Whether Section 316(b) of the Clean Water Act, authorizes EPA to compare the costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures." The Supreme Court is expected to hear the case in November or December. In the meantime, state permit-issuing authorities should be aware of these activities and conduct their 316(b) programs accordingly. For additional information, please contact Jim Stine at james.stine@nreca.coop or 703-907-5739.

OBERSTAR HOLDS HEARINGS ON BILL TO AMEND CLEAN WATER ACT

On April 16, 2008, Rep. James Oberstar, Chairman of the House Transportation and Infrastructure Committee held hearings on H.R. 2421, The Clean Water Restoration Act of 2007. Among other items, the bill would eliminate the term "navigable" from the Clean Water Act. By doing so, the bill would extend federal jurisdiction over all "waters of the United States," an essentially unlimited term that would include essentially all water regardless of where it is found. There has been a continuing disagreement over how state and federal water regulatory programs for wetlands and other programs should be

coordinated. Oberstar's bill would essentially eliminate any state controls and moot this controversy. NRECA does not expect the bill to move out of committee this year. For additional information please contact Jim Stine at james.stine@nreca.coop or 703-907-5739.

Waste Issues

USWAG SCHEDULES NEXT PCB WORKSHOP

USWAG will hold its Advanced PCB Workshop on November 19 - 20, 2008, at the Marriott Memphis Downtown hotel and Cook Convention Center in Memphis, TN. Save the date. For further information, click here. This meeting will not be a repeat of previous USWAG PCB workshops, but promises to be a practical, problem solving course for personnel with a working knowledge of the PCB regulations. Please save the date for this educational advanced training course. Information on the Workshop agenda, registration and hotel accommodations will be available in the next several weeks. If you have any questions, please contact Gayle Novak, USWAG Representative at gayle.novak@uswag.org, or at 202-508-5654.

Energy

IOWA ENACTS LAW REQUIRING CO-OPS TO SET ENERGY EFFICIENCY GOALS

On May 6, 2008, Iowa Gov. Chet Culver (D) signed legislation that will require electric cooperative utilities in the state to establish energy efficiency goals and the programs that will enable them to meet those goals. S.F. 2386, which took effect upon its signing, also mandates the creation of an energy efficiency commission, directed to devise efficiency standards for all new and existing buildings. The bill originally required co-ops to achieve energy efficiency goals that translated into usage reductions of 1.5 percent annually. When the co-ops objected both to the set goals and the increased authority of the Iowa Department of Public Safety to enforce them, the bill was amended to require co-ops to instead set goals for energy efficiency. The law also requires co-ops to report back to the state on their progress in achieving energy efficiency goals. For a copy of the bill, click here. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

Transportation

REQUALIFICATION TIMEFRAMES FOR SF6 CYLINDERS REMINDER

No DOT 3AA cylinder, commonly used to transport SF6, may be filled with a hazardous material and offered for transportation unless that cylinder has been successfully requalified pursuant to the standards in 49 C.F.R. Part 180, Subpart C, and marked accordingly. To requalify, DOT 3AA cylinders must meet the general requirements for specification cylinders in 49 C.F.R. §178.35 as well as those specific to 3AA cylinders established in §178.37. A cylinder may be requalified at any time during or before the month and year that the

requalification is due. However, a cylinder filled before the requalification becomes due may remain in service until it is emptied. A cylinder with a specified service life may not be refilled and offered for transportation after its authorized service life has expired. Generally, a DOT 3AA cylinder with a water capacity of 56.7 kg (125 lb) or less that is removed from any cluster, bank, group, rack or vehicle each time it is filled must be requalified every five years. Under certain circumstances, the requalification period can be extended to 10 years. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

INCREASE IN HAZARDOUS MATERIALS REGISTRATION FEES PROPOSED

On May 5, 2008, the Pipeline and Hazardous Materials Safety Administration proposed an increase to the hazardous materials registration fees for offerors and transporters of certain quantities of hazardous materials (identified in 49 C.F.R. §107.601) from $975 (plus a $25 administrative fee) to $2475 (plus a $25 administrative fee). The proposed increase would fully fund the Hazardous Materials Emergency Preparedness grants program to the level authorized in Department of Transportation's approved Fiscal Year 2008 budget, but would not be effective until the registration year 2009-2010. The increase would apply to all registrants except for small businesses and not-for-profit organizations. The proposed increase would also require those registrants that have pre-registered for 2009-2010 and later years to supplement their previously paid fees with the increased amount. For a copy of the proposal (73 *Fed. Reg.* 24,519), click here. For further information, contact Rich Robinson at (703) 907-5856 or at richard.robinson@nreca.coop.

Produced by the NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
Environmental Affairs Unit, Editor Richard Robinson

The Environmental Bulletin is provided free of charge to all NRECA members upon request.
Prior editions and referenced documents are posted to the Cooperative.com web site at:
https://www.cooperative.com/environmental/resources/EnvironmentalBulletin/EnvironmentalBulletin.htm

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Carol Whitman, Principal, Legislative Affairs, 703-907-5790 or carol.whitman@nreca.coop
Richard Robinson, Environmental Policy Representative, 703-907-5856 or richard.robinson@nreca.coop
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National Rural Electric Cooperative Association
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NRECA

ENVIRONMENTAL BULLETIN

June 5, 2008

What's Inside This Issue

In Appreciation of Richard Robinson

This edition of the Environmental Bulletin will be Richard Robinson's final edition, as he is leaving NRECA to return to the public sector. We will miss Richard around NRECA; he has contributed significantly to the work of the association on behalf of our membership.

The Environmental Bulletin will be taking a summer break in Richard's absence. However, the Environmental Policy Department at NRECA will continue to send information out over the listserves from time to time as necessary to keep cooperatives informed of important environmental issues.

Thank you, Richard, for all your contributions. ~ Kirk Johnson, VP Environmental Policy

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- **NRECA WEB CONFERENCE ON NEW ENVIRONMENTAL COMPLIANCE GUIDE FOR DISTRIBUTION COOPERATIVES**: Guide a tool to help distribution cooperative staff understand and manage water and waste environmental issues

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- **HOUSE PASSES BILL TO EXTEND EXPIRING TAX BREAKS, PROVIDE INCENTIVES FOR RENEWABLES**: President threatens to veto yet another attempt to pass these extensions

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- **NRECA COMMENTS ON STANDARDS FOR TESTING COMMERCIAL DRIVER SKILLS**: NRECA recommends that utilities be allowed to train their own drivers without requiring utilities to become accredited training institutions

Clean Air Act

APPEALS COURT DENIES PETITION TO REHEAR CAMR DECISION

On May 20, 2008, the full U.S. Court of Appeals for the DC Circuit denied requests to reconsider a decision by the three-judge panel that vacated the Clean Air Mercury Rule (CAMR) in February of this year. The panel ruled that EPA violated provisions of the CAA when it removed control of electric generating units from under Section 112 of the Act and promulgated CAMR under Section 111. The full court's refusal to rehear the case means that EPA will now begin working on developing a Section 112 rulemaking that requires the use of maximum achievable control technology (MACT) on every source. Meanwhile, newly constructed and reconstructed major sources are subject to case-by-case MACT review under Section 112(g). Because all federal mercury reduction regulations have now been eliminated, plants no longer need to comply with CAMR's emission limits or its mercury monitoring requirements. Sources in states that declined to adopt the CAMR cap-and-trade program, however, will need to examine whether they may continue to be subject to their state mercury emission limitations. For more information, contact Bill Wemhoff at (703) 907-5824 or at bill.wemhoff@nreca.coop.

CINERGY WINS NSR CASE

On May 22, 2008, a federal jury in Indiana unanimously cleared Cinergy Corp. of 10 of 14 alleged violations of NSR provisions, but found four violations at an Indiana coal-fired power plant (*United States v. Cinergy Corp.*, S.D. Ind., No. 99-1693, 5/22/08). In 1999, the federal government charged Cinergy with violating NSR after the company made major modifications at several power plants. The remedy portion of the case will begin on December 8, 2008, and the government will be seeking civil penalties from Cinergy on the four violations. As previously reported, in November 2007, Judge Larry McKinney refused Cinergy's request to reconsider judgments against the company, rejecting Cinergy's contention that EPA had not given it "fair notice" of its interpretation of the projects that trigger NSR requirements. McKinney also upheld EPA's narrow definition of routine maintenance projects exempted from NSR, rejecting Cinergy's claim that a project that is routine in the industry is routine even if it occurs at an individual plant only once. McKinney agreed with EPA that a project has to be routine at an individual plant to qualify as routine maintenance at that plant. For more information, contact Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

CHALLENGES FILED TO OZONE RULE

On May 27, 2008, 14 states sued EPA seeking stricter air quality standards for ozone (*New York v. EPA*, D.C. Cir., No. 08-1202, 5/27/08). Meanwhile, Mississippi and a coalition of industry trade groups also filed separate petitions for review May 23 and May 27, 2008, respectively, arguing the new standards are too strict (*Mississippi v. EPA*, D.C. Cir., No. 08-1200, 5/23/08; *Ozone NAAQS Litigation Group v. EPA*, D.C. Cir., No. 08-1204, 5/27/08). A coalition of environmental groups filed a lawsuit against EPA on May 27, 2008, also seeking to strengthen the ozone standard. The groups allege EPA Administrator Stephen Johnson was unduly pressured by the White House to consider factors such as the economic impact of the ozone rule that are expressly forbidden under the Clean Air Act

(*American Lung Ass'n v. EPA*, D.C. Cir., No. 08-1203, 5/27/08). For more information, contact Bill Wemhoff at (703) 907-5824 or at bill.wemhoff@nreca.coop.

COURT DISMISSES CHALLENGE TO PROPOSED WASTE-COAL POWER PLANT

On May 13, 2008, a federal court in Pittsburgh threw out a Clean Air Act citizen suit challenging the proposed construction of a power plant fueled by waste coal in southwestern Pennsylvania, concluding that it has no jurisdiction to hear the case (*Sierra Club v. Wellington Development-WVDT LLC*, W.D. Pa., No. 08-cv-293, 5/13/08). If the court's reason for dismissing the case is adopted by federal courts elsewhere, it could be significant for coal-fired power plant construction projects throughout the country targeted for litigation by environmental groups. The citizen suit claimed that federal and state rules invalidated a permit to build a new major stationary source of air pollutant emissions if construction does not begin with 18 months after the permit is approved, if construction is delayed for 18 months or more, or if construction does not begin within a reasonable time. In its opinion, the court said the Pennsylvania Department of Environmental Protection inspected the building site in December 2006 to evaluate and document construction activities, and concluded in writing that the company had met the requirement to begin construction within 18 months after receiving its plan approval. The court said a ruling in favor of the plaintiffs "would require us to question the agency's own conclusion, made after a site inspection, that work on the power plant had timely commenced." The court said it has no subject matter jurisdiction over a challenge to a state permitting decision. For more information, contact Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

MINNESOTA BOARD ASKED TO DENY CERTIFICATE OF NEED FOR COAL-FIRED PLANT IN SOUTH DAKOTA

On May 9, 2008, two state administrative law judges (ALJs) recommended that the Minnesota Public Utilities Commission deny a certificate of need for the Big Stone II coal-fired power plant proposed for eastern South Dakota (*In re: Otter Tail Power Co. and Others for Certification of Transmission Facilities in Western Minnesota*, Minn. OAH, No. 12-2500-17037-2, 5/9/08). The ALJs wrote that the consortium of power companies behind the proposed plant failed to show that the area's demand for electricity could not be met more cost effectively than energy conservation and load management measures, and that they failed to show that Big Stone II would be less expensive than renewable energy sources when considering its environmental costs. The ALJs also found that the companies failed to consider the full environmental costs of using coal as the energy source. While the South Dakota Public Utilities Commission has approved the project, the Minnesota Public Utilities Commission must also approve it because of the transmission lines that would have to be built in Minnesota. For more information, contact Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

UARG FILES COMMENTS ON NO2 DRAFT ASSESSMENT

On May 30, 2008, UARG submitted formal comments on EPA's draft health risk and exposure assessment for NO2. The assessment, when finalized, will support the review of the NO2 Primary National Ambient Air Quality Standard. In its comments, UARG said

that while it agrees with EPA's decision to base its health risk assessment on human clinical studies, the agency's choices in conducting the assessment have yielded an inflated, biased and alarmist portrait of risks from exposure to NO2 in ambient air. UARG said EPA must revise the assessment to be more even-handed and to reflect more accurately NO2 exposure and the slight health risk that such exposures poses. For a copy of UARG's comments on Cooperative.com, click here. For more information, contact Bill Wemhoff at (703) 907-5824 or at bill.wemhoff@nreca.coop.

Climate Change

ORAL ARGUMENTS MADE BEFORE EPA ENVIRONMENTAL APPEALS BOARD ON DESERET CASE

On May 29, 2008, EPA's three-member panel Environmental Appeals Board (EAB) heard oral arguments on whether the term "subject to regulation" in the Clean Air Act (CAA) NSR provision requires regulation of CO_2 emissions for coal-fired units under Best Available Control Technology (BACT) mandates. Deseret's planned 110 MW Fluidized Bed Unit designed to burn waste coal was the subject of the hearing. Located at the existing Bonanza plant site, the unit received a federal NSR permit because of its location on Indian Lands. The panel focused on whether 1990 CAA amendments require EPA to mandate CO_2 monitoring for coal-fired units, and if so, whether such monitoring fits the definition of CO_2 "subject to regulation" under the CAA's NSR language. NRECA filed an amicus brief supporting EPA and Deseret in the case. The panel decision is expected by end of summer. The loser can appeal the decision to a federal court of appeals. For more information, contact Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

BOXER-LIEBERMAN-WARNER RELEASE REVISED BILL FOR SENATE DEBATE

Sen. Barbara Boxer (D-CA), Chairman of the Environment and Public Works Committee, along with Sens. Joseph Lieberman (I-CT) and John Warner (R-VA), has released a "manager's amendment" to the Lieberman-Warner climate change bill (S. 2191). The 492-page revision includes funds for carbon capture and storage research and funds intended to help ease consumer and business transitions to a low-carbon economy. The bill is worse for electric co-ops than S. 2191, the previous version of the bill. The carbon allocations for cooperatives are substantially less than other utility sectors would receive. Co-op allocations are capped at eight percent of the utility allocation while co-op's produce eight percent of utility emissions. Overall, the bill now reduces carbon allocations for co-op consumers and makes co-ops even more vulnerable to the auction of allocations. The bill also fails to address other important issues such as the need for an effective safety valve and emission reduction timelines that match the availability of carbon control technologies. Affecting all utility sectors, the bill eliminates allocations to future fossil fuel power plants. NRECA opposes the current Boxer-Lieberman-Warner climate bill. For a copy of the manager's amendment, click here. For a copy of NRECA's position statement on Cooperative.com, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

SENATE REJECTS LIEBERMAN-WARNER CLIMATE BILL

The Senate has ended debate on the Boxer-Lieberman-Warner climate bill on June 6, 2008, for this year, effectively rejecting the bill. After a 74 to 14 vote to start debate, Republican Senators used up a day on a motion to proceed to the bill, then forced a full reading of the 492-page substitute amendment that lasted nearly nine hours. Opponents repeatedly pointed out that the bill would raise the price of gasoline an additional $1 per gallon while moderate and conservative Democrats worried in private about debating a climate bill when voters back home are upset about current high gas prices. In the absence of any substantive debate on the bill's timelines, international competitiveness, or economic impacts to families and workers, Majority Leader Harry Reid (D-NV) filed a motion to end the debate. The 48 to 36 vote fell short of the 60 votes needed to proceed to a vote on the bill. As described in the above article, electric cooperatives opposed the bill. While this debate is finished, its contentiousness foreshadows the difficulties that lie ahead in crafting climate legislation. For a copy of the roll call vote, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop

HOUSE CLIMATE PAPER FOCUSES ON COST CONTAINMENT, PREVIEWS LEGISLATION

On May 27, 2008, the House Energy and Commerce Committee released its fourth climate change white paper. The new paper, "Getting the Most Greenhouse Gas Reductions for our Money," discusses how to contain costs while simultaneously achieving environmental goals. The paper offers a preview of some elements of legislation likely to be introduced later in this Congress by Committee Chairman John Dingell (D-MI) and Subcommittee Chairman Rick Boucher (D-VA). Their bill would allow emitters to use offsets and to bank emissions allowances for the future. While the paper supports unlimited banking, it says the amount of offsets that could be used will be the subject of a future paper. This fourth paper also recommends that lawmakers consider a number of cost-saving features including a safety valve. NRECA will file comments to respond to numerous important questions raised in the white paper. Chairman Dingell said in a statement that he would hold hearings on the white paper in June. For a copy of the white paper, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

MARKEY CLIMATE CHANGE BILL

On June 4, 2008, Rep. Ed Markey (D-MA), Chair of the House Select Committee on Energy Independence and Global Warming and a senior member of the Energy and Commerce Committee, released his own climate bill, the "Investing in Climate Action and Protection Act," with reduction percentages even more stringent than the Lieberman-Warner proposal. The Markey bill would amend the Clean Air Act to establish an economy-wide cap and-trade system, and would auction virtually all of the allowances in lieu of free distribution. The bill's cap-and-trade program would set a cap on greenhouse gas GHG emissions at 2005 levels by 2012, 20 percent below 2005 levels by 2020, and to 85 percent below 2005 levels by 2050. In addition to the broad-based cap, the bill would require new coal-fired power plants that begin construction after January 1, 2009 to capture and sequester 85% of their total CO_2 emissions. Beginning on January 1, 2012, and at five-year intervals thereafter, EPA would be required to increase the minimum rate of capture

and geological sequestration of CO_2 emissions if a greater rate of capture and geological sequestration is achievable through the application of the best available control technology. For a copy of the bill, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

ENVIRONMENTAL GROUPS TO CHALLENGE DECISION ON POLAR BEAR LISTING

On May 20, 2008, environmental groups announced that they will be suing the Bush administration on its recent decision to list the polar bear as a threatened species under the Endangered Species Act (*Center for Biological Diversity v. Kempthorne,* N.D. Cal., No. 08-1339, 5/16/2008). The groups filed claims on May 16, 2008, targeting the interim rule the Department of the Interior (DOI) published a day earlier, claiming that the rule is illegal and denies polar bears the full protections provided under the act. The groups said Interior Secretary Dirk Kempthorne failed to provide public notice of the rule, and did not conduct the environmental review required under the National Environmental Policy Act. The groups also sent Kempthorne a 60-day notice announcing a planned lawsuit alleging violations of the Endangered Species Act (ESA) itself. Specifically, the groups claim DOI, in deciding polar bears are "threatened" rather than "endangered," ignored best available science and failed to designate critical habitat in the final listing rule. For more information, contact Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

KANSAS GOVERNOR VETOES ANOTHER ATTEMPT TO BUILD SUNFLOWER PLANT

On May 16, 2008, Kansas Gov. Kathleen Sebelius (D) vetoed an economic development and tax incentives bill because of provisions that would have allowed Sunflower Electric to build two new coal-fired generators at a power plant in western Kansas, even though a state agency had denied an air quality permit for the project. The Kansas House Speaker signaled that no effort would be made to revive the bill. In her veto statement, Sebelius criticized legislative leaders for tying together the tax incentives in the bill with the provisions related to the coal plant, which she had previously made clear were not acceptable to her. For more information, contact Rae Cronmiller at (703) 907-5791 or at rae.cronmiller@nreca.coop.

CLIMATE NOTES

The May 29, 2008 edition of *Climate Notes* is available on Cooperative.com by clicking here.

Clean Water Act

DRAFT GENERAL PERMIT FOR STORM WATER DISCHARGES FROM CONSTRUCTION PROJECTS

On May 16, 2008, EPA proposed a new general permit that will apply to storm water runoff from a construction site (73 *Fed. Reg.* 28454). The action was necessary because the 2003 general permit is about to expire. The new permit does not appear to make any significant changes in the general permit requirements. It includes language on how EPA may coordinate with local erosion and sediment control programs. The permit continues to

apply to construction sites that disturb one or more acres of land. While the EPA general permit only applies to states where EPA is the NPDES permit-issuing authority, it is important to co-ops because states with their own NPDES programs tend to incorporate the federal requirements into their regulations. For a copy of the proposal, click here. For additional information please contact Jim Stine at james.stine@nreca.coop or 703-907-5739.

Waste Issues

NRECA WEB CONFERENCE ON NEW ENVIRONMENTAL COMPLIANCE GUIDE FOR DISTRIBUTION COOPERATIVES

NRECA has scheduled a brief web conference to introduce and review CRN's recently developed "Environmental Management Guide for Distribution Cooperatives." The Guide is a practical tool to help electric distribution cooperative staff understand and manage the many water and waste environmental issues they face. It provides a "first stop" resource to help identify key environmental issues and develop appropriate programs and measures to meet those obligations. The *Environmental Management for Distribution Co-ops Web Conference* has been scheduled for July 9, 2008, from 2-3 PM Eastern Time. Conference participants will:

- Learn the basics of how to use the Environmental Management Guide.
- Get an overview of what is contained in the guide.
- Gain a general understanding of the environmental management roles and responsibilities of most co-op staff.

For complete information on the conference, click here, or contact Brian Sloboda at brian.sloboda@nreca.coop, 703-907-5689.

Energy

HOUSE PASSES BILL TO EXTEND EXPIRING TAX BREAKS, PROVIDE INCENTIVES FOR RENEWABLES

Defying another White House veto threat, the House of Representatives on May 21, 2008, passed a tax package (H.R. 6049) that would extend dozens of expired and expiring tax provisions and that includes nearly $17 billion in incentives and credits for renewable energy. In general, the bill would extend for one year a series of temporary tax provisions that expired at the end of 2007, such as the research and development tax credit, or that are set to expire at the end of 2008. The legislation also includes a series of longer-term extensions of energy policy incentives, such as an extension and modification of the Section 45 renewable energy production tax credit, and an extension through 2014 of the tax credit for solar energy and fuel cell investment. Most importantly to cooperatives, the bill would establish $2 billion of new Clean Renewable Energy Bonds to finance "clean" energy production facilities, and it would establish a new tax credit for the purchase of plug-in hybrid or electric vehicle sales. The bill also includes nearly $1.5 billion in tax credits for carbon capture and sequestration demonstration projects.

The measure would increase some other taxes to offset the extended tax breaks, a move that drew a veto threat from the administration. In a Statement of Administration Policy, the White House expressed "strong" opposition to the offsets, saying it does not believe that efforts to avoid tax increases on Americans need to be coupled with provisions to increase revenue. The measure now heads to the Senate, where its fate is uncertain. NRECA has joined a coalition supporting passage of the House bill. For a copy of the legislation, click here. For more information, contact Susan Pettit at (703) 907-5822 or at susan.pettit@nreca.coop.

Transportation

NRECA COMMENTS ON STANDARDS FOR TESTING COMMERCIAL DRIVER SKILLS

On May 22, 2008, NRECA filed comments responding to the Federal Motor Carrier Safety Administration's proposed new requirement for obtaining a Commercial Driver's License (CDL). Current rules require training for prospective CDL holders on driver qualifications, hours of service rules and whistle blower protection. The proposed rules would require CDL applicants to produce a certificate stating they have received a specified amount of behind-the-wheel training -- through an accredited training institution -- on a Commercial Motor Vehicle. NRECA's comments emphasized that paper certificates do not guarantee an increase in actual skills and recommended the agency specify the target level of relevant skills and test for it. For instance, utility drivers should be tested on the skills they need to operate bucket trucks in often-challenging conditions. Such skills are different than those needed to pilot an eighteen-wheeler. NRECA also recommended that utilities be allowed to train their own drivers without requiring utilities to become accredited training institutions. For a copy of NRECA's comments on Cooperative.com, click here. To learn more, contact Jonathan Glazier at (703) 907-5798 or jonathan.glazier@nreca.coop.

Produced by the NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
Environmental Affairs Unit, Editor Richard Robinson

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For information on corporate level policy regarding listed issues, contact:
Kirk Johnson, Vice President, Environmental Affairs, 703-907-5775 or kirk.johnson@nreca.coop.

National Rural Electric Cooperative Association
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NRECA

ENVIRONMENTAL BULLETIN

June 27, 2008

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(For more information regarding the following articles, contact Rae Cronmiller at (703) 907-5791 or rae.cronmiller@nreca.coop, or Bill Wemhoff at (703) 907-5824 or bill.wemhoff@nreca.coop. Referenced documents are posted on Cooperative.com and can be viewed by clicking here.

SEMINOLE WINS COURT DECISION OVERTURNING STATE DENIAL OF PLANNED UNIT CERTIFICATION

On June 13, a Florida district court overturned the Secretary of Florida's Department of Environmental Protection's denial of state certification for Seminole's planned 750 MW coal-fired electric generating unit to be located at its existing Seminole plant site. In a short opinion, the judge found that the state failed to provide any legal ground to deny the certification based on Florida law and the established record developed to support the certification.

EPA's EAB REQUESTS MORE BRIEFING IN DESERET CASE

On June 16, the Environmental Appeals Board (EAB) requested EPA Region 8, the defendant in a case involving a permit for a new unit being constructed by Deseret Power Cooperative, to supply more information explaining the connection between the Public Law 101-549 Section 821 requiring CO2 monitoring and the enforcement of that requirement in separate Clean Air Act (CAA) provisions. Section 821 is not within the CAA. At stake is whether CO2 is "subject to regulation" under the CAA's new source review provisions and thus must be regulated. Deseret's planned 220 MW waste coal facility is a test case because Region 8 recently issued a new permit for the unit.

UARG FILES COMMENTS GENERALLY SUPPORTING EPA'S PROPOSED NSPS REGULATIONS FOR NONMETALLIC MINERAL PROCESSING

On June 23, the Utility air regulatory Group (UARG) filed comments on EPA's proposed NSPS rule for nonmetallic mineral processing that affects any generating unit that crushes or grinds limestone at the plant site for use in a wet scrubber. The proposal requires opacity and/or particulate limits depending on the physical configuration at the site and best demonstrated technology.

EPA PROPOSES TO AMEND NSPS FOR EGUs

On June 12, EPA issued a proposed rule that would revise the new source performance standards (NSPS) for electric utility steam generating units (EGUs), (73 FR 33642). Included in the proposal are technical and editorial corrections and opacity monitoring requirements for owners and operators of affected facilities that are subject to opacity limits, but are not required to use a continuous opacity monitor system. Deadline for comments is July 28.

Climate Change

Referenced documents are posted on Cooperative.com and can be viewed by clicking here.

CLIMATE NOTES

The June 23, 2008 edition of *Climate Notes* is available on Cooperative.com.

EPA TO ISSUE ANPR ON REGULATING GHGs UNDER THE CAA

EPA is expected, any day, to release an Advance Notice of Proposed Rulemaking (ANPR) that discusses potential responses by the agency to the Supreme Court's decision in *Massachusetts v. EPA*. It will explore alternative strategies for regulating major source greenhouse gas emissions under the Clean Air Act. EPA will seek comment on a wide variety of regulatory options, ranging from establishing a new national ambient air quality standard (NAAQS) for GHGs to the creation of emissions trading programs. The agency is not suggesting any particular path for regulation but raises a number of critical questions, including the amount of discretion it has and how it should regulate the six different GHGs. A notice will be sent out over the Environmental Listserv when the ANPR becomes available. For more information, contact Rae Cronmiller at (703) 907-5791 or rae.cronmiller@nreca.coop, or Bill Wemhoff at (703) 907-5824 or bill.wemhoff@nreca.coop.

COURT RULES EPA HAS NOT UNREASONABLY DELAYED IN ITS RESPONSE TO *MASSACHUSETTS v. EPA* SUPREME COURT RULING

On June 26, the U.S. Court of Appeals for the D.C. Circuit issued an order denying petitioners claims that EPA has unreasonably delayed responding to the Supreme Court's ruling in *Massachusetts v. EPA*. In April, petitioners had asked the court to order EPA to make a determination on endangerment within 60 days regarding new motor vehicles' emission of CO2 and other greenhouse gases. A finding of endangerment regarding new motor vehicles emissions likely would have led to regulation of stationary sources as well. For more information, contact Rae Cronmiller at (703) 907-5791or rae.cronmiller@nreca.coop, or Bill Wemhoff at (703) 907-5824 or bill.wemhoff@nreca.coop.

USWAG COMMENTS ON REGULATIONS FOR GEOLOGIC SEQUESTRATION OF CO2

On June 16, USWAG provided general comments to EPA as the agency begins developing regulations for underground storage of CO2. The comments urge EPA to consider four broad issues in the rulemaking: 1) ensure flexibility to accommodate site-specific technological, geological and other factors, 2) rather than developing technical specifications to cover a wide range of sites, the agency should rely more on a performance-based regulatory approach and let local authorities focus on site-specific requirements, 3) consider both short-term and long-term financial assurance issues, and 4) consider how underground injection control (UIC) regulations will coordinate with other green house gas regulatory programs. For more information on these developments, please contact Jim Stine at james.stine@nreca.coop or 703-907-5739.

EIA PROJECTS WORLD ENERGY AND CO2 EMISSIONS WILL GROW BY 50 PERCENT BETWEEN 2005–2030

Worldwide energy consumption and CO2 emissions will grow by more than 50 percent between 2005 and 2030 according to the most likely long-term scenario outlined in a report

released June 25 by the U.S. Energy Information Administration. The forecast is in line with estimates in the U.N. Intergovernmental Panel on Climate Change Fourth Assessment Report, released in November 2007. Most of the projected emissions growth will occur in developing nations and coal use is expected to expand by 2 percent per year reaching 29 percent of total world energy consumption by 2030. More information on the *International Energy Outlook 2008* report is available at: http://www.eia.doe.gov/oiaf/ieo/index.html.

Clean Water Act and Waste Issues

(For additional more information regarding the following articles, contact Jim Stine at james.stine@nreca.coop or (703) 907-5739. Referenced documents are posted on Cooperative.com and can be viewed by clicking here (for water documents) and here (for waste documents).

EPA PUBLISHES DRAFT CONSTRUCTION GENERAL PERMIT

EPA recently published a proposed General Permit for Storm Water Runoff from Construction Activities, 73 Fed. Reg. 28,454 (May 16, 2008). The proposed permit will replace the existing general permit that is about to expire. The general permit covers runoff from construction activities in states where EPA is the permit issuing authority. The permit is important to co-ops because many states simply adopt the conditions in the federal permit. The conditions in the draft permit are very similar to the existing permit. EPA is considering more substantive changes for the future and they decided to issue the new permit for two years, essentially unchanged, to fill the gap until new requirements can be developed. NRECA submitted comments supporting the general permit.

EPA PUBLISHES DRAFT RISK ASSESSMENT FOR WOOD TREATMENT CHEMICALS

EPA recently announced the availability of a number of documents and risk assessment studies addressing the three heavy duty wood preservatives, CCA, penta and creosote, 73 Fed. Reg. 20627 (April 16, 2008). The documents can be obtained from the rulemaking docket at Docket ID No. EPA-HQ-OPP-2004-0402, on line at: www.regulations.gov. These risk assessment studies are another step toward renewing the FIFRA registrations for these chemicals. EPA plans to publish "risk management" recommendations by the end of 2008. For the first time during the multi-year review process, EPA raised concerns about lineman exposure and secondary re-use of treated wood poles. NRECA helped USWAG develop comments on the studies. Electric Utilities continue to emphasize the significant benefits of using these chemicals to treat wood poles used in distribution systems and that these benefits clearly outweigh any risks that may be involved.

Produced by the NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
Environmental Affairs Unit

The Environmental Bulletin is provided free of charge to all NRECA members upon request.
Prior editions and referenced documents are posted to the Cooperative.com web site at:
https://www.cooperative.com/environmental/resources/EnvironmentalBulletin/EnvironmentalBulletin.htm

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National Rural Electric Cooperative Association
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NRECA

ENVIRONMENTAL BULLETIN

July 17, 2008

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FEDERAL COURT VACATES CAIR RULE

On July 11th, the D.C. Federal Court of Appeals vacated the Clean Air Interstate Rule (CAIR) finding serious flaws in the complex regulation as related to the requirements in the Air Act to eliminate interstate air pollution that substantially contributes to downwind state ambient air quality standards nonattainment. Under the ruling, the court found flaws in regional reductions of SO2 emissions because the scheme did not address individual upwind state substantial contributions to downwind state nonattainment and found the CAIR trading program illegal because it required reductions in the acid rain SO2 allowances greater than one allowance per one ton of emissions. The court also found that the NOx trading program impermissibly allocated more NOx allowances to coal generation than gas. The opinion is available by clicking here.

COMMENTS FILED ON PROPOSED NSPS FOR COAL PREPARATION PLANTS

On July 14, 2008, UARG filed comments on EPA's Proposed New Source Performance Standards for Coal Preparation Plants (Subpart Y) as published at 73 FR 22901. The comments support the agency's proposed subcategorization, address EPA's conclusions regarding Best Demonstrated Technology and argue that the proposed particulate matter and opacity limits are too stringent. The comments are available by clicking here.

NOTICE OF AVAILABILITY OF DRAFT FLAG REPORT

On July 8, the National Park Service announced the availability of a draft revision of the 2000 Federal Land Managers' Air Quality Related Values Workgroup (FLAG) report (73 FR 39039). The report addresses various issues concerning air pollution effects on air quality related values in Class I areas under the control of the Federal Land Manager (FLM) agencies (the U.S. Forest Service, the National Park Service, and the U.S. Fish & Wildlife Service). Comments on the draft are due by September 8, 2008.

EPA RELEASES FINAL INTEGRATED SCIENCE ASSESSMENT ON NOx

On July 11th, EPA released its Integrated Science Assessment on Health Effects of Nitrogen Oxides ("NOx ISA"). The assessment will provide the scientific basis for EPA's review of the current primary NAAQS for NO2. It concludes that a likely causal relationship exists between short-term NO2 exposure and effects on the respiratory system, including changes in pulmonary function, increased respiratory symptoms and emergency department visits and hospital admissions. Although the ISA does not make any recommendations concerning possible revisions of the NAAQS, it implies that consideration of a short-term NO2 standard may be appropriate. The document is available by clicking here.

ENVIRONMENTAL GROUPS SUE EPA ON NSR RULE

On July 15th, environmental groups filed a lawsuit against EPA alleging an NSR rule issued May 8th exempts power plants and factories from meeting clean air standards for fine particulate matter. The groups also petitioned EPA Administrator Johnson asking him to reconsider the rule. The final rule, clarifying requirements for enforcement of the NSR program, sets significant emissions rates and allows emitters to trade emissions between states and regions but not within a given nonattainment area. A copy of the complaint is available by clicking here.

Climate Change

EPA ISSUES ANPR FOR REGULATING GHGs UNDER THE CAA

On July 11th, EPA issued an Advance Notice of Proposed Rulemaking (ANPR) that requests comment on the possibility of regulating greenhouse gas emissions (including carbon dioxide) under the Clean Air Act. The ANPR is EPA's response to the Supreme Court's decision in Massachusetts v. EPA. Although that case involved the possible regulation of greenhouse gas emissions from motor vehicles under section 202 of the Clean Air Act, the ANPR discusses the possible ramifications of a decision to regulate under section 202 and explores broadly regulation of greenhouse gas emissions under numerous other provisions of the Act. The ANPR and related Fact Sheet are available by clicking here. A White House policy memorandum and a press statement accompanying the ANPR are available by clicking here. For more information, contact Rae Cronmiller at (703) 907-5791 or rae.cronmiller@nreca.coop, or Bill Wemhoff at (703) 907-5824 or bill.wemhoff@nreca.coop.

STATE COURT DEVELOPMENTS REGARDING CO2 CONTROLS

Environmental Groups Challenge Southern Montana's air permit

The Montana Environmental Information Center has filed a petition in Montana state court against the state challenging Southern Montana's Highwood Station air permit for failing to consider "best available control technology" (BACT) for carbon dioxide emissions associated with the planned 220 MW coal-fired fluidized bed unit. The complaint follows those filed in other jurisdictions that allege the U.S. Supreme Court's decision in Massachusetts requires CO2 BACT as part of the process for obtaining a new source construction permit. The petition is available by clicking here.

Georgia Court Overturns state air permit on failure to regulate CO2.

Meanwhile a Fulton County Georgia court struck down a Georgia state air permit for a planned 1200 MW coal-fired generating unit for failing to regulate CO2 and conduct a BACT analysis as part of the new source permitting process. The opinion is available by clicking here.

Sierra Club alleges South Dakota's Co-owned Big Stone coal-fired generating unit violated NSR for CO2 emissions

In a lawsuit filed on June 10th petitioners allege Big Stone violated Clean Air Act New Source Review provisions by making several modifications including coal-switching in 1975 and making physical modifications to supply steam to an ethanol plant in the 2001. Compliant alleges hourly increases in emissions rates and a failure to obtain an NSR permit for among other emissions, CO2. For a copy of the compliant, click here.

For more information regarding, contact Rae Cronmiller at (703) 907-5791 or rae.cronmiller@nreca.coop,

COMMENTS FILED ON POLAR BEAR LISTING 4(d) RULE

On July 14, UARG filed comments supporting the 4(d) Rule issued by the U.S. Fish and Wildlife Service simultaneous with the listing of the polar bear as a threatened species under the Endangered Species Act. The 4(d) Rule limits the scope of the polar bear listing by stating that lawful activities of a single source outside of Alaska cannot constitute a "take" under section 9 of the Endangered Species Act. Effectively, this eliminates many of the problems that could arise for electric generating units in permitting and other contexts from the polar bear listing. The comments are available by clicking here. For more information, contact Rae Cronmiller at (703) 907-5791 or rae.cronmiller@nreca.coop, or Bill Wemhoff at (703) 907-5824 or bill.wemhoff@nreca.coop.

EPA RELEASES GLOBAL CHANGE RESEARCH PROGRAM INTERIM REPORT

On July 10, EPA released for public comment a draft interim report of the U.S. Global Change Research Program, "Assessment of the Impacts of Global Change on Regional U.S. Air Quality: A Preliminary Synthesis of Climate Change Impacts on Ground-Level Ozone" ("Assessment") (73 FR 39695). The overall purpose of the Assessment is to provide sufficient information on the range of possible air quality responses to future climate change to enable air quality managers to consider global change in their planning and management decisions. Among the conclusions included in the draft report is that climate change could produce significant increases in near-surface ozone concentrations in many areas of the U.S. in the range of 2 to 8 ppb, perhaps as early as 2020. Comments on the Assessment are due by August 25, 2008. For more information, contact Bill Wemhoff at (703) 907-5824 or bill.wemhoff@nreca.coop.

CLIMATE NEWS NOTES

The July 14, 2008 edition of *Climate News Notes* is available on Cooperative.com by clicking here.

EPA PROPOSES RULE ON CO2 GEOLOGIC SEQUESTRATION

On July 15th, EPA released an unofficial proposed rule on regulating CO2 geologic sequestration under the Safe Drinking Water Act Underground Injection Program (UIC). It proposes a new class of injection wells – Class VI – under the existing UIC framework. The proposal describes the minimum level of safeguards that states would have to adopt, would impose financial responsibility on the owner or operator of the well for corrective action, injection well plugging, emergency and remedial response, and post-injection care and site closure. The official version will appear in the federal register likely in several weeks with a 120 day comment period. For a copy of the unofficial version, click here. For more information, contact Rae Cronmiller at (703) 907-5791 or rae.cronmiller@nreca.coop, or Jim Stine at (703) 907-5739 or james.stine@nreca.coop.

HOUSE PANEL REVIEWS BILL TO ACCELERATE CCS TECHNOLOGY

The House Energy and Air Quality Subcommittee recently heard testimony on the Carbon Capture and Storage Early Deployment Act, a bill to aggressively fund large-scale carbon capture-storage (CCS) projects. Subcommittee Chairman Rick Boucher (D-VA) says HR 6258 is necessary because it would take too long for revenues from auctions under a CO2 cap-and-trade program to become available for CCS research. The bill sets up a Carbon Storage Research Corporation for creating a $10 billion fund over 10 years through annual fee assessments to utilities. Distribution utilities representing two-thirds of the total quantity of fossil fuel-based electricity must agree to establish the corporation. Because of the way the bill is drafted, however, NRECA and American Public Power Association members currently are excluded from participating in the decision to set up the corporation. The estimated impact on residential customer rates is $10 to $12 per year. State regulators oppose provisions that allow power companies to pass the fees to customers with only the Corporation providing oversight and no state regulatory review. The appropriate level of federal and state oversight is a dominant issue that will need to be resolved. NRECA is developing suggestions for improving the bill. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

EPA RELEASES REPORT ON CLIMATE CHANGE AND HEALTH

On July 17th, EPA released a report that discusses the potential impacts of climate change on human health, human welfare, and communities in the U.S. The report, entitled "Analyses of the Effects of Global Change on Human Health and Welfare and Human Systems," also identifies adaptation strategies to help respond to the challenges of a changing climate and identifies near- and long-term research goals for addressing data and knowledge gaps. The report can be downloaded from the EPA website by clicking here. For more information, contact Bill Wemhoff at (703) 907-5824 or bill.wemhoff@nreca.coop.

SENATOR BINGAMAN OUTLINES CLIMATE LEGISLATION PRINCIPLES

Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) has outlined 10 principles for climate legislation, signaling his committee's intention to participate in next year's climate change debate. Sen. Bingaman and Sen. Arlen Specter (R-PA) were the lead sponsors of the Low Carbon Economy Act, comprehensive climate legislation that ultimately took a backseat to the Lieberman-Warner cap-and-trade legislation passed by the Environment and Pubic Works Committee and rejected by the Senate in early June. In a recent speech, Sen. Bingaman laid out 10 principles that call for focusing legislation on efforts that reduce greenhouse gas emissions, realistic targets and timetables, containing costs, and resolving potential conflicts between a new national climate change program and existing state and federal environmental laws, such as the Clean Air Act. For a copy of the principles, click here. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

Clean Water Act and Waste Issues

EPA ISSUES FINAL GENERAL PERMIT FOR STORM WATER RUNOFF

On July 14th, EPA published a final General Permit for Storm Water Runoff from Construction Activities (CGP), (73 FR 40338). It contains substantially the same terms and conditions as the 2003 CGP and has been issued for a two-year period. EPA is also in the process of developing Effluent Limitations Guidelines for the construction and development industry. Upon completion, the agency will revise the CGP to incorporate the Effluent Guideline provisions, not later than July 2010. Additional information is available by clicking here. For more information, contact Jim Stine at james.stine@nreca.coop or (703) 907-5739.

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ENVIRONMENTAL BULLETIN

August 14, 2008

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UARG COMMENTS ON THREE PROPOSED RULES

The Utility Air Regulatory Group recently submitted formal comments on the following proposed rules:

Proposed Revisions to Boiler NSPS (Subparts D, Da, Db and Dc (73 FR 33642))
UARG urged the agency to (1) abandon its proposal to require annual visible emissions testing for all Subpart Da units, (2) exempt sources opting to use PM CEMS from the opacity standard without imposing any additional testing requirements, (3) abandon its proposal for electronic reporting of all PM CEMS test data, (4) allow repeat Method 22 testing in lieu of a Method 9 performance test, and abandon the proposed digital camera alternative, (5) clarify the Boiler NSPS applicability provisions for combined cycle combustion turbines subject to Subpart KKKK, (6) adopt a more flexible performance testing grace period under Subpart Da, and (7) abandon or significantly revise its proposal regarding the use of scrubber liquid-to-gas ration as a monitoring parameter for units not using PM CEMS.

Integrated Science Assessment for Sulfur Oxides – Health Criteria
The comments address the evidence concerning responses of some asthmatics to 5- to 10-minute exposures to SO2. UARG said the ISA falls short of the legal requirements of the CAA and does not accurately reflect the latest scientific information. The group recommended several revisions to the draft.

Proposed NAAQS for Lead (73 FR 29184)
The comments respond to EPA's request for information regarding the authority of the agency to establish zero-level NAAQS. UARG said it agrees with EPA's interpretation that setting any NAAQS at zero would run afoul of several well-established legal principles governing CAA implementation. A zero-level NAAQS would be inconsistent with CAA legislative history, the design of the statute, and several court decisions indicating that the law does not authorize the EPA Administrator to establish standards at zero.

EPA PROPOSES EIGHT-HOUR NAAQS PHASE 2 RULE

On July 21, EPA proposed to amend regulations under 40 CFR Parts 50 and 51 regarding implementation of the eight-hour ozone NAAQS – Phase 2 (73 FR 42294). The proposal clarifies when states may claim "reasonable further progress" on emissions reductions from pollution sources outside of nonattainment areas in state implementation plans. The proposal is in response to the US Circuit Court of Appeals November 2007 vacatur and remand and builds on a practice the agency already uses for fine particulate matter. Comments are due August 20, 2008.

NOx AND SOx / INTEGRATED SCIENCE ASSESSMENT RELEASED
On August 12, EPA noticed the availability of a draft "Integrated Science Assessment for Oxides of Nitrogen and Sulfur – Environmental Criteria; Second External Review Draft" (73 FR 46908). The document was prepared by the agency as part of the review of the secondary NAAQS for NO2 and SO2. Comments are due October 1, 2008.

NRECA CO-SPONSORS SITING CONFERENCE
NRECA and the Edison Electric Institute (EEI) are co-sponsoring this year's transmission and generation siting conference October 6-8 in Minneapolis, with Great River Energy and Xcel Energy serving as co-hosts. The conference will cover environmental and public relations aspects related to siting issues with presentations from entities and consultants currently involved in transmission line, renewable, fossil fuel and nuclear power projects. The conference fee from the attendees is solely to fund conference costs. A copy of the conference brochure is available by clicking here.

Climate Change

Unless indicated otherwise, referenced documents are posted on Cooperative.com and can be viewed by clicking here.

EPA FILES SUPPLEMENTAL RESPONSE IN DESERET CASE BEFORE EAB
On August 8, EPA filed a Supplemental Brief before the Environmental Appeals Board in the case involving Deseret G&T (PSD) construction permit for its planned coal-fired unit at the Bonanza site. The response addresses "enforceability" of Public Law 101-549 Section 821 and whether its required CO2 monitoring provisions constitute "regulation" under the CAA. If so, PSD permits must consider CO2 emissions as a regulated air pollutant. EPA argues that the CO2 monitoring requirements are not part of the Act, and if so monitoring is not regulation. For more information, contact Rae Cronmiller at (703) 907-5791 or rae.cronmiller@nreca.coop.

REPORT SAYS COMPUTER MODELS ACCURATE AND EFFECTIVE FOR UNDERSTANDING CLIMATE CHANGE
According to a federal study by the U.S. Climate Change Science Program, *Climate Models; An assessment of Strengths and Limitations,* the computer models used to analyze climate trends and the relationship between climate change and greenhouse gas emissions from human activity are effective and accurate. The study, released July 31, compared computer model forecasts with actual weather trends in the 20th century. It determined not only that the models are accurate, but also that temperature changes could not be explained if warming effects of anthropogenic greenhouse gas emissions were ignored, essentially confirming the human impact on climate change. The report is one of 21 synthesis and assessment products commissioned by the Climate Change Science Program, co-sponsored by 13 federal agencies. The report is available at: (http://www.climatescience.gov/Library/sap/sap3-1/final-report/default.htm.) For more information, contact Bill Wemhoff at (703) 907-5824 or bill.wemhoff@nreca.coop.

DOE PROJECT BEGINS CO2 SEQUESTRATION

The U.S. Department of Energy recently initiated its project for injecting CO2 in a large coal bed while simultaneously recovering valuable natural gas. The plan is to inject up to 35,000 tons in a 6-month demonstration near Navajo City, N.M in order to help develop ways to maximize permanent storage of the injected CO2. Additional information about the project can be obtained from the DOE website at: http://www.fossil.energy.gov/news/techlines/2008/08031-San_Juan_Basin_CO2_Injection.html. For more information, contact Bill Wemhoff at (703) 907-5824 or bill.wemhoff@nreca.coop.

ALASKA SUES DOI OVER POLAR BEAR LISTING

On August 4, the state of Alaska sued the U.S. Interior Department in US District Court over the Fish and Wildlife Service's decision to list Polar Bears as threatened under the Endangered Species Act. The lawsuit, also on behalf of the municipal governments within Alaska, alleges that the listing amounted to eight violations of the ESA and Administrative Procedures Act. It challenges the scientific basis of the listing decision, cites the increase in the worldwide polar bear population over the past 40 years, existing conservation measures already in place and contends that polar bears have survived prior warming periods.

Meanwhile, on August 11, Interior Secretary Kempthorne proposed revisions to the ESA that would provide for federal agencies to decide for themselves if construction projects threaten protected species without consulting with the Fish and Wildlife Service or National Oceanic and Atmospheric Administration. Consultation is currently required for every project that is reviewed, paid for, or approved by the federal government and that potentially could have an impact on an endangered or threatened species or habitat. The proposed regulations, to be published soon in the *Federal Register*, also would prevent federal agencies from tying global warming emissions directly to the deterioration of any species' habitat. Additional information regarding the proposal is available at: http://www.doi.gov/news/08_News_Releases/080811a.html. For more information, contact Rae Cronmiller at (703) 907-5791 or rae.cronmiller@nreca.coop, or Bill Wemhoff at (703) 907-5824 or bill.wemhoff@nreca.coop.

CLIMATE NEWS NOTES AVAILABLE

The July 28 and August 11 editions of *Climate News Notes* are available.

RGGI BEGINS BIDDING PROCESS

The Regional Greenhouse Gas Initiative (RGGI), a cooperative effort of Northeastern and Mid-Atlantic states to reduce greenhouse gas emissions, is planning the nation's first auction for CO2 allowances under a cap-and-trade program. Under RGGI, power plants must hold sufficient allowances "permits that allow an entity to emit 1 ton of CO2" to cover their emissions by January 1, 2009. Allowances will be sold in blocks of 1,000. A single entity cannot bid on more than 25 percent of the allowances. If the demand for the 12,565,387 allowances is less than or equal to the total number available, they will be sold at the reserve price of $1.86. Bidders must submit bonds, cash or letters of credit to be eligible to participate and open an account with RGGI's Allowance Tracking System. Six states will offer allowances in the September 25 online auction, including Connecticut,

Maine, Maryland, Massachusetts, Rhode Island and Vermont. Those allowances can be used by utilities in any of the 10 states regulated by the RGGI cap-and-trade system. A second auction will be held in December. For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

CLEAN COAL TECHNOLOGY ACT INTRODUCED

Senators Kent Conrad (D-ND) and Orrin Hatch (R-UT) in the Senate and Reps. Pomeroy (D-ND) and Lewis (R-KY) in the House have introduced The Carbon Reduction Technology Bridge Act of 2008 to spur the development of clean coal technology. S. 3208 (HR 6756), establishes tax incentives and a new bond program to promote increased power plant efficiency as well as carbon capture and sequestration technology. Clean coal bonds, modeled on the Clean Renewable Energy Bonds program, are provided for electric cooperatives and public power systems with $5 billion in bonding authority available until expended. Co-ops may utilize the bonds to finance any qualified projects described in the bill, including: efficiency improvements to existing plants; closed-loop biomass facilities that co-fire with coal; new efficient coal plants with carbon capture and storage; and carbon capture and storage equipment on existing or new facilities. Investor-owned utilities are eligible for tax incentives for these programs and a "carbon reduction tax credit" to reward sequestration of CO2. The credit is $30 per metric ton of CO2 stored in a geological formation; $20 per metric ton if transferred to the U.S. Government and $15 per metric ton if injected in an oil and gas pipeline for enhanced oil recovery. For a copy of the bill, see http://www.nreca.org/Documents/PublicPolicy/CarbonReductionTechnologyBridgeAct.pdf For more information, contact Carol Whitman at (703) 907-5790 or carol.whitman@nreca.coop.

Produced by the NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
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Volume 7, Issue 10
October 10, 2008

Environmental Bulletin

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Kirk's Column

Welcome to the new and updated *Environmental Bulletin*. First, please join me in welcoming Jennifer Taylor to NRECA's Environmental Policy unit. Jennifer joins us as the new editor of the Environmental Bulletin, and worked in NRECA's Communications Department before joining the Environmental Policy team. Prior to her work at NRECA, she worked for the North Carolina Association of Electric Cooperatives (statewide) and for Cape Hatteras Electric Cooperative in Buxton, North Carolina. She brings a great, fresh perspective to the group, and we are all excited to have her on board.

Less exciting are some of the challenges we continue to face related to climate change, clean air, clean water, and other environmental issues. We jokingly call it "job security," but the challenges facing co-ops are immense and complex.

This week Reps. Rich Boucher (D-VA) and John Dingell (D-MI) unveiled their discussion draft of climate change cap-and-trade legislation. We are vigilantly wading through the 461-page draft bill, trying to understand how it works. I'll tell you now it is not simple – but we are working to develop a straightforward summary of the bill for the membership.

Finally, let me say we know the Sierra Club continues to make every effort to prevent co-ops from building or even financing new generation. Unfortunately there is no easy way to overcome the Club's tactics – they will continue to use every option they can think of to fight new power plants. We have to be engaged in this hand-to-hand combat with the best information possible to show we are looking out for the energy, economic, and environmental interests of our member-consumers. The good news is that is exactly what co-ops across the country are doing. At NRECA, we'll keep doing our part to ensure our member-consumers' needs are met.

-Kirk

Clean Air Issues

EPA Seeks Rehearing on CAIR

On September 24, EPA requested a new hearing before a full federal appeals court to reconsider a decision vacating the Clean Air Interstate Rule (CAIR). According to EPA's brief, the decision to vacate CAIR and its emissions trading program contradicts a prior decision by the court upholding a similar trading system under the NOx SIP Call, involving state implementation plans under the CAA to control nitrogen oxides. The White House has pushed to have all of CAIR reinstated legislatively, but that has been opposed by environmental organizations that say the original reductions do not go far enough to protect public health. CAIR is still in effect until the court issues a mandate, at which time, co-ops will have to reinstate their NOx Budget Trading Program rules. UARG also petitioned the D.C. Circuit Court for a rehearing. NRECA and UARG are closely monitoring this case and its possible effects on co-ops.

UARG Asks Supreme Court to Hear CAMR Case

On September 17, UARG petitioned the U.S. Supreme Court to reinstate the Clean Air Mercury Rule (CAMR), which had been vacated by a federal appeals court in February (New Jersey v. EPA, D.C. Cir., No. 05-1097, Petition for Certiorari). The petition raises two questions with the D.C. Circuit's ruling, challenging whether that court overstepped precedent when judging EPA's interpretation of the CAA and whether the Bush administration is bound to regulate mercury emissions based on a finding from the outgoing Clinton administration. CAMR, issued in 2005, set up an emissions trading system to reduce mercury emissions. EPA has until October 17, 2008, to file an appeal to the Supreme Court. NRECA is working with UARG to monitor this case.

Benefits of Major Rules Exceeded Costs

The benefits of major environmental, safety, and other federal regulations implemented over the last decade, including a total of 40 major EPA rules, have greatly outweighed their costs over that period, the White House Office of Management and Budget (OMB) said in an annual report, *Draft 2008 Report to Congress on the Benefits and Costs of Federal Regulation*, released on September 24. Those 40 EPA rules imposed total annual costs between $32.2 billion and $35 billion more than offset by projected annual benefits between $83.3 billion and $592.6 billion. The OMB report said benefits of the EPA rules greatly outweighed the costs largely due to a single CAA regulation the agency promulgated to address fine particulate matter.

UARG Files Comments on Interagency Cooperation under Endangered Species Act

Final UARG comments were filed on the proposed rule on Interagency Cooperation under the Endangered Species Act of the Fish and Wildlife Service (FWS) and National Marine Fisheries Service (NMFS). The proposed rule clarifies that consultation under Section 7 of the Endangered Species Act is not required in connection with species listed for climate change purposes (such as the polar bear) in federal actions involving a single greenhouse gas emissions source. Comments on the proposed rule are not due until October 14, 2008 (a 30-day extension was granted). Because it is highly important that

FWS and NMFS complete this rule before the end of this administration, UARG filed its comments early to allow the agencies time to review the additional support that UARG is providing for this rule and to aid the agencies in completing the rule quickly.

UARG Files Comments on Available Portion of Draft on NO2 Health Effects

On September 26, UARG filed comments on available portions of the Second External Review Draft of the Risk and Exposure Assessment (REA) on Health Effects of NO2. EPA announced the release of the draft on September 2, and requested comments. Portions of the REA and associated appendices were released in August; however, not all sections have been made available to the public. In its comments, UARG complained that it is unreasonable to require the public to comment on an incomplete draft and said that the portions of the assessment made available contains information that is inaccurate and misleading and includes policy judgments that should be made by the Administrator.

Under the CAA, EPA sets primary National Ambient Air Quality Standards (NAAQS) for certain pollutants, including NO2, at a level that is requisite to protect the public health with an adequate margin of safety. Standards that are at the requisite level are "not lower or higher than is necessary" to provide that degree of protection. EPA must review NAAQS at least every five years, revising them "as appropriate." The REA is being prepared as a part of EPA's review of the primary NO2 NAAQS.

Climate Change

House Energy Committee Leaders Issue Cap-and-Trade Discussion Draft for 2009 Action

Key House Democrats on energy issues released a draft climate change bill they plan to bring up for legislative debate next year. House Energy and Commerce Committee Chairman John Dingell (D-MI) and Energy and Air Quality Subcommittee Chairman Rick Boucher (D-VA) outlined climate change cap-and-trade legislation that would cover 88 percent of greenhouse gas emissions. The 461-page plan is intended to be a guide for efforts to pass a bill in the next Congress, when Democrats are expected to hold a larger number of seats in the House and Senate. "Reaching a consensus on a national approach to addressing climate change will be difficult under the best of circumstances," the committee leaders said.

The program would begin in 2012, and require overall emissions reductions of 6 percent below 2005 levels by 2020, a 44 percent cut by 2030, and an 80 percent cut by 2050. The discussion draft offers four options for distributing emission allowances to affected industries, and the sponsors are asking interested stakeholders to comment on the different options. NRECA is reviewing this complex proposal for potential impacts on electric cooperatives and will send you a detailed summary shortly. NRECA was asked to submit detailed comments on this discussion draft, and we will take that opportunity. A summary of the draft climate change bill and other materials are available at http://energycommerce.house.gov/Climate_Change/index.shtml.

Interior Department Agrees to Designate Habitat for Polar Bears

The U.S. Fish and Wildlife Service has agreed to designate by June 30, 2010, critical habitat for the polar bear, under an agreement announced October 6, that partially settles a lawsuit by environmental advocates. The agreement addresses a lawsuit challenging the

Bush administration's recent decision to list the polar bear as a threatened species and a related ruling exempting the bear from many of the protections the Endangered Species Act provides. Interior Secretary Dirk Kempthorne listed the polar bear as threatened due to receding sea ice, but said the listing should not open the door to use the Endangered Species Act to regulate greenhouse gases.

GAO Reports Power Plants Lack Incentives for CCS

In a report released on September 30, *Federal Actions Will Greatly Affect the Viability of Carbon Capture and Storage as a Key Mitigation Option,* the GAO states that without a comprehensive set of climate change policies, coal-fired power plants are unlikely to have the incentive to build commercial-scale CCS systems. The GAO report said the "absence of a national strategy to control CO2 emissions" has deterred DOE, EPA, and other agencies from resolving a series of practical issues, including how sequestered carbon dioxide might be transported from power plants to underground storage areas. Regulatory agencies also have to resolve numerous challenges posed by injecting large volumes of emissions into the ground, the report said, including how the Comprehensive Environmental Response, Compensation, and Liability Act (CERLA) and the Resource Conservation and Recovery Act (RCRA) apply to injected carbon dioxide. NRECA, through UWAG, is monitoring those regulatory issues.

On a related note, proponents of cap-and-trade legislation are citing a new GAO report that says the establishment of a federal policy to limit CO2 emissions would help lower the cost CCS and resolve issues surrounding liability for CO2 stored underground. The GAO findings could be used to counter claims by the coal industry and its congressional allies that providing billions of dollars in federal funding for development of CCS technology should precede any effort to limit CO2 emissions, as a way to ease compliance burdens and transition the economy to low-carbon energy sources.

EPA Misses Deadline for GHG Reporting Rule

EPA missed a congressional deadline for proposing a rule that would require mandatory reporting of greenhouse gases from the largest emission sources in the country. EPA was required by the omnibus appropriations bill (Pub. L. No. 110-161) approved by Congress in December 2007 to propose the rule by September 26. EPA is required to finalize the rule by June 2009. The electric power industry already reports CO2 emissions from generation units to EPA under the CAA Amendments of 1990. However, other industries do not have similar requirements to report emissions.

The proposed rule would likely cover emissions of carbon dioxide, methane, nitrogen dioxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The rule would represent the first broad-based mandatory greenhouse gas reporting requirements by the federal government. More information on the EPA greenhouse gas reporting rulemaking is available.

Climate News Notes Available

The latest editions of Climate News Notes have been posted to Cooperative.com
Climate News Notes – September 15
Climate News Notes – September 29

Clean Water Issues

EPA Issues Final Permit for Storm Water Runoff

EPA recently issued the final general NPDES permit covering discharges of storm water from "Industrial Activities." In most cases, co-ops do not use the EPA general permit. Instead, they usually have storm water runoff from power plants covered under their site-wide NPDES permits issued by the state. However, the states usually adopt the federal requirements into their own programs, so new requirements from the federal general permit could start showing up soon in state permits as well.

The EPA industrial storm water permit is also known as the Multi-Sector General Permit (MSGP), and it was published at (73 Fed. Reg. 56,572) September 29, 2008. It is effective immediately. Possibly the most significant development is the prohibition on using the general permit for discharges to waterways that are covered by a TMDL. The general permit is not allowed in these cases, and it is not clear that even an individual permit will be issued, unless different pollutants are in the discharge and in the receiving body or the discharger shows (and EPA agrees) that the storm water discharge will not cause or contribute to an excursion of water quality standards. NRECA will provide a summary of the new federal permit shortly.

EPA Releases Final Strategy to Reduce Climate Change Effects on Water Resources

On October 2, EPA's water office released a final strategy, *National Water Program Strategy: Response to Climate Change* that outlines actions to manage programs and invest resources aimed at reducing adverse effects on water from climate change. The strategy divides water program responses into five areas: reducing greenhouse gas emissions; adapting to climate change; conducting climate change-related research; managing water programs; and educating water program professionals. To address these challenges, the report said the National Water Program will expand existing programs that result in greenhouse gas reduction and expand efforts related to carbon dioxide sequestration. The agency also will support carbon sequestration related to energy production and industrial processes. NRECA through UWAG commented on the draft version of the strategy several months ago.

Proposed UIC Rule for Geologic Storage of CO2

On September 25, NRECA held a conference call regarding the proposed regulations for geologic storage of CO2 under the Underground Injection Control (UIC) program and the Safe Drinking Water Act (73 FR 43492). NRECA will be distributing draft comments soon. Next, we will finalize them and prepare a template our members can use to comment before the deadline on November 24. NRECA helped USWAG develop testimony that was presented at an EPA public hearing in Denver, Colo., on October 2. NRECA will continue working with our members and other industry groups on this rule. A copy of the NRECA summary of the proposal, USWAG's Denver testimony and the appendix of technical requirements is available on Cooperative.com.

Waste Issues

Canadian PCB Phase-Out Regulations

On September 18, Canada adopted final regulations requiring the phase-out of electrical equipment containing PCBs. EPA has been considering a similar phase-out of PCBs and NRECA and USWAG have been trying to discourage this effort. Canada links their action to the international agreement on persistent organic pollutants (the POPs treaty), which includes a deadline for phasing-out virtually all PCBs. One of the most troubling aspects of the Canadian program is that it requires all PCB equipment that is being stored for re-use to be "removed" by the end of 2009. We have told EPA and Congress that we believe the United States is already meeting its POPs obligations under existing TSCA regulations. Nonetheless, the Canadian phase-out will put additional pressure on EPA to adopt its own phase-out program, which could place a significant cost burden on co-ops by forcing them to remove a great deal of existing electrical equipment like transformers and capacitors long before the equipment reaches the end of its useful life.

EPA Posts 'Raw' Toxics Release Data

On September 10, EPA announced it has posted its facility-level data for 2007 on releases of hazardous chemicals submitted to the agency through the Toxics Release Inventory program. The facility-level information made available via the Electronic-Facility Data Release, or e-FDR, is considered "raw" data that are not grouped in any way or subjected to analysis by the agency. Industries covered by the TRI program were required to submit data on 2007 releases by July 1, 2008. Industries that are required to report their TRI release include electric utilities. Cooperative data is not reported in a separate category, but is included with all the data for electric utilities. Co-ops should be aware of the data release in the event it is covered by local media.

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Volume 7, Issue 11
October 24, 2008

Environmental Bulletin

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Kirk's Column

Well, we're only 12 days from the election, and we'll soon be rid of the incessant political commercials on television and the radio. More importantly, we'll know who the political leadership of the country will be for the next Administration and Congress. Environmental issues will have a higher profile than they have in recent memory, while energy and financial issues will also dominate the federal policy stage. Under any plausible scenario at this point, we'll have our hands full across the board – regardless of who sits in the White House. Both Senator McCain and Senator Obama will be more aggressive on climate change policy than President Bush has been, and the new Congress will place new priorities on clean air, clean water, and climate change issues.

This week brought some interesting news that may play into how aggressively the new Congress addresses clean air issues. The DC Circuit Court of Appeals indicated it may be willing to reconsider its decision to completely vacate the Clean Air Interstate Rule (CAIR), saying there may be room for compromise with the parties to the case. If the Court arrives at some compromise and remands CAIR to the EPA, it may impact how aggressive the next Congress may be on SO2 and NOx emission reduction requirements.

We're also digging more and more into the Boucher-Dingell climate change bill, and it is living up to what one would expect from a seasoned legislator like Chairman Dingell – it is more carefully thought out than the Lieberman-Warner-Boxer bill from the Senate this year and includes some good and some bad. It is too early to have any kind of realistic economic analysis of the bill, and we all know how much the economy has become the dominant issue in politics lately.

Finally, this week NRECA filed an amicus brief in support of Southern Montana G&T's effort to build a coal-based power plant to meet its distribution systems' base load power needs. While it seems like a cut-and-dried case to me, the court will make its decision in the coming months. Many thanks to Rae Cronmiller and Aleeta Harrington here in Environmental Policy for their work to get the amicus brief filed in Montana.

-Kirk

Clean Air Issues

EPA Adopts More Stringent Lead NAAQS

On October 15, EPA dramatically strengthened the National Ambient Air Quality Standards (NAAQS) for lead. The new standards tighten the allowable lead level 10 times to 0.15 micrograms of lead per cubic meter of air (ug/m3). This decision marks the first time the lead standards have changed in 30 years. The previous standards, set in 1978, were 1.5 ug/m3. EPA's action sets two standards: a primary standard at 0.15 ug/m3 to protect health, and a secondary standard at the same level to protect the public welfare, including the environment. EPA is also requiring additional monitoring for lead and relocation of some of the existing monitors. Notice of the revised NAAQS will be published in the *Federal Register* within the next several weeks.

Final UARG Comments on the Integrated Science Assessment for NOx and SOx

Final UARG comments on the Integrated Science Assessment (ISA) for oxides of nitrogen and sulfur were filed with EPA on October 10, 2008. They address concerns regarding the scientific analysis of the welfare effects of NOx and SOx. Briefly, UARG challenged EPA's treatment of ammonia and ammonium, mercury methylation, and its characterization of the state of the science regarding numerous other environmental effects. As explained in the comments, UARG continues to disagree with EPA's conclusions and characterizations of the science, and therefore urges the agency to revise the ISA significantly before proceeding with the review of the secondary national ambient air quality standards ("NAAQS") for SOx and NOx. NRECA, through UARG, will closely follow EPA's finalization of the ISA.

EPA Proposed Performance Specification for CPMS

EPA has proposed Performance Specification (PS) 17 and Procedure 4 (QA/QC) for continuous parameter monitoring systems (CPMS) for use under the New Source Performance Standards (NSPS) and NESHAPS published at (73 Fed. Reg. 59,956) October 9, 2008. These specifications address monitoring of parameters like temperature, pressure, liquid flow rate, and pH. Miscellaneous conforming amendments to the general provisions, and Appendix F, Procedure 1, are also proposed. Comments on the proposal are due to EPA by December 8, 2008.

Emissions Data from 2005 Available Online

On October 16, EPA announced the online availability of 2005 air emissions data from power plants. EPA has issued a new edition of its Emissions & Generation Resource Integrated Database (eGRID) and updated Power Profiler. eGRID is an air emissions database of electric power plants in the United States, including emissions data on nitrogen oxides, sulfur dioxide, carbon dioxide and mercury. The new edition of eGRID now also provides emissions data on methane and nitrous oxide. Power Profiler is a tool for consumers to see how their individual energy use is impacting air emissions. Please be familiar with these EPA online tools in the event you are contacted by local press or concerned citizens.

Climate Change

Summary on Early Review of Dingell-Boucher Cap-and-Trade Discussion Draft

In following up on the release of the climate change cap-and-trade discussion draft legislation by House Energy and Commerce Committee Chairman John Dingell (D-Mich.) and Energy and Air Quality Subcommittee Chairman Rick Boucher (D-Va.), NRECA prepared a high-level, two-page summary of this legislation. This is a very complex, well-drafted bill and more complicated than the Lieberman-Warner-Box bill debated earlier this year. NRECA will provide more updates as we continue to review this bill for electricity sector and electric cooperative impacts.

NRECA Files Amicus Brief in Support of Southern Montana G&T

On October 21, NRECA filed an amicus brief supporting Montana's issuance of Southern Montana G&T's air (PSD) permit for construction of a 250 MW coal-fired unit at Highwood Station. Since Montana air law departs little from the federal version, the arguments mostly followed the theories espoused in the NRECA Deseret brief filed on March 21, with additional material added to address issues that have arisen since the Deseret brief. The brief was limited to 20 pages, so the brief is content heavy.

Obama Campaign in Talks with Key House Lawmaker on Cap and Trade

Advisers to Democratic presidential nominee Barack Obama and Energy and Air Quality Subcommittee Chairman Rick Boucher (D-Va.) have begun preliminary talks about how to write global warming legislation early next year should the Illinois senator win the White House. Boucher, an early endorser of Obama, predicted he could bridge differences between Obama's campaign platform on climate change and a proposal he released earlier this month with House Energy and Commerce Chairman John Dingell (D-Mich.). Boucher and Obama both back the launch of a cap-and-trade program, but they differ on how to distribute what would be billions of dollars in emission allowances for about three-quarters of the U.S. economy. Boucher says the House is likely to lead congressional debate on comprehensive climate legislation in 2009.

IEA Report Says CCS Lags Due to Cost Barriers

Carbon capture and sequestration (CCS) technology is being hindered by a lack of funding and regulatory certainty, says a new report from the International Energy Agency (IEA), an arm of the Organization for Economic Cooperation and Development (OECD). An executive summary of the IEA report released October 20, argues, "CCS will need to contribute nearly one-fifth of the necessary emissions reductions to reduce global GHG emissions by 50% by 2050 at a reasonable cost." The report also states, "Current spending and activity levels are nowhere near enough to achieve these deployment goals...If these demonstration projects do not materialize in the near future, it will be impossible for CCS to make a meaningful contribution to GHG mitigation efforts." Cost continues to be the main barrier as investors remain skittish about investing billions of dollars in CCS projects.

Climate News Notes Available

The latest edition of Climate News Notes have been posted to Cooperative.com
Climate News Notes – October 14, 2008

Clean Water Issues

National Research Council Releases Harsh Report on EPA's Stormwater Program

On October 15, the National Research Council released its long-anticipated report, "Urban Stormwater Management in the United States." The report reflects the results of a 26-month study of EPA's stormwater program, with a focus on the effectiveness of existing regulatory approaches and controls. The stormwater study found that EPA's existing program was deficient in important areas, and identified specific areas needing improvement. While the report was directed primarily at EPA's program for municipal stormwater management, the failures identified and the changes called for are so broad that they are likely to affect the entire stormwater regulatory program both at federal and state levels. This could lead to stricter requirements in co-op stormwater permits, including numeric water quality-based limits for runoff from industrial sites and construction activities. NRECA, through UWAG, will monitor the different agency and public reactions to the report very carefully and alert you to new developments.

New Mercury TMDL Guidance

EPA has released new guidance styled, "Elements of Mercury TMDLs Where Mercury Loadings are Predominantly from Air Deposition." The guidance is comprised of a cover memorandum, as well as a "checklist" that is predicated on approaches and lessons learned by EPA in approving previous mercury TMDLs. UWAG, through the Federal Water Quality Coalition, commented on an earlier draft of the checklist. EPA accepted some of these comments but rejected others. The final checklist is an improvement over the draft, but it remains problematic in certain areas identified in the industry comments. If your state indicates an interest in using this guidance, you may wish to consult the comments for advice on how to promote more meaningful, step-wise and implementable TMDLs in your state.

Final Chemical Reporting Rules Revise Standards

EPA announced on October 17, changes to emergency planning, emergency release notification, and hazardous chemical reporting regulations under the Emergency Planning and Community Right-to-Know Act that were proposed more than a decade ago. The final rule includes clarifications on how to report hazardous chemicals in mixtures, and changes to Tier I and Tier II forms, which include, respectively, general and chemical-specific information.

In addition, the Tier I and Tier II reporting forms and their instructions have been removed from the Code of Federal Regulations and are now available at the agency's Emergency Management Web site. Tier I forms contain aggregate information for applicable hazard categories and must be submitted annually. Tier II forms contain more detailed information, including the specific names of each chemical, and are submitted on the request of agencies that receive the Tier I version. Facilities are also now required to report their North American Industry Classification System code on the forms. Another new requirement is that the chemical or common name of the chemical as provided on its Material Safety Data Sheet must be provided on the Tier II form. Cooperative G&Ts are often affected by the Tier I and II reporting requirements and should be aware of these new regulations.

Waste Issues

EPA Issues Report on FGD Materials

EPA's Office of Research and Development (ORD) has published "Characterization of Coal Combustion Residues from Electric Utilities Using Wet Scrubbers for Multi-Pollutant Control," an evaluation of the leaching characteristics of FGD materials. Data presented in this report will be used by EPA to develop in the future a report addressing the fate of mercury as part of an ongoing effort by EPA to use a holistic approach to account for the fate of mercury and other metals in coal throughout the life-cycle stages of CCP management including disposal and beneficial use. It is important to note that this is a data report. EPA will be preparing a report evaluating these data in the future. Because of the potential impact of this report on EPA's Bevill rulemaking, this is an issue that NRECA, through USWAG, will continue to monitor.

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BIG RIVERS ELECTRIC CORPORATION'S
SUPPLEMENTAL RESPONSE TO THE ATTORNEY GENERAL'S
SUPPLEMENTAL REQUEST FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
(Original Response March 6, 2008)
November 7, 2008

Item 82) Please reference the Response to OAG 1-71. Please provide the information requested.

Response) The following table updates the transaction related expenditures in excess of $250,000 by vendor for the period 2003 to current. These amounts have been or will be reimbursed by E.ON to the extent described in the Reimbursement Agreements filed in this proceeding.

Total Unwind-Vendors Exceeding $250,000

Black & Veatch	$ 2,556,222.98
CRA International, Inc	3,898,884.11
Hogan Hartson	1,870,007.20
JDG Consulting	483,976.17
Orrick, Herrington & Sutcliffe	16,588,081.65
Arnold & Porter-RUS Counsel Escrow	395,326.80
Stanley Consultants	1,332,634.31
Sullivan, Mountjoy, Stainback & Miller	2,230,562.03
Utility and Economic Consulting	409,148.54
Total	$ 29,764,843.79

Witness) C. William Blackburn

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(Original Response March 6, 2008)
November 7, 2008

Item 87) Please reference the Response to HMP&L 1-3. Please answer the question without requiring the Attorney General to extrapolate the number from the attachments.

Response) In responding to HMP&L 1-3, Big Rivers presented the O&M and Capital expenditures necessary to meet the generation levels in the Big Rivers production model. Big Rivers' Production Work Plan now has been updated to reflect different levels of O&M non-labor costs and Capital expenditures attributable to the Reid/Station Two units. Attached, Big Rivers submits tables listing the 2009-2011 O&M Non-Labor and Capital budgets for the Reid/Station Two units. The tables present the O&M Non-Labor Budget (Gross) attributable to the Reid/Station Two units on a monthly basis beginning January 2009 and ending December 2011. The tables also present the capital expenditures attributable to the Reid/Station Two units in the 2009, 2010, and 2011 Capital Budgets.

Witness) Mark A. Bailey

Reid/Station Two

2009 O&M Non-Labor Budget (Gross)

Number	Description	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	GROSS TOTAL
RD109USO Total	R1 - Unscheduled Outages	17,500	17,500	17,500	17,500	17,500	17,500	17,500	17,500	17,500	17,500	17,500	17,500	210,000
RD109xxx Total	R1 - Major Initiatives	0	0	0	0	0	0	80,000	0	0	0	0	0	80,000
RD109ASIL Total	R1 - Rebuild "A" Silo Sump Pump	0	0	0	18,000	0	0	0	0	0	0	0	0	18,000
RD109xxx Total	R1 - Major Initiatives	0	0	371,315	0	0	19,500	15,000	10,000	19,500	0	0	0	435,315
RDMAIR Total	RDM Air System	5,000	3,420	5,000	40,150	4,270	4,290	1,830	5,800	4,350	3,520	3,920	950	82,500
RDMASH Total	RDM Ash Handling	6,250	5,300	3,954	6,750	755	12,960	5,880	3,435	8,166	3,450	10,200	4,400	71,500
RDMBFW Total	RDM Feedwater System	1,400	2,200	1,200	1,550	200	400	400	300	850	900	1,200	1,400	12,000
RDMCDS Total	RDM Condensate System	1,000	1,250	1,000	1,600	600	700	600	500	850	1,500	1,500	1,100	12,200
RDMCHS Total	RDM Fuel Feed: Fuel Conveying System	11,400	30,320	22,800	42,620	25,420	41,020	27,420	35,520	27,320	28,680	17,400	23,420	333,540
RDMCHSBUS Total	RDM Fuel Handling:Coal Unloading Barge	4,000	3,500	14,780	4,500	7,000	14,250	12,500	10,100	4,000	7,800	15,400	5,000	102,800
RDMCW Total	RDM Cooling Water System	400	350	125	400	200	150	330	400	350	150	170	0	3,025
RDMCWS Total	RDM Circulating Water/Cooling Towers	1,000	1,000	1,000	1,000	1,900	1,350	1,400	1,450	600	1,700	0	1,700	14,100
RDMCWSINT Total	RDM Screenwell Maintenance	2,500	7,050	13,500	12,000	2,800	1,800	5,400	4,300	3,550	1,500	2,500	4,000	61,000
RDMDWS Total	RDM Demineralized Water System	900	1,300	1,500	1,000	1,800	800	900	1,000	400	1,800	1,300	1,300	14,000
RDMEDGT Total	RDM Combustion Turbine-Electrical Distribution	400	400	800	300	500	900	500	500	400	0	600	300	5,800
RDMEDT Total	RDM Switchgear/Bus	250	1,300	450	150	1,400	6,000	300	7,700	6,000	200	500	100	24,350
RDMEL Total	RDM Bldgs & Grounds: Elevators	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,925	46,550
RDMENV Total	RDM Emission Controls: CEM	3,500	1,570	2,100	2,550	820	1,050	600	900	1,700	4,200	3,100	1,910	24,000
RDMFOS Total	RDM Fuel Oil System	900	600	400	800	650	665	575	500	210	700	500	900	7,400
RDMFPS Total	RDM Fire Protection	400	1,200	1,200	2,700	650	1,800	200	700	1,100	2,800	800	800	14,350
RDMFSPGT Total	RDM Combustion Turbine-Fire Protection	1,000	450	600	500	500	200	600	400	200	400	3,000	200	8,050
RDMGEU Total	RDM General Use Equipment	3,200	1,700	2,700	1,700	3,200	2,700	2,200	1,200	3,200	1,700	1,200	2,700	27,400
RDMGT Total	RDM Combustion Turbine	0	1,000	7,000	3,200	2,000	0	1,000	0	3,000	17,700	61,100	1,000	97,000
RDMHVC Total	RDM Bldgs & Grounds: HVAC	580	3,980	1,980	3,680	2,680	3,460	5,075	3,600	5,050	340	3,260	2,040	35,725
RDMMBBLU Total	RDM Plant Lubrication	3,000	3,000	3,000	3,000	3,000	3,500	3,500	3,000	3,000	3,000	3,000	3,000	37,000
RDMMBBMT Total	RDM Maintenance Training	1,250	3,250	1,250	1,250	1,250	24,250	6,250	3,250	1,250	1,250	3,250	1,250	49,000
RDMMEQ Total	RDM Non-Fuels Equipment	600	600	600	600	600	600	600	600	600	600	600	600	7,200
RDMMEQCLE Total	RDM Mobile Fuels Equipment	6,900	6,900	6,900	6,900	59,900	6,900	6,900	6,900	6,900	6,900	46,900	6,900	175,800
RDMOHC Total	RDM Overhead Cranes & Hoists	3,000	600	3,000	1,900	0	5,500	2,000	400	3,700	800	1,000	0	21,900
RDMPCM Total	RDM Plant Communications	1,350	1,800	1,000	1,850	1,500	1,600	1,700	1,950	1,600	2,200	1,500	1,250	19,300
RDMPCS Total	RDM Controls/Computer Systems	1,000	1,000	16,000	500	1,000	1,100	1,000	1,000	500	1,100	1,000	500	25,700
RDMPFP Total	RDM Bldgs & Grounds:Winterization	1,510	1,000	600	500	500	0	0	410	1,050	15,410	410	610	22,000
RDMPLS Total	RDM Plant Lighting System	2,800	4,850	1,350	9,850	5,850	5,000	2,550	10,000	5,750	6,400	2,000	1,550	57,750
RDMPST Total	RDM Bldgs & Grounds Site Mtce/Improvements	4,850	5,750	3,950	4,450	3,700	3,100	6,700	1,400	2,200	1,950	3,350	2,600	44,000
RDMPVE Total	RDM Vehicles	4,650	4,500	4,400	5,500	4,650	6,300	4,450	4,050	5,450	5,600	5,100	3,350	58,000
RDMPWS Total	RDM Potable Water System	800	350	370	500	1,100	620	900	450	500	850	450	600	7,490
RDMRID Total	RDM Recording/Indicating Devices	1,000	1,500	750	600	225	450	740	450	180	900	1,000	500	8,295
RDMSGU Total	RDM Boilers & Burners	10,300	12,500	11,300	6,500	2,580	3,350	4,790	3,900	2,850	12,800	12,500	9,200	92,570
RDMSGUFDE Total	RDM Fans/Draft System	1,500	3,400	1,600	3,600	750	1,000	2,550	1,100	1,900	600	2,500	5,500	28,000
RDMSGUFPE Total	RDM Fuel Feed: Mills and Feeders	2,500	5,800	2,500	6,400	600	2,700	1,000	1,400	500	5,100	1,400	2,150	32,050
RDMSGUPCP Total	RDM Emission Controls:Precipitators	500	500	5,800	500	700	1,100	1,500	500	1,100	200	200	700	13,300
RDMTGN Total	RDM Turbine/Generator	2,500	2,500	2,600	1,750	700	850	1,100	800	1,100	1,750	2,100	2,250	20,000
RDMWTS Total	RDM Bldgs & Grounds: Sumps	3,250	1,650	8,050	4,250	1,050	5,150	15,150	9,450	3,650	4,050	1,250	3,150	60,100
RDMWWS Total	RDM Effluent Control(Waste Water Treatment)	750	13,000	750	1,000	750	1,000	750	1,000	750	1,000	750	1,000	22,500
RDOSGUFPE Total	RDO Mills and Feeders	5,000	5,000	5,000	5,000	0	0	0	0	0	5,000	5,000	5,000	35,000
GT09STKLR Total	GT - Stack Liner Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0
ST09DGB Total	H0 - Turbine Crane Drive Gear Box	0	0	0	0	0	0	0	0	0	30,000	0	0	30,000
RH09BUBP Total	RH - Barge Unloader Bumper Pad	0	0	0	0	0	0	0	0	0	0	0	0	0
ST109AMIL Total	H1 - OH "B" Mill Gear Box	0	80,000	0	0	0	0	0	0	0	0	0	0	80,000
ST109ASHB Total	H1 - Overhaul "B" Ash Sluice Pump	0	0	0	0	0	0	0	0	30,000	0	0	0	30,000
ST109MFSR Total	H1 - Rebuild "B" Mass Flow/Screw Feeder	0	0	150,000	0	0	0	0	0	0	0	0	0	150,000
ST109SPG Total	H1 - Planned Outage (General)	0	0	2,036,990	0	0	0	0	0	0	0	0	0	2,142,990
ST109SPN Total	H1 - Planned Outage (Nox)	0	0	73,000	0	0	0	0	0	0	0	0	0	73,000
ST109SPO Total	H1 - Planned Outage (Ops)	0	0	232,000	0	0	0	0	0	0	0	0	0	232,000
ST109SPS Total	H1 - Planned Outage (Scrubber)	0	0	202,260	0	0	0	0	0	0	0	0	0	202,260
ST109SPT Total	H1 - Planned Outage (Turbine)	0	0	192,830	0	0	0	0	0	20,000	0	5,000	0	217,830
ST109USO Total	H1 - Unscheduled Outages	7,000	7,000	0	0	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	70,000
ST209ASHC Total	H2 - Rebuild "C" Ash Sluice Pump	0	0	0	0	0	0	30,000	0	0	0	0	0	30,000
ST209USO Total	H2 - Unscheduled Outages	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	360,000
STCHCSM Total	FH Consumables	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
STCHOIS Total	FH Outside Industrial Svc	5,500	5,500	5,500	5,500	5,500	6,785	6,785	6,786	6,786	6,786	6,786	6,786	75,000

Reid/Station Two

2009 O&M Non-Labor Budget (Gross)

Number	Description	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	GROSS TOTAL
STCHPST Total	FH Buildings & Grounds	6,750	6,750	3,750	6,900	6,150	10,465	5,465	5,465	5,465	2,465	2,465	5,460	67,550
STCHTR Total	FH Tool Room	700	700	700	700	700	700	700	700	700	700	700	700	8,400
STDREDGE Total	ST Dredging Ash Ponds	0	0	0	0	0	15,000	0	0	10,000	0	0	0	25,000
STMASH Total	STM Ash Handling	16,100	43,800	15,450	18,050	3,450	19,300	16,700	37,150	13,600	16,350	18,400	10,800	229,150
STMBFW Total	STM Feedwater System	5,000	5,900	9,800	6,700	4,500	6,000	5,200	5,200	7,000	7,000	7,900	5,500	75,500
STMCDS Total	STM Condensate System	1,900	1,200	1,600	1,850	1,700	1,500	1,625	2,175	10,600	2,050	2,250	1,250	29,500
STMCHS Total	STM Fuel Feed: Fuel Conveying System	3,975	6,200	6,175	6,275	9,075	6,175	8,900	7,475	7,875	5,525	3,550	7,025	76,225
STMCSM Total	STM Consumables	18,670	16,920	16,420	18,620	16,920	19,620	17,620	21,570	23,320	19,320	22,320	17,320	228,840
STMCW Total	STM Cooling Water System	1,000	700	950	1,000	1,500	1,700	1,500	1,150	750	700	1,150	1,500	13,600
STMCWS Total	STM Circulating Water/Cooling Towers	5,400	4,550	6,650	6,350	6,700	8,050	5,550	5,550	6,000	15,900	5,200	5,200	81,100
STMEDT Total	STM Switchgear/Bus	1,400	7,900	7,500	2,400	6,500	6,700	7,850	450	6,250	1,200	12,400	1,200	63,750
STMEL Total	STM Bldgs & Grounds: Elevators	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,925	46,550
STMEVS Total	STM Emission Controls:CEM	8,150	7,900	9,900	6,550	16,050	6,250	9,550	7,300	7,250	13,900	6,250	7,450	106,500
STMFGD Total	STM Emission Controls: Scrubbers	7,250	7,800	22,700	10,450	6,650	14,225	2,900	5,700	12,300	9,875	13,100	2,200	114,950
STMFGX Total	STM Limestone Grinding/Processing	4,888	14,588	21,386	18,188	12,988	11,988	10,688	8,688	7,189	13,189	10,189	6,189	140,160
STMFGXMEW Total	STM Emission Controls: SDRS Mist Eliminator	0	1,500	4,300	500	0	3,100	500	2,000	2,000	500	2,000	900	17,800
STMFGXPWS Total	STM Emission Controls:SDRS Potable Water	400	200	100	200	500	200	100	200	100	200	100	500	2,800
STMFGXSAB Total	STM Emission Controls:SDRS Absorber Bldg	1,500	5,000	1,000	1,500	2,500	1,000	3,100	1,300	1,500	1,500	2,400	1,200	23,500
STMFGXSBB Total	STM Emission Controls:SDRS Scrubber Bldg	100	150	100	150	100	150	700	150	150	150	150	250	2,300
STMFGXSTK Total	STM Emission Controls:SDRS Scrubber Stack	500	0	1,000	400	0	1,400	0	500	1,700	500	700	700	7,400
STMFGXTRW Total	STM Emission Controls:SDRS Thickener Return	750	750	750	4,750	900	7,750	800	750	1,050	750	1,150	750	20,900
STMFOS Total	STM Fuel Oil System	1,100	900	1,200	850	650	1,300	1,100	1,200	800	400	800	1,300	11,600
STMFPS Total	STM Fire Protection	1,000	1,000	3,500	1,500	3,000	1,000	1,500	1,500	2,500	1,000	3,500	1,000	22,000
STMHVC Total	STM Bldgs & Grounds:HVAC	1,200	3,630	3,750	3,750	5,750	5,760	6,275	4,250	4,100	2,050	5,000	2,285	47,800
STMOHC Total	STM Overhead Cranes & Hoists	0	2,500	3,600	4,000	0	1,000	0	0	4,000	1,600	1,500	1,000	19,200
STMPAS Total	STM Air System	13,660	3,590	3,050	2,100	18,500	3,100	2,750	3,050	3,300	3,650	1,950	2,800	61,500
STMPCM Total	STM Plant Communications	1,600	1,600	1,600	1,500	1,950	2,150	2,300	1,800	1,800	1,000	2,100	1,300	20,900
STMPCS Total	STM Plant Controls	1,800	2,000	1,900	1,700	1,800	1,800	1,000	1,200	1,900	2,000	1,300	1,300	19,700
STMPLC Total	STM Controls/Computer Systems	3,100	3,800	161,085	4,900	3,500	17,850	2,800	4,250	2,800	3,000	3,500	2,750	213,335
STMPLS Total	STM Plant Lighting System	11,800	8,200	12,850	12,250	15,350	7,250	8,000	8,700	11,450	14,750	10,500	9,000	130,100
STMPWS Total	STM Service Water System	100	100	100	100	100	100	100	100	100	100	100	100	1,200
STMRID Total	STM Recording/Indicating Devices	900	1,150	3,350	1,800	500	0	500	1,000	1,500	1,500	1,500	0	13,700
STMSCR Total	STM Nox Reduction-SCR Maintenance	7,000	3,000	30,200	41,500	3,000	5,000	3,000	22,200	10,680	8,100	2,000	2,000	137,680
STMSGU Total	STM Boilers & Burners	38,650	39,800	31,050	31,050	41,050	27,500	28,800	31,075	26,725	30,800	33,200	29,100	388,800
STMSGUFDE Total	STM Fans/Draft System	1,000	4,750	6,250	5,500	4,000	8,500	3,200	3,500	7,350	2,600	3,700	1,600	51,950
STMSGUFPE Total	STM Fuel Feed: Mills and Feeders	6,100	8,250	12,500	9,500	5,500	7,400	6,000	4,500	9,000	7,000	8,500	3,900	88,150
STMSGUPRP Total	STM Emission Controls: Precipitators	4,000	6,500	7,000	4,000	6,000	6,000	5,500	5,000	6,500	5,000	3,500	500	61,500
STMTGN Total	STM Turbine/Generator	4,000	5,000	3,100	4,750	3,500	3,500	5,400	4,600	4,150	5,600	4,000	3,000	50,500
STMTGNDGS Total	STM Diesel/Generator	100	70	0	600	200	0	200	500	0	1,500	0	800	3,970
STMTR Total	STM Tool Room	3,500	3,400	4,050	3,250	3,600	4,000	4,700	6,000	5,500	4,500	5,500	4,500	52,500
STMWWS Total	STM Effluent Control(Waste Water Treatment)	500	400	350	400	500	400	500	400	500	400	350	400	5,100
STOADM Total	STO Administrative	17,112	17,112	22,262	22,162	17,112	24,432	18,262	22,362	20,012	20,262	17,112	17,137	235,359
STOCHSBUS Total	FH Coal Unloading Barge	0	0	12,000	0	12,000	0	37,000	50,000	25,000	12,000	0	0	148,000
STOCSM Total	STO Consumables	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
STOFGD Total	STO HMPL FGD Shared Equipment	38,638	38,638	38,638	38,638	38,638	38,638	38,638	38,638	38,638	38,638	38,638	38,638	463,656
STOIS Total	STO Outside Industrial Svc	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	156,000
STOLAB Total	STO Laboratory	13,050	15,350	30,400	16,750	22,300	33,700	13,200	15,450	36,880	16,250	15,900	23,700	254,930
STOMEQ Total	FH Mobile Fuels Equipment	8,600	8,600	8,600	8,600	8,600	24,715	24,715	24,715	24,715	24,715	24,715	24,715	216,005
STOMEQCVH Total	STO Vehicles (Mtc, Gas, Oil)	3,300	3,300	3,300	3,300	3,300	5,015	5,015	5,015	5,015	5,015	5,015	5,015	51,605
STOPST Total	STO Buildings & Grounds	11,640	14,640	11,640	19,595	10,595	12,195	12,195	35,695	10,695	10,695	19,695	12,025	181,305
STOSCR Total	STO SCR Operation	6,250	6,250	30,250	6,250	6,250	126,250	6,250	6,250	6,250	82,250	84,250	6,250	373,000
STOSGU Total	STO Boilers and Burners	27,000	33,000	25,500	0	19,200	42,000	18,000	0	27,800	33,000	18,000	0	243,500
STOSGUFPE Total	STO Mills and Feeders	13,500	13,500	13,500	7,000	13,500	13,500	13,500	13,500	13,500	13,500	13,500	13,500	155,500
STOTGN Total	STO Turbine/Generator	5,330	5,330	5,340	5,330	5,330	5,340	5,330	5,330	5,340	5,330	5,330	5,340	64,000
STOTR Total	STO Tool Room	0	0	2,550	0	1,000	0	1,500	0	350	1,000	0	1,000	7,400
Grand Total		515,803	697,958	4,227,662	663,458	605,458	842,768	717,673	659,604	715,011	781,515	718,975	481,065	11,626,950
Total 2009 Budget		515,803	697,958	4,192,299	663,458	605,458	842,768	717,673	659,604	715,011	781,515	718,975	481,065	11,626,950
HMPL Allocation		122,850	170,218	1,129,166	162,991	152,845	211,799	156,156	161,469	175,743	188,794	164,403	113,838	2,910,274
BREC Share		392,953	527,740	3,063,133	500,467	452,613	630,969	561,517	498,135	539,268	592,721	554,572	367,227	8,716,676

Reid/Station Two

2010 O&M Non-Labor Budget (Gross)

Number	Description	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	TOTAL
RD110SPO Total	R1 - Planned Outage (Ops)	0	0	0	0	0	0	0	0	0	0	0	0	0
RD110USO Total	R1 - Unscheduled Outages	0	0	0	0	0	0	0	0	0	0	0	0	0
RD110xxx Total	RD - Major Initiatives	130,550	30,550	155,050	396,550	30,550	60,000	230,000	0	497,550	30,550	30,550	30,514	1,621,414
RDMAIR Total	RDM Air System	4,450	3,520	2,870	26,000	4,720	2,370	15,250	5,000	2,950	2,870	3,100	1,300	74,400
RDMASH Total	RDM Ash Handling	5,450	6,150	4,050	7,350	1,500	10,650	5,350	3,350	7,900	3,350	8,100	3,800	67,000
RDMBFW Total	RDM Feedwater System	0	0	0	0	0	3,000	3,000	3,000	0	0	0	0	9,000
RDMCDS Total	RDM Condensate System	0	0	0	0	0	3,000	3,000	3,000	0	0	0	0	9,000
RDMCHS Total	RDM Fuel Feed: Fuel Conveying System	11,400	33,300	25,600	45,400	25,920	39,720	27,920	28,020	28,020	23,820	17,900	23,420	330,440
RDMCHSBUS Total	RDM Fuel Handling:Coal Unloading Barge	3,500	3,500	16,450	4,500	10,500	15,250	10,000	7,100	4,000	5,800	13,900	5,300	99,800
RDMCW Total	RDM Cooling Water System	0	350	925	400	0	320	330	0	530	350	470	0	3,675
RDMCWS Total	RDM Circulating Water/Cooling Towers	1,000	1,000	400	500	1,900	1,350	2,700	1,450	600	1,700	500	1,700	14,800
RDMCWSINT Total	RDM Screenwell Maintenance	200	3,700	21,300	14,200	13,200	200	7,200	4,500	8,450	200	200	200	73,550
RDMDWS Total	RDM Demineralized Water System	1,400	2,100	1,000	1,000	1,300	11,000	1,000	1,600	300	1,200	1,300	800	24,000
RDMEDGT Total	RDM Combustion Turbine-Electrical Distribution	0	400	800	300	500	900	4,500	500	500	0	600	300	9,300
RDMEDT Total	RDM Switchgear/Bus	250	800	450	650	400	6,350	800	6,400	6,000	700	500	100	23,400
RDMEL Total	RDM Bldgs & Grounds: Elevators	3,600	3,600	4,100	4,100	4,100	4,100	4,600	4,100	3,600	4,600	3,600	4,600	48,700
RDMENV Total	RDM Emission Controls: CEM	0	0	0	0	0	3,000	3,000	3,000	0	0	0	0	9,000
RDMFOS Total	RDM Fuel Oil System	0	0	0	0	0	3,000	3,000	3,000	0	0	0	0	9,000
RDMFPS Total	RDM Fire Protection	700	850	3,400	700	650	500	500	700	2,100	2,600	750	700	14,350
RDMFSPGT Total	RDM Combustion Turbine-Fire Protection	0	350	400	2,900	300	700	600	400	0	1,700	3,000	200	10,550
RDMGEU Total	RDM General Use Equipment	3,200	1,200	2,700	2,700	2,700	2,700	2,200	1,200	3,200	1,700	1,700	2,700	27,900
RDMGT Total	RDM Combustion Turbine	100	100	6,100	6,100	6,100	100	100	100	4,100	20,100	66,900	100	111,000
RDMHVC Total	RDM Bldgs & Grounds: HVAC	730	3,630	1,030	4,130	3,130	3,600	4,200	4,075	3,800	500	4,950	2,300	36,075
RDMMBBLU Total	RDM Plant Lubrication	3,000	3,500	3,500	4,000	2,500	4,000	3,500	4,000	3,000	4,000	3,000	4,000	42,000
RDMMBBMT Total	RDM Maintenance Training	1,250	3,250	1,250	1,250	1,250	24,250	6,250	3,250	1,250	1,250	3,250	1,250	49,000
RDMMEQ Total	RDM Non-Fuels Equipment	900	900	1,100	1,300	900	1,100	900	1,100	900	1,100	900	900	12,000
RDMMEQCLE Total	RDM Mobile Fuels Equipment	6,400	6,400	6,400	6,900	6,900	66,900	6,900	6,900	6,900	6,900	6,900	6,900	141,300
RDMOHC Total	RDM Overhead Cranes & Hoists	3,000	1,300	5,300	2,400	0	3,000	2,500	1,000	3,500	1,900	2,000	0	25,900
RDMPCM Total	RDM Plant Communications	1,450	2,200	1,000	1,650	1,500	1,700	1,800	1,450	1,600	2,200	1,000	1,850	19,400
RDMPCS Total	RDM Controls/Computer Systems	0	0	15,000	0	0	0	0	0	0	0	0	0	15,000
RDMPFP Total	RDM Bldgs & Grounds:Winterization	1,500	900	900	800	0	0	0	400	100	12,900	1,220	1,000	19,720
RDMPLS Total	RDM Plant Lighting System	4,400	7,700	2,300	11,350	6,650	4,100	4,100	10,950	6,850	5,800	4,100	2,550	70,850
RDMPST Total	RDM Bldgs & Grounds Site Mtce/Improvements	3,000	2,600	2,100	7,700	2,100	3,300	14,200	2,200	3,200	4,150	2,350	3,600	50,500
RDMPVE Total	RDM Vehicles	4,600	4,700	4,350	5,500	5,100	5,600	4,450	3,750	5,300	4,400	4,500	3,650	55,900
RDMPWS Total	RDM Potable Water System	800	350	370	500	2,350	300	900	450	500	800	450	600	8,370
RDMRID Total	RDM Recording/Indicating Devices	1,000	1,500	750	600	225	0	540	450	380	900	1,000	0	7,345
RDMSGU Total	RDM Boilers & Burners	0	0	0	0	0	3,385	3,385	3,390	0	0	0	0	10,160
RDMSGUFDE Total	RDM Fans/Draft System	0	0	0	0	0	3,000	3,000	3,000	0	0	0	0	9,000
RDMSGUFPE Total	RDM Fuel Feed: Mills and Feeders	0	0	0	0	0	3,000	3,000	3,000	0	0	0	0	9,000
RDMSGUPCP Total	RDM Emission Controls:Precipitators	0	0	0	0	0	3,000	3,000	3,000	0	0	0	0	9,000
RDMTGN Total	RDM Turbine/Generator	0	0	0	0	0	3,000	3,000	3,000	0	0	0	0	9,000
RDMWTS Total	RDM Bldgs & Grounds: Sumps	550	650	11,750	4,650	550	8,650	15,250	9,850	4,050	2,850	1,750	550	61,200
RDMWWS Total	RDM Effluent Control(Waste Water Treatment)	950	950	1,000	9,950	950	950	950	900	850	850	850	850	20,000
RDOSGUFPE Total	RDO Mills and Feeders	0	0	0	0	0	0	0	0	0	0	0	0	0
RH10xxx Total	RH - Major Initiatives	0	0	0	0	0	0	0	0	40,000	15,000	0	0	55,000
ST110USO Total	H1 - Unscheduled Outages	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	360,000
ST110xxx Total	H1 - Major Initiatives	0	15,000	30,000	25,000	0	0	0	0	0	0	22,000	0	92,000
ST210SPG Total	H2 - Planned Outage (General)	0	0	829,482	1,161,635	0	0	0	0	0	0	0	0	1,991,097
ST210SPN Total	H2 - Planned Outage (Nox)	0	0	0	73,000	0	0	0	0	0	0	0	0	73,000
ST210SPO Total	H2 - Planned Outage (Ops)	0	0	0	162,000	0	0	0	0	0	0	0	0	162,000
ST210SPS Total	H2 - Planned Outage (Scrubber)	0	0	13,950	141,810	0	0	0	0	0	0	0	0	155,760
ST210SPT Total	H2 - Planned Outage (Turbine)	0	0	51,080	161,750	0	0	0	0	0	0	0	0	212,830
ST210USO Total	H2 - Unscheduled Outages	7,000	7,000	3,500	0	3,500	7,000	7,000	7,000	7,000	7,000	7,000	7,000	70,000
ST210xxx Total	H2 - Major Initiatives	0	0	90,000	110,000	0	0	30,000	0	0	0	22,000	0	252,000
STCHCSM Total	FH Consumables	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
STCHOIS Total	FH Outside Industrial Svc	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	75,000
STCHPST Total	FH Buildings & Grounds	6,250	6,250	3,250	7,000	6,250	12,375	6,250	6,250	7,375	3,775	3,250	6,250	74,525
STCHTR Total	FH Tool Room	700	700	700	700	700	700	700	700	700	700	700	700	8,400
STDREDGE Total	ST Dredging Ash Ponds	0	0	0	0	0	5,000	0	10,000	0	0	0	0	15,000

Reid/Station Two

2010 O&M Non-Labor Budget (Gross)

Number	Description	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	TOTAL
STMASH Total	STM Ash Handling	14,450	41,200	18,000	21,500	7,050	28,250	14,900	40,500	7,300	17,000	13,950	10,550	234,650
STMBFW Total	STM Feedwater System	8,000	5,500	10,700	9,200	5,000	5,800	3,000	8,900	8,300	5,000	11,800	5,500	86,700
STMCDS Total	STM Condensate System	2,750	1,650	3,700	1,650	2,250	2,750	2,575	2,575	11,500	2,150	3,400	1,250	38,200
STMCHS Total	STM Fuel Feed: Fuel Conveying System	3,650	6,375	6,900	7,300	9,300	7,200	10,400	9,100	8,300	8,100	2,850	5,750	85,225
STMCSM Total	STM Consumables	21,320	20,070	19,570	22,070	20,070	21,070	19,070	22,320	23,070	19,070	22,070	17,070	246,840
STMCW Total	STM Cooling Water System	1,600	700	1,800	1,500	1,000	1,700	2,000	1,150	750	700	1,150	0	14,050
STMCWS Total	STM Circulating Water/Cooling Towers	5,000	4,700	6,000	6,150	5,700	16,550	4,750	4,800	5,700	40,500	4,900	4,200	108,950
STMEDT Total	STM Switchgear/Bus	1,900	8,400	7,500	1,400	7,000	8,700	6,850	1,200	7,250	1,200	14,400	1,300	67,100
STMEL Total	STM Bldgs & Grounds: Elevators	4,800	4,800	3,300	4,300	3,800	3,800	3,500	3,200	3,800	3,400	3,600	3,400	45,700
STMEVS Total	STM Emission Controls:CEM	8,250	7,750	10,700	6,550	15,150	6,450	10,650	7,550	7,450	14,300	8,250	7,450	107,500
STMFGD Total	STM Emission Controls: Scrubbers	3,350	7,900	26,800	11,550	3,950	14,325	3,500	5,800	13,450	10,775	10,300	2,300	114,000
STMFGX Total	STM Limestone Grinding/Processing	5,535	15,235	21,534	16,834	13,934	12,134	7,034	3,834	7,334	12,464	5,334	6,334	127,540
STMFGXMEW Total	STM Emission Controls: SDRS Mist Eliminator	0	3,100	3,200	600	0	4,100	200	2,200	2,500	200	1,800	900	18,800
STMFGXPWS Total	STM Emission Controls:SDRS Potable Water	200	200	300	1,800	300	200	300	200	100	200	100	100	3,800
STMFGXSAB Total	STM Emission Controls:SDRS Absorber Bldg	1,500	5,000	2,000	1,000	2,500	1,000	3,600	1,300	2,000	1,500	1,400	1,200	24,000
STMFGXSBB Total	STM Emission Controls:SDRS Scrubber Bldg	150	150	150	1,000	100	200	150	150	150	100	150	100	2,550
STMFGXSTK Total	STM Emission Controls:SDRS Scrubber Stack	500	0	1,000	1,200	0	1,400	0	600	1,700	0	700	700	7,800
STMFGXTRW Total	STM Emission Controls:SDRS Thickener Return	800	9,250	750	750	350	300	750	1,150	750	1,150	550	750	17,300
STMFOS Total	STM Fuel Oil System	900	1,700	1,500	1,150	450	1,100	1,100	1,800	1,300	500	700	900	13,100
STMFPS Total	STM Fire Protection	1,550	2,050	2,750	2,550	1,550	2,050	1,250	2,550	1,550	1,050	4,050	1,050	24,000
STMHVC Total	STM Bldgs & Grounds:HVAC	1,900	3,700	4,415	3,600	5,800	4,500	4,900	3,850	3,700	2,200	3,700	1,900	44,165
STMOHC Total	STM Overhead Cranes & Hoists	1,000	2,500	2,500	3,000	0	1,000	2,000	0	3,600	1,500	2,600	1,000	20,800
STMPAS Total	STM Air System	1,000	4,050	3,000	8,300	30,000	3,000	3,000	2,150	9,900	3,700	2,100	3,000	73,200
STMPCM Total	STM Plant Communications	1,300	1,700	3,100	1,900	1,300	1,900	1,600	1,300	3,200	1,900	1,300	1,200	21,700
STMPCS Total	STM Plant Controls	2,100	1,900	2,100	1,000	3,260	1,000	0	1,000	2,100	2,000	1,400	1,400	19,260
STMPLC Total	STM Controls/Computer Systems	3,100	4,100	119,435	8,100	2,900	16,200	5,600	5,500	4,200	2,900	4,300	4,200	180,535
STMPLS Total	STM Plant Lighting System	9,100	6,450	8,950	6,200	7,850	4,900	9,000	4,100	5,000	10,700	9,300	6,100	87,650
STMPWS Total	STM Service Water System	100	100	100	100	100	100	100	100	100	100	100	100	1,200
STMRID Total	STM Recording/Indicating Devices	900	1,150	3,350	2,000	500	200	500	1,000	1,500	1,500	1,500	0	14,100
STMSCR Total	STM Nox Reduction-SCR Maintenance	4,000	4,000	51,200	26,500	4,000	5,000	4,000	22,200	24,000	17,500	4,000	4,000	170,400
STMSGU Total	STM Boilers & Burners	26,750	37,050	33,750	36,450	37,250	61,300	33,700	28,875	34,225	33,200	27,000	30,500	419,050
STMSGUFDE Total	STM Fans/Draft System	1,800	5,250	4,450	5,100	3,200	9,000	2,900	4,300	6,250	4,400	2,900	3,100	52,650
STMSGUFPE Total	STM Fuel Feed: Mills and Feeders	5,800	9,700	12,000	11,100	3,800	7,400	5,000	4,900	9,900	8,000	11,100	3,900	92,600
STMSGUPRP Total	STM Emission Controls: Precipitators	4,000	6,500	7,000	4,000	8,000	6,000	5,750	5,000	6,750	5,000	3,500	500	62,000
STMTGN Total	STM Turbine/Generator	4,000	5,000	3,100	5,250	3,500	4,000	5,400	7,600	3,150	4,500	4,000	3,000	52,500
STMTGNDGS Total	STM Diesel/Generator	100	70	300	600	300	200	250	330	200	1,250	0	500	4,100
STMTR Total	STM Tool Room	3,500	3,400	4,050	3,250	3,800	4,000	4,700	6,000	5,500	4,500	5,500	4,500	52,500
STMWWS Total	STM Effluent Control(Waste Water Treatment)	350	350	350	1,500	350	400	300	400	300	400	550	350	5,600
STOADM Total	STO Administrative	17,261	17,261	22,411	17,261	17,786	24,561	18,956	22,511	23,961	17,661	17,261	17,291	234,202
STOCHSBUS Total	FH Coal Unloading Barge	0	0	12,000	0	12,000	0	37,000	52,000	25,000	12,000	0	0	150,000
STOCSM Total	STO Consumables	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
STOFGD Total	STO HMPL FGD Shared Equipment	35,254	35,254	35,254	35,254	35,254	35,254	35,254	35,254	35,254	35,254	35,254	35,254	423,048
STOIS Total	STO Outside Industrial Svc	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	160,800
STOLAB Total	STO Laboratory	14,050	16,350	25,400	20,050	23,300	43,700	14,200	16,450	37,180	17,250	16,900	23,700	268,530
STOMEQ Total	FH Mobile Fuels Equipment	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	216,000
STOMEQCVH Total	STO Vehicles (Mtc, Gas, Oil)	4,350	4,350	4,350	4,350	4,350	4,350	4,350	4,350	4,350	4,350	4,350	4,350	52,200
STOPST Total	STO Buildings & Grounds	12,245	15,245	12,245	19,695	10,695	12,195	12,195	35,695	10,695	10,695	19,695	12,245	183,540
STOSCR Total	STO SCR Operation	9,000	9,000	9,000	21,000	9,000	129,000	9,000	9,000	9,000	85,000	87,000	9,000	394,000
STOSGU Total	STO Boilers and Burners	27,000	30,000	18,000	0	19,200	39,000	18,000	0	27,800	30,000	18,000	9,000	236,000
STOSGUFPE Total	STO Mills and Feeders	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	192,000
STOTGN Total	STO Turbine/Generator	5,330	5,330	5,340	5,330	5,330	5,340	5,330	5,330	5,340	5,330	5,330	5,340	64,000
STOTR Total	STO Tool Room	0	0	2,550	0	1,000	0	1,500	0	350	1,000	0	1,000	7,400
Grand Total		580,425	622,090	1,971,241	2,872,319	587,624	984,369	876,539	652,309	1,169,464	727,214	728,984	462,568	12,235,146
Total 2010 Budget		580,425	622,090	1,971,241	2,872,319	587,624	984,369	876,539	652,309	1,169,464	727,214	728,984	462,568	12,235,146
HMPL Allocation		118,178	157,704	521,633	725,291	146,073	240,584	162,048	162,952	175,897	179,969	171,263	113,899	2,875,493
BREC Share		462,247	464,386	1,449,608	2,147,028	441,551	743,785	714,491	489,357	993,567	547,245	557,721	348,669	9,359,653

Reid/Station Two

2011 O&M Non-Labor Budget (Gross)

Number	Description	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	TOTAL
RD111USO Total	R1 - Unscheduled Outages	0	0	0	0	0	0	0	0	0	0	0	0	0
RD111xxx Total	RD - Major Initiatives	32,500	32,500	32,500	62,500	32,500	66,000	0	0	132,500	32,500	32,500	32,500	487,500
RDMAIR Total	RDM Air System	4,450	3,520	2,870	26,000	4,720	2,370	1,250	5,000	2,950	2,870	3,100	1,300	60,400
RDMASH Total	RDM Ash Handling	4,100	3,950	4,050	7,350	1,500	9,300	5,350	3,100	5,700	3,350	5,700	3,800	57,250
RDMBFW Total	RDM Feedwater System	0	0	0	0	0	3,250	3,250	3,250	0	0	0	0	9,750
RDMCDS Total	RDM Condensate System	0	0	0	0	0	3,250	3,250	3,250	0	0	0	0	9,750
RDMCHS Total	RDM Fuel Feed: Fuel Conveying System	11,400	33,300	25,600	45,400	25,920	39,720	27,920	28,020	28,020	23,820	17,900	23,420	330,440
RDMCHSBUS Total	RDM Fuel Handling:Coal Unloading Barge	3,500	3,500	16,450	4,500	10,500	15,250	10,000	7,100	4,000	5,800	13,900	6,300	99,800
RDMCW Total	RDM Cooling Water System	0	350	925	400	0	320	330	0	530	350	470	0	3,675
RDMCWS Total	RDM Circulating Water/Cooling Towers	1,000	1,000	400	500	1,900	1,350	2,700	1,450	600	1,700	500	1,700	14,800
RDMCWSINT Total	RDM Screenwell Maintenance	200	3,700	21,300	14,200	13,200	200	7,200	4,500	8,450	200	200	200	73,550
RDMDWS Total	RDM Demineralized Water System	1,400	2,100	1,000	1,000	1,300	1,000	1,000	1,600	300	1,200	1,300	800	14,000
RDMEDGT Total	RDM Combustion Turbine-Electrical Distribution	0	400	800	300	500	900	4,500	500	500	0	600	300	9,300
RDMEDT Total	RDM Switchgear/Bus	250	800	450	650	400	6,350	800	6,400	6,000	700	500	100	23,400
RDMEL Total	RDM Bldgs & Grounds: Elevators	3,600	3,600	4,100	4,100	4,100	4,100	4,600	4,100	3,600	4,600	3,600	4,600	48,700
RDMENV Total	RDM Emission Controls: CEM	0	0	0	0	0	3,250	3,250	3,250	0	0	0	0	9,750
RDMFOS Total	RDM Fuel Oil System	0	0	0	0	0	3,250	3,250	3,250	0	0	0	0	9,750
RDMFPS Total	RDM Fire Protection	700	850	3,400	700	650	500	500	700	2,100	2,800	750	700	14,350
RDMFSPGT Total	RDM Combustion Turbine-Fire Protection	0	350	400	2,900	300	700	600	400	0	1,700	3,000	200	10,550
RDMGEU Total	RDM General Use Equipment	3,200	1,200	2,700	2,700	2,700	2,700	2,200	1,200	3,200	1,700	1,700	2,700	27,900
RDMGT Total	RDM Combustion Turbine	100	100	8,100	5,100	8,100	100	100	100	4,100	20,100	66,900	100	111,000
RDMHVC Total	RDM Bldgs & Grounds: HVAC	730	3,630	1,030	4,130	3,130	3,600	4,200	4,075	3,600	600	4,950	2,300	36,075
RDMMBBLU Total	RDM Plant Lubrication	3,000	3,500	3,500	4,000	2,500	4,000	3,500	4,000	3,000	4,000	3,000	4,000	42,000
RDMMBBMT Total	RDM Maintenance Training	1,250	3,250	1,250	1,250	1,250	24,250	6,250	3,250	1,250	1,250	3,250	1,250	49,000
RDMMEQ Total	RDM Non-Fuels Equipment	900	900	1,100	1,300	900	1,100	900	1,100	900	1,100	900	900	12,000
RDMMEQCLE Total	RDM Mobile Fuels Equipment	8,950	8,950	8,950	8,950	8,950	8,950	9,200	8,900	8,950	38,950	8,950	8,950	137,600
RDMOHC Total	RDM Overhead Cranes & Hoists	3,000	1,300	5,300	2,400	0	3,000	2,500	1,000	3,500	1,900	2,000	0	25,900
RDMPCM Total	RDM Plant Communications	1,450	2,200	1,000	1,650	1,500	1,700	1,800	1,450	1,600	2,200	1,000	1,850	19,400
RDMPCS Total	RDM Controls/Computer Systems	0	0	15,000	0	0	0	0	0	0	0	0	0	15,000
RDMPFP Total	RDM Bldgs & Grounds:Winterization	1,500	900	900	800	0	0	0	400	100	12,900	1,220	1,000	19,720
RDMPLS Total	RDM Plant Lighting System	2,975	6,375	1,475	10,525	5,625	2,175	2,775	10,125	6,025	4,975	3,175	1,725	68,150
RDMPST Total	RDM Bldgs & Grounds Site Mtce/Improvements	3,000	2,600	2,100	7,700	2,100	3,300	14,200	2,200	3,200	4,150	2,350	3,600	50,500
RDMPVE Total	RDM Vehicles	4,650	4,400	4,300	5,400	4,650	5,800	4,350	3,950	5,050	4,800	4,500	3,250	54,900
RDMPWS Total	RDM Potable Water System	600	350	370	500	2,350	300	900	450	500	800	450	600	8,370
RDMRID Total	RDM Recording/Indicating Devices	1,000	1,500	750	600	225	0	540	450	380	900	1,000	0	7,345
RDMSGU Total	RDM Boilers & Burners	0	0	0	0	0	3,250	3,250	3,250	0	0	0	0	9,750
RDMSGUFDE Total	RDM Fans/Draft System	0	0	0	0	0	3,250	3,250	3,250	0	0	0	0	9,750
RDMSGUFPE Total	RDM Fuel Feed: Mills and Feeders	0	0	0	0	0	3,250	3,250	3,250	0	0	0	0	9,750
RDMSGUPCP Total	RDM Emission Controls:Precipitators	0	0	0	0	0	3,250	3,250	3,250	0	0	0	0	9,750
RDMTGN Total	RDM Turbine/Generator	0	0	0	0	0	3,250	3,250	3,250	0	0	0	0	9,750
RDMWTS Total	RDM Bldgs & Grounds: Sumps	550	650	11,750	4,650	550	8,650	15,250	9,950	4,050	2,850	1,750	550	61,200
RDMWWS Total	RDM Effluent Control(Waste Water Treatment)	950	950	1,000	9,950	950	950	950	900	850	850	850	850	20,000
RDOSGUFPE Total	RDO Mills and Feeders	0											0	0
RH11xxx Total	RH - Major Initiatives	0	0	0	0	0	0	0	24,000	0	0	0	0	24,000
ST111SPG Total	H1 - Planned Outage (General)	0	0	0	615,850	1,041,066	0	0	0	0	0	0	0	1,656,915
ST111SPN Total	H1 - Planned Outage (Nox)	0	0	0	73,000	0	0	0	0	0	0	0	0	73,000
ST111SPO Total	H1 - Planned Outage (Ops)	0	0	0	177,000	0	0	0	0	0	0	0	0	177,000
ST111SPS Total	H1 - Planned Outage (Scrubber)	0	0	0	55,850	99,910	0	0	0	0	0	0	0	155,760
ST111SPT Total	H1 - Planned Outage (Turbine)	0	0	0	2,431,330	901,500	0	0	0	0	0	0	0	3,332,830
ST111USO Total	H1 - Unscheduled Outages	7,000	7,000	7,000	0	0	7,000	7,000	7,000	7,000	7,000	7,000	7,000	70,000
ST111xxx Total	H1 - Major Initiatives	0	60,000	255,000	35,000	0	15,000	30,000	12,000	0	0	0	0	427,000
ST211USO Total	H2 - Unscheduled Outages	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	360,000
ST211xxx Total	H2 - Major Initiatives	0	15,000	0	20,000	0	0	45,000	0	12,000	0	0	0	92,000
STCHCSM Total	FH Consummables	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
STCHOIS Total	FH Outside Industrial Svc	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	78,000
STCHPST Total	FH Buildings & Grounds	6,250	6,250	3,250	7,000	6,250	12,375	6,250	6,250	7,375	3,775	3,250	6,250	74,525
STCHTR Total	FH Tool Room	700	700	700	700	700	700	700	700	700	700	700	700	8,400
STDREDGE Total	ST Dredging Ash Ponds	0	0	0	0	0	5,000	0	0	20,000	0	0	0	25,000
STMASH Total	STM Ash Handling	14,450	42,200	18,000	21,500	7,050	28,250	30,900	40,500	7,300	18,250	13,950	10,550	262,900
STMBFW Total	STM Feedwater System	8,000	5,500	10,700	9,200	5,000	5,800	3,000	8,900	8,300	5,000	11,800	5,500	86,700

Reid/Station Two

2011 O&M Non-Labor Budget (Gross)

Number	Description	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	TOTAL
STMCDS Total	STM Condensate System	2,750	650	3,700	1,650	2,250	1,750	2,575	2,075	11,500	2,150	3,400	1,250	36,700
STMCHS Total	STM Fuel Feed: Fuel Conveying System	3,650	6,375	6,900	7,300	9,300	7,200	10,400	9,100	8,300	8,100	2,650	6,750	86,225
STMCSM Total	STM Consummables	21,650	20,400	19,900	22,400	20,400	21,400	19,400	22,650	23,400	19,400	22,400	17,400	250,800
STMCW Total	STM Cooling Water System	1,600	700	1,800	1,500	1,000	1,700	2,000	1,150	750	700	1,150	0	14,050
STMCWS Total	STM Circulating Water/Cooling Towers	5,050	4,800	5,950	6,900	5,900	6,400	4,850	5,350	6,750	40,400	5,200	4,800	102,150
STMEDT Total	STM Switchgear/Bus	1,900	8,400	7,500	1,400	7,000	8,700	6,850	1,200	7,250	1,200	14,400	1,300	67,100
STMEL Total	STM Bldgs & Grounds: Elevators	4,800	4,800	3,300	4,300	3,800	3,800	3,500	3,200	3,800	3,400	3,800	3,400	45,700
STMEVS Total	STM Emission Controls:CEM	8,250	7,750	10,700	8,550	15,150	6,450	10,850	7,550	7,450	14,300	5,250	7,450	107,500
STMFGD Total	STM Emission Controls: Scrubbers	3,350	7,800	26,800	11,550	3,950	14,325	3,000	5,800	13,400	10,775	9,550	2,300	112,700
STMFGX Total	STM Limestone Grinding/Processing	5,535	16,235	19,534	16,834	13,934	10,134	16,534	3,834	7,334	10,464	5,334	6,334	131,040
STMFGXMEW Total	STM Emission Controls: SDRS Mist Eliminator	0	3,100	3,200	600	0	4,100	200	2,200	2,500	200	1,600	900	18,600
STMFGXPWS Total	STM Emission Controls:SDRS Potable Water	200	200	300	1,800	300	200	300	200	100	200	100	100	3,800
STMFGXSAB Total	STM Emission Controls:SDRS Absorber Bldg	1,500	5,000	2,000	1,000	2,500	1,000	3,800	1,300	2,000	1,500	1,400	1,200	24,000
STMFGXSBB Total	STM Emission Controls:SDRS Scrubber Bldg	150	150	150	1,000	100	200	150	150	150	100	150	100	2,550
STMFGXSTK Total	STM Emission Controls:SDRS Scrubber Stack	500	0	1,000	1,200	0	1,400	0	600	1,700	0	700	700	7,800
STMFGXTRW Total	STM Emission Controls:SDRS Thickener Return	600	8,250	750	750	350	300	750	1,150	750	1,150	550	750	17,300
STMFOS Total	STM Fuel Oil System	900	1,700	1,500	1,150	450	1,100	1,100	1,800	1,300	500	800	900	13,200
STMFPS Total	STM Fire Protection	1,550	2,050	2,750	2,550	1,550	2,050	1,250	2,550	1,550	1,050	4,050	1,050	24,000
STMHVC Total	STM Bldgs & Grounds:HVAC	1,900	3,700	4,415	3,600	5,600	4,500	4,900	3,850	3,700	2,200	3,700	1,900	44,165
STMOHC Total	STM Overhead Cranes & Hoists	1,000	2,500	2,600	3,000	0	1,000	2,000	0	3,600	1,500	2,500	1,000	20,800
STMPAS Total	STM Air System	10,000	4,050	3,000	8,300	21,000	3,000	3,000	2,150	9,900	3,700	2,100	3,000	73,200
STMPCM Total	STM Plant Communications	1,300	1,700	3,100	1,900	1,300	1,900	1,600	1,300	3,200	1,800	1,300	1,200	21,700
STMPCS Total	STM Plant Controls	2,100	1,900	2,100	1,000	3,260	1,000	0	1,000	2,100	2,000	1,400	1,400	19,260
STMPLC Total	STM Controls/Computer Systems	3,100	4,100	122,535	8,100	62,900	16,200	5,600	5,500	4,200	2,900	4,300	4,200	243,635
STMPLS Total	STM Plant Lighting System	11,300	8,200	12,900	12,350	14,950	7,100	7,500	8,800	11,750	14,350	10,100	8,500	127,800
STMPWS Total	STM Service Water System	100	100	100	100	100	100	100	100	100	100	100	100	1,200
STMRID Total	STM Recording/Indicating Devices	900	1,150	3,350	1,500	500	200	500	1,000	1,500	1,500	1,500	0	13,600
STMSCR Total	STM Nox Reduction-SCR Maintenance	8,000	4,000	51,200	26,500	4,000	5,000	4,000	22,200	24,000	21,500	3,000	3,000	176,400
STMSGU Total	STM Boilers & Burners	26,750	39,050	33,750	35,450	37,250	61,300	33,700	26,875	34,225	33,200	27,000	30,500	421,050
STMSGUFDE Total	STM Fans/Draft System	1,800	5,150	4,450	5,100	3,200	9,000	2,900	4,300	6,250	4,400	2,900	3,100	52,550
STMSGUFPE Total	STM Fuel Feed: Mills and Feeders	5,800	9,700	12,000	11,100	3,800	7,400	5,000	4,900	9,900	8,000	11,100	3,900	92,600
STMSGUPRP Total	STM Emission Controls: Precipitators	4,000	6,500	7,000	4,000	6,000	6,000	5,750	5,000	6,750	5,000	3,500	500	62,000
STMTGN Total	STM Turbine/Generator	4,000	5,000	3,100	5,250	3,500	4,000	5,400	7,600	3,150	4,500	4,000	3,000	52,500
STMTGNDGS Total	STM Diesel/Generator	100	70	300	600	300	200	250	330	200	1,250	0	500	4,100
STMTR Total	STM Tool Room	3,500	3,400	4,050	3,250	3,600	4,000	4,700	6,000	5,500	4,500	5,500	4,500	52,500
STMWWS Total	STM Effluent Control(Waste Water Treatment)	350	350	350	1,500	350	400	300	400	300	400	550	350	5,600
STOADM Total	STO Administrative	18,636	18,011	23,161	23,736	18,011	25,831	19,161	23,261	24,761	18,411	18,011	18,040	248,961
STOCHSBUS Total	FH Coal Unloading Barge	0	0	12,000	0	12,000	0	37,000	54,000	25,000	12,000	0	0	152,000
STOCSM Total	STO Consummables	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
STOFGD Total	STO HMPL FGD Shared Equipment	31,869	31,869	31,869	31,869	31,869	31,869	31,869	31,869	31,869	31,869	31,869	31,869	382,428
STOIS Total	STO Outside Industrial Svc	13,800	13,800	13,800	13,800	13,800	13,800	13,800	13,800	13,800	13,800	13,800	13,800	165,600
STOLAB Total	STO Laboratory	14,050	16,550	69,500	25,350	19,400	33,900	14,300	16,850	22,380	17,450	17,000	23,900	280,430
STOMEQ Total	FH Mobile Fuels Equipment	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	216,000
STOMEQCVH Total	STO Vehicles (Mtc, Gas, Oil)	4,450	4,450	4,450	4,450	4,450	4,450	4,450	4,450	4,450	4,450	4,450	4,450	53,400
STOPST Total	STO Buildings & Grounds	13,095	16,095	22,095	11,325	11,325	12,900	12,900	36,400	11,400	11,400	20,400	13,170	192,505
STOSCR Total	STO SCR Operation	9,000	9,000	9,000	24,000	9,000	139,000	9,000	9,000	9,000	86,000	87,000	9,000	407,000
STOSGU Total	STO Boilers and Burners	27,000	30,000	18,000	0	19,200	39,000	18,000	0	27,800	30,000	18,000	9,000	236,000
STOSGUFPE Total	STO Mills and Feeders	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	192,000
STOTGN Total	STO Turbine/Generator	5,330	5,330	5,340	5,330	5,330	5,340	5,330	5,330	5,340	5,330	5,330	5,340	64,000
STOTR Total	STO Tool Room	0	0	2,550	0	1,000	0	1,500	0	350	1,000	0	1,000	7,400
Grand Total		497,170	706,010	1,141,769	4,123,729	2,682,174	924,109	702,404	687,394	787,339	751,939	684,359	466,948	14,155,344
Total 2011 Budget		497,170	706,010	1,141,769	4,123,729	2,682,174	924,109	702,404	687,394	787,339	751,939	684,359	466,948	14,155,344
HMPL Allocation		122,119	182,612	303,864	1,207,299	783,588	224,292	178,485	171,957	172,277	185,808	157,146	114,482	3,803,928
BREC Share		375,051	523,398	837,905	2,916,430	1,898,586	699,817	523,919	515,437	615,062	566,131	527,213	352,466	10,351,416

Big Rivers Electric Cooperative
2009 Capital Budget

Project Description	Gross Capital Budget	City of Henderson Share	Net Capital Budget
Reid / HMPL Station II			
RGH - Confined Space Training Trailer	15,000	1,715	13,285
RGH - HEPA Air Machines (2)	5,000	572	4,428
RGH - Panama Mine Bldg Roof	107,000	12,232	94,768
RGH - Heavy Equipment Bldg Roof	53,000	6,059	46,941
RGH - Used Front Endloader (Rpl 560 Loader)	0	0	0
RGH - Plant Sewage System	300,000	34,296	265,704
RH - Misc Capital Projects	100,000	25,199	74,801
RH - Misc Tools & Equipment	10,000	2,520	7,480
RH - Electric Wrench	5,000	1,260	3,740
RH - Passport Multi Gas	7,000	1,764	5,236
RH - Passport Ammonia	6,000	1,512	4,488
RH - Client & Monitors	20,000	5,040	14,960
RH - 4" Sump Pump & Hose (Moved from '08)	25,750	6,489	19,261
RH - Misc Capital Valves	90,000	22,679	67,321
RH - Misc Conveyor Belts	90,000	22,679	67,321
RH - Booth System Control Box	22,000	5,544	16,456
RH - Loop Calibrators (2)	4,000	1,008	2,992
RH - Plant Phone & PA New System	0	0	0
RH - Control Room Pressurizing Fans	35,000	8,820	26,180
RH - Water Plant Bldg Heat Improvements	25,000	6,300	18,700
H0 - DCS Engineering (Complete in 2010)	166,000	50,545	115,455
H0 - Rpl PI Server & SemAPI	10,000	3,045	6,955
H0 - Upgrade CEMs	30,000	9,135	20,865
H0 - Rpl Bleed Lines 8" (2)	200,000	60,897	139,103
H0 - Rpl Elevator Doors/Frames	100,000	30,449	69,551
H0 - Rpl Thickener Return Line 16"	200,000	60,897	139,103
H0 - Wetbottom Drains	300,000	91,346	208,654
H1 - Rpl WDPF FGD & SCR Controls	140,000	42,628	97,372
H1 - CCS Field Wiring & Devices	118,565	36,102	82,463
H1 - CCS Controls	461,435	140,501	320,934
H1 - Control Room	100,000	30,449	69,551
H1 - AH Inlet Expansion Joints (2)	160,000	48,718	111,282
H1 - Burner Deck Vent Fans	30,000	9,135	20,865
H1 - Cooling Tower Distribution Deck	200,000	60,897	139,103
H1 - FD Fan Outlet Damper A&B Rexa Drives	20,000	6,090	13,910
H1 - Feedwater Heater Emergency drain Valve	160,000	48,718	111,282
H1 - Hydrogen Purity Meters	22,000	6,699	15,301
H1 - Install Sootblower Power Disconnects	16,000	4,872	11,128
H1 - Rpl Mist Eliminator	175,000	53,285	121,715
H1 - Rpl Precip Hoppers (9-12) 4 total	250,000	76,122	173,878
H1 - Rpl Slag Grinders (2)	75,000	22,837	52,163
H1 - Rpl Sootblowers (20-23 of 23) 4 total	112,000	34,103	77,897
H1 - Rpl Wallblowers (8-10 of 24) 3 total	40,000	12,179	27,821
H1 - Rpl Temperature Reheater Tubes	1,400,000	306,943	1,093,057
H2 - Burner Deck Vent Fans	30,000	9,135	20,865
H2 - Rpl WDPF FGD & SCR Controls	60,000	18,269	41,731
H1 - High Energy Pipe Hangers	100,000	30,449	69,551
H1 - Rpl AH Steam Coils (2)	21,000	6,394	14,606
H2 - #6 HP Heater Re-tube	300,000	91,346	208,654
R1 - Rpl Reclaim Vent Fan	30,000	0	30,000
R1 - Stack Lighting	200,000	0	200,000
R1 - Upgrade CEMs	20,000	0	20,000
HMPL Stack Lighting	287,558	87,558	200,000
R-CT reliability study & upgrades	1,125,509	0	1,125,509
HMPL SCR Catalyst Replacement-additional $ (net)	878,102	267,371	610,731
H Replace layer of catalyst	305,800	93,112	212,688
Total Reid / HMPL Station II	**$ 8,763,719**	**$ 2,015,910**	**$ 6,747,809**

Big Rivers Electric Cooperative

2010 Capital Budget

Project Description	Gross Capital Budget	City of Henderson Portion	Net Capital Budget
Reid / HMPL Station			
RGH - Stack Climbing Devices (2)	20,000	2,286	17,714
RGH - Rpl Panama Bldg External Sheeting	40,000	4,573	35,427
RH - Misc Capital Projects	100,000	25,199	74,801
RH - Misc Tools & Equipment	10,000	2,520	7,480
RH - Electric Welding Machine	5,000	1,260	3,740
RH - Client & Monitors	20,000	5,040	14,960
RH - 1 Ton Mtc Truck (Rpl S9 - 1990 Ford)	20,000	5,040	14,960
RH - Misc Capital Valves	90,000	22,679	67,321
RH - Misc Conveyor Belts	90,000	22,679	67,321
RH - "5A" Raw River Reclaim vent fans	25,000	6,300	18,700
RH - 480 Volt Welder	3,000	756	2,244
RH - Barge Unloader Bucket	70,000	17,639	52,361
RH - Rpl 480 Volt MCC	200,000	50,398	149,602
RH - Rpl River Intake 480 Volt MCC	100,000	25,199	74,801
RH - Temperature Bath Calibrator	8,000	2,016	5,984
H0 - Rpl F1-F4 Building Heating Fans	200,000	60,897	139,103
H0 - DCS Engineering (Complete in 2010)	99,600	30,327	69,273
H2 - Rpl WDPF FGD & SCR Controls	90,000	27,404	62,596
H1 - Performance OPT Software	150,000	45,673	104,327
H0 - Rpl PLC Controls for Water Plant	20,000	6,090	13,910
H1 - Cooling Tower Controls	12,000	3,654	8,346
H1 - Feedwater Heater Level Controls	7,000	2,131	4,869
H1 - Precipitator Controls	3,000	913	2,087
H2 - Performance OPT Software	150,000	45,673	104,327
H2 - AH Outlet Expansion Joint	85,000	25,881	59,119
H2 - Burner Igniter Conversion	150,000	45,673	104,327
H2 - High Energy Pipe Hangers	35,000	10,657	24,343
H2 - Rpl Mist Eliminator	175,000	53,285	121,715
H2 - Rpl Precip Hoppers on #9-#12	200,000	60,897	139,103
H2 - Rpl Precip Outlet Duct to Bypass Stack Breeching	300,000	91,346	208,654
H2 - Rpl Slag Grinders (2)	75,000	22,837	52,163
H2 - Rpl Sootblowers (14-17 of 23) 4 total	115,000	35,016	79,984
H2 - Rpl Wallblowers (4-6 of 24) 3 total	48,000	14,615	33,385
H2 - Feedwater Heater Emergency Drain Valve	160,000	48,718	111,282
H2 - Voltage Regulator	175,000	53,285	121,715
H2 - Waterwall Overlay	1,000,000	363,375	636,625
H2 - #5 Heater Retube	300,000	91,346	208,654
H2 - Boiler to AH Breeching Expansion Joints (2)	160,000	48,718	111,282
H2 - Rpl AH Steam Coils (2)	20,000	6,090	13,910
R1 - Rpl AH Steam Coils (2) - Moved from 2009	20,000	0	20,000
HMPL SCR Catalyst Replacement	958,746	291,926	666,820
Total Reid / HMPL Station II	**$ 5,509,346**	**$ 1,680,013**	**$ 3,829,333**

Big Rivers Electric Cooperative

2011 Capital Budget

Project Description	Gross Capital Budget	City of Henderson Portion	Net Capital Budget
Reid / HMPL Station			
RGH - Stack Climbing Devices (2)	20,000	2,286	17,714
RH - Misc Capital Projects	100,000	25,199	74,801
RH - Misc Tools & Equipment	10,000	2,520	7,480
RH - Client & Monitors	20,000	5,040	14,960
RH - Replace D8N with a D8T	600,000	151,194	448,806
RH - Rpl Band Saw	12,000	3,024	8,976
RH - Misc Capital Valves	90,000	22,679	67,321
RH - Misc Conveyor Belts	90,000	22,679	67,321
RH - Plant Phone & PA New System	650,000	163,793	486,207
RH - Rpl Silo Sump Pump Discharge Line	120,000	30,239	89,761
RH - Truck Hopper Vent Fan	25,000	6,300	18,700
RH - Rpl DI Water Plant Components	275,000	69,297	205,703
RH - Ground Resistance Tester	6,000	1,512	4,488
RH - Water Plant Heating System	25,000	6,300	18,700
RH - Rpl Barge Unloader Switching Center	100,000	25,199	74,801
H0 - CT Sump Pump (make-up pit)	12,000	3,654	8,346
H0 - Rpl PLC Controls for Water Plant	180,000	54,808	125,192
H1 - Cooling Tower Controls	113,000	34,407	78,593
H1 - Feedwater Heater Level Controls	68,000	20,705	47,295
H1 - Precipitator Controls	27,000	8,221	18,779
H1 - Burner Igniter Conversion	150,000	45,673	104,327
H1 - AH Outlet Expansion Joint	85,000	25,881	59,119
H1 - Economizer Outlet Expansion Joint	85,000	25,881	59,119
H1 - Rpl Slag Grinders (2)	75,000	22,837	52,163
H1 - Wet Bottom Vent Fans	25,000	7,612	17,388
H1 - Feedwater Heater Extraction MOV	160,000	48,718	111,282
H1 - Rpl Wallblowers (11-13 of 24) 3 total	50,000	15,224	34,776
H1 - Blading Replacement	125,000	38,061	86,939
H1 - Burner Replacement (added $200K)	3,200,000	974,359	2,225,641
H1 - Nozzle Coating	100,000	30,449	69,551
H1 - Turbine packing HP-IP rows	125,000	38,061	86,939
H1 - High Energy Pipe Hangers	45,000	13,702	31,298
H1 - Addition of 480 Volt MCC's (1 ea)	200,000	60,897	139,103
H1 - Rpl 480V MCC at Cooling Tower	300,000	91,346	208,654
H1 - Transformer Deluge System	35,000	10,657	24,343
H1 - Rpl AH Steam Coils (2)	22,000	6,699	15,301
H1 - Install Servo Valve Isolation & Filter Block	50,000	15,224	34,776
H1 - Server Replacement	20,000	6,090	13,910
H1 - Catalyst Regeneration	737,000	224,407	512,593
H2 - Turbine Trip Block Upgrade	20,000	6,090	13,910
H2 - Cooling Tower Controls	12,000	3,654	8,346
H2 - Feedwater Heater Level Controls	7,000	2,131	4,869
H2 - Precipitator Controls	3,000	913	2,087
H2 - Wet Bottom Vent Fans	25,000	7,612	17,388
H2 - Loop Seal Vapor Extractor Frequency Drive	2,000	609	1,391
R1 - Rpl Boiler Roof	55,000	0	55,000
Total Reid / HMPL Station II	**$ 8,256,000**	**$ 2,381,843**	**$ 5,874,157**

BIG RIVERS ELECTRIC CORPORATION'S
SUPPLEMENTAL RESPONSE TO THE ATTORNEY GENERAL'S
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Item 94) Please refer to page 2 of the (claimed confidential) Stone and Webster report, attached to the Smelters' Response to OAG #3, where it states: "The Big Rivers capital budget amount is larger than the WKE capital budget for each unit." Explain why the Big Rivers capital budget is larger than the WKE capital budget for each unit.

Response) Attached, Big Rivers presents a chart detailing by unit the capital budget items included in the most recent Big Rivers capital budget that are not included in the WKEC capital budget referenced in this question. Individual unit budget line items and their increased costs are presented in this chart. The chart also summarizes the differences in each year 2009 through 2017 as well as summarizing the total differences for the period 2009 through 2017.

Witness) Mark A. Bailey

BREC Capital Budget Items Not in the WKE Capital Budget

Item Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	TOTAL 2009-2017
Coleman										
(none)										
Green										
Green 2 Precip Repair	$ 1,060,900		$ 1,125,509							$ 2,186,409
Green 1 Precip Repair		$ 1,092,727		$ 1,159,274						$ 2,252,001
Green 1&2 FGD Rehab	$ 4,243,600	$ 3,020,908	$ 2,251,018							$ 9,515,526
Green 1&2 Paint Boiler, Precip & FGD	$ 1,442,824	$ 1,486,109	$ 1,530,692	$ 1,576,613	$ 1,623,911					$ 7,660,149
HMP&L										
HMPL Stack Lighting	$ 200,000									$ 200,000
Reid 1 and CT										
R-CT reliability study & upgrades	$ 1,125,509									$ 1,125,509
Reid CT Cooling Tower Repair							$ 1,827,604			$ 1,827,604
Wilson										
Make flue gas SO3 treat. System permanent.		$ 1,138,500	$ 2,225,641							$ 3,364,141
WL FGD Additional Amount for Inlet Guillotine (net diff)	$ 300,000									$ 300,000
WL FGD Additional Amount for Outlet Guillotine (net diff)	$ 300,000									$ 300,000
WL FGD Recycle Pump Suction Valve Replacement (8)	$ 280,000									$ 280,000
WL FGD Repl 3 absorber mist eliminator panels & mounting frames	$ 900,000									$ 900,000
WL FGD Repl mist eliminator piping & nozzles	$ 470,000									$ 470,000
WL FGD Structural Improvements		$ 2,425,000								$ 2,425,000
WL FGD Repl 75 stack tension bands with 316L SS material		$ 850,000								$ 850,000
WL FGD Repl 4 dewatering filter drums incl vacuum skids & pumps		$ 1,700,000								$ 1,700,000
WL FGD Repair ductwork hot and wet sides			$ 3,114,272							$ 3,114,272
WL FGD PLC FGD/Flyash Control System Replacement			$ 20,000							$ 20,000
WL FGD Structural Improvements (net diff)			$ 1,675,000							$ 1,675,000
WL FGD Inlet and outlet damper replacement 2 absorbers			$ 1,200,000							$ 1,200,000
										$ -
Total Added Capital	$ 10,322,833	$ 11,713,244	$ 13,142,132	$ 2,735,887	$ 1,623,911	$ -	$ 1,827,604	$ -	$ -	$ 41,365,611

Note: Total Added for WL FGD 2009-2013 - $13,234,272

BIG RIVERS ELECTRIC CORPORATION'S
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Item 95) Please refer to page 4 of the (claimed confidential) Stone & Webster report, attached to the Smelter's Response to OAG #3, where it states: "The one concern that Stone & Webster Consultants has is that Big Rivers has included in their Business Plan a very comprehensive capital expenditure and major modification plan over the next five years. Stone & Webster Consultants' opinion is that the WKE capital expenditure budget should be the baseline and that additional capital expenditures may be required." Please provide:

a. A sensitivity run of the Unwind Financial Model (Exhibit 8), with the sole change being to utilize the WKE capital expenditure budget in place of the capital expenditures contained in the model.

b. Indicate whether any other inputs should be changed in concert with this change in capital expenditures in order to maintain internal consistency of results, and specify any such other inputs that should be changed, and why.

c. An electronic spreadsheet copy (.xls file) of the sensitivity run in a, above.

Response) a. b. and c. As Big Rivers noted in its original response to this question, the Stone & Webster report refers to an outdated version of Big Rivers Production Work Plan that has evolved over time. Big Rivers in its March 6, 2008 response accordingly provided a response demonstrating the incremental impact on rates of removing the referenced differences in capital budget items based on the then-current Big Rivers Production Work Plan. The Big Rivers Production Work Plan has since been revised as described in the October 9, 2008 filings.

Using Big Rivers' Unwind Financial Model, Big Rivers has performed a new sensitivity run using the updated Big Rivers Production Work Plan to demonstrate the incremental impact on rates of removing the referenced differences in capital budget items as provided in the updated response to AG Supplemental Item 94. The results of this sensitivity run are shown in Tables 1 and 2 attached. A CD with an electronic

spreadsheet copy of the tables and the sensitivity run of the Financial Model is attached. As before, it would be difficult if not impossible to note each and every input difference between the WKEC plan and the current Big Rivers plan. The request would take a line item by line item review of each plan to determine differences and to explain.

Witness) Mark A. Bailey
Robert S. Mudge

BIG RIVERS ELECTRIC CORPORATION'S
SUPPLEMENTAL RESPONSE TO THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION TO JOINT APPLICANTS
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TABLE 1

		Wtd Avg	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Member Non-Smelters																
	Base Case																
1	Base	37.01	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	38.67	38.64	38.62	38.61	38.58	38.56	38.67
2	Regulatory Account	0.60	-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
3	FAC	11.91	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
4	Env. Surcharge	4.72	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
5	Surcredit	(3.80)	(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
6	Rebate Realized	(0.11)	-	(0.09)	(1.69)	-	-	-	-	-	-	-	-	-	-	-	-
7	MRSM	(2.85)	(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
8	Effective Rate - Cash	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
	Incremental BREC Capex Removed																
1	Base	36.90	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	38.43	38.41	38.39	38.37	38.35	38.33	38.47
2	Regulatory Account	0.60	-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
3	FAC	11.91	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
4	Env. Surcharge	4.72	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
5	Surcredit	(3.80)	(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
6	Rebate Realized	(0.11)	-	(0.10)	(1.75)	0.00	-	(0.00)	-	-	-	-	-	-	-	-	-
7	MRSM	(2.85)	(10.13)	(10.07)	(8.32)	(10.19)	(9.35)	-	-	-	-	-	-	-	-	-	-
8	Effective Rate - Cash	47.37	35.45	37.42	39.29	41.26	44.07	47.01	47.49	47.64	49.71	50.31	50.61	52.44	52.65	53.34	53.78

Attachment to AG's Supplemental Request Item 95

BIG RIVERS ELECTRIC CORPORATION'S
SUPPLEMENTAL RESPONSE TO THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
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November 7, 2008

TABLE 2

		Wtd Avg	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Smelters																
	Base Case																
1	Lg. Indus. Rate @ 98% LF	29.17	27.90	27.90	27.90	27.86	27.90	27.90	27.90	27.86	30.62	30.62	30.62	30.58	30.62	30.62	30.71
2	Addl. Smelt. Charge	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
3	Base	29.42	28.15	28.15	28.15	28.11	28.15	28.15	28.15	28.11	30.87	30.87	30.87	30.83	30.87	30.87	30.96
4	TIER Adjustment	2.40	-	-	1.79	2.25	1.59	1.64	2.78	2.59	3.55	0.54	3.67	2.97	4.30	3.53	4.75
5	FAC	12.01	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
6	Env. Surcharge	4.60	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
7	PPA	0.97	0.08	(0.39)	0.48	0.27	0.57	0.26	0.44	0.58	2.09	0.88	1.78	1.15	2.07	1.74	2.54
8	Surcharge	2.15	1.57	1.57	1.57	1.87	1.87	1.87	1.87	1.87	2.60	2.60	2.60	2.59	2.60	2.60	2.60
9	Rebate Realized	(0.12)	-	(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-
10	Effective Rate - Cash	51.42	43.20	44.61	47.46	52.33	53.92	46.67	48.42	48.44	54.47	50.77	55.05	54.30	56.77	56.32	58.53
	Incremental BREC Capex Removed																
1	Lg. Indus. Rate @ 98% LF	29.08	27.90	27.90	27.90	27.86	27.90	27.90	27.90	27.86	30.44	30.44	30.44	30.39	30.44	30.44	30.56
2	Addl. Smelt. Charge	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
3	Base	29.33	28.15	28.15	28.15	28.11	28.15	28.15	28.15	28.11	30.69	30.69	30.69	30.64	30.69	30.69	30.81
4	TIER Adjustment	2.29	-	-	1.59	1.95	1.28	1.32	2.46	2.26	3.55	0.54	3.69	2.99	4.34	3.57	4.75
5	FAC	12.01	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
6	Env. Surcharge	4.60	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
7	PPA	0.97	0.08	(0.39)	0.48	0.27	0.57	0.26	0.44	0.58	2.09	0.88	1.78	1.15	2.07	1.74	2.54
8	Surcharge	2.15	1.57	1.57	1.57	1.87	1.87	1.87	1.87	1.87	2.60	2.60	2.60	2.59	2.60	2.60	2.60
9	Rebate Realized	(0.13)	-	(0.10)	(1.79)	-	-	-	-	-	-	-	-	-	-	-	-
10	Effective Rate - Cash	51.22	43.20	44.61	47.19	52.04	53.61	46.36	48.10	48.12	54.28	50.60	54.88	54.14	56.62	56.18	58.37

Attachment to AG Supplemental Request Item 95

BIG RIVERS ELECTRIC CORPORATION'S
SUPPLEMENTAL RESPONSE TO THE ATTORNEY GENERAL'S
SUPPLEMENTAL REQUEST FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
(Original Response March 6, 2008)
November 7, 2008

Item 99) Please refer to Sections 8 of the (claimed confidential) Stone and Webster report, attached to the Smelters' Response to OAG #3, which provides a technical assessment of operations and maintenance. Provide documents which compare annual operations and maintenance expenditure amounts incorporated in the Unwind Financial Model for purposes similar or identical to Stone & Webster's recommended annual operations and maintenance expenditure levels. To the extent the Unwind Financial Model contains lower projected annual expenditure amounts than Stone & Webster's recommended level explain how Big Rivers will address the negative consequences of such lack of expenditure as outlined in this report.

Response) The updated Big Rivers Production Work Plan which is included in the updated Unwind Financial Model (Exhibit 79) contains detailed O&M expenses for 2009 through 2011. Please see the attachment, which reconciles the WKEC current O&M plan to the now updated Big Rivers Plan. Individual Non-Labor Fixed O&M Budget items are presented for each unit over the period 2009 through 2023. As before, there is no O&M table in the Stone & Webster report to compare against, and Big Rivers has made no attempt to extrapolate the numbers.

Witness) Mark A. Bailey

BREC non-Labor Fixed O&M Budget Items Not in the WKE Budget

(response to AG request # 11 dated 10/24/2008 updated AG request # 99)

Item Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman																
structural & life-assess. Inspections		$265,225	$273,182	$281,377												
clean coal dust & ash from boilers, etc		$106,090														
Coleman Ash Pond dredging		$265,225														
Green																
structural & life-assess. Inspections		$265,225	$273,182													
clean coal dust & ash from boilers, etc		$106,090														
Green ash pond dredging										$3,566,057						
HMP&L																
structural & life-assess. Inspections		$265,225	$273,182													
clean coal dust & ash from boilers, etc		$106,090														
SCR Catalyst Regeneration																
R/HMPL Ash pond dredging								$5,508,362								
Reid																
structural & life-assess. Inspections		$265,225														
clean coal dust from boilers, etc		$106,090														
R-1 Lay-Up										$1,200,000						
Wilson																
structural & life-assess. Inspections		$265,225														
clean coal dust from boilers, etc		$106,090														
SCR Catalyst Regeneration																
sub-Total	$0	$2,121,800	$819,546	$281,377	$0	$0	$0	$5,508,362	$0	$4,766,057	$0	$0	$0	$0	$0	$0
Total	$13,497,142															

Summary of Changes Since the Filed Response to AG Request # 99

SCR Catalyst Regeneration moved from O&M expense to capital, consistent with WKE capitalization guidelines ($41,093,615 Total)
Added $1,200,000 in 2017 for the possible lay-up of R-1
Added $3,566,057 in 2017 to dredge the Green ash pond

BIG RIVERS ELECTRIC CORPORATION'S
SUPPLEMENTAL RESPONSE TO THE ATTORNEY GENERAL'S
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Item 100) Please refer to Sections 8 of the (claimed confidential) Stone and Webster report, attached to the Smelters' Response to OAG #3, provide documents which show SO_2 emissions, SO_2 allowances, and net excess/shortfall of allowances by year.

Response) Attached is an updated table depicting forecasted SO2 emissions, allowances allotted and consumed, and net allowance excess/shortfalls by year.

Witness) David A. Spainhoward

BIG RIVERS ELECTRIC CORPORATION'S
SUPPLEMENTAL RESPONSE TO THE ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION TO JOINT APPLICANTS
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Emissions Costs (Nominal dollars)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
forecasted SO2 allowance Price	$ 140	$ 115	$ 434	$ 439	$ 438	$ 425	$ 294	$ 288	$ 265	$ 247	$ 195	$ 144	$ 122	$ 106	$ 98
Total SO2(ktons) - emitted	20.430	21.740	20.538	21.040	20.628	21.140	20.836	21.282	19.910	21.199	20.456	21.001	20.812	21.263	20.716
Total SO2(ktons) - REQUIRED for compliance	20.430	21.740	41.076	42.080	41.256	42.281	59.591	60.865	56.944	60.630	58.504	60.063	59.521	60.812	59.247
Total SO2 Allowances (ktons)	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487
sub-total SO2 tons left for BREC	32.057	30.747	11.411	10.407	11.231	10.206	(7.104)	(8.378)	(4.457)	(8.143)	(6.017)	(7.576)	(7.034)	(8.325)	(6.760)
Station II SO2(ktons) - emitted	4.285	4.289	4.122	4.092	4.289	4.285	4.297	4.317	4.259	4.273	4.143	3.928	4.314	4.328	4.217
Station II SO2(ktons) - REQUIRED for compliance	4.285	4.289	8.244	8.184	8.578	8.569	12.289	12.346	12.180	12.220	11.849	11.233	12.339	12.379	12.061
Station II Allowances (ktons)	11.694	11.694	11.694	11.694	11.694	11.694	11.694	11.694	11.694	11.694	11.694	11.694	11.694	11.694	11.694
Excess H-1&2 Allowances Back to City (30% of net)	2.223	2.221	1.035	1.053	0.935	0.937	0.000	0.000	0.000	0.000	0.000	0.138	0.000	0.000	0.000
SO2 allowances (ktons) left	29.834	28.526	10.377	9.354	10.296	9.269	(7.104)	(8.378)	(4.457)	(8.143)	(6.017)	(7.715)	(7.034)	(8.325)	(6.760)
SO2 allowances Sales	$4,176,763	$3,280,485	$4,503,410	$4,106,353	$4,504,500	$3,939,334	($2,091,361)	($2,416,757)	($1,179,635)	($2,010,195)	($1,180,289)	($1,114,066)	($860,861)	($879,123)	($659,417)

(Assumes CAIR resumes in 2011)
(model run: annual output - 09-08-08)

BIG RIVERS ELECTRIC CORPORATION'S
SUPPLEMENTAL RESPONSE TO THE ATTORNEY GENERAL'S
SUPPLEMENTAL REQUEST FOR INFORMATION TO JOINT APPLICANTS
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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 is not aware of any consent fees that will be required of it to close the Unwind Transaction.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S OCTOBER 24, 2008
SUPPLEMENTAL REQUEST FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
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Item 12) Please state whether or not any further agreements or understandings exist between BREC and any other party or entity regarding the proposed transaction which have not been explicitly identified or presented to the Commission which could be construed or understood as a "side deal" as that term is commonly understood. If any such "side deal" does exist, identify each one and describe it in detail.

Response) Big Rivers has disclosed to the Commission all agreements with any person respecting the Unwind Transaction. The agreement for Big Rivers to make the additional payment to the Smelters described in the Supplemental Testimony of C. William Blackburn at pages 53 and 54 of Exhibit 78 must be memorialized, but the material agreement is as described.

Witness) Mark A. Bailey

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S OCTOBER 24, 2008
SUPPLEMENTAL REQUEST FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
November 7, 2008

Item 13) Please provide a demonstration that Rural sales (e.g, 2.44 TWh for 2009) are in fact synchronized with Rural operating receipts (e.g., $90.8 million for 2009), such that the operating receipts would in fact be received within the calendar year as shown.

a. Please identify and estimate any factors which might or would cause BREC's operating receipts as modeled for Rural consumers to be different than actual receipts (assuming identical volumes).

Response) The correspondence of Rural sales (2.44 TWh for 2009) to Rural operating receipts ($90.8 million for 2009) in the Financial Model (Exhibit 79) can be shown by:

i) calculating the Effective (cash) rate for rural customers (line 4 divided by line 5, on page 2 of 2), and

ii) showing how the cash rate differs from the accrued rate, which difference is based on the timing of Rebate payments (lines 10 and 11, on page 2 of 2).

Big Rivers' operating receipts for Rural consumers in 2009 will be based on existing tariff rates, plus the Fuel Adjustment Charge (FAC), the Regulatory Account Charge, the Environmental Surcharge (ES), Smelter Surcredit, and draws on the Economic Reserve. No Rebate is paid in 2009. Tariff rates for 2009 are not expected to depart from those modeled. The FAC and ES will be subject to adjustment periodically through 2009, but are reflected in the Financial Model on an average basis for the year (as are underlying costs). The Smelter Surcredit is a negotiated payment under the Smelter Agreements.

Note that, to the degree assumptions beyond sales volumes such as fuel costs were to change within a reasonably expected range, effective rates to Rural consumers would be held constant by adjustments to draws on the Economic Reserve.

	Rural Rates	Location in Financial Model	2009
1			
2	*i) Effective (Cash) Rate Derivation ($/ MWh)*		
3	Operating Receipts (M$)	Proforma, line 107	90.8
4	Divided by: Sales (TWH)	Proforma, line 3	2.44
5	Effective Rate ($/MWh)	line 4/ line 5	37.22
6			
7	*ii) Reconciliation of Effective (Cash) Rate to Accrued Rate*		
8	Cash Rate ($/MWh)	Line 6	37.22
9	Add Back Rebate Realized Based on Prior Year ($/MWh)		-
10	Recognize Rebate Accrued in Current Year ($/MWh)	Proforma, line 45	(0.10)
11	Accrual Rate ($/MWh)	Proforma, line 46	37.12
12			

Witness) Robert S. Mudge

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Item 14) Please provide a demonstration that Smelter sales (e.g, 7.30 TWh for 2009) are in fact synchronized with Smelter operating receipts (e.g., $314.6 million for 2009), such that the operating receipts would in fact be received within the calendar year as shown.

a. Please identify and estimate any factors which might or would cause BREC's operating receipts as modeled for Smelter consumers to be different than actual receipts (assuming identical volumes).

Response) The correspondence of Smelter sales (7.30 TWh for 2009) to Smelter operating receipts ($315.3 million for 2009[1]) in the Financial Model can be shown by:

i) calculating the Effective (cash) rate for Smelter consumers (line 4 divided by line 5, page 2 of 2), and

ii) showing how the cash rate differs from the accrued rate, which difference is based on the timing of Rebate payments (lines 10 and 11, page 2 of 2).

Big Rivers' operating receipts for Smelter consumers in 2009 will be based on existing tariff rates (via the large industrial rate, load-factor adjusted), plus a negotiated $0.25/ MWh surcharge, the TIER Adjustment, the Fuel Adjustment Charge (FAC), Power Purchase Adjustment (PPA), Environmental Surcharge (ES), and Smelter Surcharges. No Rebate is paid in 2009. Tariff rates underlying the Large Industrial rate for 2009 are not expected to depart from those modeled. The TIER Adjustment, FAC, ES, and PPA will be subject to adjustment periodically through 2009 but are reflected in the Financial

[1] The amount of $314.6 million cited in question 14 above corresponds to accounting income from Smelter sales in 2009, not operating receipts.

Model on an average basis for the year (as are underlying costs). The Smelter Surcharges are negotiated payments under the Smelter Agreements.

Note that, to the degree assumptions beyond sales volumes--such as fuel costs--were to change, they would be reflected in changes to Smelter rates.

	Smelter Rates	**Location in Financial Model**	**2009**
1			
2			
3	*i) Effective (Cash) Rate Derivation ($/ MWh)*		
4	Operating Receipts (M$)	Proforma, line 109	315.27
5	Divided by: Sales (TWH)	Proforma, lines 7 + 9	7.30
6	Effective Rate ($/MWh)	line 4/ line 5	43.20
7			
8	*ii) Reconciliation of Effective (Cash) Rate to Accrued Rate*		
9	Cash Rate ($/MWh)	Line 6	43.20
10	Add Back Rebate Realized Based on Prior Year ($/MWh)		-
11	Recognize Rebate Accrued in Current Year ($/MWh)	Proforma, line 97	(0.10)
12	Accrual Rate ($/MWh)	Proforma, line 98	43.11

Witness) Robert S. Mudge

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Item 15) The Unwind Financial Model includes projections of cash balances, which appear to be determined on a net basis from modeled receipts, costs, investing, and modeling assumptions and processes.

a. Does BREC agree with this statement and characterization? If not, please state why not.

b. Please compare and contrast the model's projected cash balances to the minimum cash cushion that BREC will need for purposes of operating the business going forward.

c. Please estimate and quantify the minimum cash cushion that BREC will need to operate the business over the next five years, as compared to the model's projected cash balances for the same period.

Response) a. Big Rivers agrees with the statement and characterization in part a of question 15, when the additional factor of capital markets borrowings starting at the end of 2011 is additionally taken into account.

b. Average cash balances, projected line of credit, and Days Cash on Hand are reproduced from the Financial Model of 10/08, page 3 of 3. Overall through 2023, cash balances average $115 million inclusive of the Transition Reserve. Including Big Rivers' anticipated line of credit, average liquidity is modeled at $215 million. Average Days Cash on Hand stands at 73 days --or approximately 2 and 1/2 months-- without the line of credit and 135 days--or 4 and 1/2 months--including the line of credit.

Big Rivers has had several conversations with Mark Glotfelty of Goldman Sachs and Company, concerning the level of cash Big Rivers needs to maintain in order to obtain an investment grade rating. Based on these discussions, Big Rivers has learned that there is not a hard and fast rule that the rating agencies use to determine the exact amount of cash a company should carry as a minimum cushion.

Generally, Rating agencies like to see a company carry a minimum cash cushion of 90 days of operating expenses (enough for approximately one financial quarter). In order to operate the business and maintain eligibility for an investment grade rating, Big Rivers determined that it would target at least 90 days of cash on hand at all times in the Unwind Financial Model. Line 351 of the attached table shows the cash on hand including the lines of credit that Big Rivers intends to carry in the future. The lowest projected level of cash on hand occurs in 2017, where Big Rivers is projected to have 109 days of cash on hand.

If we look at cash only and exclude any lines of credit, Line 352 of the attached table shows a strong cash position for years 2009, 2010 and 2011. Big Rivers in the future will evaluate its operating cash levels in light of current circumstances and if the cash levels as modeled today materialize, Big Rivers will determine if the cash levels are sufficient to maintain its investment grade rating, and if not, will pursue changes as necessary.

c. Over the next five years, cash balances average $134 million inclusive of the Transition Reserve. Including Big Rivers' anticipated line of credit, average liquidity is modeled at $234 million. Average Days Cash on Hand stands at 85 days --or nearly 3 months--without the line of credit and 148 days--or nearly 5 months--including the line of credit.

Witness) C. William Blackburn

Cash Analysis * - $Millions (unless otherwise indicated)

		Averages		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
		Overall	1st 5 Years															
333	Days Cash on Hand																	
334	Average Cash Balance	115.3	133.7	148.7	139.9	152.3	132.9	94.9	87.7	185.5	179.4	75.1	84.4	90.3	83.9	86.4	92.8	96.1
335	Line of Credit	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
336	Total	215.3	233.7	248.7	239.9	252.3	232.9	194.9	187.7	285.5	279.4	175.1	184.4	190.3	183.9	186.4	192.8	196.1
337	Divided by																	
338	Total Operating Expense																	
339	PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
340	Fuel Costs	286.7	316.7	270.8	301.0	305.8	339.5	366.4	276.1	259.3	261.7	260.2	267.6	268.0	275.4	277.0	285.9	285.5
341	SEPA & Other Purchases	33.1	23.9	22.8	19.3	25.9	24.3	27.1	26.5	28.1	29.4	41.7	31.9	38.8	39.1	46.6	44.0	51.3
342	Non-Fuel Variable Production O&M	49.1	36.7	30.8	33.7	38.3	39.9	40.9	41.8	51.4	53.0	52.9	55.3	55.3	58.1	60.4	61.4	63.3
343	Fixed Production O&M	115.2	102.1	101.3	93.3	105.0	104.9	106.0	102.3	111.8	108.5	129.6	113.5	129.3	123.8	133.5	128.7	137.0
344	Transmission O&M	9.9	8.5	8.0	8.3	8.5	8.8	9.0	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.4	11.8	12.1
345	APM, L/C, Cogen, CW & TVA Trans	6.6	6.0	6.3	6.5	5.8	5.7	5.9	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
346	A&G	33.6	29.3	29.5	27.8	29.2	29.5	30.3	31.7	32.1	33.0	34.3	35.1	36.0	37.5	38.2	39.5	40.9
347	Property Taxes & Insurance	9.5	7.8	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
348	Interest Expense (Incl. Financing Fees)	43.4	49.9	53.1	48.9	48.4	51.0	47.9	46.4	44.8	43.5	42.0	40.4	40.1	38.4	36.9	35.2	33.7
349	Total	587.2	580.9	529.7	545.7	574.8	612.2	642.3	549.2	552.5	554.9	587.5	571.3	595.8	601.2	622.5	625.5	643.5
350																		
351	*Days Cash on Hand (including Line of Credit)*	135.1	148.3	171.3	160.4	160.2	138.8	110.8	124.8	188.6	183.8	108.8	117.8	116.6	111.6	109.3	112.5	111.2
352	*Days Cash on Hand (excluding Line of Credit)*	72.7	85.2	102.4	93.6	96.7	79.2	53.9	58.3	122.5	118.0	46.6	53.9	55.3	50.9	50.6	54.1	54.5

* Including Transition Reserve

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Item 16) Has BREC modeled projected future rates for Rural consumers, assuming current BREC circumstances and position, and that the Unwind Transaction does not occur? If so, please provide this financial modeling including the projected future rates for Rural consumers (unblended).

Response) Big Rivers provided PSC staff with data corresponding to the "Existing Transaction" which assumes the Unwind Transaction does not occur and further assumes Big Rivers' current circumstances and position (including lease buyouts), as Exhibit 100 to Big Rivers' filing dated October 9, 2008. Projected future wholesale rates to Big Rivers' members for rural delivery points (unblended) corresponding to Exhibit 100 are provided on the following page:

Witness) Robert S. Mudge

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	Wtd. Avg.	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Future rates for rural delivery points (unblended) corresponding to Exhibit 100 ("Existing Transaction Economics, 10/08/08")																
Arbitrage Case	41.80	44.36	38.87	38.80	40.85	40.83	40.80	40.77	40.74	40.72	40.70	40.68	44.37	44.35	44.33	44.31
Smelter Case	47.78	44.36	38.87	47.51	49.14	45.65	45.62	45.59	48.26	48.23	48.21	48.18	50.99	50.97	50.95	50.92

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Item 17) Please provide the effective rate as paid by the smelters in 2008, similar to that presented for Rural and Large industrial customers on page 3 of the Unwind Financial Model.

Response) Big Rivers requested and the Smelter granted approval to Kenergy to provide Big Rivers with the effective rate paid by the Smelters to Kenergy during 2008.

For nine months ending September 30, 2008, Kenergy has booked revenue from Alcan and Century at $36.364/MWh and $34.216/MWh, respectively.

Witness) C. William Blackburn

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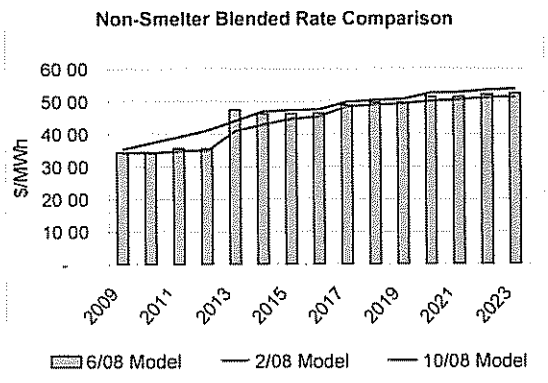
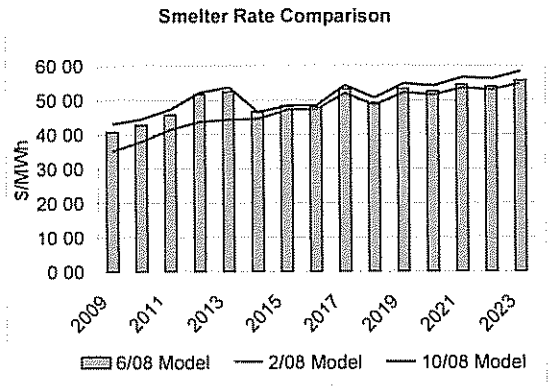
Item 18) Please refer to the October 2008 presentation "Summary of Changes in the Unwind Financial Model, June 2008 vs. October 2008, pages 10 and 12. Please provide graphs augmented to also include and depict rates from the "errata version" of the Unwind Financial Model as filed in this matter in February 2008.

Response) Below are the rate comparisons comparable to those on pages 10 and 12 of the Unwind Financial Model presentation of 10/20/08 for each of the Non-Smelter Members and the Smelters, with the addition of rates from the February filing reflecting the Base Case. The principal difference between rates shown in February and those shown in June are related to updated fuel price projections, as previously summarized for Commission staff. Note that compensation to be paid to the Smelters by E.ON in respect of the higher fuel costs modeled between the February and June model runs is handled outside of the Unwind Financial Model, and hence not reflected in Smelter rates.





Witness) Robert S. Mudge

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Item 19) Identify each item identified by BREC in its due diligence activities since April 2008 for which action and expenditure of resources will be required by BREC, following assumed closing of the proposed Unwind Transaction.

a. For each item, identify the action necessary and expenditure of resources anticipated to be required, and the source of funds for those expenditures.

Response) One such due diligence activity performed by Big Rivers involves the Production Work Plan attached to the October 9 filing as Exhibit 105. Big Rivers began with the Western Kentucky Energy plan and developed its own plan resulting from its due diligence activities. The major changes which Big Rivers made are attached. All of these changes are reflected in the Financial Model.

A second action and expenditure of resources is contained in the Third Amendment to the Termination Agreement, Application Exhibit 80. The concept in the Third Amendment is that Big Rivers will not have to expend any money or other resources beyond those captured in the Financial Model. The E.ON Parties are paying for costs and/or indemnifying Big Rivers against the contingencies contained in the Third Amendment not already reflected in the Financial Model.

The last items identified in due diligence activities that may require action are captured, as nearly as possible, in Exhibit DAS – 2 ("Status of Disposition of Certain Closing Conditions") to the Supplemental Testimony of David Spainhoward (Application Exhibit 99). Big Rivers and E.ON Parties are working diligently to resolve issues as they occur. The objective is to make sure that issues are resolved so that Big Rivers does not have to expend resources after the close that have not been reflected in the Financial Model.

Witness) David A. Spainhoward
Mark A. Bailey

BREC Capital Budget Items Not in the WKE Capital Budget

Item Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	TOTAL 2009-2017
Coleman										
(none)										
Green										
Green 2 Precip Repair	$ 1,060,900		$ 1,125,509							$ 2,186,409
Green 1 Precip Repair		$ 1,092,727		$ 1,159,274						$ 2,252,001
Green 1&2 FGD Rehab	$ 4,243,600	$ 3,020,908	$ 2,251,018							$ 9,515,526
Green 1&2 Paint Boiler, Precip & FGD	$ 1,442,824	$ 1,486,109	$ 1,530,692	$ 1,576,613	$ 1,623,911					$ 7,660,149
HMP&L										
HMPL Stack Lighting	$ 200,000									$ 200,000
Reid 1 and CT										
R-CT reliability study & upgrades	$ 1,125,509									$ 1,125,509
Reid CT Cooling Tower Repair							$ 1,827,604			$ 1,827,604
Wilson										
Make flue gas SO3 treat. System permanent.		$ 1,138,500	$ 2,225,641							$ 3,364,141
WL FGD Additional Amount for Inlet Guillotine (net diff)	$ 300,000									$ 300,000
WL FGD Additional Amount for Outlet Guillotine (net diff)	$ 300,000									$ 300,000
WL FGD Recycle Pump Suction Valve Replacement (8)	$ 280,000									$ 280,000
WL FGD Repl 3 absorber mist eliminator panels & mounting frames	$ 900,000									$ 900,000
WL FGD Repl mist eliminator piping & nozzles	$ 470,000									$ 470,000
WL FGD Structural Improvements		$ 2,425,000								$ 2,425,000
WL FGD Repl 75 stack tension bands with 316L SS material		$ 850,000								$ 850,000
WL FGD Repl 4 dewatering filter drums incl vacuum skids & pumps		$ 1,700,000								$ 1,700,000
WL FGD Repair ductwork hot and wet sides			$ 3,114,272							$ 3,114,272
WL FGD PLC FGD/Flyash Control System Replacement			$ 20,000							$ 20,000
WL FGD Structural Improvements (net diff)			$ 1,675,000							$ 1,675,000
WL FGD Inlet and outlet damper replacement 2 absorbers			$ 1,200,000							$ 1,200,000
										$ -
Total Added Capital	$ 10,322,833	$ 11,713,244	$ 13,142,132	$ 2,735,887	$ 1,623,911	$ -	$ 1,827,604	$ -	$ -	$ 41,365,611

Note: Total Added for WL FGD 2009-2013 - $13,234,272

Attachment to AG's Supplemental Request Item 94

BREC non-Labor Fixed O&M Budget Items Not in the WKE Budget

(response to AG request # 11 dated 10/24/2008 updated AG request # 99)

Item Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Coleman																
structural & life-assess. Inspections		$265,225	$273,182	$281,377												
clean coal dust & ash from boilers, etc		$106,090														
Coleman Ash Pond dredging		$265,225														
Green																
structural & life-assess. Inspections		$265,225	$273,182													
clean coal dust & ash from boilers, etc		$106,090														
Green ash pond dredging										$3,566,057						
HMP&L																
structural & life-assess. Inspections		$265,225	$273,182													
clean coal dust & ash from boilers, etc		$106,090														
SCR Catalyst Regeneration																
R/HMPL Ash pond dredging								$5,508,362								
Reid																
structural & life-assess. Inspections		$265,225														
clean coal dust from boilers, etc		$106,090														
R-1 Lay-Up										$1,200,000						
Wilson																
structural & life-assess. Inspections		$265,225														
clean coal dust from boilers, etc		$106,090														
SCR Catalyst Regeneration																
sub-Total	$0	$2,121,800	$819,546	$281,377	$0	$0	$0	$5,508,362	$0	$4,766,057	$0	$0	$0	$0	$0	$0
Total	$13,497,142															

Summary of Changes Since the Filed Response to AG Request # 99

SCR Catalyst Regeneration moved from O&M expense to capital, consistent with WKE capitalization guidelines ($41,093,615 Total)

Added $1,200,000 in 2017 for the possible lay-up of R-1

Added $3,566,057 in 2017 to dredge the Green ash pond

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Item 20) Identify each item which remains open and subject to further due diligence evaluation and review by BREC.

Response) Please see Exhibit DAS – 2 ("Status of Disposition of Certain Closing Conditions") to the testimony of David Spainhoward (Exhibit 99) in the October 2008 filing. Big Rivers will continue its due diligence on the generating assets up to and including the day of the unwind transaction close. Big Rivers will be as certain as it can be that each closing condition contained in Exhibit DAS – 2 is met as of the closing date and time. Until then, due diligence will continue and Big Rivers and WKEC will continue to resolve issues as and when they arise.

Witness) David A. Spainhoward

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Item 21) State the extent to which the "resolution" of the fuel issue by an increased termination payment of $82 million from E.ON is intended to wholly insulate rural consumers from increased rates due to increased fuel costs over an applicable time period.

a. Please describe and quantify why the $82 million amount is the appropriate amount to resolve the "fuel issue", as opposed to some other amount (e.g., $100 million; $150 million; etc.).

Response) The additional $82 million from E.ON is intended to mitigate the increased fuel cost via the FAC impact on the Non-Smelter Members.

WKEC solicited for coal supply during March 2008. Big Rivers collaborated with WKEC in regards to fuel bidding, evaluation, selection, and planned coal supply contractual agreement assignment upon completion of the lease termination.

Big Rivers noted in the coal supply bids that: the solid fuel pricing had changed substantially from the modeling performed earlier in regards to present and future coal supplies; and, normal bid offers had reverted to shorter periods of time (one to three year term offers versus bids of one to four or one to five years in length of contract pricing disclosure. While consultants considered the run-up in market fuel pricing to be a near-term affect (a "bubble" of up to two years), Big Rivers took a more conservative approach in its projected price estimations through the five-year window, as shown on page 3 of 3, for years 2009-2013.

Based upon the market pricing signals provided WKEC and Big Rivers in the bid solicitation, Big Rivers then extrapolated pricing forward using forecasts obtained from consulting firms Global Insight and Hill and Associates. Three scenarios were established: an optimistic, most-likely, and pessimistic forecast for future coal supply. In

each scenario, the pricing was estimated to be above prior consultant coal forecasts utilized by Big Rivers for generation planning. The optimistic scenario estimated a $75 million increase; the most-likely scenario estimated $85 million; and the pessimistic scenario estimated a $95 million dollar future cost of fuel increase.

It became apparent that the Economic Reserve under the optimistic scenario would not last for the desired period of five years; however, the most-likely estimated scenario provided reasonable probability that the customers would be protected from increased rates due to fuel costs. The pessimistic scenario provided additional years of assurance for the customers at the expense of increased contributions from E.ON. The calculations for the estimated $85 million scenario are shown on page 3 of 3.

Big Rivers has attempted to use its best efforts, along with reputable industry consultants, to assign probable fuel cost scenarios and to attempt to mitigate such potential fuel cost increases for its non-smelter customers. Based upon the marketplace bid evaluation, consultant analysis of coal markets, and consultant modeling of impact of forward fuel cost increases (which protects its customers for an estimated five-years), Big Rivers and E.ON settled upon the $82 million amount.

Witness) C. William Blackburn

Estimated Coal Supply Expense ($/MMBTU) for BREC 2009 - 2013

December 2007 estimated fuel prices for BREC modeling ($/MMBTU).

	2009	2010	2011	2012	2013
Coleman	$ 1.797	$ 1.830	$ 1.837	$ 1.843	$ 1.860
Green	$ 1.337	$ 1.742	$ 1.750	$ 1.750	$ 1.760
HMPL	$ 1.580	$ 1.735	$ 1.738	$ 1.742	$ 1.760
Reid	$ -	$ -	$ -	$ -	$ -
Wilson	$ 1.256	$ 1.286	$ 1.288	$ 1.517	$ 1.770
System	$ 1.507	$ 1.648	$ 1.701	$ 1.175	$ 1.806

Revised estimated fuel prices for BREC modeling May 2008 ($/MMBTU).
Basis: March 2008 WKE coal supply bid, plus 15% escalation per year.

	2009	2010	2011	2012	2013
Coleman	$ 2.400	$ 2.480	$ 2.550	$ 2.780	$ 2.910
Green	$ 1.680	$ 2.040	$ 2.190	$ 2.150	$ 2.500
HMPL	$ 1.900	$ 2.520	$ 2.550	$ 2.650	$ 2.780
Reid	$ 2.500	$ 2.800	$ 2.850	$ 2.900	$ 3.050
Wilson	$ 1.770	$ 1.700	$ 1.750	$ 2.450	$ 2.570
System	$ 1.950	$ 2.145	$ 2.230	$ 2.450	$ 2.680
Differential	$ 0.443	$ 0.497	$ 0.529	$ 1.275	$ 0.874
Open Tonnage:	1,637,000	1,800,000	2,300,000	3,000,000	3,000,000
Dollar Value:	$ 7,614,505.50	$ 9,393,300.00	$ 12,775,350.00	$ 40,162,500.00	$ 27,531,000.00

Total:	$ 97,476,656
Sensitivity -10%.	$ 87,728,990
Sensitivity -15%.	$ 77,981,324

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Item 22) Please refer to the Supplemental Direct Testimony of Robert Mudge, at page 5, where it references "changes to non-labor fixed costs and capital expenditures." Please provide a document or schedule which shows the revisions to these items on an individual basis within the enumerated "four major categories."

Response) Please see the attached schedule comparing principal components of the four major cost categories cited above in the October Financial Model as compared to the June Financial Model.

Witness) Robert S. Mudge

		Location in Financial Model	Total	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Analysis of Change in Fixed Production O&M, A&G Costs, Marketing Fees, and Capital Costs ($M; 2009 - 2023)																		
1	**1. Fixed Production O&M**	*Production-Fixed*																
2	10/08																	
3	Labor	*line 31*	827.9	48.4	45.6	47.0	48.4	49.9	51.3	52.9	54.5	56.1	57.8	59.5	61.3	63.2	65.0	67.0
4	Non-Labor																	
5	Baseline	*line 33*	760.9	40.3	45.4	45.9	42.5	54.5	42.3	53.4	45.5	47.1	53.9	54.3	54.6	60.4	53.1	67.8
6	Plant Maintenance	*line 43*	11.6	2.0	0.7	0.3	-	-	-	3.8	-	4.8	-	-	-	-	-	-
7	T/G Overhauls	*line 46*	101.0	9.2	-	10.2	12.4	-	7.0	-	6.7	19.8	-	13.5	5.9	7.8	8.4	-
8	Subtotal		873.5	51.5	46.1	56.4	54.9	54.5	49.3	57.2	52.2	71.7	53.9	67.8	60.5	68.2	61.5	67.8
9	Emissions Fees	*line 48*	27.0	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0	2.1	2.1	2.2
10	Total		1,728.4	101.3	93.3	105.0	104.9	106.0	102.3	111.8	108.5	129.6	113.5	129.3	123.8	133.5	128.7	137.0
11	Delta																	
12	Labor		22.3	5.0	0.5	0.0	(0.2)	(0.2)	0.0	0.6	1.2	1.8	2.1	2.2	2.2	2.3	2.4	2.4
13	Non-Labor																	
14	Baseline		19.2	3.3	4.3	4.0	2.8	4.2	0.4	-	-	-	-	-	-	-	-	-
15	Plant Maintenance		(28.0)	(1.7)	(1.4)	(2.3)	(2.0)	(1.5)	(1.1)	(1.5)	(1.3)	(1.8)	(1.4)	(2.4)	(2.0)	(2.6)	(2.2)	(2.8)
16	T/G Overhauls		2.9	-	-	1.0	2.0	-	-	-	-	-	-	-	-	-	-	-
17	Subtotal		(5.9)	1.6	2.9	2.7	2.8	2.7	(0.7)	(1.5)	(1.3)	(1.8)	(1.4)	(2.4)	(2.0)	(2.6)	(2.2)	(2.8)
18	Emissions Fees		27.0	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0	2.1	2.1	2.2
19	Total		43.5	8.1	4.9	4.3	4.2	4.1	1.1	0.8	1.7	1.8	2.6	1.7	2.2	1.8	2.3	1.8
20	6/08																	
21	Labor	*line 31*	805.5	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
22	Non-Labor																	
23	Baseline	*line 33*	741.7	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
24	Plant Maintenance	*line 43*	39.7	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
25	T/G Overhauls	*line 46*	98.0	9.2	-	9.3	10.5	-	7.0	-	6.7	19.8	-	13.5	5.9	7.8	8.4	-
26	Subtotal		879.4	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
27	Emissions Fees		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total		1,685.0	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
29																		

		Location in Financial Model	Total	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Analysis of Change in Fixed Production O&M, A&G Costs, Marketing Fees, and Capital Costs ($M; 2009 - 2023)																		
30	**2. Administrative and General Costs**	*Production-Fixed*																
31																		
32	10/08																	
33	Labor	*line 2*	195.4	11.0	10.8	11.1	11.4	11.8	12.1	12.5	12.9	13.3	13.7	14.1	14.5	14.9	15.4	15.8
34	Non-Labor	*line 3*	225.3	12.1	12.5	12.9	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.3	16.8	17.3	17.8	18.3
35	Intellectual Property	*line 4*	84.0	6.4	4.5	5.3	4.8	4.9	5.5	5.1	5.2	5.7	5.7	5.6	6.2	6.0	6.3	6.7
36	Total		504.6	29.5	27.8	29.2	29.5	30.3	31.7	32.1	33.0	34.3	35.1	36.0	37.5	38.2	39.5	40.9
37	Delta																	
38	Labor		(8.6)	0.0	(0.5)	(0.5)	(0.5)	(0.5)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)
39	Non-Labor		39.8	2.2	2.2	2.3	2.3	2.4	2.5	2.6	2.6	2.7	2.8	2.9	3.0	3.0	3.1	3.2
40	Intellectual Property		37.8	2.4	1.9	2.5	2.3	2.3	2.5	2.4	2.4	2.5	2.7	2.6	2.7	2.7	3.0	2.9
41	Total		69.0	4.6	3.6	4.3	4.1	4.2	4.4	4.3	4.4	4.5	4.8	4.8	4.9	5.1	5.4	5.4
42	6/08																	
43	Labor	*line 2*	203.9	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
44	Non-Labor	*line 3*	185.5	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
45	Intellectual Property	*line 4*	46.2	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
46	Total		435.6	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
47																		
48	**3. Marketing Fees**	*Pro forma*																
49																		
50	10/08																	
51	APM, L/C, Cogen, CW & TVA Trans	*line 200*	99.1	6.3	6.5	5.8	5.7	5.9	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
52	Delta																	
53	APM, L/C, Cogen, CW & TVA Trans		18.7	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.5	1.5
54	10/08																	
55	APM, L/C, Cogen, CW & TVA Trans	*line 200*	80.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
56																		

		Location in Financial Model	Total	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Analysis of Change in Fixed Production O&M, A&G Costs, Marketing Fees, and Capital Costs ($M; 2009 - 2023)																		
57	**4. Capital Expenditures**	*Pro forma*																
58																		
59	10/08																	
60	Generation	*line 143*	526.6	36.2	20.6	31.5	23.4	38.5	32.8	33.8	34.8	35.9	36.9	38.1	39.2	40.4	41.6	42.8
61	Transmission	*line 144*	53.3	10.3	5.3	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
62	Transmission Upgrades	*line 145*	11.2	5.6	5.6	-	-	-	-	-	-	-	-	-	-	-	-	-
63	A&G	*line 146*	24.7	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
64	Extraordinary Generation	*line 147*	127.7	28.7	17.4	25.4	10.7	8.8	5.2	4.4	2.3	2.8	2.4	7.0	3.4	3.1	2.7	3.3
65	Other (HQ Building, IP)	*line 148*	24.5	11.4	1.0	0.9	0.8	0.8	1.0	0.8	0.8	1.0	0.9	0.9	1.1	0.9	0.9	1.2
66	Total		768.0	93.5	51.3	63.7	42.2	50.1	40.9	41.2	41.1	44.1	45.3	51.2	49.1	49.9	50.9	53.3
67	Delta		22.7	3.6	(3.2)	2.7	(6.7)	8.2	1.6	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0
68	Generation		(3.2)	0.7	(3.9)	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Transmission		3.5	(0.4)	3.9	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Transmission Upgrades		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71	A&G		40.1	7.5	(3.4)	4.9	(2.9)	7.2	2.2	4.4	2.3	2.8	0.6	2.9	2.5	3.1	2.7	3.3
72	Extraordinary Generation		(8.9)	6.0	(0.7)	(0.3)	(2.1)	(0.8)	(0.3)	(2.2)	(0.6)	(0.4)	(2.7)	(0.6)	(0.4)	(2.5)	(0.7)	(0.8)
73	Other (HQ Building, IP)		54.2	17.5	(7.3)	7.4	(11.6)	14.6	3.4	3.9	3.4	4.1	(0.3)	4.1	4.0	2.6	4.0	4.5
74	Total																	
75	6/08																	
76	Generation	*line 143*	503.9	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
77	Transmission	*line 144*	56.5	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
78	Transmission Upgrades	*line 145*	7.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
79	A&G	*line 146*	24.7	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
80	Extraordinary Generation	*line 147*	87.6	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
81	Other (HQ Building, IP)	*line 148*	33.4	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
82	Total		713.8	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

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Item 23) Please refer to the Supplemental Direct Testimony of Robert Mudge, at page 11, where an "Overall Revenue Requirements" table is provided for the period 2009 – 2023. Please provide a table displaying the same information, but on an annual basis with each year 2009 – 2023 depicted.

Response) Please see the attached table displaying the Overall Revenue Requirements information on an annual basis with each year 2009 – 2023 depicted.

Witness) Robert S. Mudge

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

		Total	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	*Filed Model (6/08)*	8,325.2	417.7	435.6	465.7	512.4	566.2	523.2	540.2	542.4	593.9	573.9	608.4	616.5	634.4	637.8	657.0
2	Increases from Operations																
3	Fuel Costs	184.5	8.9	23.7	8.3	20.3	55.5	6.4	9.0	10.0	6.3	5.3	5.3	3.6	6.6	7.5	7.6
4	Non-Fuel Variable Production O&M	112.2	2.1	3.6	5.0	4.3	5.9	3.8	9.6	9.5	9.2	9.3	9.5	9.8	10.1	10.3	10.2
5	A&G	69.0	4.6	3.6	4.3	4.1	4.2	4.4	4.3	4.4	4.5	4.8	4.8	4.9	5.1	5.4	5.4
6	Fixed Production O&M	43.5	8.1	4.9	4.3	4.2	4.1	1.1	0.8	1.7	1.8	2.6	1.7	2.2	1.8	2.3	1.8
7	Gain on Sale of Emissions Allowances	24.0	11.8	(2.8)	1.2	1.9	3.7	1.1	2.0	1.4	0.9	0.7	0.7	0.5	0.4	0.5	0.2
8	Marketing Fees	18.7	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.5	1.5
9	Smelter Economic Reserve	7.7	3.3	3.4	1.1	-	-	-	-	-	-	-	-	-	-	-	-
10	Transmission O&M	3.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3
11	Interest Earnings	10.2	1.2	0.8	(0.8)	(2.0)	(1.0)	(0.1)	0.8	1.5	1.8	2.0	1.1	1.4	1.6	1.2	0.8
12	Subtotal - Increases	473.1	41.2	38.4	24.4	34.2	73.8	18.1	28.0	29.9	26.1	26.3	24.7	24.0	27.2	28.9	27.8
13																	
14	Reductions from Operations																
15	Offsystem Sales	(243.5)	3.7	(26.7)	0.8	(24.2)	(42.8)	(17.3)	(22.8)	(21.7)	(17.7)	(16.8)	(13.0)	(12.2)	(13.1)	(11.7)	(7.9)
16	SEPA & Other Purchases	(20.6)	(5.0)	(10.4)	(7.8)	(6.9)	(9.9)	(2.0)	(3.3)	(1.4)	4.2	3.4	2.5	3.0	5.4	3.5	4.1
17	Depreciation & Amortization	(7.3)	(3.2)	(3.2)	(0.4)	(0.4)	(0.4)	(0.2)	(0.1)	(0.0)	(0.1)	(0.1)	(0.0)	0.1	0.2	0.3	0.4
18	Member Economic Reserve	(16.2)	(9.9)	(3.0)	10.5	14.8	(28.6)	-	-	-	-	-	-	-	-	-	-
19	Income Tax	(1.0)	-	-	-	-	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
20	RUS Note & PCB Restructuring Charge	(0.4)	(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)	-	-
21	Subtotal - Reductions	(288.9)	(14.4)	(43.4)	3.2	(16.7)	(81.7)	(19.7)	(26.3)	(23.2)	(13.7)	(13.6)	(10.7)	(9.3)	(7.7)	(8.1)	(3.6)
22																	
23	Lease Buyout																
24	Discontinuation of Net Lease Income	25.9	1.7	1.8	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
25	Discontinuation of CoBank Patronage	13.0	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
26	BofA Lease Gain not Amortized	10.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
27	Subtotal - Lease Buyout	49.5	3.0	3.3	3.4	3.4	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
28																	
29	Interest Expense (Incl. Financing Fees)	45.9	2.5	2.7	2.9	6.1	3.8	3.1	2.3	1.4	1.6	1.6	3.0	3.0	3.5	3.8	4.6
30																	
31	Net Margin	(37.8)	(1.9)	0.6	(2.0)	(1.3)	(2.0)	(2.3)	(2.6)	(3.0)	(3.1)	(3.3)	(3.1)	(3.3)	(3.4)	(3.5)	(3.6)
32																	
33	Rebate Realized	6.9	(8.7)	22.5	(6.9)	(0.0)	(0.0)	0.0	-	-	-	-	-	-	-	-	-
34	Total	248.7	21.7	24.1	25.0	25.7	(2.8)	2.6	4.6	8.4	14.1	14.3	17.2	17.8	22.9	24.5	28.5
35	*December Close/ $60.9m Buyout*	8,573.9	439.4	459.7	490.7	538.1	563.5	525.7	544.8	550.8	608.1	588.2	625.6	634.2	657.3	662.3	685.5
36																	
37	Percent Change	3%															

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Item 24) Please refer to the Supplemental Direct Testimony of Michael Core at page 7, where it is stated "the anticipated benefits of the Unwind Transaction significantly outweigh the potential costs." Please identify and describe each item that is viewed as a "potential cost" in this statement.

Response) The "potential costs" of the Unwind Transaction are the costs of owning and operating Big Rivers' generating units. Big Rivers' best estimate of those potential costs is shown in the Unwind Financial Model, the latest iteration of which is Exhibit 79 to the Application.

Witness) Michael H. Core

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Item 25) Does BREC understand the proposed electric supply agreements with the smelters to permit the rate charged to the smelters to vary to the extent the Commission later varies the Large Industrial rate? If not, please explain why not?

Response) Yes. Big Rivers understands the relationship of the "Large Industrial Rate" (demand and energy rates), as may be adjusted from time to time by the Commission, and how a change to an individual element of this rate would impact the "Base Rate" charged to the Smelters. "Large Industrial Rate" and "Base Rate" are defined in terms in the Smelter Agreements.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
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Item 26) Please produce a "what if" run of the model provided as Exhibit 79, varying inputs only as necessary to include an additional $400 million in generation plant capital expenditure added over four years beginning in 2012, which capital expenditure is entirely funded with increased debt.

Response) The "what if" model reflecting an additional $400 million in generation plant capital expenditure added over four years beginning in 2012 is attached. Key assumptions include the following:

- The $400 million in generation plant capital expenditure is assumed allocated entirely to the maintenance of existing plant, and hence has no incremental revenues or costs associated with it.

- The capital expenditures are funded with $100 million in capital markets borrowings at the beginning of each of 2012, 2013, 2014, and 2015.

- All-in interest costs are modeled at 7.25% (inclusive of costs of issuance).

- Principal repayments are modeled at $10 million per year starting in 2016.

- Incremental costs associated with the additional borrowings are covered by Smelter TIER adjustments and general rate adjustments affecting both Smelters and Non-Smelter Members (see lines 18 - 30, below).

Witness) Robert S. Mudge
C. William Blackburn

"What-If" Scenario Assuming $400m Additional Capital Expenditures in 2012 - 2015

		Location in Financial Model	2009 - 2023	2009 - 2016	2017 - 2023
1	**Analysis of Change in Total Revenue Requirement ($M; 2009 - 2023)**				
2					
3	*Financial Model, 10/08*	Proforma Lines 107 + 108 + 109	8,573.9	4,112.6	4,461.2
4	Increased Depreciation	Proforma Line 203	102.4	25.5	76.9
5	Interest Earnings	Proforma Line 188	(18.8)	(2.3)	(16.5)
6	Interest Expense	Proforma Line 205	284.2	101.5	182.7
7	Net Margin (.24 x Interest Expense)	Proforma Line 217	68.2	24.4	43.8
8	Total		436.0	149.1	287.0
9	*+ $400m of Capital Expenditures*	Proforma Lines 107 + 108 + 109	9,009.9	4,261.7	4,748.2
10					
11	**Energy Sales (TWh)**				
12					
13	Members	Proforma Lines 9 + 11	61.96	30.5	31.5
14	Smelters	Proforma Lines 13 + 15	109.52	58.4	51.1
15					
16	**Rate Impact Analysis ($/ MWh)**				
17					
18	***1. Non-Smelter Members***				
19					
20	*Financial Model, 10/08*	Proforma Lines (107 + 108)/ (9 + 11)	47.49	42.70	52.12
21	GRA	Proforma Line 75	3.00	1.52	4.43
22	*+ $400m of Capital Expenditures*	Proforma Lines (107 + 108)/ (9 + 11)	50.49	44.22	56.56
23					
24	***2. Smelters***				
25					
26	*Financial Model, 10/08*	Proforma Lines (109)/ (13 + 15)	51.42	48.14	55.17
27	GRA (embedded in Base Rate)	Proforma Line 75	2.25	1.14	3.52
28	TIER Adjustment	Proforma Line 89	0.03	0.62	(0.63)
29	Total		2.28	1.76	2.88
30	*+ $400m of Capital Expenditures*	Proforma Lines (109)/ (13 + 15)	53.70	49.89	58.06

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Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			12/31/2008	
I. Sales (TWH)																				
Rural	2.23	2.41	2.40	-		2.44	2.49	2.54	2.59	2.65	2.70	2.76	2.82	2.88	2.94	3.00	3.06	3.12	3.18	3.24
Large Industrial	0.96	0.92	0.95	-		1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
Century	-	-	-	-		4.14	4.14	4.14	4.15	4.14	4.14	4.14	4.15	4.14	4.14	4.14	4.15	4.14	4.14	4.14
Alcan	-	-	-	-		3.16	3.16	3.16	3.17	3.16	3.16	3.16	3.17	3.16	3.16	3.16	3.17	3.16	3.16	3.16
Market	2.06	2.84	1.66	-		1.55	1.83	1.38	1.36	1.41	1.32	1.29	1.24	1.05	1.12	0.87	0.89	0.87	0.85	0.78
Total Sales	5.25	6.16	5.01	-		12.35	12.71	12.35	12.44	12.56	12.56	12.62	12.68	12.56	12.72	12.57	12.70	12.77	12.83	12.87

Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			12/31/2008	
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)																				
General Rate Adjustment (%)	0.00%	0.00%	0.00%			0.00%	0.00%	0.00%	1.46%	1.80%	3.12%	3.94%	0.00%	10.55%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FAC ($/ MWH)						11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
FAC Roll-In ($/MWh)						0.08	(0.39)	0.48	0.27	0.57	0.26	0.44	0.58	2.09	0.88	1.78	1.15	2.07	1.74	2.54
PPA ($/ MWH)																				
Environmental Surcharge Adjustment ($/ MWH)																				
Rural						2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Large Industrial						2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Smelters						2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Rural																				
Load Factor (%)	61.6%	63.3%	62.5%			60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
Demand ($/ KW-mo.)	7.37	7.37	7.37			7.37	7.37	7.37	7.48	7.61	7.85	8.16	8.16	9.02	9.02	9.02	9.02	9.02	9.02	9.02
Energy ($/ MWH)	20.40	20.40	20.40			20.40	20.40	20.40	20.70	21.07	21.73	22.59	22.59	24.97	24.97	24.97	24.97	24.97	24.97	24.97
Base	36.79	36.36	36.55			37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
MRDA	(1.20)	(1.14)	(1.14)			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regulatory Account Charge	-	-	-			-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
GRA	-	-	-			-	-	-	0.54	1.22	2.42	3.97	3.97	8.29	8.29	8.28	8.27	8.27	8.27	8.26
FAC	-	-	-			11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
Environmental Surcharge	-	-	-			2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Surcredit	-	-	-			(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
Non-Smelter Member Economic Reserve	-	-	-			(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
Net	-	-	-			-	2.09	5.69	6.00	8.91	11.28	11.80	11.97	10.87	11.50	11.83	12.54	12.82	13.55	13.72
Pre TIER Rebate Total	35.58	35.22	35.41			37.22	39.29	42.75	43.58	47.15	51.21	53.25	53.39	56.59	57.19	57.48	59.29	59.51	60.20	60.48
TIER Related Rebate	-	-	-			(0.10)	(1.79)	-	-	-	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	35.58	35.22	35.41			37.12	37.49	42.75	43.58	47.15	51.21	53.25	53.39	56.59	57.19	57.48	59.29	59.51	60.20	60.48
Large Industrial																				
Load Factor (%)	78.1%	76.5%	77.7%			78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
Demand ($/ KW-mo.)	10.15	10.15	10.15			10.15	10.15	10.15	10.30	10.48	10.81	11.24	11.24	12.42	12.42	12.42	12.42	12.42	12.42	12.42
Energy ($/ MWH)	13.72	13.72	13.72			13.72	13.72	13.72	13.92	14.17	14.61	15.18	15.18	16.79	16.79	16.79	16.79	16.79	16.79	16.79
Base	31.51	31.90	31.61			31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
Power Factor Penalty/ Demand Cr. (Lrg.	0.19	0.08	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MRDA	(1.04)	(1.02)	(0.98)			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regulatory Account Charge	-	-	-			-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
GRA	-	-	-			-	-	-	0.46	1.03	2.05	3.36	3.37	7.03	7.03	7.03	7.03	7.03	7.03	7.03
FAC	-	-	-			11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
Environmental Surcharge	-	-	-			2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Surcredit	-	-	-			(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
Non-Smelter Member Economic Reserve	-	-	-			(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
Net	-	-	-			-	2.09	5.69	6.00	8.91	11.28	11.80	11.97	10.87	11.50	11.83	12.54	12.82	13.55	13.72
Pre TIER Rebate Total	30.67	30.96	30.62			31.39	33.49	36.98	37.76	41.24	45.15	46.97	47.15	49.70	50.32	50.64	52.51	52.72	53.43	53.74
TIER Related Rebate	-	-	-			(0.09)	(1.59)	-	-	-	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	30.67	30.96	30.62			31.31	31.90	36.98	37.76	41.24	45.15	46.97	47.15	49.70	50.32	50.64	52.51	52.72	53.43	53.74

	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
69	Non-Smelter Member Blend																				
72	Base	35.26	35.15	35.14			35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
73	MRDA	(1.15)	(1.11)	(1.10)			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	Regulatory Account Charge						-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
75	GRA	-	-	-			-	-	-	0.52	1.16	2.30	3.78	3.78	7.89	7.89	7.88	7.88	7.87	7.87	7.87
76																					
77	FAC	-	-	-			11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
78	Environmental Surcharge						2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
79	Surcredit	-	-	-			(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
80	Non-Smelter Member Economic Reserve	-	-	-			(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
81	Net						-	2.09	5.69	6.00	8.91	11.28	11.80	11.97	10.87	11.50	11.83	12.54	12.82	13.55	13.72
82																					
83	Pre TIER Rebate Total	34.11	34.04	34.04			35.45	37.51	40.98	41.78	45.30	49.31	51.27	51.42	54.40	55.00	55.29	57.12	57.33	58.02	58.30
84	TIER Related Rebate	-	-	-			(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-	-
85	*Effective Rate*	34.11	34.04	34.04			35.36	35.78	40.98	41.78	45.30	49.31	51.27	51.42	54.40	55.00	55.29	57.12	57.33	58.02	58.30
86																					
87	Smelters																				
88	Base Rate	-	-	-			28.15	28.15	28.15	28.52	29.07	29.97	31.14	31.10	34.40	34.40	34.40	34.35	34.40	34.40	34.40
89	TIER Adjustment	-	-	-			-	-	1.79	2.95	2.95	2.95	3.55	3.39	3.55	0.32	3.23	2.31	3.42	2.43	3.61
90	Smelter Rate Subject to Price Cap	-	-	-			28.15	28.15	29.95	31.47	32.02	32.92	34.69	34.49	37.95	34.72	37.63	36.66	37.83	36.83	38.01
91	FAC						11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
92	PPA	-	-	-			0.08	(0.39)	0.48	0.27	0.57	0.26	0.44	0.58	2.09	0.88	1.78	1.15	2.07	1.74	2.54
93	Environmental Surcharge						2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
94	Surcharge 1	-	-	-			0.70	0.70	0.70	1.00	1.00	1.00	1.00	1.00	1.40	1.40	1.40	1.39	1.40	1.40	1.40
95	Surcharge 2						0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	1.20	1.20	1.20	1.20	1.20	1.20	1.20
96	Smelter FAC Reserve						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
97	TIER Related Rebate	-	-	-			(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-	-
98	Effective Rate	-	-	-			43.11	42.98	49.19	53.44	56.19	49.80	52.18	52.24	58.00	54.09	58.14	57.16	59.42	58.76	60.83
99																					
100	Market	40.45	52.68	48.74			60.94	59.20	63.59	66.81	70.55	62.13	63.43	63.52	64.53	66.02	68.95	67.21	67.69	69.01	69.79
101																					
102	Overall Blend	36.60	42.62	38.92			43.15	43.29	48.35	51.38	54.47	50.95	53.05	53.07	57.34	55.44	57.89	57.85	59.24	59.16	60.43
103																					

	Calendar Year	2006	2007	2008	Transaction	Lease Terminat ion	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
104	**III. Cash Flows (M$)**																				
105																					
106	Operating Receipts																				
107	Rural	79.4	84.8	84.8	-	0.0	90.8	97.5	104.2	113.1	125.0	138.5	147.1	150.5	162.9	167.9	172.3	181.3	185.7	191.4	196.0
108	Large Industrial	29.3	28.5	29.2	-	0.0	33.4	36.6	40.1	44.0	49.5	55.7	59.6	61.4	66.5	69.1	71.3	75.6	77.8	80.7	83.0
109	Smelters	-	-	-	-	-	315.3	325.6	346.3	391.0	410.1	363.4	380.8	382.2	423.2	394.7	424.2	418.3	433.6	428.7	443.9
110	Offsystem	83.4	149.4	81.1	-	-	94.3	108.5	87.7	90.9	99.4	82.2	82.1	78.8	67.6	73.6	59.7	59.5	59.1	58.4	54.7
111	*WKEC Lease*	47.9	50.8	47.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	Transmission	6.0	6.3	5.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113	Smelter - Tier 3 Transmission	1.7	1.7	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
114	Gain on Sale of Allowances	-	-	-	-	-	3.8	3.0	(0.6)	(0.4)	(0.2)	(1.9)	(16.3)	(15.1)	(14.5)	(15.6)	(14.2)	(15.5)	(15.6)	(16.0)	(16.5)
115	Cobank Patronage Capital & Other	0.6	0.6	0.6	-	-	-	-	-	0.7	1.6	1.5	-	-	-	-	-	-	-	-	-
116	Lease Buyout					(59.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
117	Interest Earnings	3.7	6.8	5.0	-	0.0	6.4	5.5	5.7	5.7	4.2	3.8	4.3	4.5	4.5	4.7	5.9	5.8	6.0	6.5	7.0
118	Total Receipts	252.0	328.9	255.3	-	(59.6)	543.9	576.7	583.4	645.0	689.5	643.2	657.6	662.3	710.3	694.3	719.2	724.9	746.6	749.8	768.1
119																					
120	Operating Disbursements																				
121	PPA	98.0	96.3	95.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122	*Fuel Costs*	-	-	-	-	0.0	270.6	304.9	307.9	344.6	370.3	259.1	259.3	262.0	261.0	267.6	268.7	275.7	277.5	286.7	285.8
123	SEPA & Other Purchases	11.4	68.0	11.6	-	0.0	23.1	17.9	28.1	25.7	29.7	25.8	28.2	30.1	48.9	34.0	45.0	37.4	49.3	45.3	55.8
124	Carbon Tax					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
125	Carbon Allowance Cost					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
126	Environmental	0.4	0.5	0.6	-	(0.0)	30.8	33.7	38.3	39.9	40.9	41.8	51.4	53.0	52.9	55.3	55.3	58.1	60.4	61.4	63.3
127	Fixed O&M	-	-	-	-	0.0	101.3	93.3	105.0	104.9	106.0	102.3	111.8	108.5	129.6	113.5	129.3	123.8	133.5	128.7	137.0
128	Transmission O&M	6.6	7.1	7.4	-	0.0	8.0	8.3	8.5	8.8	9.0	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.4	11.8	12.1
129	APM, L/C, Cogen, CW & TVA Trans	4.7	8.8	5.9	-	0.0	6.3	6.5	5.8	5.7	5.9	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
130	A&G	13.8	15.6	17.2	-	0.0	29.5	27.8	29.2	29.5	30.3	31.7	32.1	33.0	34.3	35.1	36.0	37.5	38.2	39.5	40.9
131	Property Taxes & Insurance	2.4	2.3	2.2	-	0.0	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
132	Working Capital	6.8	4.6	(4.9)	-	0.0	(31.5)	(1.1)	(0.2)	(1.1)	(0.6)	10.0	1.1	0.4	(0.4)	1.3	(1.0)	0.0	(0.9)	0.2	(0.7)
133	PCB Restructuring	-	-	-	-	-	7.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
134	Other	2.3	1.9	2.0	-	(0.0)	(0.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
135	Total Disbursements	146.3	205.1	137.5	-	0.0	451.6	498.3	530.3	566.6	600.2	495.1	509.0	512.7	552.9	534.4	561.5	561.6	587.8	592.6	613.9
136																					
137	Operating Receipts less Disbursements	105.7	123.8	117.8	-	(59.6)	92.4	78.4	53.1	78.4	89.3	148.0	148.6	149.6	157.4	159.9	157.8	163.3	158.8	157.2	154.2
138																					

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	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:				12/31/2008	
139																					
140	Operating Receipts less Disbursements	105.7	123.8	117.8	-	(59.6)	92.4	78.4	53.1	78.4	89.3	148.0	148.6	149.6	157.4	159.9	157.8	163.3	158.8	157.2	154.2
141																					
142	Capital Expenditures																				
143	Generation	6.4	6.6	6.7	-	(0.0)	36.2	20.6	31.5	123.4	138.5	132.8	133.8	34.8	35.9	36.9	38.1	39.2	40.4	41.6	42.8
144	Transmission	5.9	9.6	18.4	-	-	10.3	5.3	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
145	Transmission Upgrades	-	4.1	-	-	-	5.6	5.6	-	-	-	-	-	-	-	-	-	-	-	-	-
146	A&G	0.9	1.3	1.3	-	0.0	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
147	Extraordinary Generation	-	-	-	-	-	28.7	17.4	25.4	10.7	8.8	5.2	4.4	2.3	2.8	2.4	7.0	3.4	3.1	2.7	3.3
148	Other (HQ Building, IP)	-	-	-	-	0.0	11.4	1.0	0.9	0.8	0.8	1.0	0.8	0.8	1.0	0.9	0.9	1.1	0.9	0.9	1.2
149	Total Capital Expenditures	13.2	21.6	26.4	-	0.0	93.5	51.3	63.7	142.2	150.1	140.9	141.2	41.1	44.1	45.3	51.2	49.1	49.9	50.9	53.3
150																					
151	Income Taxes from Operations	0.4	0.2	0.4	-	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
152																					
153	Net Pre-Finance Cash Flow	92.1	102.0	91.0	-	(59.6)	(1.1)	27.1	(10.6)	(63.8)	(60.8)	6.9	7.1	108.1	112.9	114.2	106.1	113.8	108.4	105.8	100.4
154																					
155	Financing																				
156	Principal (Net)	26.4	13.3	41.8	-	-	13.3	15.1	(42.5)	(20.6)	(68.4)	(66.5)	(271.5)	243.5	48.2	25.8	52.8	55.3	44.0	45.9	48.2
157	Interest	36.9	36.9	51.5	-	0.0	43.2	42.5	41.6	50.9	54.7	60.0	65.2	63.2	60.5	57.6	56.0	52.8	49.5	46.8	43.8
158	Financing Fees					-	-	-	1.0	-	-	-	7.0	-	-	-	-	-	-	-	-
159	Line of Credit	-	-	-	-	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
160	Aggregate Debt Service (incl. Line of C	63.4	50.2	93.3	-	0.0	57.0	58.0	0.6	30.8	(13.2)	(6.0)	(198.7)	307.2	109.2	83.9	109.3	108.6	94.0	93.2	92.5
161																					
162	Post-Finance Cash Flow	28.7	51.9	(2.3)	-	(59.6)	(58.1)	(31.0)	(11.2)	(94.6)	(47.6)	12.8	205.8	(199.1)	3.7	30.2	(3.2)	5.2	14.4	12.5	7.9
163																					
164	Unwind Transaction																				
165	Cash Proceeds	-			387.7																
166	Debt Reduction	-			(147.0)																
167	Misc. Transaction				(3.1)																
168	Net Before Member Reserves				237.6																
169	Non-Smelter Member Economic Reserve	-			(157.0)	-	35.5	36.1	30.8	38.3	35.7	-	-	-	-	-	-	-	-	-	-
170	Smelter Fuel Payment				(7.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
171																					
172	Net Before Transition Reserve				73.6	-	35.5	36.1	30.8	38.3	35.7	-	-	-	-	-	-	-	-	-	-
173																					
174	Ending Cash Balances (Incl. Transition	96.5	148.3	146.0	219.6	160.0	137.3	142.5	162.05	105.713	93.8	106.6	312.4	113.3	117.0	147.2	144.1	149.24	163.6	176.2	184.1
175	Reserve)																				

	Calendar Year	2006	2007	2008	Transaction	Lease Terminat ion	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
176	**IV. Income Statement (MS)**																				
177																					
178	Revenues																				
179	Rural	79.4	84.76	84.8	-	0.0	90.5	93.2	108.7	113.1	125.0	138.5	147.1	150.5	162.9	167.9	172.3	181.3	185.7	191.4	196.0
180	Large Industrial	29.3	28.53	29.2	-	-	33.3	35.0	41.8	44.0	49.5	55.7	59.6	61.4	66.5	69.1	71.3	75.6	77.8	80.7	83.0
181	Smelters	-	-	-	-	-	314.6	313.6	359.0	391.0	410.1	363.4	380.8	382.2	423.2	394.7	424.2	418.3	433.6	428.7	443.9
182	Off-System	83.4	149.38	81.1	-	-	94.3	108.5	87.7	90.9	99.4	82.2	82.1	78.8	67.6	73.6	59.7	59.5	59.1	58.4	54.7
183	Transmission	6.0	6.29	5.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
184	Smelter - Tier 3 Transmission	1.8	1.80	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
185	Gain on Sale of Allowances	-	-	-	-	-	3.8	3.0	(0.6)	(0.4)	(0.2)	(1.9)	(16.3)	(15.1)	(14.5)	(15.6)	(14.2)	(15.5)	(15.6)	(16.0)	(16.5)
186	WKEC Lease (Net)	52.3	52.33	52.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
187	Lease Buyout					(16.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
188	Interest Earnings	3.7	6.83	5.0	-	0.0	6.4	5.5	5.7	5.7	4.2	3.8	4.3	4.5	4.5	4.7	5.9	5.8	6.0	6.5	7.0
189	Total Revenues	255.9	329.92	259.4	-	(16.1)	542.9	558.9	602.2	644.3	688.0	641.7	657.6	662.3	710.3	694.3	719.2	724.9	746.6	749.8	768.1
190																					
191	Expenses																				
192	PPA	98.0	96.29	95.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
193	Fuel Costs	-	-	-	-	(0.0)	270.8	301.0	305.8	339.5	366.4	276.1	259.3	261.7	260.2	267.6	268.0	275.4	277.0	285.9	285.5
194	SEPA & Other Purchases	11.4	68.01	11.61	-	0.0	22.8	19.3	25.9	24.3	27.1	26.5	28.1	29.4	41.7	31.9	38.8	39.1	46.6	44.0	51.3
195	Carbon Tax					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
196	Carbon Allowance Cost					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
197	Non-Fuel Variable Production O&M	0.4	0.48	0.6	-	(0.0)	30.8	33.7	38.3	39.9	40.9	41.8	51.4	53.0	52.9	55.3	55.3	58.1	60.4	61.4	63.3
198	Fixed Production O&M	-	-	-	-	0.0	101.3	93.3	105.0	104.9	106.0	102.3	111.8	108.5	129.6	113.5	129.3	123.8	133.5	128.7	137.0
199	Transmission O&M	6.6	7.07	7.4	-	0.0	8.0	8.3	8.5	8.8	9.0	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.4	11.8	12.1
200	APM, L/C, Cogen, CW & TVA Trans	4.7	8.78	5.9	-	0.0	6.3	6.5	5.8	5.7	5.9	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
201	A&G	13.8	15.62	17.2	-	0.0	29.5	27.8	29.2	29.5	30.3	31.7	32.1	33.0	34.3	35.1	36.0	37.5	38.2	39.5	40.9
202	Property Taxes & Insurance	2.4	2.32	2.2	-	0.0	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
203	Depreciation & Amortization	32.8	32.15	32.5	-	0.0	34.4	35.6	44.6	47.1	49.3	51.6	55.4	58.1	74.6	75.9	77.3	78.7	80.2	81.6	83.2
204	Income Tax	-	-	-	-	-	-	-	-	-	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8
205	Interest Expense (Incl. Financing Fees)	60.7	60.90	59.9	-	0.0	53.1	48.9	48.4	58.2	62.4	68.2	73.8	72.5	70.3	68.0	67.0	64.5	62.3	59.8	57.6
206	RUS Note & PCB Restructuring Charge	-	-	-	-	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
207	Net Sale-Leaseback	(2.6)	(2.56)	(3.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208	Other - Net	(6.0)	(6.32)	(6.6)	-	(0.0)	(0.3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
209	Total Expenses	222.3	282.74	222.9	-	(0.0)	564.1	581.7	619.8	667.0	707.0	623.5	638.0	643.0	691.4	675.9	701.0	707.2	729.3	733.0	751.8
210																					
211	Unwind Transaction	-	-	-	690.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
212																					
213	Non-Smelter Member Economic Reserve	-	-	-	(157.0)	-	35.5	36.1	30.8	36.3	35.7	-	-	-	-	-	-	-	-	-	-
214																					
215	Smelter FAC Payment	-	-	-	(7.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216																					
217	Net Margin	33.7	47.18	36.5	526.8	(16.1)	14.3	13.3	13.2	15.6	16.7	18.2	19.6	19.3	18.9	18.4	18.2	17.7	17.3	16.8	16.3

Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			12/31/2008	
V. Balance Sheet (MS)																				
Assets																				
Property																				
Total Utility Plant in Service	1,731.2	1,749.9	1,783.8	1,882.3	1,882.3	1,986.7	2,038.8	2,103.3	2,246.4	2,397.3	2,539.1	2,681.1	2,723.1	2,768.1	2,814.3	2,866.3	2,916.3	2,967.1	3,018.8	3,073.0
Construction in Progress	13.1	15.1	15.1	15.1	15.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Depreciation & Amortization	827.5	854.1	886.6	886.6	886.6	921.0	956.5	1,001.2	1,048.3	1,097.6	1,149.2	1,204.6	1,262.7	1,337.3	1,413.2	1,490.5	1,569.2	1,649.4	1,731.0	1,814.2
Other Property	190.7	197.8	200.9	200.9	4.1	4.4	4.4	4.4	3.7	2.2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Current																				
Cash General Funds & Special Deposits	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	0.0	0.0	0.0	0.0
General Cash Balance	96.5	148.3	146.0	184.6	125.0	100.9	104.6	122.7	64.8	51.2	62.3	266.4	65.4	67.2	95.4	90.2	93.2	105.4	115.6	121.1
Transition Reserve	-	-	-	35.0	35.0	36.4	37.9	39.4	40.9	42.6	44.3	46.1	47.9	49.8	51.8	53.9	56.0	58.3	60.6	63.0
Non-Smelter Member Economic Reserve	-	-	-	157.0	157.0	127.8	96.8	69.9	34.4	-	-	-	-	-	-	-	-	-	-	-
Smelter FAC Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Accounts Receivable	17.5	26.3	19.9	19.9	19.87	44.71	46.1	49.7	53.2	57.0	53.2	54.4	54.8	58.8	57.5	59.4	59.9	61.7	61.9	63.4
Regulatory Asset	-	-	-	-	-	0.3	-	1.0	2.4	5.0	4.4	4.4	5.2	12.3	14.3	20.5	18.8	21.5	22.8	27.4
Fuel Stock & Related	-	-	-	31.4	31.4	31.3	35.2	37.3	42.4	46.3	29.2	29.3	29.5	30.3	30.4	31.2	31.5	31.9	32.7	33.0
Emissions Inventory				2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Materials and Supplies Other	0.8	0.8	0.8	20.4	20.4	21.0	21.6	22.3	22.9	23.6	24.3	25.1	25.8	26.6	27.4	28.2	29.1	29.9	30.8	31.8
Other Current Assets	4.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Credits																				
AMBAC/Credit Suisse July '98	4.7	4.3	3.8	3.8	3.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Tax	4.7	5.0	5.4	6.8	6.8	6.8	6.8	6.8	6.8	6.3	6.0	5.7	5.4	5.1	4.8	4.5	4.2	3.8	3.5	3.1
Deferred Debt Debits/PCB Refunding 10/0	0.6	0.8	0.7	1.1	1.1	7.1	6.7	7.3	6.9	6.5	6.0	12.6	11.9	11.2	10.5	9.8	9.0	8.3	7.5	6.8
Other Deferred Assets	-	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
LEM Settlement Note/Marketing Payment	17.1	16.1	15.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Assets	1,253.4	1,313.3	1,308.1	1,676.8	1,420.3	1,456.5	1,452.6	1,473.1	1,486.8	1,550.6	1,630.5	1,931.4	1,717.3	1,703.0	1,704.1	1,684.4	1,659.7	1,649.4	1,634.2	1,619.2
Liabilities & Equities																				
Margins & Equities	(218.2)	(175.0)	(138.5)	388.3	372.2	386.4	399.7	413.0	428.6	445.3	463.5	483.1	502.4	521.3	539.7	557.9	575.6	592.9	609.7	626.1
Long-Term Debt																				
Existing Debt	1,053.1	1,061.7	1,027.1	871.7	871.7	864.8	856.5	906.2	934.5	1,010.9	1,085.8	1,366.2	1,132.0	1,093.6	1,078.2	1,036.4	992.7	961.5	928.6	894.2
Sale-Leaseback Obligation	177.3	183.9	189.7	189.7	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
Total Long-Term Debt	1,230.4	1,245.6	1,216.9	1,061.4	871.7	864.8	856.5	906.2	934.5	1,010.9	1,085.8	1,366.2	1,132.0	1,093.6	1,078.2	1,036.4	992.7	961.5	928.6	894.2
Current & Accrued Liabilities																				
Accounts Payable	12.6	18.0	12.7	12.7	12.7	69.5	72.5	76.8	81.9	86.7	73.3	74.0	74.6	79.5	77.4	81.0	82.1	85.4	86.1	88.9
Regulatory Liability					0.0	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
Taxes Accrued	0.2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2
Non-Smelter Member Economic Reserve	-	-	-	157.0	157.0	127.8	96.8	69.9	34.4	-	-	-	-	-	-	-	-	-	-	-
Smelter FAC Reserve Deferred Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest Accrued	7.6	7.8	7.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other Accrued Liabilities	6.0	5.2	5.4	5.4	5.4	5.6	5.7	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
Deferred TIER Rebate Payable					0.0	1.0	18.8	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
WKEC Lease (Resid. Value Obligation)	158.1	156.9	152.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sale-Leaseback Gain	56.4	53.5	50.6	50.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Deferred Credits & Century Reactive	0.4	0.3	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Liabilities & Equity	1,253.4	1,313.3	1,308.1	1,676.8	1,420.3	1,456.5	1,452.6	1,473.1	1,486.8	1,550.6	1,630.5	1,931.4	1,717.3	1,703.0	1,704.1	1,684.4	1,659.7	1,649.4	1,634.2	1,619.2

	Calendar Year	2006	2007	2008	Transact ion	Lease Terminat ion	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
267	Change in Working Capital																				
268	Other Property	6.7	7.1	3.1	-	(196.8)	0.3	-	-	(0.7)	(1.6)	(1.5)	-	-	-	-	-	-	-	-	-
269	Accounts Receivable	1.2	8.9	(6.4)	-	-	24.8	1.4	3.6	3.5	3.8	(3.8)	1.3	0.4	4.0	(1.3)	2.0	0.5	1.8	0.2	1.5
270	Materials, Supplies & Other	0.1	(0.0)	0.0	-	0.0	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9
271	Other Current Assets	3.8	(3.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
272	Accounts Payable	0.5	(5.4)	5.3	-	-	(56.8)	(3.0)	(4.3)	(5.1)	(4.8)	13.4	(0.7)	(0.5)	(5.0)	2.1	(3.6)	(1.1)	(3.3)	(0.7)	(2.8)
273	Taxes Accrued	0.2	(0.8)	(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)	(0.0)
274	Other Accruals	(0.1)	0.8	(0.2)	-	(0.0)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
275	Investment - Special Deposit (B/S)	(6.0)	(6.2)	(6.4)	-	196.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	Net SLB	(0.3)	(0.3)	0.5																	
277	CoBank Patronage Capital	(0.4)	(0.4)	(0.4)	-	(0.0)	(0.3)	-	-	0.7	1.6	1.5	-	-	-	-	-	-	-	-	-
278	Adjustment	1.1	4.1	(0.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
279	Total	6.8	4.6	(4.9)	-	0.0	(31.5)	(1.1)	(0.2)	(1.1)	(0.6)	10.0	1.1	0.4	(0.4)	1.3	(1.0)	0.0	(0.9)	0.2	(0.7)
280																					
281	Cash Balance																				
282	Beginning	67.8	96.5	148.3	146.0	219.6	160.0	137.3	142.5	162.0	105.7	93.8	106.6	312.4	113.3	117.0	147.2	144.1	149.2	163.6	176.2
283	Ending	96.5	148.3	146.0	219.6	160.0	137.3	142.5	162.0	105.7	93.8	106.6	312.4	113.3	117.0	147.2	144.1	149.2	163.6	176.2	184.1
284																					
285	**VI. Credit Measures**																				
286																					
287	Contract TIER																				
288	Earnings						14.25	13.29	13.24	15.64	16.71	18.16	19.59	19.33	18.89	18.40	18.24	17.72	17.28	16.78	16.34
289	Plus: Interest Expense, Financing Fees, and Restructuring						53.6	49.3	48.8	58.6	62.8	68.6	74.3	72.9	70.7	68.4	67.4	64.9	62.7	60.2	58.0
290	Plus: Imputed Rate Increase in 2010						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
291	Less: Offset to Imputed Rate Increase in 2010						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
292	Less: Interest on Sequestered Funds						(1.40)	(1.46)	(1.51)	(1.57)	(1.64)	(1.70)	(1.77)	(1.84)	(1.92)	(1.99)	(2.07)	(2.16)	(2.24)	(2.33)	(2.42)
293	Total						66.4	61.1	60.6	72.7	77.9	85.0	92.1	90.3	87.7	84.8	83.5	80.4	77.7	74.7	71.9
294	Plus Sale-Leaseback Interest						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
295	Total						66.4	61.1	60.6	72.7	77.9	85.0	92.1	90.3	87.7	84.8	83.5	80.4	77.7	74.7	71.9
296	Divided by																				
297	Interest Expense, Financing Fees, and Restructuring						53.6	49.3	48.8	58.6	62.8	68.6	74.3	72.9	70.7	68.4	67.4	64.9	62.7	60.2	58.0
298	Plus Sale-Leaseback Interest						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
299	Total						53.6	49.3	48.8	58.6	62.8	68.6	74.3	72.9	70.7	68.4	67.4	64.9	62.7	60.2	58.0
300																					
301	*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
302																					
303	Conventional TIER																				
304	Earnings						14.3	13.3	13.2	15.6	16.7	18.2	19.6	19.3	18.9	18.4	18.2	17.7	17.3	16.8	16.3
305	Plus: Interest Expense, Financing Fees, and Restructuring						53.6	49.3	48.8	58.6	62.8	68.6	74.3	72.9	70.7	68.4	67.4	64.9	62.7	60.2	58.0
306	Plus Income Tax						-	-	-	-	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8
307	Total						67.8	62.6	62.1	74.3	80.1	87.3	94.5	92.8	90.3	87.5	86.3	83.3	80.7	77.8	75.2
308	Plus Sale-Leaseback Interest						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
309	Total						67.8	62.6	62.1	74.3	80.1	87.3	94.5	92.8	90.3	87.5	86.3	83.3	80.7	77.8	75.2
310	*Divided by*																				
311	Interest Expense, Financing Fees, and Restructuring						53.6	49.3	48.8	58.6	62.8	68.6	74.3	72.9	70.7	68.4	67.4	64.9	62.7	60.2	58.0
312	Plus Sale-Leaseback Interest						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
313	Total						53.6	49.3	48.8	58.6	62.8	68.6	74.3	72.9	70.7	68.4	67.4	64.9	62.7	60.2	58.0
314																					
315	*Conventional TIER*						1.27	1.27	1.27	1.27	1.28	1.27	1.27	1.27	1.28	1.28	1.28	1.28	1.29	1.29	1.30
316																					

	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
317	DSCR - Cash Basis, Pre Capex, incl Sale-Leaseback																				
318	Cash Available for Debt Service																				
319	Receipts less Disbursements						92.4	78.4	53.1	78.4	89.3	148.0	148.6	149.6	157.4	159.9	157.8	163.3	158.8	157.2	154.2
320	Economic Reserve						35.5	36.1	30.8	38.3	35.7	-	-	-	-	-	-	-	-	-	-
321	Taxes						(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.3)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)
322	Net						127.8	114.5	83.8	116.7	125.0	147.8	148.3	149.2	157.0	159.5	157.3	162.9	158.3	156.7	153.7
323	*Plus Sale-Leaseback Interest*						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
324	Total						127.8	114.5	83.8	116.7	125.0	147.8	148.3	149.2	157.0	159.5	157.3	162.9	158.3	156.7	153.7
325	Divided by																				
326	Interest Expenditures						43.7	43.0	42.1	51.4	55.2	60.5	65.7	63.7	61.0	58.1	56.5	53.3	50.0	47.3	44.3
327	Scheduled Principal						13.3	15.1	15.8	16.7	31.6	33.5	35.6	7.1	38.2	40.4	42.8	45.3	34.0	35.9	38.2
328	Plus Sale-Leasback Interest						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
329	Total Debt Service						57.0	58.0	57.9	68.1	86.8	94.0	101.3	70.8	99.2	98.5	99.3	98.6	84.0	83.2	82.5
330																					
331	*DSCR*						2.24	1.97	1.45	1.71	1.44	1.57	1.46	2.11	1.58	1.62	1.58	1.65	1.89	1.88	1.86
332																					
333	Days Cash on Hand																				
334	Average Cash Balance	96.5	122.4	147.2	182.8	189.8	148.7	139.9	152.3	133.9	99.8	100.2	209.5	212.9	115.2	132.1	145.7	146.7	156.4	169.9	180.1
335	Line of Credit	100.0				100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
336	Total	196.5	122.4	147.2	182.8	289.8	248.7	239.9	252.3	233.9	199.8	200.2	309.5	312.9	215.2	232.1	245.7	246.7	256.4	269.9	280.1
337	Divided by																				
338	Total Operating Expense																				
339	PPA	98.0	96.3	95.4	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
340	Fuel Costs	-	-	-	-		270.8	301.0	305.8	339.5	366.4	276.1	259.3	261.7	260.2	267.6	268.0	275.4	277.0	285.9	285.5
341	SEPA & Other Purchases	11.4	68.0	11.6	-		22.8	19.3	25.9	24.3	27.1	26.5	28.1	29.4	41.7	31.9	38.8	39.1	46.6	44.0	51.3
342	Non-Fuel Variable Production O&M	0.4	0.5	0.6	-		30.8	33.7	38.3	39.9	40.9	41.8	51.4	53.0	52.9	55.3	55.3	58.1	60.4	61.4	63.3
343	Fixed Production O&M	-	-	-	-		101.3	93.3	105.0	104.9	106.0	102.3	111.8	108.5	129.6	113.5	129.3	123.8	133.5	128.7	137.0
344	Transmission O&M	6.6	7.1	7.4	-		8.0	8.3	8.5	8.8	9.0	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.4	11.8	12.1
345	APM, L/C, Cogen, CW & TVA Trans	4.7	8.8	5.9	-		6.3	6.5	5.8	5.7	5.9	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
346	A&G	13.8	15.6	17.2	-		29.5	27.8	29.2	29.5	30.3	31.7	32.1	33.0	34.3	35.1	36.0	37.5	38.2	39.5	40.9
347	Property Taxes & Insurance	2.4	2.3	2.2	-		6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
348	Interest Expense (Incl. Financing Fee	60.7	60.9	59.9	-		53.1	48.9	48.4	58.2	62.4	68.2	73.8	72.5	70.3	68.0	67.0	64.5	62.3	59.8	57.6
349	Total	198.0	259.5	200.4	-		529.7	545.7	574.8	619.5	656.8	570.9	581.5	583.9	615.7	598.9	622.6	627.3	647.9	650.2	667.4
350																					
351	*Days Cash on Hand (including Line of C*	362.2	172.2	268.1			171.3	160.4	160.2	*137.8*	*111.0*	*128.0*	*194.3*	*195.6*	127.5	141.5	144.0	143.5	144.5	151.5	153.2
352	*Days Cash on Hand (excluding Line of C*	177.8	172.2	268.1			102.4	93.6	96.7	78.9	55.4	64.1	131.5	133.1	68.3	80.5	85.4	85.3	88.1	95.4	98.5
353																					

	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
354	VII. Debt Service Detail, as of Transaction Date (MS)																				
355																					
356	Capital Markets Issue (Tranche 1)																				
357	Beginning Principal			-						58.3	58.3	49.1	39.2	28.6	28.6	28.6	53.2	53.2	53.2	52.7	24.9
358	Principal			-					(58.3)	-	9.3	9.9	10.6	-	-	(24.6)	-	-	0.5	27.9	15.7
359	Interest			-					-	4.1	4.1	3.4	2.7	2.0	2.0	2.0	3.5	3.5	3.5	3.4	1.6
360	*Debt Service*			-					(58.3)	4.1	13.3	13.3	13.3	2.0	2.0	(22.6)	3.5	3.5	3.9	31.3	17.3
361	Blended Interest Cost		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	6.50%	6.50%	6.50%	6.50%	6.50%
362																					
363	Capital Markets Issue (Tranche 2)																				
364	Beginning Principal			-										207.0	207.0	207.0	207.0	207.0	207.0	207.0	199.0
365	Principal			-									(207.0)	-	-	-	-	-	-	8.0	22.5
366	Interest			-									-	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.2
367	*Debt Service*			-									(207.0)	11.6	11.6	11.6	11.6	11.6	11.6	19.7	33.7
368	Blended Interest Cost		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.63%
369																					
370	Variable Rate Bonds																				
371	Beginning Principal			-																	
372	Principal			-																	
373	Interest			-																	
374	Debt Service			-																	
375	Blended Interest Cost		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
376																					
377	Ongoing RUS Note (Stated)																				
378	Beginning Principal			768.4	628.2	628.2	614.9	599.8	584.0	504.7	482.3	458.7	433.7	200.2	162.0	121.6	78.8	33.5	0.0	0.0	
379	Principal			140.2	-	13.3	15.1	15.8	79.4	22.3	23.6	25.0	233.5	38.2	40.4	42.8	45.3	33.5	-	-	
380	Interest			-	0.0	36.1	35.4	34.5	32.5	29.0	27.7	26.4	13.4	11.5	9.3	7.0	4.5	1.9	0.0	0.0	
381	Debt Service		-	140.2	0.0	49.4	50.4	50.3	111.9	51.4	51.4	51.4	246.9	49.7	49.7	49.8	49.8	35.4	0.0	0.0	
382	Blended Interest Cost			0.00%	0.00%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%		
383																					
384	ARVP																				
385	Beginning Principal			104.1	104.1	104.1	110.2	116.8	123.7	131.0	138.7	146.9	155.6	164.8	174.6	184.9	195.8	207.4	219.7	232.7	
386	Principal/ Reserve			-																	
387	Interest/ Reserve			-																	
388	Debt Service			-																	
389	Accretion Rate		0.00%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
390																					
391	PCB																				
392	Beginning Principal			142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	
393	Principal			-																	
394	Interest			-	0.0	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
395	Debt Service		-	-	0.0	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
396	Blended Interest Cost			0.00%	0.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
397																					
	Additional Debt									-	100.0	200.0	300.0	400.0	390.0	380.0	370.0	360.0	350.0	340.0	330.0
	Beginning Principal									(100.0)	(100.0)	(100.0)	(100.0)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
	Principal									7.3	14.5	21.8	29.0	29.0	28.3	27.6	26.8	26.1	25.4	24.7	23.9
	Interest									(92.8)	(85.5)	(78.3)	(71.0)	39.0	38.3	37.6	36.8	36.1	35.4	34.7	33.9
	Debt Service																				
	Blended Interest Cost																				
398	Total (Incorporates RUS on Stated Basis)																				
399	Beginning Principal			1,014.6	874.4	874.4	867.2	858.7	908.1	936.0	1,012.2	1,086.9	1,367.0	1,132.7	1,094.3	1,078.8	1,036.9	993.2	961.5	928.6	
400	Principal			140.2	-	13.3	15.1	(42.5)	(20.6)	(68.4)	(66.5)	(271.5)	243.5	48.2	25.8	52.8	55.3	44.0	45.9	48.2	
401	Interest			-	0.0	43.2	42.5	41.6	50.9	54.7	60.0	65.2	63.2	60.5	57.6	56.0	52.8	49.5	46.8	43.8	
402	Line of Credit Fee			-	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	

October 2008

	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
403	Debt Service				140.2	0.0	57.0	58.0	(0.4)	30.8	(13.2)	(6.0)	(205.7)	307.2	109.2	83.9	109.3	108.6	94.0	93.2	92.5

Transaction Closing Date: 12/31/2008

Smelt. .late Structure

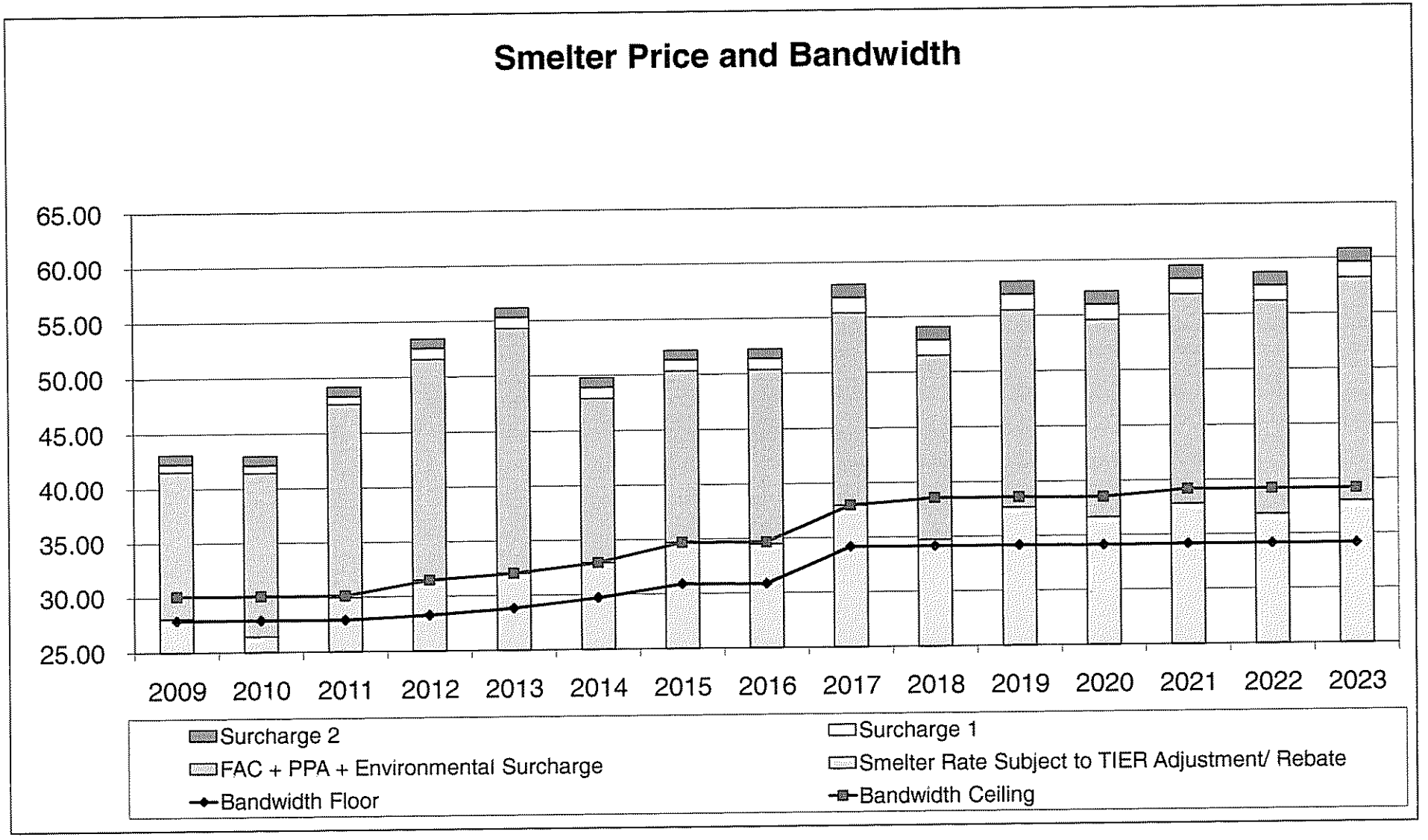
October 2008

Smelter Rates

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Days in Year	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
General Rate Adjustment (%)	0.00%	0.00%	0.00%	1.46%	1.80%	3.12%	3.94%	0.00%	10.55%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1 Smelter Sales															
2 Century	4.14	4.14	4.14	4.15	4.14	4.14	4.14	4.15	4.14	4.14	4.14	4.15	4.14	4.14	4.14
3 Alcan	3.16	3.16	3.16	3.17	3.16	3.16	3.16	3.17	3.16	3.16	3.16	3.17	3.16	3.16	3.16
4 Total Energy (TWh)	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
5 Total Demand (GW)	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200
6 Smelter Load Factor (%)	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
7															
8 Smelter Rate ($/ MWh)															
9 Large Industrial Rate															
10 Sales (TWH)	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
11 Load Factor (%)	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
12 Demand ($/ KW-mo.)	10.15	10.15	10.15	10.30	10.48	10.81	11.24	11.24	12.42	12.42	12.42	12.42	12.42	12.42	12.42
13 Energy ($/ MWH)	13.72	13.72	13.72	13.92	14.17	14.61	15.18	15.18	16.79	16.79	16.79	16.79	16.79	16.79	16.79
14 Power Factor Penalty/ Demand Cr. ($/ MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15 MRDA ($/ MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16 Regulatory Account Charge	-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
17 Less: Regulatory Account Charge	-	-	0.10	0.10	0.10	(0.42)	(0.41)	(0.40)	(0.41)	(0.40)	(0.39)	(1.52)	(1.48)	(1.45)	(1.59)
18 Net Rate ($/ MWH)	31.39	31.39	31.39	31.86	32.43	33.44	34.76	34.78	38.42	38.42	38.42	38.45	38.42	38.42	38.42
19															
20 Large Industrial Rate @ 98% LF	27.90	27.90	27.90	28.27	28.82	29.72	30.89	30.85	34.15	34.15	34.15	34.10	34.15	34.15	34.15
21 Plus Margin	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
22 Smelter Base Rate	28.15	28.15	28.15	28.52	29.07	29.97	31.14	31.10	34.40	34.40	34.40	34.35	34.40	34.40	34.40
23 Plus TIER Adjustment	-	-	1.79	2.95	2.95	2.95	3.55	3.39	3.55	0.32	3.23	2.31	3.42	2.43	3.61
24 Less TIER Related Rebate	(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Smelter Rate Subject to TIER Adjustment	28.06	26.42	29.95	31.47	32.02	32.92	34.69	34.49	37.95	34.72	37.63	36.66	37.83	36.83	38.01
26															
27 Plus FAC + PPA + Environmental Surcharge	13.48	14.99	17.67	20.10	22.30	15.01	15.62	15.87	17.45	16.77	17.91	17.91	19.00	19.33	20.22
28 Plus Surcharge 1	0.70	0.70	0.70	1.00	1.00	1.00	1.00	1.00	1.40	1.40	1.40	1.39	1.40	1.40	1.40
29 Plus Surcharge 2	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	1.20	1.20	1.20	1.20	1.20	1.20	1.20
30 Effective Smelter Rate (Incl. PPA, Surcharge, & Rebate)	43.11	42.98	49.19	53.44	56.19	49.80	52.18	52.24	58.00	54.09	58.14	57.16	59.42	58.76	60.83
31															
32 TIER Adjustment Cap ($/ MWh)															
33 Bandwidth Floor	28.15	28.15	28.15	28.52	29.07	29.97	31.14	31.10	34.40	34.40	34.40	34.35	34.40	34.40	34.40
34 Bandwidth Range	1.95	1.95	1.95	2.95	2.95	2.95	3.55	3.55	3.55	4.15	4.15	4.15	4.75	4.75	4.75
35 Bandwidth Ceiling	30.10	30.10	30.10	31.47	32.02	32.92	34.69	34.65	37.95	38.55	38.55	38.50	39.15	39.15	39.15
36 Smelter Rate Subject to TIER Adjustment/ Rebate	28.06	26.42	29.95	31.47	32.02	32.92	34.69	34.49	37.95	34.72	37.63	36.66	37.83	36.83	38.01

Smelter Rates

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Days in Year	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
General Rate Adjustment (%)	0.00%	0.00%	0.00%	1.46%	1.80%	3.12%	3.94%	0.00%	10.55%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%



Smelt. .late Structure

Smelter Rates

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Days in Year	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
	General Rate Adjustment (%)	0.00%	0.00%	0.00%	1.46%	1.80%	3.12%	3.94%	0.00%	10.55%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	**TIER Adjustment Rebate/Charge**															
38	Pre-TIER Rebate Member Revenues	124.1	134.4	150.5	157.1	174.5	194.2	206.7	211.9	229.4	236.9	243.5	257.0	263.5	272.1	279.1
39	Pre-TIER Adj/Rebate Smelter Revenues	315.3	326.2	345.9	369.5	388.5	341.9	354.9	357.4	397.3	392.4	400.7	401.4	408.6	411.0	417.5
40	Other Revenues	140.0	153.1	123.5	134.5	139.2	84.1	70.0	68.2	57.7	62.7	51.5	49.7	49.5	48.9	45.2
41	Pre TIER Adj/Rebate Revenues	579.4	613.8	620.0	661.1	702.2	620.2	631.7	637.5	684.4	692.0	695.7	708.1	721.6	732.1	741.8
42	Total Expenses	564.1	581.7	619.8	667.0	707.0	623.5	638.0	643.0	691.4	675.9	701.0	707.2	729.3	733.0	751.8
43	Net Margin Before TIER Adjustment	15.3	32.1	0.1	(5.9)	(4.8)	(3.4)	(6.3)	(5.5)	(7.0)	16.1	(5.3)	0.8	(7.7)	(0.9)	(10.0)
44																
45	Interest + Margin	68.8	81.4	49.0	52.7	58.0	65.2	67.9	67.4	63.7	84.4	62.0	65.7	55.0	59.3	48.0
46	Interest Charges	53.6	49.3	48.8	58.6	62.8	68.6	74.3	72.9	70.7	68.4	67.4	64.9	62.7	60.2	58.0
47	Pre-TIER Adjustment TIER	1.29	1.65	1.00	0.90	0.92	0.95	0.91	0.92	0.90	1.24	0.92	1.01	0.88	0.98	0.83
48																
49	Increment needed for 1.24x TIER	(2.4)	(20.3)	11.6	20.0	19.9	19.8	24.1	23.0	24.0	0.3	21.5	14.7	22.7	15.4	23.9
50	Contract TIER Adjustments															
51	Plus: Imputed Rate Increase in 2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Less: Offset to Imputed Rate Increase in 2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Less: Interest on Sequestered Funds	(1.4)	(1.5)	(1.5)	(1.6)	(1.6)	(1.7)	(1.8)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)
54	Total Adjustments	(1.4)	(1.5)	(1.5)	(1.6)	(1.6)	(1.7)	(1.8)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)
55	Increment needed for 1.24x TIER with Adj.	(1.0)	(18.8)	13.1	21.6	21.5	21.5	25.9	24.8	25.9	2.3	23.6	16.9	25.0	17.7	26.3
56																
57	Rebate Amount ($M)	(1.0)	(18.8)	-	-	-	-	-	-	-	-	-	-	-	-	-
58	TIER Adjustment Charge ($M)	-	-	13.1	21.6	21.5	21.5	25.9	24.8	25.9	2.3	23.6	16.9	25.0	17.7	26.3
59																
60	Rebate to Members/Smelters ($/MWh)															
61	Rurals	(0.10)	(1.79)	-	-	-	-	-	-	-	-	-	-	-	-	-
62	Large Industrials	(0.09)	(1.59)	-	-	-	-	-	-	-	-	-	-	-	-	-
63	Smelters	(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-	-
64																
65	TIER Adjustment Charge to Smelters ($/MWh)	-	-	1.79	2.95	2.95	2.95	3.55	3.39	3.55	0.32	3.23	2.31	3.42	2.43	3.61

Memb[illegible] Rates Cash Method

Oct[illegible] 2008

Member Rates (Cash Method) Calculation

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Member Sales (TWh)															
Rural	2.44	2.49	2.54	2.59	2.65	2.70	2.76	2.82	2.88	2.94	3.00	3.06	3.12	3.18	3.24
Large Industrial	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
Total	3.50	3.58	3.67	3.76	3.85	3.94	4.03	4.12	4.22	4.31	4.40	4.50	4.60	4.69	4.79
Rates (Cash Method)															
Rural															
Load Factor (%)	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
Demand ($/ KW-mo.)	7.37	7.37	7.37	7.48	7.61	7.85	8.16	8.16	9.02	9.02	9.02	9.02	9.02	9.02	9.02
Energy ($/ MWH)	20.40	20.40	20.40	20.70	21.07	21.73	22.59	22.59	24.97	24.97	24.97	24.97	24.97	24.97	24.97
Base	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
MRDA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regulatory Account Charge	-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
GRA	-	-	-	0.54	1.22	2.42	3.97	3.97	8.29	8.29	8.28	8.27	8.27	8.27	8.26
FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
Env. Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Surcharge Rebate	(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
TIER Related Rebate	-	(0.10)	(1.76)	-	-	-	-	-	-	-	-	-	-	-	-
Non-Smelter Member Economic Reserve	(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
Net	-	2.00	3.93	6.00	8.91	11.28	11.80	11.97	10.87	11.50	11.83	12.54	12.82	13.55	13.72
Effective Rate	37.22	39.19	41.00	43.58	47.15	51.21	53.25	53.39	56.59	57.19	57.48	59.29	59.51	60.20	60.48
Large Industrial															
Load Factor (%)	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
Demand ($/ KW-mo.)	10.15	10.15	10.15	10.30	10.48	10.81	11.24	11.24	12.42	12.42	12.42	12.42	12.42	12.42	12.42
Energy ($/ MWH)	13.72	13.72	13.72	13.92	14.17	14.61	15.18	15.18	16.79	16.79	16.79	16.79	16.79	16.79	16.79
Base	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
MRDA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regulatory Account Charge	-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
GRA	-	-	-	0.46	1.03	2.05	3.36	3.37	7.03	7.03	7.03	7.03	7.03	7.03	7.03
FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
Env. Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Surcharge Rebate	(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
TIER Related Rebate	-	(0.08)	(1.54)	-	-	-	-	-	-	-	-	-	-	-	-
Non-Smelter Member Economic Reserve	(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
Net	-	2.01	4.15	6.00	8.91	11.28	11.80	11.97	10.87	11.50	11.83	12.54	12.82	13.55	13.72
Effective Rate	31.39	33.40	35.44	37.76	41.24	45.15	46.97	47.15	49.70	50.32	50.64	52.51	52.72	53.43	53.74

Memb Rates Cash Method

Oct 2008

Member Rates (Cash Method) Calculation

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Non-Smelter Member Blend															
Base	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
MRDA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regulatory Account Charge	-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
GRA	-	-	-	0.52	1.16	2.30	3.78	3.78	7.89	7.89	7.88	7.88	7.87	7.87	7.87
FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
Env. Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Surcharge Rebate	(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
TIER Related Rebate	-	(0.09)	(1.69)	-	-	-	-	-	-	-	-	-	-	-	-
Non-Smelter Member Economic Reserve	(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
Net	-	2.00	4.00	6.00	8.91	11.28	11.80	11.97	10.87	11.50	11.83	12.54	12.82	13.55	13.72
Effective Rate	35.45	37.42	39.29	41.78	45.30	49.31	51.27	51.42	54.40	55.00	55.29	57.12	57.33	58.02	58.30
Revenues Delta($M)															
Rural	0.24	4.22	(4.46)	-	-	-	-	-	-	-	-	-	-	-	-
LI	0.09	1.65	(1.74)	-	-	-	-	-	-	-	-	-	-	-	-
Total	0.33	5.87	(6.20)	-	-	-	-	-	-	-	-	-	-	-	-
Smelter Rebate Lag															
TWh	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
Accrued ($/ MWh)	(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-	-
Realized ($/ MWh)	-	(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-
Adjust ($M)	0.70	11.94	(12.63)	-	-	-	-	-	-	-	-	-	-	-	-

Regulatory Accounts

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Purchased Power Cost not Included in Member Rates ($M)	0.26	(1.39)	1.77	1.03	2.20	1.02	1.76	2.39	8.83	3.78	7.86	5.17	9.50	8.16	12.18
1 **EXPENSE DEFERRAL METHOD**															
2															
3 **Income Statement (Change in Regulatory Account)**															
4 1. Deferral															
5 Power Purchase Expense															
6 Debit	-	1.39	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Credit	(0.26)	-	(1.77)	(1.03)	(2.20)	(1.02)	(1.76)	(2.39)	(8.83)	(3.78)	(7.86)	(5.17)	(9.50)	(8.16)	(12.18)
8 Total	(0.26)	1.39	(1.77)	(1.03)	(2.20)	(1.02)	(1.76)	(2.39)	(8.83)	(3.78)	(7.86)	(5.17)	(9.50)	(8.16)	(12.18)
9															
10 2. Recognition of Prior Year Balance (Set to Start in 2013)			(0.37)	(0.37)	(0.37)	1.67	1.67	1.67	1.72	1.72	1.72	6.82	6.82	6.82	7.61
11 Credit Member Revenue (Charge to Members)			(0.37)	(0.37)	(0.37)	1.67	1.67	1.67	1.72	1.72	1.72	6.82	6.82	6.82	7.61
12 Debit Power Purchase Expense															
13															
14 Net Income	0.26	(1.39)	1.77	1.03	2.20	1.02	1.76	2.39	8.83	3.78	7.86	5.17	9.50	8.16	12.18
15															
16 **Balance Sheet**															
17 Assets															
18 Cash			(0.4)	(0.7)	(1.1)	0.5	2.2	3.9	5.6	7.3	9.1	15.9	22.7	29.5	37.1
19 Regulatory Asset	0.3	-	1.0	2.4	5.0	4.4	4.4	5.2	12.3	14.3	20.5	18.8	21.5	22.8	27.4
20 Total	0.3	-	0.6	1.7	3.9	4.9	6.7	9.1	17.9	21.7	29.5	34.7	44.2	52.4	64.5
21															
22 Liabilities & Equity															
23 Equity	0.3	(1.1)	0.6	1.7	3.9	4.9	6.7	9.1	17.9	21.7	29.5	34.7	44.2	52.4	64.5
24 Regulatory Liability	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Total	0.3	-	0.6	1.7	3.9	4.9	6.7	9.1	17.9	21.7	29.5	34.7	44.2	52.4	64.5

FAC . . A Env Sur

October 2008

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Production (TWh)**	11.9	12.4	11.8	12.0	12.1	12.1	12.2	12.2	11.8	12.2	11.9	12.1	12.1	12.2	12.1
2	**Sales (TWh)**	12.3	12.7	12.3	12.4	12.6	12.6	12.6	12.7	12.6	12.7	12.6	12.7	12.8	12.8	12.9
3																
4																
5	**A. FAC**															
6	Fuel Costs ($M)	270.8	301.0	305.8	339.5	366.4	276.1	259.3	261.7	260.2	267.6	268.0	275.4	277.0	285.9	285.5
7																
8	Total Costs for Passthrough ($/ MWh Sold)	21.94	23.67	24.76	27.30	29.18	21.99	20.54	20.64	20.72	21.04	21.32	21.68	21.70	22.28	22.19
9	Fuel Cost Base ($/MWh)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)
10	FAC ($/MWh)	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
11	**B. PPA**															
12	Purchased Power Costs ($M)	22.55	17.35	27.57	25.20	29.18	25.26	27.61	29.57	48.30	33.44	44.44	36.86	48.75	44.80	55.28
13																
14	Total Costs for Passthrough ($/ MWh Sold)	1.83	1.36	2.23	2.03	2.32	2.01	2.19	2.33	3.85	2.63	3.54	2.90	3.82	3.49	4.30
15	Purchased Power Cost Base ($/MWh)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)
16	Purchase Power Passthrough ($/MWh)	0.08	(0.39)	0.48	0.27	0.57	0.26	0.44	0.58	2.09	0.88	1.78	1.15	2.07	1.74	2.54
17																
18	**C. Environmental Surcharge**															
19	Eligible Cost ($M)	27.00	30.76	38.88	40.35	41.08	43.74	67.70	68.06	67.34	70.95	69.42	73.61	76.01	77.42	79.85
20																
21	Total Costs for Passthrough ($/ MWh Sold)	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
22	Env. Surcharge Cost Base ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Environmental Surcharge Passthrough ($/M	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
24																
25																
26	**1 - FAC + Environmental Surcharge to Members**															
27	Rurals															
28	FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
29	Environmental Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
30	**Total**	13.41	15.37	17.19	19.83	21.73	14.75	15.18	15.29	15.36	15.90	16.13	16.76	16.94	17.59	17.68
31	Large Industrials															
32	FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
33	Environmental Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
34	**Total**	13.41	15.37	17.19	19.83	21.73	14.75	15.18	15.29	15.36	15.90	16.13	16.76	16.94	17.59	17.68
35	**2 - FAC + PPA + Environmental Surcharge to Smelters**															
36	FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
37	PPA	0.08	(0.39)	0.48	0.27	0.57	0.26	0.44	0.58	2.09	0.88	1.78	1.15	2.07	1.74	2.54
38	Environmental Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
39	**Total**	13.48	14.99	17.67	20.10	22.30	15.01	15.62	15.87	17.45	16.77	17.91	17.91	19.00	19.33	20.22

UW Transaction

	($M)	2008	Transaction	Lease Termination
	Unwind Allocation	-	-	0.000
	Pre-Transaction Allocation	1.000	-	-
	Transaction Index	-	1.000	-
	A. Transaction Components			
1	1. Cash Payment/ Credit Escrow Draws	.	387.7	.
2	2. WKE Residual Value Obligation			
3	WKE Gen. Capex - Cum.			
4	Non-Incremental (RV Obligation Balance)			
5	Beginning Balance	50.2	55.0	.
6	WKE Share of Non-Incremental Capex	7.0	.	-
7	Amortization of WKE Share	2.1	-	-
8	Net	55.0	55.0	.
9	Incremental			
10	Beginning Balance	90.9	86.3	-
11	WKE Share of Non-Incremental Capex	-	-	.
12	Amortization of WKE Share	4.6	.	-
13	Net	86.3	86.3	-
14	Total	141.4	141.4	
15	3. LG&E Rental Income Advance			
16	Cash Flow	47.7	.	-
17	Income Statement	52.3	-	-
18	Balance	(11.2)	(11.2)	.
19	4. Fuel & Other Inventories	-	51.0	-
20	5. Cancellation of Settlement Prom. Note	.	15.7	-
21	6. Coleman Scrubber Completion	.	98.5	.
22	7. LG&E Emissions Allowance	-	2.0	.
23	8. Expense Unamortized Mktg Payment/ Settlement Note		(15.1)	
24	9. Assurances Agreement	.	1.5	-
25				
26	Total Residual Value Obligation	152.6	152.6	-
27	Cancellation of RV Obligation	.	152.6	-
28	Reclassification as Equity			
29				
30	Net WKE Obligation	152.6	.	-
31				

UW Transaction

		2008	Transaction	Lease Termination
($M)				
Unwind Allocation		-	-	0.000
Pre-Transaction Allocation		1.000	-	-
Transaction Index		-	1.000	-
B. Transaction Cash Flows				
Cash Balances Pre-Transaction			146.0	
Transaction Proceeds			387.7	
Lease Buyout			-	
Smelter Payment (Assurances Agreement)			(1.5)	
Consent Fee to Lease-Equity Parties			-	
Lump-Sum Member Rebate			.	
Net DSL Termination			.	
Century/Century Reactive Power Transaction Refund			(0.2)	
Income Tax			(1.3)	
Net Transaction Cash			384.6	
Debt Restructuring:				
Debt Reduction (Net)			(147.0)	
Underwriting Costs	1.75%		.	
Bond Insurance	0.80%		-	
ARVP Defeasance Premium			-	
Total			(147.0)	
Restricted Cash Balances:				
Transition Reserve			(35.0)	
Non-Smelter Member Economic Reserve			(157.0)	
Smelter Economic Reserve			-	
Unrestricted Cash Balances Post-Transaction			191.6	
C. Debt Restructuring:				
Beginning Balance - GAAP			1,027.1	
Cancellation of Settlement Prom. Note			(15.7)	
Capitalize Accrued Interest on RUS New Note			6.9	
Step-Up RUS New Note to Stated Basis:				
GAAP RUS New Note			765.3	
Ending Balance			6.9	
Accrued Interest			772.2	
Total				
Stated RUS New Note			768.4	
Ending Balance			6.8	
Accrued Interest			775.2	
Total			3.0	
Step-Up			1,021.4	
Beginning Balance - Stated				
Cash Flow:			(147.0)	
Prepay RUS New Note			-	
Defease ARVP			-	
Issue Capital Markets Debt			(147.0)	
Net			874.4	
Ending Balance - Stated			(2.7)	
Step-Down Remaining RUS New Note to GAAP Basis:			871.7	
Ending Balance - GAAP				

UW Tr. .saction

		2008	Transaction	Lease Termination
($M)		-	-	0.000
Unwind Allocation		1.000	-	-
Pre-Transaction Allocation		-	1.000	-
Transaction Index				
D. Reflection on Income Statement				
1. Cash		-	387.675	-
2. Residual Value Payment		-	141.356	-
3. LG&E Rental Income Advance		-	11.222	-
4. Fuel Inventory & Other		-	51.040	-
5. Settlement Promissory Note		-	15.659	-
6. Coleman Scrubber		-	98.520	-
7. SO2 Allowances		-	1.960	-
8. Expense Unamortized Mktg Payment/ Settlement Note		-	(15.068)	-
9. Assurances Agreement Payment		-	(1.525)	-
Total		-	690.839	-
E. Non-Patronage Allocations and Taxable Income				
Cash Flows	15%	-	58.15	-
Income Statement				
Cash	15%	-	58.15	-
RVP	15%	-	22.89	-
Fuel Inventory & Other (plus emissions allowances)	15%	-	7.95	-
Settlement Promissory Note	15%	-	2.35	-
Coleman Scrubber	15%	-	14.78	-
Expense Unamortized Mktg Payment/ Settlement Note	15%	-	(5.83)	-
Total		-	100.29	-
Taxable Income				
Gain on Transaction (above)		-	100.29	-
Less RVP		-	(22.89)	-
Less M1 - Coleman Scrubber		-	(14.78)	-
Plus Previously Expensed Mktg. Pmt.		-	4.20	-
Total		-	66.82	-

Produc ...n-Fixed

Production - Fixed

	(SM)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	A&G															
2	Labor	10.99	10.79	11.12	11.45	11.79	12.15	12.51	12.89	13.27	13.67	14.08	14.50	14.94	15.39	15.85
3	Non-Labor	12.12	12.48	12.85	13.24	13.63	14.04	14.46	14.90	15.34	15.80	16.28	16.77	17.27	17.79	18.32
4	Intellectual Property	6.42	4.51	5.26	4.82	4.91	5.51	5.09	5.18	5.69	5.66	5.65	6.19	5.98	6.33	6.74
5	Intellectual Property Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total	29.54	27.78	29.22	29.51	30.33	31.70	32.06	32.96	34.31	35.14	36.01	37.46	38.19	39.51	40.91
7																
8	APM, L/C, Cogen, CW & TVA Trans	6.31	6.46	5.80	5.69	5.86	6.03	6.21	6.39	6.58	6.78	6.98	7.19	7.40	7.62	7.85
9																
10	Property Insurance	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
11																
12	Property Tax															
13	Baseline	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
14	Transmission -- Operations	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
15	General Plant -- Operations	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
16	Total	2.86	2.94	3.54	4.11	4.23	4.36	4.49	4.63	4.76	4.91	5.05	5.21	5.36	5.52	5.69
17																
18	Transmission O&M															
19	Baseline Labor	6.07	6.25	6.43	6.63	6.83	7.03	7.24	7.46	7.68	7.91	8.15	8.40	8.65	8.91	9.17
20	Baseline Non-Labor	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
21	Upgrades, Phase I															
22	O&M	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
23	Property Tax	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
24	Property Ins.	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
25	Total (Real)	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
26	Total (Nominal)	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.45	0.47	0.48
27	Total Transmission O&M	8.02	8.26	8.51	8.76	9.02	9.29	9.57	9.86	10.16	10.46	10.77	11.10	11.43	11.77	12.13
28																
29	Fixed O&M															
30																
31	Labor	48.36	45.62	46.99	48.40	49.85	51.35	52.89	54.47	56.11	57.79	59.53	61.31	63.15	65.05	67.00
32																
33	Non-Labor	40.30	45.41	45.93	42.50	54.48	42.33	53.38	45.49	47.13	53.86	54.34	54.56	60.42	53.05	67.77
34																
35	Plant Maintenance															
36	Coleman	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
37	Green	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
38	HMP&L	0.24	0.17	-	-	-	-	2.94	-	-	-	-	-	-	-	-
39	Reid	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
40	Wilson	0.34	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Adjust for Station 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Total (Real)	1.84	0.65	0.24	-	-	-	2.94	-	3.44	-	-	-	-	-	-
43	Total (Nominal)	2.01	0.74	0.28	-	-	-	3.83	-	4.77	-	-	-	-	-	-
44																
45	T/G Overhauls (Cash Flows)	9.17	-	10.22	12.45	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
46	T/G Overhauls (Income Statement)	9.17	-	10.22	12.45	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
47																
48	Environmental Monitoring and Other	1.46	1.50	1.54	1.59	1.64	1.69	1.74	1.79	1.84	1.90	1.95	2.01	2.07	2.14	2.20
49																
50	08/2007 Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51																
52	Total Fixed O&M (to Cash Flows)	101.30	93.26	104.96	104.93	105.97	102.31	111.83	108.49	129.65	113.55	129.28	123.79	133.46	128.67	136.97
53	Total Fixed O&M (to Income Statement)	101.30	93.26	104.96	104.93	105.97	102.31	111.83	108.49	129.65	113.55	129.28	123.79	133.46	128.67	136.97

	($M)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Transmission--Basic		5.91	9.62	18.39	10.28	5.26	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
2																				
3	Transmission Upgrades																			
4	Phase I		-	4.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Phase II		-	-	-	5.40	5.30	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total Real		-	4.00	-	5.40	5.30	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Total Nominal	3.00%	-	4.12	-	5.56	5.62	-	-	-	-	-	-	-	-	-	-	-	-	-
8																				
9	A&G		0.86	1.25	1.29	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
10																				
11	Shared HQ Building																			
12	Phase I		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Phase II		-	-	-	1.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total		-	-	-	1.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																				
16	Intellectual Property																			
17	Total			-	-	9.74	1.02	0.92	0.79	0.80	0.98	0.83	0.85	1.00	0.92	0.94	1.06	0.89	0.91	1.23
18																				
19	WKE Share of Generation Capex																			
20	(%)		51%	51%	51%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	($M)		6.69	6.84	6.99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22																				
23	Generation																			
24	Baseline		-	-	-	33.10	18.29	27.20	103.33	112.65	104.86	102.56	25.92	25.92	25.92	25.92	25.92	25.92	25.92	25.92
25	Adjustment for Station 2		-	-	-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
26	Total Real		-	-	-	33.10	18.29	27.20	103.33	112.65	104.86	102.56	25.92	25.92	25.92	25.92	25.92	25.92	25.92	25.92
27	*Total Nominal*	3.00%	13.12	13.41	13.71	36.16	20.59	31.54	123.38	138.55	132.83	133.81	34.83	35.87	36.95	38.06	39.20	40.38	41.59	42.83
28																				
29	Plant Maintenance																			
30	Coleman		-	-	-	1.14	1.11	2.37	1.05	1.02	-	-	-	-	-	-	-	-	-	-
31	Green		-	-	-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
32	HMP&L		-	-	-	0.94	1.16	2.36	3.72	3.25	2.86	0.43	0.43	0.43	0.43	1.03	1.03	0.43	0.43	0.43
33	Reid		-	-	-	1.03	-	-	-	-	-	1.40	-	-	-	-	-	-	-	-
34	Wilson		-	-	-	14.63	6.47	11.19	1.91	1.57	1.24	1.57	1.24	1.57	1.24	3.74	1.24	1.57	1.24	1.57
35	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Total Real		-	-	-	26.29	15.49	20.16	8.97	7.15	4.10	3.40	1.68	2.00	1.68	4.77	2.28	2.00	1.68	2.00
37	Total Nominal	3.00%	-	-	-	28.73	17.44	23.37	10.71	8.80	5.19	4.44	2.25	2.77	2.39	7.01	3.44	3.12	2.69	3.31
38																				
39	Environmental																			
40	NOx Removal Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Mecury Monitoring		-	-	-	-	-	1.73	-	-	-	-	-	-	-	-	-	-	-	-
42	Clmn FGD Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	FGD ongoing upkeep capital (0.10%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Additional FGD thickener & filter drum		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	R-CT reliability study & upgrades		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Wilson super heater tubes replacment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Total Real		-	-	-	-	-	1.73	-	-	-	-	-	-	-	-	-	-	-	-
49	Total Nominal	3.00%	-	-	-	-	-	2.00	-	-	-	-	-	-	-	-	-	-	-	-
50																				
51	BigRivers Capex																			
52	Gross Generation		13.12	13.41	13.71	36.16	20.59	31.54	123.38	138.55	132.83	133.81	34.83	35.87	36.95	38.06	39.20	40.38	41.59	42.83
53	*Less* WKE Generation Share		6.69	6.84	6.99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	BigRivers Generation		6.43	6.57	6.72	36.16	20.59	31.54	123.38	138.55	132.83	133.81	34.83	35.87	36.95	38.06	39.20	40.38	41.59	42.83
55	Transmission		5.91	9.62	18.39	10.28	5.26	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
56	Transmission Upgrades		-	4.12	-	5.56	5.62	-	-	-	-	-	-	-	-	-	-	-	-	-
57	A&G		0.86	1.25	1.29	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
58	Shared HQ Building		-	-	-	1.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Intellectual Property		-	-	-	9.74	1.02	0.92	0.79	0.80	0.98	0.83	0.85	1.00	0.92	0.94	1.06	0.89	0.91	1.23
60	Plant Maintenance		-	-	-	28.73	17.44	23.37	10.71	8.80	5.19	4.44	2.25	2.77	2.39	7.01	3.44	3.12	2.69	3.31
61	Environmental		-	-	-	-	-	2.00	-	-	-	-	-	-	-	-	-	-	-	-
62	08/2007 Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
63	Cash Adder		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	Total		13.19	21.56	26.40	93.47	51.30	63.67	142.23	150.11	140.90	141.16	41.14	44.13	45.35	51.24	49.11	49.94	50.92	53.27

	(SM)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
65																				
66																				
67	Depreciation																			
68																				
69	Additional Book Depreciation																			
70	Prior year non-incremental + in service		12.83	13.12	13.41	112.234	66.56	38.03	56.91	134.08	147.35	138.02	138.25	37.08	38.64	39.34	45.06	42.64	43.49	44.28
71	Current year non-incremental + in service		13.12	13.41	112.23	66.559	38.030	56.909	134.083	147.346	138.022	138.253	37.080	38.644	39.338	45.063	42.641	43.494	44.276	46.143
72	Average of Production		12.97	13.26	62.82															
73	Prior year Transmission and A&G					17.333	17.17	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
74	Current year Transmission and A&G					17.174	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
75	Average of Transmission and A&G		6.38	10.88	17.33															
76	Total		19.35	24.14	80.16															
77	Rate to Apply to 2007 Capital in 08		1.53%	1.53%	1.54%															
78	Capital Depreciation Rate (excl. Environmental)					1.53%	1.53%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
79	Additional Depreciation		0.30	0.37	1.23	1.63	1.02	1.49	2.69	3.83	3.81	3.69	2.38	1.10	1.15	1.25	1.29	1.28	1.30	1.34
80																				
81	HMP&L Station Two																			
82	Prior year non-incremental		12.83	13.12	13.41	13.71	36.16	20.59	31.54	123.38	138.55	132.83	133.81	34.83	35.87	36.95	38.06	39.20	40.38	41.59
83	Depreciation as a Percentage of Gross PPE		0.05%	0.05%	0.05%	0.11%	0.10%	0.10%	0.10%	0.10%	0.10%	0.11%	0.11%	0.12%	0.12%	0.12%	0.12%	0.12%	0.13%	0.13%
84	Additional Depreciation		0.01	0.01	0.01	0.01	0.04	0.02	0.03	0.12	0.14	0.14	0.15	0.04	0.04	0.04	0.05	0.05	0.05	0.05
85																				
86	Environmental																			
87	Prior year environmental					-	-	-	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
88	Current year environmental					-	-	2.00	-	-	-	-	-	-	-	-	-	-	-	-
89	Environmental Depreciation Rate					1.53%	1.53%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
90	Additional Depreciation					-	-	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
91																				
92	Other																			
93	Prior year		6.00	6.77	14.99	19.68	17.17	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
94	Current year		6.77	10.87	19.68	17.17	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
95	Average		6.38	8.82	17.33															
96	Rate to Apply to 2007 Capital in 08		0.00	0.00	0.00															
97	Capital Depreciation Rate (excl. Environmental)					0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%
98	Additional Depreciation		0.02	0.03	0.05	0.11	0.09	0.05	0.04	0.03	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
99																				
100	Book Depreciation & Amortization																			
101	Generation																			
102	Big Rivers' Plants		26.89	26.17	26.414	28.077	29.100	49.24	51.98	55.85	59.71	63.45	65.88	67.03	68.24	69.54	70.88	72.21	73.57	74.96
103																				
104	Intellectual Property					0.149	0.164	0.31	0.33	0.35	0.38	0.40	0.42	0.45	0.47	0.49	0.52	0.55	0.57	0.60
105	HMP&L Station Two		0.92	0.93	0.934	0.949	0.986	1.01	1.04	1.16	1.30	1.45	1.60	1.64	1.68	1.73	1.78	1.82	1.88	1.93
106	Total Generation Depr & Amort		27.81	27.10	27.349	29.175	30.251	50.55	53.34	57.36	61.39	65.30	67.90	69.12	70.39	71.76	73.18	74.58	76.01	77.49
107	Other		5.03	5.06	5.106	5.214	5.300	5.35	5.39	5.42	5.43	5.44	5.46	5.48	5.51	5.54	5.57	5.60	5.63	5.67
108	*Blended Depreciation Adj.*		-	-	-	-	-	(11.27)	(11.61)	(13.51)	(15.23)	(15.34)	(15.26)	-	-	-	-	-	-	-
109	Total		32.84	32.15	32.45	34.389	35.551	44.64	47.13	49.27	51.59	55.40	58.10	74.60	75.90	77.30	78.75	80.18	81.65	83.16
110																				
111	Years Depreciation					56	57	46	46	47	48	47	47	37	37	37	37	37	37	37

Unwind

	($M)		Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation		0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			0.000	0.000	1.000	2.000	3.000	4.000	5.000	6.000	7.000	8.000	9.000	10.000	11.000	12.000	13.000	14.000	15.000
1	Capital Markets (Tranche 1)																		
2	Beginning Balance							58.3	58.3	49.1	39.2	28.6	28.6	28.6	53.2	53.2	53.2	52.7	24.9
3	Coupon		0.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	6.50%	6.50%	6.50%	6.50%	6.50%
4	Principal (%)		0.00%	0.00%	0.00%	0.00%	-100.00%	0.00%	15.86%	16.98%	18.11%	0.00%	0.00%	-42.21%	0.00%	0.00%	0.80%	47.82%	26.69%
5	Interest							4.1	4.1	3.4	2.7	2.0	2.0	2.0	3.5	3.5	3.5	3.4	1.6
6	Principal						(58.3)		9.3	9.9	10.6			(24.6)			0.5	27.9	15.7
7	Debt Service						(58.3)	4.1	13.3	13.3	13.3	2.0	2.0	(22.6)	3.5	3.5	3.9	31.3	17.3
8																			
9	Capital Markets (Tranche 2)																		
10	Beginning Balance											207.0	207.0	207.0	207.0	207.0	207.0	207.0	199.0
11	Coupon		0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
12	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.88%	10.86%
13	Interest											11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.2
14	Principal										(207.0)							8.0	22.5
15	Debt Service										(207.0)	11.6	11.6	11.6	11.6	11.6	11.6	19.7	33.7
16																			
17	RUS -- GAAP																		
18	Beginning Balance		765.3	625.5	625.5	612.5	597.7	582.2	503.1	481.0	457.6	432.9	199.5	161.3	121.0	78.3	33.0		
19	Coupon		0.00%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
20	Principal (%)		0.00%	0.00%	2.12%	2.40%	2.51%	12.63%	3.56%	3.76%	3.98%	37.17%	6.08%	6.44%	6.81%	7.21%	5.33%	0.00%	0.00%
21	Interest			0.0	36.4	35.6	34.8	33.9	29.3	28.0	26.6	25.2	11.6	9.4	7.0	4.6	1.9		
22	Mid Year Prepay Adjustment to Interes							(1.1)				(11.6)					0.5		
23	Principal + Accrued Interest		139.8	0.0	13.0	14.8	15.5	79.1	22.1	23.4	24.8	233.4	38.1	40.4	42.7	45.3	33.0	0.0	0.0
24	Debt Service		139.8	0.0	49.4	50.4	50.3	111.9	51.4	51.4	51.4	246.9	49.7	49.7	49.8	49.8	35.4	0.0	0.0
25																			
26	Variable																		
27	Beginning Balance																		
28	Coupon		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	Interest+Remarketing																		
31	Principal																		
32	Debt Service																		
33																			
34	PCB																		
35	Beginning Balance		142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
36	Coupon		0.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
37	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
38	Interest			0.0	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
39	Principal																		
40	Debt Service			0.0	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
41																			
42	ARVP																		
43	Beginning Balance		104.1	104.1	104.1	110.2	116.8	123.7	131.0	138.7	146.9	155.6	164.8	174.6	184.9	195.8	207.4	219.7	232.7
44	Accretion Rate	5.9%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
45	Interest Rate		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%	0.00%
46	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
47	Accretion			0.0	6.2	6.5	6.9	7.3	7.7	8.2	8.7	9.2	9.7	10.3	10.9	11.6	12.3	13.0	13.8
48	Interest																		
49	Principal																		
50	Debt Service																		
51																			
	Additional Debt																		
	Beginning Balance							-	100.0	200.0	300.0	400.0	390.0	380.0	370.0	360.0	350.0	340.0	330.0
	Interest							7.3	14.5	21.8	29.0	29.0	28.3	27.6	26.8	26.1	25.4	24.7	23.9
	Principal							(100.0)	(100.0)	(100.0)	(100.0)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
52	Total																		
53	Beginning Balance		1,011.5	871.7	871.7	864.8	856.5	906.2	934.5	1,010.9	1,085.8	1,366.2	1,132.0	1,093.6	1,078.2	1,036.4	992.7	961.5	928.6
54	Accretion			0.0	6.2	6.5	6.9	7.3	7.7	8.2	8.7	9.2	9.7	10.3	10.9	11.6	12.3	13.0	13.8
55	Principal		139.8	0.0	13.0	14.8	(42.8)	(20.9)	(68.7)	(66.7)	(271.7)	243.4	48.1	25.7	52.7	55.3	43.5	45.9	48.2
56	Interest			0.0	43.5	42.7	41.9	51.2	55.0	60.3	65.5	63.3	60.6	57.7	56.1	52.9	50.0	46.8	43.8
57	Debt Service		139.8	0.0	56.5	57.5	(0.9)	30.3	(13.7)	(6.5)	(206.2)	306.7	108.7	83.4	108.8	108.1	93.5	92.7	92.0
58	Ending Balance		871.7	871.7	864.8	856.5	906.2	934.5	1,010.9	1,085.8	1,366.2	1,132.0	1,093.6	1,078.2	1,036.4	992.7	961.5	928.6	894.2
59																			

	($M)		Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation		*0.000*	*0.000*	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	*0.000*	*0.000*	*0.000*
			0.000	0.000	1.000	2.000	3.000	4.000	5.000	6.000	7.000	8.000	9.000	10.000	11.000	12.000	13.000	14.000	15.000
60	*Supporting Schedules*																		
61	Amortization of Financing Costs																		
62	Capital Markets (Tranche 1)																		
63	Straightline																		
64	BB						-	1.0	1.0	1.0	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7	0.6
65	Accretion						(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
66	EB						1.0	1.0	1.0	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7	0.6	0.6
67																			
68	Capital Markets (Tranche 2)																		
69	Net Borrowing and YTM	5.94%									(200)	12	12	12	12	12	12	20	34
70	BB										-	200	200	201	201	201	201	202	194
71	YTM											12	12	12	12	12	12	12	12
72	Principal Amort.										(200)	-	-	-	-	-	-	8	22
73	*Accretion*										-	0	0	0	0	0	0	0	0
74	EB										200	200	201	201	201	201	202	194	172
75																			
76	Variable																		
77	Net Borrowing and YTM	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
78	BB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79	YTM		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80	Principal Amort.		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
81	Accretion		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
82	EB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
83																			
84																			
85	Amortization of Financing Costs																		
86	*Deferred debit - BOY*		-	-	-	-	-	1.0	1.0	1.0	0.9	7.9	7.6	7.3	7.0	6.7	6.3	6.0	5.6
87	Financing Costs						1.0				7.0								
88	Amortization		-	-	-	-	-	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4
89	*Deferred debit - EOY*		-	-	-	-	1.0	1.0	1.0	0.9	7.9	7.6	7.3	7.0	6.7	6.3	6.0	5.6	5.2
90																			
91	Interest Expense																		
92	Total Interest		-	0.0	43.5	42.7	41.9	51.2	55.0	60.3	65.5	63.3	60.6	57.7	56.1	52.9	50.0	46.8	43.8
93	ARVP Accretion		-	0.0	6.2	6.5	6.9	7.3	7.7	8.2	8.7	9.2	9.7	10.3	10.9	11.6	12.3	13.0	13.8
94	Capitalized Interest		-	-	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
95	AMBAC Amortization (PCB) A/C 165		-	0.0	3.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
96	Line of Credit Fee		-	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
97	Total		-	0.0	53.1	48.9	48.4	58.2	62.4	68.1	73.8	72.1	70.0	67.7	66.7	64.1	61.9	59.5	57.3

Sale L. eback

	($M)	2005	2006	2007	2008	se Termina	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	BOY Deferred Gain	62.1	59.3	56.4	53.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Amortization (I/S)	2.9	2.9	2.9	2.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	EOY Deferred Gain (B/S)	59.3	56.4	53.5	50.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4																					
5																					
6	Investment - Special Deposit (B/S)	180.6	186.7	192.9	199.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Adjustment	0.5	0.7	0.7	(2.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Balance Sheet	181.2	187.4	193.7	196.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																					
10	Liability - Long-Term Debt (B/S)	171.0	177.3	183.9	189.7	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
11																					
12	Cash Flow (Investment and Liability)	5.7	6.0	6.2	6.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13																					
14	True Unrecognized Gain	(49.6)	(47.0)	(44.4)	(41.0)	(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)
15																					
16	Sale-Leaseback Interest Income	11.7	12.1	12.5	12.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17																					
18	Sale-Leaseback Interest Expense	12.0	12.4	12.8	12.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Sale-Leaseback Gain Amortization	2.9	2.9	2.9	2.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Net Sale-Leaseback Expense	9.1	9.5	9.9	9.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21																					
22	Net Sale-Leaseback Income	2.6	2.6	2.6	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23																					
24	Sale-Leaseback - LeaseCo.																				
25	Defeasance Income	63.5	64.1	64.5	64.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Rent Expense	(48.9)	(48.9)	(48.9)	(48.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Net	14.7	15.2	15.6	15.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Gain on Lease Buyout																				
29	BOY Deferred Gain					(16.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Amortization (I/S)					(16.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	EOY Deferred Gain (B/S)					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32																					
33	Supporting Schedules																				
34	Original Gain Amortization			2.9	2.9	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Adjusted for Lease Buyout			2.9	2.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Applied to Gain on Lease Buyout					(16.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Income Taxes

	($M)	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Summary**																	
2	Income Tax Expense	-	-	-	-	-	-	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8
3	Income Taxes Paid	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
4	Current Provision for Deferred Income Tax	(1.3)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
5																		
6	**Calculation**																	
7	Offsystem Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Interest Earnings	-	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4
9	Nonpatronage Revenues	-	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4
10	Nonpatronage Expenses																	
11	Nonpatronage MWH	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%
12	Nonpatronage Expenses (Ex. Int.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Nonpatronage Interest Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Nonpatronage Net Margin (pre-tax)	-	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4
15																		
16	Transaction Impact	66.8	-	-														
17																		
18																		
19	Temporary Differences (Timing)																	
20	Depreciation:																	
21	Prorated from Pre-Transaction Model	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Effect of Additional Capex (Incl. Coleman Scrubber)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Other Ms	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Sale-Leaseback																	
25	Defeasance Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Rent Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Other Interest Allocation																	
28	Net	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Taxable Income before NOLs	66.8	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4
31																		
32	Regular Tax																	
33	Regular NOLs Used	66.8	0.0	1.4	1.5	1.5	1.6	-	-	-	-	-	-	-	-	-	-	-
34	Taxable Income after NOLs	-	-	-	-	-	-	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4
35	Regular Tax before Min. Credit Carryover	-	-	-	-	-	-	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8
36	AMT Offset (Min. Tax Credit Carryover Utilized)	-	-	-	-	-	-	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
37	Tax	-	-	-	-	-	-	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
38																		
39	AMT																	
40	ACE Adjustment	-	(0.0)	(0.9)	(0.9)	(0.6)	(0.4)	(0.4)	(0.3)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
41	Taxable Income	66.8	0.0	0.5	0.6	0.9	1.1	1.3	1.4	1.7	1.8	1.9	2.0	2.1	2.1	2.2	2.3	2.4
42	AMT NOLs Used	60.1	0.0	0.5	0.5	0.8	1.0	1.1	-	-	-	-	-	-	-	-	-	-
43	Net Taxable Income	6.7	0.0	0.1	0.1	0.1	0.1	0.1	1.4	1.7	1.8	1.9	2.0	2.1	2.1	2.2	2.3	2.4
44	TMT	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
45	Less Regular Tax Paid (up to AMT)	-	-	-	-	-	-	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
46	Net AMT	1.3	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
47	AMT Balance																	
48	BB	5.3	6.7	6.7	6.7	6.7	6.7	6.7	6.2	5.9	5.6	5.3	5.0	4.7	4.4	4.1	3.7	3.4
49	Additions	1.3	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
50	Reductions	-	-	-	-	-	-	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
51	EB	6.7	6.7	6.7	6.7	6.7	6.7	6.2	5.9	5.6	5.3	5.0	4.7	4.4	4.1	3.7	3.4	3.0
52																		
53	Total Tax	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
54																		
55	Est. Book Tax	-	-	-	-	-	-	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8

($M)	Lease Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
56																	
57 Capex Not Reflected in Pre-Transaction Tax Calculation																	
58																	
59 WKE Share			0.5	0.5	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
60 Non-Incremental			0.8	0.8	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
61 Incremental																	
62 Capex Amounts			18.4	10.5	18.8	81.6	91.6	87.8	88.5	23.0	23.7	24.4	25.2	25.9	26.7	27.5	28.3
63 Non-Incremental																	
64 Incremental Generation			18.4	10.5	18.8	81.6	91.6	87.8	88.5	23.0	23.7	24.4	25.2	25.9	26.7	27.5	28.3
65 WKE Total			28.7	17.4	23.4	10.7	8.8	5.2	4.4	2.3	2.8	2.4	7.0	3.4	3.1	2.7	3.3
66 Plant Maintenance			-	-	2.0	-	-	-	-	-	-	-	-	-	-	-	-
67 Environmental			5.6	5.6	-	-	-	-	-	-	-	-	-	-	-	-	-
68 Transmission Upgrades			1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-
69 Shared HQ Building			9.7	1.0	0.9	0.8	0.8	1.0	0.8	0.8	1.0	0.9	0.9	1.1	0.9	0.9	1.2
70 Intellectual Property			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71 8/07 Adjustment			64.1	34.6	45.1	93.0	101.2	94.0	93.7	26.1	27.5	27.7	33.1	30.4	30.7	31.1	32.9
72 Total																	
73			64.1	98.7	143.9	236.9	338.1	432.1	525.8	551.9	579.4	607.1	640.2	670.6	701.3	732.4	765.3
74 Cumulative Balance																	
75			1.1	1.7	3.1	5.1	7.2	9.0	11.2	11.9	15.7	16.5	17.4	18.3	19.1	20.0	20.9
76 Book Depreciation																	
77			3.2	4.9	7.2	11.8	16.9	21.6	26.3	27.6	29.0	30.4	32.0	33.5	35.1	36.6	38.3
78 Tax Depreciation @ 20 Years																	
79			(2.1)	(3.2)	(4.1)	(6.7)	(9.7)	(12.6)	(15.1)	(15.7)	(13.2)	(13.8)	(14.6)	(15.3)	(15.9)	(16.6)	(17.4)
80 Timing Difference (Tax Deduction)																	

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STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	(5,694,777)	(1,488,056)	0	0
1984	22,448,681	0	(11,951,703)	(10,496,978)	0	0
1985	67,286,392	0	(67,286,392)	0	0	0
1986	56,198,468	0	(56,198,468)	0	0	0
1987	75,567,924	0	(75,567,924)	0	0	0
1988	44,315,156	0	(44,315,156)	0	0	0
1989	22,819,745	0	(22,819,745)	0	0	0
1990	36,952,270	0	(34,627,493)	(2,324,777)	0	0
1991	29,446,433	0	(20,568,120)	(8,878,313)	0	0
1992	14,648,800	0	(14,648,800)	0	0	0
1993	30,220,578	0	(30,220,578)	0	0	0
1994	36,390,275	0	(36,390,275)	0	0	0
1995	43,631,999	0	(43,631,999)	0	0	0
1996	12,713,387	0	(6,225,540)	(6,487,847)	0	0
1997	29,946,372	0	(1,574,810)	(28,371,562)	0	0
1998	(5,694,777)	5,694,777	0	0	0	0
1999	(11,951,703)	11,951,703	0	0	0	0
2000	(211,273,153)	211,273,153	0	0	0	0
2001	(20,133,776)	20,133,776	0	0	0	0
2002	(18,036,546)	18,036,546	0	0	0	0
2003	(17,437,192)	17,437,192	0	0	0	0
2004	(14,433,689)	14,433,689	0	0	0	0
2005	(19,500,822)	19,500,822	0	0	0	0
2006	(20,568,120)	20,568,120	0	0	0	0
2007	(42,500,882)	42,500,882	0	0	0	0
2008	(17,426,731)	17,426,731	0	0	0	0
Transaction	(66,819,339)	66,819,339	0	0	0	0
	(0)	0	0	0	0	0
2009	(1,400,000)	1,400,000	0	0	0	0
2010	(1,456,000)	1,456,000	0	0	0	0
2011	(1,514,240)	1,514,240	0	0	0	0
2012	(1,574,810)	1,574,810	0	0	0	0
2013	(1,637,802)	0	0	0	0	0
2014	(1,703,314)	0	0	0	0	0
2015	(1,771,447)	0	0	0	0	0
2016	(1,842,304)	0	0	0	0	0
2017	(1,915,997)	0	0	0	0	0
2018	(1,992,637)	0	0	0	0	0
2019	(2,072,342)	0	0	0	0	0
2020	(2,155,236)	0	0	0	0	0
2021	(2,241,445)	0	0	0	0	0
2022	(2,331,103)	0	0	0	0	0
2023	(2,424,347)	0	0	0	0	0
Total Carryforward to 2024	35,959,561	471,721,779	(471,721,779)	(58,047,534)	0	0
				222,668,370		

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	280,715,904	249,053,409	(249,053,409)	(11,985,034)	268,730,870	268,730,870
Total Carryforward to 2003	262,679,358	267,089,955	(267,089,955)	(11,985,034)	250,694,324	250,694,324
Total Carryforward to 2004	245,242,166	284,527,147	(284,527,147)	(11,985,034)	233,257,132	233,257,132
Total Carryforward to 2005	230,808,477	298,960,836	(298,960,836)	(11,985,034)	218,823,443	218,823,443
Total Carryforward to 2006	211,307,655	318,461,658	(318,461,658)	(14,309,811)	196,997,844	196,997,844
Total Carryforward to 2007	190,739,535	339,029,778	(339,029,778)	(23,188,124)	167,551,411	167,551,411
Total Carryforward to H1 2008	148,238,653	381,530,660	(381,530,660)	(23,188,124)	125,050,529	125,050,529
Total Carryforward to Transactio	130,811,923	398,957,390	(398,957,390)	(23,188,124)	107,623,799	107,623,799
Total Carryforward to H2 2008	63,992,583	465,776,730	(465,776,730)	(23,188,124)	40,804,459	40,804,459
Total Carryforward to 2009	63,992,583	465,776,730	(465,776,730)	(23,188,124)	40,804,459	40,804,459
Total Carryforward to 2010	62,592,583	467,176,730	(467,176,730)	(23,188,124)	39,404,459	39,404,459
Total Carryforward to 2011	61,136,583	468,632,730	(468,632,730)	(23,188,124)	37,948,459	37,948,459
Total Carryforward to 2012	59,622,343	470,146,970	(470,146,970)	(29,675,971)	29,946,372	29,946,372
Total Carryforward to 2013	58,047,534	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2014	56,409,732	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2015	54,706,418	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2016	52,934,971	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2017	51,092,667	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2018	49,176,670	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2019	47,184,033	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2020	45,111,691	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2021	42,956,456	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2022	40,715,011	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2023	38,383,908	471,721,779	(471,721,779)	(58,047,534)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

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BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
EIN: 61-0597287
STATEMENT 61

ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	0	0	(7,182,833)	0	0
1984	22,448,681	0	0	0	(22,448,681)	0	0
1985	67,286,392	0	0	(67,286,392)	0	0	0
1986	56,198,468	0	0	(56,198,468)	0	0	0
1987	74,385,162	0	0	(62,522,466)	(11,862,696)	0	0
1988	44,314,663	0	0	(14,775,845)	(29,538,819)	0	0
1989	20,107,778	0	0	(12,087,111)	(8,020,667)	0	0
1990	29,346,400	0	0	(16,651,074)	(12,695,326)	0	0
1991	22,667,781	0	0	(17,624,779)	(5,043,002)	0	0
1992	9,553,735	0	0	(9,553,735)	0	0	0
1993	21,693,629	0	0	(21,693,629)	0	0	0
1994	27,573,481	0	0	(27,573,481)	0	0	0
1995	34,018,244	0	0	(34,018,244)	0	0	0
1996	9,443,662	0	0	(9,443,662)	(19,689,813)	0	0
1997	32,657,152	0	0	(12,967,339)	0	0	0
1998	44,897	0	0	(44,897)	(6,993,634)	0	0
1999	8,082,161	0	0	(1,088,527)	0	0	0
2000	(165,931,656)	149,338,490	(16,593,166)	0	0	0	0
2001	(19,634,252)	19,634,252	0	0	0	0	0
2002	(17,034,584)	17,034,584	(1,641,761)	0	0	0	0
2003	(16,417,605)	14,775,845	(1,343,012)	0	0	0	0
2004	(13,430,123)	12,087,111	(1,850,119)	0	0	0	0
2005	(18,501,193)	16,651,074	(1,958,309)	0	0	0	0
2006	(19,583,088)	17,624,779	(4,158,342)	0	0	0	0
2007	(41,583,419)	37,425,077	(1,650,927)	0	0	0	0
2008	(16,509,268)	14,858,341	(6,681,934)	0	0	0	0
Transaction	(66,819,339)	60,137,405	(0)	0	0	0	0
	(0)	0	(50,612)	0	0	0	0
2009	(506,119)	455,507	(57,990)	0	0	0	0
2010	(579,898)	521,908	(91,430)	0	0	0	0
2011	(914,296)	822,866	(114,332)	0	0	0	0
2012	(1,143,318)	1,028,986	(125,936)	0	0	0	0
2013	(1,259,361)	1,133,424	(1,441,534)	0	0	0	0
2014	(1,441,534)	0	(1,673,867)	0	0	0	0
2015	(1,673,867)	0	(1,818,705)	0	0	0	0
2016	(1,818,705)	0	(1,910,473)	0	0	0	0
2017	(1,910,473)	0	(1,987,258)	0	0	0	0
2018	(1,987,258)	0	(2,067,109)	0	0	0	0
2019	(2,067,109)	0	(2,149,688)	0	0	0	0
2020	(2,149,688)	0	(2,236,063)	0	0	0	0
2021	(2,236,063)	0	(2,325,886)	0	0	0	0
2022	(2,325,886)	0	(2,419,295)	0	0	0	0
2023	(2,419,295)						
Total Carryforward to 2024	67,127,724	363,529,649	(56,347,746)	(363,529,649)	(123,475,470)	0	0

AMT N_ _ES

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
EIN: 61-0597287
STATEMENT 61

ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	301,439,211	168,972,742	(16,593,166)	(168,972,742)	(29,631,514)	288,400,863	288,400,863
Total Carryforward to 2003	284,404,627	186,007,326	(16,593,166)	(186,007,326)	(41,494,210)	259,503,583	259,503,583
Total Carryforward to 2004	267,987,022	200,783,171	(18,234,926)	(200,783,171)	(71,033,028)	215,188,920	215,188,920
Total Carryforward to 2005	254,556,899	212,870,282	(19,577,938)	(212,870,282)	(79,053,695)	195,081,142	195,081,142
Total Carryforward to 2006	236,055,706	229,521,355	(21,428,058)	(229,521,355)	(91,749,022)	165,734,742	165,734,742
Total Carryforward to 2007	216,472,618	247,146,135	(23,386,367)	(247,146,135)	(96,792,024)	143,066,961	143,066,961
Total Carryforward to 2008	174,889,199	284,571,211	(27,544,708)	(284,571,211)	(96,792,024)	105,641,884	105,641,884
Total Carryforward to Transact	158,379,931	299,429,552	(29,195,635)	(299,429,552)	(96,792,024)	90,783,543	90,783,543
	158,379,931	359,566,958	(35,877,569)	(359,566,958)	(96,792,024)	97,465,477	97,465,477
Total Carryforward to 2009	91,560,592	359,566,958	(35,877,569)	(359,566,958)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2010	91,054,474	360,022,464	(35,928,181)	(360,022,464)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2011	90,474,576	360,544,373	(35,986,171)	(360,544,373)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2012	89,560,280	361,367,239	(36,077,600)	(361,367,239)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2013	88,416,962	362,396,225	(36,191,932)	(362,396,225)	(116,481,836)	FALSE	FALSE
Total Carryforward to 2014	87,157,602	363,529,649	(36,317,868)	(363,529,649)	(116,481,836)	FALSE	FALSE
Total Carryforward to 2015	85,716,067	363,529,649	(37,759,403)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2016	84,042,200	363,529,649	(39,433,270)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2017	82,223,496	363,529,649	(41,251,974)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2018	80,313,022	363,529,649	(43,162,448)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2019	78,325,764	363,529,649	(45,149,706)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2020	76,258,656	363,529,649	(47,216,814)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2021	74,108,967	363,529,649	(49,366,503)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2022	71,872,905	363,529,649	(51,602,565)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2023	69,547,019	363,529,649	(53,928,451)	(363,529,649)	(123,475,470)	FALSE	FALSE
						0	0
						0	0
						0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

** For years ended December 31, 2001 and December 31, 2002, the Job Creation and Worker Assistance Act of 2002 allowed 100% of the AMTI to be offset with NOL carryforwards.

Inputs

	Electricity Sales, Purchases, and Production	Source:	00s/ Othe	2006	2007	2008	Transactione Termin ########	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Sales																					
2	Rural																					
3	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls and file: Anni		2.232	2.406	2.396		0.000	2.438	2.487	2.543	2.595	2.651	2.704	2.763	2.819	2.879	2.935	2.997	3.059	3.120	3.180	3.242
4	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		61.62%	63.26%	62.51%		60.17%	60.02%	60.12%	60.21%	60.15%	60.40%	60.49%	60.57%	60.61%	60.74%	60.82%	60.89%	60.83%	61.04%	61.11%	61.17%
5	MW			413	434	437		0	464	472	482	492	501	510	521	532	541	551	562	574	584	594	605
6	Large Industrial																					
7	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls + 5	MW/year	0.957	0.921	0.953		0.000	1.063	1.097	1.131	1.165	1.200	1.235	1.269	1.303	1.338	1.373	1.407	1.440	1.476	1.510	1.545
8	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		78.12%	76.45%	77.71%		78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
9	MW			140	138	140		0	154	159	164	170	174	179	184	190	194	199	204	210	214	219	224
10	Alcan																					
11	TWH	Smelter Retail Agreement, Section 1.1.17				0	0	0.000	3.159	3.159	3.159	3.168	3.159	3.159	3.159	3.168	3.159	3.159	3.159	3.160	3.159	3.159	3.159
12	LF	Smelter Retail Agreement, Section 1.1.17				98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
13	MW	Smelter Retail Agreement, Section 1.1.15						368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368
14	Century																					
15	TWH	Smelter Retail Agreement, Section 1.1.16						0.000	4.138	4.138	4.138	4.149	4.138	4.138	4.138	4.149	4.138	4.138	4.138	4.149	4.138	4.138	4.138
16	LF	Smelter Retail Agreement, Section 1.1.16				98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
17	MW	Smelter Retail Agreement, Section 1.1.14						482	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482
18																						
19	Offsystem (TWh)	file: Annual Output - 9-8-08 - BREC Update.xls		2.06	2.84	1.66			1.55	1.83	1.38	1.36	1.41	1.32	1.29	1.24	1.05	1.12	0.87	0.89	0.87	0.85	0.78
20																						
21	Purchases & Production																					
22	Purchases (TWh)																					
23	Market	file: Annual Output - 9-8-08 - BREC Update.xls		0.07	0.02	0.01		0.00	0.24	0.16	0.31	0.22	0.30	0.26	0.30	0.32	0.62	0.40	0.54	0.42	0.53	0.49	0.61
24	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		0.24	0.20	0.10		0.00	0.30	0.31	0.30	0.30	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
25	Production (TWh)	file: Annual Output - 9-8-08 - BREC Update.xls						(0.00)	11.90	12.35	11.84	12.02	12.10	12.14	12.17	12.20	11.79	12.17	11.88	12.13	12.09	12.20	12.11
26	Loss Rate (%)	file: Annual Output - 9-8-08 - BREC Update.xls				0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
27																						
28	Fuel Consumption (Millions of MMBtu)	file: Annual Output - 9-8-08 - BREC Update.xls						0.0	132.9	137.2	131.9	133.5	133.6	134.1	134.4	134.7	130.3	134.4	131.2	134.1	133.5	134.7	133.6
29																						
30	Startup Costs (M$)	file: Annual Output - 9-8-08 - BREC Update.xls							11.46	11.89	11.74	10.64	10.39	11.00	10.23	10.81	13.05	11.43	13.62	12.55	12.50	14.15	13.39
31	Kentucky Coal Tax Credit ($M)								0	1.4	0.7	0	0	0	0	0	0	0	0	0	0	0	0
32	Emissions																					
33	SO2																					
34	Emitted (Tons)	file: Annual Output - 9-8-08 - BREC Update.xls							19,145	20,453	19,301	19,812	19,341	19,855	20,836	21,282	19,910	21,199	20,456	19,823	20,812	21,263	20,716
35	Allocation (Tons)	file: Annual Output - 9-8-08 - BREC Update.xls							48,979	48,979	24,489	24,489	24,489	24,489	18,352	18,352	18,352	18,352	18,352	17,125	18,352	18,352	18,352
36	NOX																					
37	Emitted (Tons)	file: Annual Output - 9-8-08 - BREC Update.xls							5,141	5,105	13,489	13,371	13,531	13,340	13,579	13,378	13,303	13,413	13,214	13,553	13,445	13,365	13,558
38	Allocation (Tons)	file: Annual Output - 9-8-08 - BREC Update.xls							4,652	4,652	11,068	11,057	11,057	11,057	8,944	8,944	8,491	8,297	8,153	7,948	7,713	7,491	7,419
39	NOX Season (Mo./Yr.)																						
40																						
41	Rates																					
42	Fuel ($/ MMBtu)	file: Annual Output - 9-8-08 - BREC Update.xls						1.96	1.95	2.15	2.25	2.50	2.69	1.85	1.85	1.87	1.90	1.91	1.94	1.96	1.96	2.02	2.04
43	Power Purchases ($/ MWh)																					
44	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		26.98	26.98	22.44		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
45	Market	file: Annual Output - 9-8-08 - BREC Update.xls		67.8347	77.90	200.00		65.53	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
46	Variable Production ($/ MWh sales)	file: Annual Output - 9-8-08 - BREC Update.xls				2.59		2.59	2.59	2.73	3.23	3.32	3.38	3.44	4.22	4.34	4.48	4.54	4.65	4.79	4.99	5.03	5.23
47	SO2 Allowances ($/ Ton)	file: Annual Output - 9-8-08 - BREC Update.xls				140		140	140	115	868	878	875	850	842	825	757	706	561	413	350	302	279
48	NOX Allowances ($/ Ton)	file: Annual Output - 9-8-08 - BREC Update.xls				700		700	700	650	2,120	1,951	1,909	2,570	3,071	2,663	2,764	2,665	2,564	2,574	2,578	2,581	2,584
49																						
50	Coal used (ktons)	file: Annual Output - 9-8-08 - BREC Update.xls	100%					0	6,041	6,219	5,967	6,046	6,058	6,063	6,097	6,100	5,910	6,095	5,938	6,078	6,058	6,083	6,065
51																						
52	**Sales Rates & Related**																					
53																						
54	General Rate Adjustments (*)	Stipulated Inputs (subject to Commission Approval at time)						0.00%	0.00%	0.00%	0.00%	1.46%	1.80%	3.12%	3.94%	0.00%	10.55%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
55	Shadow 2010 Rate (0=start 2011)	Smelter Retail Agreements, Section 4.7.5(a)	0	0																		
56	Market ($/ MWh)	file: Annual Output - 9-8-08 - BREC Update.xls		40.45	52.68	48.74		60.94	60.94	59.20	63.59	66.81	70.55	62.13	63.43	63.52	64.53	66.02	68.95	67.21	67.69	69.01	69.79
57																						
58	Rural																					
59	Demand ($/ kW-mo.)	Current Member Tariff		7.37	Escalated by GRAs																		
60	Energy ($/ MWh)	Current Member Tariff		20.4	Escalated by GRAs			0															
61																						
62	Large Industrial																					
63	Demand ($/ KW-mo.)	Current Member Tariff		10.15	Escalated by GRAs																		
64	Energy ($/ MWh)	Current Member Tariff		13.715	Escalated by GRAs			0															
65																						
66	Smelters																					
67	Margin ($/ MWh)	Smelter Retail Agreements, Section 1.1.20 (*Alcan*) and 1.1.19 (*Century*)						0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
68	Annual Revenue Guarantee ($/ MWh)	Smelter Retail Agreements, Section 4.7 (see formula in Smelter Rate Structure, lines 99 - 127)						(0.25)			1.79	2.95	2.95	2.95	3.55	3.39	3.55	0.32	3.23	2.31	3.42	2.43	3.61
69	Surcharge 1 (M$)	Smelter Retail Agreements, Section 4.11 (a)						5.11	5.11	5.11	5.11	7.30	7.30	7.30	7.30	7.30	10.18	10.18	10.18	10.18	10.18	10.18	10.18
70	Surcharge 2 ($/MWh)	Smelter Retail Agreements, Sections 4.11 (b) and (c)	0					0.60	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	1.20	1.20	1.20	1.20	1.20	1.20	1.20
71	Base Fixed Energy	line 11 + line 15						0.00	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
72	Surcharge 2 (M$)	line 70 * line 71						0.00	6.36	6.36	6.36	6.38	6.36	6.36	6.36	6.38	8.76	8.76	8.76	8.78	8.76	8.76	8.76
73																						
74	Member Revenue Discount Adjustment (M$)	Amortization of Gain on Year 2000 Sale-Leaseback rans	E	3.68	3.68000	3.68000																	
75	MRDA Ratio (Rural to Industrial)	Allocated by Base Revenue + FAC post transaction		0.73	0.75	0.75		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
76	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	Big Rivers Assumption		0.19	0.07																		
77																							
78	TIER Rebate Related to Rurals ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on Smelter Retail Agreements, below							0.24	4.46													
79	TIER Rebate Related to Large Industrials ($M)	*Big Rivers Assumption (based on Rebate available to non-Smelters* based on !							0.09	1.74													
80	TIER Rebate Related to Smelters ($M)	Smelter Retail Agreements, Section 4.9 (energy basis allocation)							0.70	12.63													
81	FAC Base, 12/2004 ($/ MWh Sold)																						
82	W/o Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY_ADJ_6mo-12-(	10.72																				
83	W/ Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY_ADJ_6mo-12-(	12.47																				
84	Allocation of Revenues on '																						
85	Total																						
86	NOx + SO3	file: Annual Output - 9-8-08 - BREC Update.xls																					
87	VOM	file: Annual Output - 9-8-08 - BREC Update.xls						0.00	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
88	Allowances	file: Annual Output - 9-8-08 - BREC Update.xls							0.34	0.29	5.13	4.51	4.72	5.87	14.23	12.70	13.30	13.63	12.98	14.43	14.78	15.16	15.86
89	SO2	file: Annual Output - 9-8-08 - BREC Update.xls																					

Inputs

		Source:	005/ Othe	2006	2007	2008	Transactione	Terminu	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
90	VOM	file: Annual Output - 9-8-08 - BREC Update.xls						(0.00)	27.54	30.00	34.69	36.14	37.24	37.71	47.28	48.57	48.85	50.68	50.77	53.35	55.51	56.21	58.27
91	Net Allowances	file: Annual Output - 9-8-08 - BREC Update.xls							(4.18)	(3.28)	(4.50)	(4.11)	(4.50)	(3.94)	2.09	2.42	1.18	2.01	1.18	1.11	0.86	0.88	0.66
92	Total	file: Annual Output - 9-8-08 - BREC Update.xls						0.00	27.00	30.76	38.88	40.35	41.08	43.74	67.70	68.06	67.34	70.95	69.42	73.61	76.01	77.42	79.85
93	Allowed In ES																						
94	NOx + SO3	file: Annual Output - 9-8-08 - BREC Update.xls																					
95	VOM	file: Annual Output - 9-8-08 - BREC Update.xls						0.00	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
96	Allowances	file: Annual Output - 9-8-08 - BREC Update.xls							0.34	0.29	5.13	4.51	4.72	5.87	14.23	12.76	13.30	13.63	12.98	14.43	14.78	15.16	15.86
97	SO2	file: Annual Output - 9-8-08 - BREC Update.xls																					
98	VOM in Excess of 2009	file: Annual Output - 9-8-08 - BREC Update.xls						(0.00)	27.54	30.00	34.69	36.14	37.24	37.71	47.28	48.57	48.85	50.68	50.77	53.35	55.51	56.21	58.27
99	Net Allowance Costs in Excess of 2009	file: Annual Output - 9-8-08 - BREC Update.xls							(4.18)	(3.28)	(4.50)	(4.11)	(4.50)	(3.94)	2.09	2.42	1.18	2.01	1.18	1.11	0.86	0.88	0.66
100	Total	file: Annual Output - 9-8-08 - BREC Update.xls						0.00	27.00	30.76	38.88	40.35	41.08	43.74	67.70	68.06	67.34	70.95	69.42	73.61	76.01	77.42	79.85
101																							
102	Smelter Rate Structure																						
103	Bandwidth	Smelter Retail Agreements, Section 4.7.1						2.20	2.20	2.20	2.20	3.20	3.20	3.20	3.80	3.80	3.80	4.40	4.40	4.40	5.00	5.00	5.00
104																							
105																							
106	**Financing**																						
107																							
108	Principal Schedules																						
109	Capital Markets Tranche 1	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances						0.00%	0.00%	0.00%	-100.00%	0.00%	15.88%	16.96%	18.11%	0.00%	0.00%	-42.21%	0.00%	0.00%	0.80%	47.82%	26.89%
110	Capital Markets Tranche 2	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.88%	10.86%
111	RUS	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances						0.00%	2.12%	2.40%	2.51%	12.63%	3.56%	3.76%	3.98%	37.17%	6.08%	6.44%	6.61%	7.21%	5.33%	0.00%	0.00%
112	Variable	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
113	PCB (Swapped to Fixed)	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
114	ARVP	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
115																							
116	Rates																						
117	Capital Markets Tranche 1	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	6.50%	6.50%	6.50%	6.50%	6.50%
118	Capital Markets Tranche 2	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
119	RUS -- Stated	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
120	Variable	NA						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
121	PCB (Swapped to Fixed/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
122	ARVP (Accretion/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls	0.05914					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
123	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
124																							
125	Beginning Balances (M$)																						
126	Capital Markets Tranche 1	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances									58.3												
127	Capital Markets Tranche 2	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances													207.0								
128	Variable	NA																					
129	PCB	Long Term Debt Schedule - Historical from July 1998 - Actual 2007 - Budget 2008.xls + Modeling fc					142																
130	ARVP	Long Term Debt Schedule - Historical from July 1998 - Actual 2007 - Budget 2008.xls + I				249.89	104																
131	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls					626																
132	Remarketing on Variable	NA	0.25%																				
133																							
134	Fees																						
135	Underwriting & Other	Goldman Sachs verbal guidance.	1.75%																				
136	Bond Insurance	Goldman Sachs verbal guidance.	0.80%																				
137																							
138	Capitalized Interest	Big Rivers' estimate		(0.24)	(0.39)	(0.51)			(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)
139	Deferred Debt - PCB Refunding A/C 181																						
140	Beginning Balance	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		0.90	0.84	0.79	0.74	0.74	0.74														
141	Amortization	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		0.05	0.05	0.05		0.00	0.74														
142	Ending Balance	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		0.84	0.790	0.737	0.737	0.74															
143	AMBAC Amortization (PCB) A/C 165																						
144	Amortization	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		0.42	0.42	0.42		0.00	3.85														
145	Balance	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		4.69	4.27	3.85	3.85	3.85															
146	Settlement Note/Marketing Payment																						
147	Amortization	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		1.00	1.00	1.00		0.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.01
148	Ending Balance	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		17.08	16.07	15.07	15.07	15.07	14.06	13.06	12.06	11.05	10.05	9.04	8.04	7.04	6.03	5.03	4.02	3.02	2.02	1.01	
149	Green River Coal Settlement Ending Balance			0.09	0.05	0.00	0.00	0.00															
150	Other			(0.21)																			
151	Line of Credit	Big Rivers' estimate	0.50%	100.00																			
152	Prepayment on Transaction Date	Modeled to achieve target cash balances					147.00																
153	Pre-Transaction Debt Service																						
154	Principal	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		26.43	13.30	41.79																	
155	Interest (Cash Flow)	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		36.93	36.866	51.493																	
156	Interest (Income Statement)	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		60.72	60.90	59.91																	
157	Amortization of RUS/PCB Account	Straightline amortization of RUS and PCB restructuring costs					0.34	0.34	7.13	6.73	6.32	5.92	5.51	5.11	4.70	4.30	3.89	3.49	3.08	2.68	2.27	1.89	1.51
158	NEW RUS NOTE (Stated)																						
159																							
160	Beginning Principal	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		812.23	803.60	807.56	768.39	628.18	628.18	614.89	599.80	584.02	504.66	482.33	458.70	433.69	200.18	161.98	121.56	78.78	33.50	0.00	0.00
161	Base Payment	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		54.48	42.69	84.83																	
162	Interest Expense	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		45.88	46.80	45.14		0.00	36.12	35.36	34.49	32.50	29.02	27.73	26.38	13.44	11.51	9.31	6.99	4.53	1.93	0.00	0.00
163	Interest Payment	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		31.57	31.14	45.67		0.00	36.12	35.36	34.49	32.50	29.02	27.73	26.38	13.44	11.51	9.31	6.99	4.53	1.93	0.00	0.00
164	Accrued Interest	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		7.16	7.32	6.79	6.79																
165	Principal Payment	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		22.91	11.54	39.17			13.29	15.09	15.78	79.36	22.33	23.62	25.01	233.51	38.20	40.43	42.78	45.29	33.50		
166	Ending Principal	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		803.60	807.56	768.39	768.39	628.18	614.89	599.80	584.02	504.66	482.33	458.70	433.69	200.18	161.98	121.56	78.78	33.50	0.00	0.00	0.00
167	Orig Scheduled Principal Payment	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		24.00	26.00	34.00	34.00																
168	Original Maximum Allowed Principal Balance	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		938.60	912.60	878.61	878.61																
169																							
170	*New RUS Promissory Note (GAAP)*																						
171	Beginning Principal - RUS New Note	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		815.30	807.04	811.51	772.18	772.18															
172	Interest Expense	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		46.21	47.16	45.50		0.00															
173	Interest Payment	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		32.29	31.24	46.03		0.00															
174	Accrued Interest	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		7.25	7.41	6.88	6.88	6.89															
175	Principal Payment	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		22.19	11.45	38.80		0.00															
176	Principal Balance	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		799.79	804.10	765.30	765.30	765.29															
177	Imputed Interest	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		0.00	0.00			0.00															
178																							
179	***Receipts (M$)***																						
180																							

		Source:	005/ Othe	2006	2007	2008	Transactions Termin		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
181	WKEC Lease	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.89	50.82	47.75																	
182	Transmission	*Historic results and adapted from 2007 Budget-REVISED-MARCH 2*		5.95	6.29	5.12																	
183	Smelter - Tier 3 Transmission (Cash Flow)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.70	1.72	1.72		1.20	1.74	1.74	4.42	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
184	Smelter - Tier 3 Transmission (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.78	1.80	1.80		1.22	1.82	1.82	4.45	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
185	Proceeds of Unwind Transaction (LG&E Payment)	Termination Agreement					387.68																
186	Cobank Patronage Capital & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.57	0.58	0.58	(0.20)					0.70	1.56	1.46									
187	Interest Earnings	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		3.73	6.83	5.03																	
188	Net Conforming Receipts	Big Rivers' estimate																					
189	Cobank Patronage Capital - Balance Sheet	Historic results and adapted from 2007 Budget-REVISED	*2.19*	*2.59*	*2.98*	*3.38*	*3.38*	*3.38*	*3.72*	*3.72*	*3.72*	*3.02*	*1.46*										
190	Lease Related & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.04	5.34	5.58																	
191	Cobank Patronage Capital (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.96	0.98	0.98		0.00	0.34														
192																							
193																							
194	**Fixed Production (MS)**																						
195																							
196	Fixed O&M																						
197	Non-Labor (Real)	file: Fin Model inputs BREC Aug-08 net City rev 2.xls	2008 Fact	0.0%				0.00	36.88	40.34	39.62	35.59	44.30	33.41	40.91	33.85	34.05	37.77	37.00	36.07	38.78	33.06	41.00
198	Labor (Nominal)	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls							48.36	45.62	46.99	48.40	49.85	51.35	52.89	54.47	56.11	57.79	59.53	61.31	63.15	65.05	67.00
199	Plant Maintenance (Real Basis)																						
200	Coleman	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0					0.58	0.24	0.24												
201	Green	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0					0.34	0.24							2.58						
202	HMP&L	*file: Fin Model inputs BREC Aug-08 net City rev 2.xls*		0					0.24	0.17					2.94								
203	Reid	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0					0.34								0.87						
204	Wilson	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0					0.34														
205	Adjust for Station 2	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0																			
206	Fixed Environmental O&M, Clear Skies (Real Basis)																						
207	NOx ongoing	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0																			
208				0																			
209	Non-Production			0																			
210	Production			0																			
211	Transition			0																			
212	O&M (Includes Consultants)			0																			
213	Outsource to LG&E for 2006			0																			
214	Adjustment (8/2007)			0.3																			
215																							
216	T/G Overhauls (Cash Flows)	file: Fin Model inputs BREC Aug-08 net City rev 2.xls						0.00	9.17		10.22	12.45		6.95		6.74	19.80		13.46	5.91	7.82	8.44	
217	T/G Overhauls (Income Statement)	file: Fin Model inputs BREC Aug-08 net City rev 2.xls						0.00	9.17		10.22	12.45		6.95		6.74	19.80		13.46	5.91	7.82	8.44	
218																							
219	Environmental Monitoring and Other		0																				
220	WKE "Incremental" items moved to O&M								1.46	1.50	1.54	1.59	1.64	1.69	1.74	1.79	1.84	1.90	1.95	2.01	2.07	2.14	2.20
221	*W-1 stack repair*	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
222	boiler waterwall metal overlays	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
223	SCR catalyst replacement	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
224	Transmission O&M																						
225	Baseline Labor (06 and 07 labor & non-labor combined	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls		6.59	7.07	7.43		0.00	6.07	6.25	6.43	6.63	6.83	7.03	7.24	7.46	7.68	7.91	8.15	8.40	8.65	8.91	9.17
226	Baseline Non-Labor	2005 actual escalated @ 3% plus 100K							1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
227	Upgrades, Phase I (Real Basis)																						
228	O&M	Historic results and adapted from 2007 Budget-REVISED-MARCH 2						*0.00*	*0.25*	*0.25*	*0.25*	*0.25*	*0.25*	*0.25*	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
229	Property Tax	Historic results and adapted from 2007 Budget-REVISED-MARCH 2						0.00	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
230	Property Ins.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2						0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
231																							
232	AAG																						
233	Labor	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls							10.99	10.79	11.12	11.45	11.79	12.15	12.51	12.89	13.27	13.67	14.08	14.50	14.94	15.39	15.85
234	*Non-Labor*	*2004 actual escalated @ 3%*						0.00	12.12	12.48	12.85	13.24	13.63	14.04	14.46	14.90	15.34	15.80	16.28	16.77	17.27	17.79	18.32
235	Intellectual Property (Nominal Basis)	Unwind spreadsheet -- 8-29-07_Rev1.xls							6.42	4.51	5.26	4.82	4.91	*5.51*	*5.09*	*5.18*	*5.69*	*5.66*	*5.65*	*6.19*	*5.98*	*6.33*	*6.74*
236	Intellectual Property Contingency																						
237	Total			13.81	15.62	17.16		0.00	29.54	27.78	29.22	29.51	30.33	31.70	32.06	32.96	34.31	35.14	36.01	37.46	38.19	39.51	40.91
238																							
239	APM, LIC, Cogen, CW & TVA Trans	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		4.66	8.78	5.94		0.00	6.31	6.46	5.80	5.69	5.86	6.03	6.21	6.39	6.58	6.78	6.98	7.19	7.40	7.62	7.85
240																							
241	Property Insurance	2004 actual escalated @ 3%		*0.40*	*0.36*	*0.35*		*0.00*	*4.05*	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
242			2244.57																				
243	Property Tax			3.94	3.94	3.86																	
244	Baseline	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.10	1.08	1.11		0.00	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
245	Transmission -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.74	0.77	0.75		0.00	0.88	0.91	0.96	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
246	General Plant -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.11	0.04		0.00	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
247																							
248																							
249	**Capital Expenditures**																						
250																							
251	Generation			13.12	13.41	13.71																	
252	Baseline (Real Basis 2006)	file: Fin Model inputs BREC Aug-08 net City rev 2.xls	08 Factor	0.00					33.10	18.29	27.20	103.33	112.65	104.86	102.56	25.92	25.92	25.92	25.92	25.92	25.92	25.92	25.92
253	*Adjustment for Station 2 (Real Basis 2006)*	file: Fin Model inputs BREC Aug-08 net City rev 2.xls						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
254																							
255	Gross Incremental																						
256																							
257	Transmission (Nominal)	Per Crockett Memo dated 11/12/07		5.91	9.62	18.39			10.28	5.26	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
258																							
259	AAG (Nominal)	$1.25M 2007 escalated @ 3%		0.86	1.25	1.29		0.00	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
260																							
261	WKE Share of Generation Capex	Participation Agreement - Cost Sharing		51%	51%	51%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
262																							
263	Plant Maintenance (Real Basis 2007)																						
264	Coleman	file: Fin Model inputs BREC Aug-08 net City rev 2.xls							1.14	1.11	2.37	1.05	1.02										
265	Green	file: Fin Model inputs BREC Aug-08 net City rev 2.xls							8.55	6.75	4.23	2.29	1.32										
266	HMP&L	file: Fin Model inputs BREC Aug-08 net City rev 2.xls							0.94	1.16	2.36	3.72	3.25	2.86	0.43	0.43	0.43	0.43	1.03	1.03	0.43	0.43	0.43
267	Reid	file: Fin Model inputs BREC Aug-08 net City rev 2.xls							*1.00*						1.40								
268	Wilson	file: Fin Model inputs BREC Aug-08 net City rev 2.xls							14.63	6.47	11.19	1.91	1.57	1.24	1.57	1.24	1.57	1.24	3.74	1.24	1.57	1.24	1.57
269	Adjustment for Station 2	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
270																							
271	Plant Maintenance Claim Amount																						

	Source:	2005/ Othe	2006	2007	2008	Transactione	Termin	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Environmental (Real Basis 2006)																						
NOx Removal Equipment Capital	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
Mercury Monitoring	file: Fin Model inputs BREC Aug-08 net City rev 2.xls									1.73												
Clmn FGD Equipment Capital	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
FGD ongoing upkeep capital (0.10%)	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
Additional FGD thickener & filter drum	*file: Fin Model inputs BREC Aug-08 net City rev 2.xls*																					
R-CT reliability study & upgrades	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
Wilson super heater tubes replacment	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
Adjustment for Station 2	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
Transmission Upgrades																						
Phase I	Per Crockett Memo dated 11/12/07			4.00																		
Phase II	Per Crockett Memo dated 11/12/07							5.40	5.30													
Shared HQ Building																						
Phase I																						
Phase II								1.66														
Intellectual Property																						
Capex Purposes	Unwind spreadsheet -- 8-29-07_Rev1.xls						0.00	9.74	1.02	0.92	0.79	0.80	0.98	0.83	0.85	1.00	0.92	0.94	1.06	0.89	0.91	1.23
Depreciation Purposes	Depreciated at Average Capital Depreciation Rate						0.00	0.15	0.16	0.31	0.33	0.35	0.38	0.40	0.42	0.45	0.47	0.49	0.52	0.55	0.57	0.60
Trial Balance Adjust		101.0%																				
Cash Adder																						
Other Disbursements (M$)																						
PPA	*Historic results and adapted from 2007 Budget-REVISED-MARCH 2*		98.00	96.29	95.44																	
Environmental	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.41	0.46	0.65																	
PCB Restructuring	Proforma transaction and bond insurance costs							7.20														
LEM Settlement Note	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		1.82	1.82	1.82		0.00	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.06
'Other Deductions'	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.13	0.15		(0.00)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.06)
Transition Costs																						
Deferred Debit - PCB Refunding A/C 181	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		(0.05)	(0.05)	(0.05)		(0.00)	(0.74)														
Green River Coal Settlement	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		0.35	0.05	0.04		0.00															
MISO Credit Fee																						
Deferred Tax Asset Write-Down																						
Payment to City of Henderson	file: Annual Output - 9-8-08 - BREC Update.xls							0.52	0.52	0.52	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
Smelter Payment (Assurances Agreement)	Coordination Agreement					1.53																
Lease-Equity Consent Fees/ Smelter Exit																						
Non-Smelter Member Excess Cash Rebate																						
Economic Reserve						157.00		(35.46)	(36.13)	(30.80)	(38.31)	(35.74)										
Working Capital Adj.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.09	4.06	(0.45)																	
CoBank Patronage Capital	Historic results and adapted from 2007 Budget-REVISED	2.25	2.64	3.04	3.43		3.43	3.77	3.77	3.77	3.07	1.51	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Amortization of RUS/PCB Charges	Straightline amortization of RUS and PCB restructuring costs						0.00	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.38	0.38
Other Assumptions																						
Interest Earnings Rate on Cash Balances	Big Rivers estimate	4.00%																				
Inflation	*Big Rivers estimate*	3.00%																				
Receivables (days)	Big Rivers estimate	30.00																				
Payables (days)	Big Rivers estimate	52.50																				
Non-Patronage Taxable Allocation (Transaction)	Orrick Herrington/ Deloitte	15%																				
Sequestered Cash Ending Balance	Smelter Retail Agreements, Section 1.1.119	35.00		0																		
Balance Sheet (2005)																						
Assets																						
Property																						
Total Utility Plant in Service	Historic Balance Sheet	1,714.8	1,731.2	1,749.9	1,783.8																	
Construction in Progress	Historic and Projected Balance Sheet	12.7	13.1	15.1	15.1	15.1	15.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Depreciation & Amortization	Historic Balance Sheet	798.7	827.5																			
Other Property	*Historic Balance Sheet*	184.0	190.7																			
Current																						
Cash General Funds & Special Deposits	Historic Balance Sheet	0.0	0.0	0.0	0.0	0.0																
Ending Cash Balance	Historic Balance Sheet	67.8	96.5																			
Accounts Receivable	*Historic Balance Sheet*	16.3	17.5	26.3	19.9																	
Fuel Stock & Related	Historic Balance Sheet																					
Credit Escrow	Economic Reserve					157.0	157.0	127.6	96.8	69.9	34.4											
Materials and Supplies Other	Historic Balance Sheet	0.7	0.8	0.8	0.8																	
Other Current Assets	Historic Balance Sheet	0.3	4.1	1.1	1.1	1.1																
Credits																						
AMBAC/Credit Suisse July '98	Historic and Projected Balance Sheet	5.1	4.7	4.3	3.8	3.8	3.8															
Deferred Tax	Historic Balance Sheet	4.3																				
Other Deferred Debits/PCB Refunding 10/01	Historic Balance Sheet																					
LEM Settlement Note/Marketing Payment	Historic Balance Sheet																					
Total Assets		18.1	17.1	16.1	15.1																	
Liabilities																						
Margins & Equities	Historic Balance Sheet	(251.9)	(218.2)	(175.0)	(138.5)																	
Long-Term Debt																						
Existing Debt	Historic Balance Sheet	1,058.2	1,053.1	1,061.7	1,027.1																	
Sale-Leaseback Obligation	Historic Balance Sheet	171.0	177.3	183.9	189.7																	
Total Long-Term Debt																						
Current & Accrued Liabilities																						

Inputs

		Source:	2005/ Othe	2006	2007	2008	Transactione	Termin	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
363	Accounts Payable	Historic Balance Sheet	13.1	12.6	16.0	12.7																	
364	Taxes Accrued	Historic Balance Sheet	0.4	0.2	1.0	1.0																	
365	Deferred Revenue (Credit Escrow)	Historic Balance Sheet	7.5	7.6	7.8	7.3	0.4	0.4															
366	Interest Accrued	Historic Balance Sheet	5.9	6.0	5.2	5.4	5.4	5.4															
367	Other Accrued Liabilities	Historic Balance Sheet		158.1	156.9	152.6																	
368	WKEC Lease (Resid. Value Obligation)*	Historic Balance Sheet																					
369	Sale-Leaseback Gain	Historic Balance Sheet	1.0	0.4	0.3	0.2																	
370	Other Deferred Credits & Century Reactive Power	Historic Balance Sheet																					
371	Total Liabilities & Equity																						
372																							
373	Misc included in Other Property																						
374																							
375																							
376	**Sale-Leaseback**																						
377			62.12																				
378	BOY Deferred Gain	Sale-Leaseback	2.86	2.88	2.90	2.92		0.00	2.76	2.79	2.83	2.84	2.85	2.87	2.88	2.89	2.91	2.92	2.94	2.95	2.97	2.99	3.01
379	Amortization (I/S)	Sale-Leaseback																					
380			160.65																				
381	Investment - Special Deposit (B/S)	Sale-Leaseback	0.50	0.73	0.74																		
382	Adder	Sale-Leaseback																					
383			170.95																				
384	Liability - Long-Term Debt (B/S)	Sale-Leaseback																					
385			11.67	12.07	12.48	12.61																	
386	Interest Income (I/S)	Sale-Leaseback	11.97	12.39	12.82	12.16																	
387	Interest Expense (I/S)	Sale-Leaseback																					
388			5.72	6.03	6.24	6.24																	
389	Cash Flow (Investment and Liability)	Sale-Leaseback																					
390																							
391	Sale-Leaseback - LeaseCo.		63.53	64.06	64.47	64.47																	
392	Defeasance Income	Sale-Leaseback	(48.87)	(48.87)	(48.87)	(48.87)																	
393	Rent Expense	Sale-Leaseback																					
394																							
395																							
396	**Unwind Transaction**																						
397																							
398	WKE Residual Value Obligation																						
399	WKE Gen. Capex - Cum.																						
400	Non-Incremental (RV Obligation Balance)																						
401	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		40.2	45.3	50.3	55.2																
402	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		6.7	6.8	7.0																	
403	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.6	1.8	2.1																	
404	Unattributed Plugs	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(145.1)																			
405	Incremental																						
406	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		100.2	95.6	90.9	86.3																
407	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.8																			
408	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.4	4.6	4.6																	
409																							
410	LG&E Rental Income Advance																						
411	Cash Flow	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.9	50.8	47.7																	
412	Income Statement	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		52.3	52.3	52.3																	
413	Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(17.3)	(15.8)	(11.2)	(11.2)																
414																							
415	Net WKE Obligation																						
416																							
417	Fuel & Other Inventories	Termination Agreement					51.0																
418																							
419	Coleman Scrubber Completion	Termination Agreement/ file: Coleman Scrubber.xls					98.5																
420																							
421	Cancellation of Settlement Prom. Note	Termination Agreement					15.7																
422																							
423	6. Other 3rd Party Add-ons																						
424	Smelter Payment	Smelter Coordination Agreement					1.5																
425	Consent Fees																						
426																							
427	7. Non-Smelter Member Excess Cash Rebate																						
428																							
429	8. Non-Smelter Member Excess Cash Rate Mitigation Account								157.0	157.0	127.8	96.8	69.9	34.4									
430	BB								0.0	6.3	5.1	3.9	2.8	1.4									
431	IE	Assumed 4.28% interest earnings rate					157.0																
432	Contribution	LG&E Unwind Deal Stipulated								(35.5)	(36.1)	(30.8)	(38.3)	(35.7)									
433	Release/ Amortization	Releases to offset FAC + ES, net of surcharge rebates																					
434	EB						157.0		157.0	127.8	96.8	69.9	34.4										
435																							
436	10. DSL Termination																						
437																							
438	11. LG&E Emissions Allowance						14,000																
439	Volume (tons)	Termination Agreement					140																
440	Price ($/ton)	file: Annual Output - 9-8-08 - BREC Update.xls																					
441																							
442	Lease Termination Payment																						
443	Assumed Make Whole to CoBank																						
444	Total Expense																						
445																							
446	Lease Termination Payment from Unwind Counterparties																						
447	Recognition of Deferred Gain on Original Lease																						
448	Lease Termination Payment from Unwind Counterparties																						
449																							
450	DSL Termination			0																			
451	PMCC Share			0																			
452	Net SLB																						
453	**Depreciation**																						

Inputs

...tober 2008

		Source:	005/ Othe	2006	2007	2008	Transactions	Termina	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
454																							
455	Additional Book Depreciation																						
456	Prior year non-incremental + in service	Historic		12.83	13.12	13.41																	
457	Average of Transmission and A&G	Historic		6.38	10.68	17.33																	
458	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.02	0.02	0.02		0.02															
459	Capitalization Policy (0=longer rate)		1	2011	2.4%																		
460	Capital Depreciation Rate (excl. Environmental)	Based on 1993 Depreciation Study	38																				
461	Capital Depreciation Rate (Environmental)	Based on 1993 Depreciation Study	38																				
462																							
463																							
464	HMP&L Station Two																						
465	Prior year non-incremental	Historic		12.83	13.12	13.41																	
466	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
467																							
468	Other																						
469	Prior year	Historic		6.00	6.77	14.99																	
470	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
471																							
472	Book Depreciation & Amortization																						
473	Generation																						
474	Big Rivers' Plants	Historic		26.69	26.17	26.41		26.58	28.08														
475	HMP&L Station Two	Historic		0.92	0.93	0.93		0.93	0.93														
476	Other	Historic		5.03	5.06	5.11		5.06	5.11														
477																							
478	Adjustment to Depreciation		0																				
479	9/24/07 Blended Depreciation Amount	*Coordination Agreement, Section 3.10*						0.01976	0.0204	0.02103	0.02155	0.02167	0.02122	0.0209	0.02123	0.0215							
480	**Income Tax Related**																						
481																							
482	Previously Expensed Marketing Payment	Historic		0	0	0	4.196																
483																							
484	Status Quo Depreciation	Proforma	23.69																				
485																							
486	WKE Share of Capex																						
487	Non-Incremental	Participation Agreement - Cost Sharing		51%	51%	51%		51%	51%	51%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
488	Incremental	Participation Agreement - Cost Sharing		0%	80%	80%		80%	80%	80%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
489	Incremental Dep			0.60	0.00	0.00																	
490	Temporary Differences																						
491	*2005 Cumulative Balance of Capex not reflected in SO*	*Historic*	149.87																				
492	Other Temporary Differences	Historic	19.65																				
493																							
494	NOL Related																						
495	Year			1983	1984	1984	1984	1984	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
496																							
497	Tax Rates																						
498	Regular	Big Rivers' estimate	35%																				
499	AMT	Big Rivers' estimate	20%																				
500																							
501	ACE																						
502	ACE Deduction			(1.23)	(1.22)	(1.22)		(0.00)	(1.19)	(1.17)	(0.80)	(0.58)	(0.50)	(0.35)	(0.13)	(0.03)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
503	ACE %		75%																				
504																							
505	SO Addition	Historic		0.41	0.25	0.38	#REF!	0.26	0.44	0.43	0.71	1.61	0.47	0.90	1.35	1.77	2.26	4.72	5.56	6.36	6.71	6.76	7.87
506	2006 AMT BB			4.28	4.69	4.93	5.32																
507																							
508	Nonpatronage MWH	Historic	1	38%	0.46009	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
509	Offsystem Sales	Orrick Herrington/ Deloitte	PE																				
510	Interest Income on Unrestricted Cash	Orrick Herrington/ Deloitte	PE																				
511	Interest on Transition Reserve	Orrick Herrington/ Deloitte	NP																				
512	Interest on Economic Reserve	Orrick Herrington/ Deloitte	PE																				
513																							
514	Carbon Tax Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year																					
515	Carbon Allowance Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year																					
516	Carbon BY Allowance Cost ($/MWh)	5,073,775 tons in base year, *$7/ton charge starting in 2012, escalating at $1/year*																					
517																							
518	Smelter Excess Cash Rate Mitigation Account																						
519	BB																						
520	IE	Assumed 4.28% interest earnings rate																					
521	Contribution	Smelter Retail Agreement, Section 7?																					
522	Release/ Amortization	*Releases to offset FAC increase from Feb. Filed Model*																					
523	EB																						
524	RUS Prepay Adjustments																						
525	Stated											######				######							
526	GAAP											######				######					500.4		
527	Interest earnings											(750.0)				######							
528	Smelter Payment						-7																
529	Other Deferred Assets				2.1373	2.1373	2.137299	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373
530	Historic Purchases Through Close				68	12																	
					7	4																	
					61	8																	

Fuel In .tory

		Transacti on	Lease Terminati on	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	(SM)																	
	Unwind Allocation	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	Inventory Maintenance	100%																
2																		
3	Fuel Purchases ($/mmbtu)	1.56	1.96	1.95	2.15	2.25	2.50	2.69	1.85	1.85	1.87	1.90	1.91	1.94	1.96	1.98	2.02	2.04
4																		
5	Heat Value btu/ lb		500	10,999	11,028	11,050	11,037	11,024	11,061	11,019	11,038	11,020	11,025	11,045	11,029	11,023	11,074	11,030
6	Heat Value mmbtu/ ton		1.00	22.00	22.06	22.10	22.07	22.05	22.12	22.04	22.08	22.04	22.05	22.09	22.06	22.05	22.15	22.06
7	Coal Consumed [from PCM (000s tons)]		0	6,041	6,219	5,967	6,046	6,058	6,063	6,097	6,100	5,910	6,095	5,938	6,078	6,058	6,083	6,065
8	Coal Consumed (Gbtus)		0	132,904	137,165	131,878	133,453	133,576	134,113	134,367	134,658	130,264	134,396	131,171	134,064	133,548	134,716	133,785
9																		
10	***Volumes Fuel Inventory (Gbtus)***																	
11	BB	-	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210
12	Fuel Purchased		0	132,904	137,165	131,878	133,453	133,576	134,113	134,367	134,658	130,264	134,396	131,171	134,064	133,548	134,716	133,785
13	LG&E Additions to Fuel Inventory	20,210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Fuel Consumed	-	(0)	(132,904)	(137,165)	(131,878)	(133,453)	(133,576)	(134,113)	(134,367)	(134,658)	(130,264)	(134,396)	(131,171)	(134,064)	(133,548)	(134,716)	(133,785)
15	EB	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210
16																		
17	***$MIllions***																	
18	BB	-	31.4	31.4	31.3	35.2	37.3	42.4	46.3	29.2	29.3	29.5	30.3	30.4	31.2	31.5	31.9	32.7
19	Fuel Purchased		0.0	259.2	294.4	296.9	334.0	359.9	248.1	249.1	251.2	248.0	256.2	255.1	263.2	265.0	272.5	272.4
20	LG&E Additions to Fuel Inventory	31.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Fuel Expensed	-	0.0	(259.4)	(290.5)	(294.8)	(328.9)	(356.0)	(265.1)	(249.0)	(250.9)	(247.2)	(256.2)	(254.3)	(262.8)	(264.5)	(271.7)	(272.1)
22	EB	31.4	31.4	31.3	35.2	37.3	42.4	46.3	29.2	29.3	29.5	30.3	30.4	31.2	31.5	31.9	32.7	33.0

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	Transactior	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1 **SO2 Emissions Inventory**																	
2																	
3 *Price ($/ ton)**	$ 140	$ 140	$ 140	$ 115	$ 868	$ 878	$ 875	$ 850	$ 842	$ 825	$ 757	$ 706	$ 561	$ 413	$ 350	$ 302	$ 279
4 *LG&E Contribution*	14,000																
5 *Excess Sold Annually (2008-2010)*	100%																
6 *Excess Sold Annually (post 2010)*	100%																
7 *CAIR Factor*	1.00	1.00	1.00	1.00	2.00	2.00	2.00	2.00	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86
8																	
9 **Allowances (in tons)**																	
10 BB	-	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
11 Allocated	14,000	-	48,979	48,979	24,489	24,489	24,489	24,489	18,352	18,352	18,352	18,352	18,352	17,125	18,352	18,352	18,352
12 Consumed		-	(19,145)	(20,453)	(19,301)	(19,812)	(19,341)	(19,855)	(20,836)	(21,282)	(19,910)	(21,199)	(20,456)	(19,823)	(20,812)	(21,263)	(20,716)
13 Sold	-	-	(29,834)	(28,526)	(5,188)	(4,677)	(5,148)	(4,635)	2,484	2,929	1,558	2,847	2,104	2,697	2,460	2,911	2,364
14 Net Contributed	14,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15 Withdrawn/ Sold	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16 EB	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
17 **Dollars (Balance Sheet)**																	
18 BB	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19 Net Contributed	1,960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20 Withdrawn/ Sold	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21 EB	1,960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22 Average Inventory Value ($/ Allowance)	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23																	
24																	
25 Income Statement																	
26 Revenue																	
27 Sales	-	-	4,177	3,280	4,503	4,106	4,505	3,939	(2,091)	(2,417)	(1,180)	(2,010)	(1,180)	(1,114)	(861)	(879)	(659)
28 Allocation to Inventory	1,960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29 Expense																	
30 Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31 Net	1,960	-	4,177	3,280	4,503	4,106	4,505	3,939	(2,091)	(2,417)	(1,180)	(2,010)	(1,180)	(1,114)	(861)	(879)	(659)
32																	
33 Cash Flow																	
34 Sales	-	-	4,177	3,280	4,503	4,106	4,505	3,939	(2,091)	(2,417)	(1,180)	(2,010)	(1,180)	(1,114)	(861)	(879)	(659)
35 Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36 Net	-	-	4,177	3,280	4,503	4,106	4,505	3,939	(2,091)	(2,417)	(1,180)	(2,010)	(1,180)	(1,114)	(861)	(879)	(659)
37																	
38 Balance Sheet (Incremental)																	
39 Cash	-	-	4,177	7,457	11,961	16,067	20,572	24,511	22,419	20,003	18,823	16,813	15,633	14,519	13,658	12,779	12,119
40 Emissions Inventory	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960
41 Total	1,960	1,960	6,137	9,417	13,921	18,027	22,532	26,471	24,379	21,963	20,783	18,773	17,593	16,479	15,618	14,739	14,079
42																	

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	Transactior	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NOX Emissions Inventory																	
Price ($/ ton)*	$ 700	$ 700	$ 700	$ 650	$ 2,120	$ 1,951	$ 1,909	$ 2,570	$ 3,071	$ 2,863	$ 2,764	$ 2,665	$ 2,564	$ 2,574	$ 2,578	$ 2,581	$ 2,584
LG&E Contribution																	
Excess Sold Annually	100%																
Allowances																	
BB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Allocated		-	4,652	4,652	11,068	11,057	11,057	11,057	8,944	8,944	8,491	8,297	8,153	7,948	7,713	7,491	7,419
Consumed		-	(5,141)	(5,105)	(13,489)	(13,371)	(13,531)	(13,340)	(13,579)	(13,378)	(13,303)	(13,413)	(13,214)	(13,553)	(13,445)	(13,365)	(13,558)
Sold		-	489	453	2,421	2,314	2,474	2,284	4,635	4,435	4,811	5,116	5,061	5,605	5,732	5,874	6,139
Net Contributed	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Withdrawn/ Sold		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dollars (Balance Sheet)																	
BB	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Contributed	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Withdrawn/ Sold	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Average Inventory Value ($/ Allowance)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Statement																	
Revenue																	
Sales		-	(342)	(295)	(5,132)	(4,514)	(4,723)	(5,870)	(14,233)	(12,697)	(13,299)	(13,634)	(12,976)	(14,428)	(14,776)	(15,160)	(15,862)
Allocation to Inventory	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expense																	
Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net	-	-	(342)	(295)	(5,132)	(4,514)	(4,723)	(5,870)	(14,233)	(12,697)	(13,299)	(13,634)	(12,976)	(14,428)	(14,776)	(15,160)	(15,862)
Cash Flow																	
Sales	-	-	(342)	(295)	(5,132)	(4,514)	(4,723)	(5,870)	(14,233)	(12,697)	(13,299)	(13,634)	(12,976)	(14,428)	(14,776)	(15,160)	(15,862)
Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net	-	-	(342)	(295)	(5,132)	(4,514)	(4,723)	(5,870)	(14,233)	(12,697)	(13,299)	(13,634)	(12,976)	(14,428)	(14,776)	(15,160)	(15,862)
Balance Sheet (Incremental)																	
Cash	-	-	(342)	(637)	(5,769)	(10,283)	(15,005)	(20,875)	(35,109)	(47,805)	(61,104)	(74,738)	(87,713)	(102,141)	(116,917)	(132,078)	(147,940)
Emissions Inventory	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	(342)	(637)	(5,769)	(10,283)	(15,005)	(20,875)	(35,109)	(47,805)	(61,104)	(74,738)	(87,713)	(102,141)	(116,917)	(132,078)	(147,940)

Lease Buyout Summary

October 2008

Lease Buyout Impact

	Total	Journal Entries	
		Debit	Credit
Assets			
Sale-Leaseback Investments	(196.8)	-	196.8
Cash & Investments	(59.6)	-	59.6
	-		
Assets	(256.4)		
	-		
Liabilities & Equities	-		
Equities	(16.1)	16.1	-
Sale-Leaseback Obligation & Unamortiz	-	-	-
Obligation	(189.7)	189.7	-
Unamortized Gain	(50.6)	50.6	-
Total	-	-	-
Liabilities & Equities	(256.4)		
Check	-	256.4	256.4

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S OCTOBER 24, 2008
SUPPLEMENTAL REQUEST FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
November 7, 2008

Item 27) Exhibit PWT-9 attached to the Supplemental Testimony of Paul W. Thompson provides the "resolution" of four "Existing Contract Disputes." Provide the current estimated amount, separately, to resolve each of the four disputed items assuming the Unwind Transaction proceeds as proposed by the Joint Applicants. Please also indicate which party or entity would bear those estimated costs.

Response) This question is directed to information in the testimony of Paul W. Thompson. Big Rivers defers to Mr. Thompson's response to Item 4 of this data request.

Witness) Mark A. Bailey
David A. Spainhoward

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S OCTOBER 24, 2008
SUPPLEMENTAL REQUEST FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
November 7, 2008

Item 28) Please provide "what if" Unwind Financial Model runs performed by or for BREC in the period September 1, 2008 to current, to reflect alternative resolutions contemplated to obtain Henderson's consent to the proposed transaction. For each "what if" model run, please specify the input assumptions for the model on the parameters which were assumed to obtain Henderson's consent.

Response) There are no "what if" Unwind Financial Model runs performed by or for Big Rivers in the period September 1, 2008 to current to reflect alternative resolutions contemplated to obtain Henderson's consent to the Unwind Transaction. Big Rivers has not performed any such sensitivity analyses on the Unwind Financial Model because, as Big Rivers has informed HMP&L and Commission Staff at the October 20, 2008 Informal Conference, any alternative resolution to obtain Henderson's consent to the proposed transaction cannot come at any increased cost to Big Rivers or its Members – beyond the amounts already provided for in the Unwind Financial Model.

Witness) Mark A. Bailey

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Item 29) Please summarize the key points which define the contractual relationship, rights and responsibilities of Henderson and BREC (separately) with regard to the operation of Station Two, from a business perspective.

Response) The key documents which have defined the relationship of Big Rivers and the City of Henderson ("City") since 1970 are the Power Plant Construction and Operation Agreement (the "Operating Agreement"), a Power Sales Contract (the "Power Sales Contract") and a Joint Facilities Agreement, each dated August 1, 1970. Each has been amended a number of times since its execution, including in 1998 in connection with the assumption by WKE Station Two Inc. (predecessor to WKEC) of most of Big Rivers' obligations under these three contracts at the time of Big Rivers' emergence from bankruptcy. Big Rivers was not released from its obligations under the Operating Agreement, the Power Sales Contract and the Joint Facilities Agreement when they were assumed by WKEC. Big Rivers remains secondarily liable for all those obligations. Big Rivers operated Station Two, as an independent contractor, in accordance with the provisions of the Operating Agreement from the commencement of operation of Station Two until Big Rivers emerged from bankruptcy in 1998. In that capacity, Big Rivers provided all operating personnel, materials, supplies (with the exception of coal and some reagents) and technical services required for the operation of Station Two. The Operating Agreement includes a specific identification of those costs to be allocated to the operation of Station Two. The Operating Agreement addresses budgeting, accounting, auditing, billing and payments associated with the operation of Station Two. The Operating Agreement also includes rights of first offer with respect to Station Two and Big Rivers' Reid Station. Additionally, please refer to Big Rivers' response dated November 7, 2008 to the Attorney General's October 24, 2008 Supplemental Data Request Items 31 and 32.

Big Rivers purchased power from the City under the Power Sales Contract from the commencement of operation of Station Two until Big Rivers' emerged from bankruptcy in 1998. The Power Sales Contract provides a mechanism for determining the capacity of Station Two from time to time and for allocating capacity between the City and Big Rivers based upon five year assessments of the requirements of the City for its internal needs and annual adjustments of up to 5 MW.

Big Rivers is obligated to take and pay for capacity from Station Two in excess of that designated by the City as required for the "needs of the City and its inhabitants" as such phrase is defined in the Power Sales Contract. The Power Sales Contract also establishes limits on the City's ability to alienate its generating capacity from Station Two. The Power Sales Contract establishes pricing and payment provisions relating to the energy purchased by Big Rivers there under as well as for an annual audit of the financial accounts of Station Two.

Pursuant to the Joint Facilities Agreement, Big Rivers and the City have agreed to the use of certain facilities used in the operation of both Station Two and Big Rivers' Reid Station. The Joint Facilities Agreement addresses the ownership, maintenance and expenses associated with these facilities.

In addition to the Operating Agreement, Power Sales Contract and Joint Facilities Agreement, Big Rivers and the City also executed a System Reserves Agreement dated January 1, 1974. Furthermore, the City, Big Rivers and WKE Station Two Inc. executed the Station Two G & A Allocation Agreement dated July 15, 1998, which amended and restated a prior Agreement dated February 15, 1991 between the City and Big Rivers, sets forth an agreement among such three parties relating to the allocation to Station Two of (i) the costs of maintaining an inventory of parts for Station Two and (ii) the parties' general and administrative expenses incurred in the performance of their respective obligations under the Operating Agreement, the Power Sales Contract and the Agreement and Amendment to Agreements dated July 15, 1998 by and among the City, Big Rivers and three subsidiaries of LG&E (the "Station Two Agreement").

In 2005, the City, Big Rivers, WKE Station Two Inc. and LG&E Energy Marketing executed a 2005 Amendments to Contracts dated as of April 1, 2005 (the "2005 Amendments") amending the Operating Agreement, the Power Sales Contract and the Joint Facilities Agreement in order to accommodate the design, acquisition, construction, testing, operation, maintenance and funding of the SCR System for Station Two and to provide for an allocation of the NOx allowances associated with Station Two in light of the parties' respective contributions toward the cost of the Station Two SCR System. The amendments to the Power Sales Contract affected by the 2005 Amendments also provide for the continued maintenance by Big Rivers and the City of separate Station Two Operations and Maintenance Funds in the amounts of $400,000 and $100,000, respectively. In accordance with the aforementioned Station Two Agreement, in 1998 Big Rivers assigned most of its rights under the Operating Agreement, the Power Sales Contract and the Joint Facilities Agreement to WKE Station Two Inc. (predecessor in interest to WKEC), and WKE Station Two Inc. assumed most of Big Rivers' obligations under such agreements. Big Rivers does retain certain obligations to the City in respect of incremental environmental operation and maintenance costs associated with Station Two and for certain capital improvements to Station Two. Should there be no Unwind, the rights assigned to WKEC by contract revert to Big Rivers on January 1, 2024 without action by the City.

From the inception of the Big Rivers – City relationship for Station Two commencing with the execution of the Operating Agreement, the Power Sales Contract and the Joint Facilities Agreement, the arrangement has provided Big Rivers (and during the period of WKEC operation, WKEC) with a reliable source of base load generation to serve the needs of Big Rivers' members at reasonable costs. This is so, notwithstanding the fact that, over the term of the arrangement, Big Rivers has paid a higher percentage of the total capital costs of Station Two in the form of capacity payments than the percentage of the total energy output from Station Two which Big Rivers has taken for its own use.

From the City's perspective, the Station Two arrangements have provided it with a source of base load generation to satisfy the needs of its consumers which, because of the economies inherent in a larger generating facility than the City's own needs would support, was at an attractive cost. Big Rivers' take and pay obligation in the Power Sales Contract with respect to capacity from Station Two in excess of the "needs of the City and its inhabitants" has provided the City significant flexibility in satisfying its future capacity requirements while paying none of the capacity costs until such time as it desires to increase its designated capacity. Until 2005 (and only for the SCR capital), the agreements provided for no reimbursement to Big Rivers or WKEC for previously incurred capital costs as the City's capacity reservation increases. Indeed, the form of amendment to the Power Sales Contract which Big Rivers has submitted to the Kentucky Public Service Commission in connection with its request for the KPSC's consent for the Unwind, will enhance the existing arrangements from the City's perspective by providing that Big Rivers will take and pay for excess energy resulting from the City's failure to use the full amount of energy associated with its reserved capacity and providing that Big Rivers will pay $2.50 per MWH for this energy as opposed to $1.50 per MWH in the existing arrangements (along with all other operating costs such as fuel, reagent, allowances, etc.).

Witness) David A. Spainhoward

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Item 30) To what extent does Henderson believe the costs of rectifying its concerns regarding maintenance and condition of Station Two exceed the $3 million offered by E.ON to meet such concerns.

Response) Big Rivers does not know what the City of Henderson and the City of Henderson, Utility Commission ("Henderson") actually "believe" about "the cost of rectifying its concerns regarding maintenance and condition of Station Two." The positions taken by Henderson on this subject are reflected in the correspondence furnished in response to Item 33 of this data request.

Witness) Mark A. Bailey
David A. Spainhoward

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Item 31) Please assume the Unwind Transaction closes as proposed. For each capital dollar that is necessary to rectify Henderson concerns regarding the operating condition of Station Two, how much of that is BREC obligated to pay?

Response) Big Rivers is not fully aware of the complete scope of Henderson's concerns regarding the operating condition of Station Two, what is necessary to rectify those concerns, or where capital expenditures would be made to rectify those concerns. However, we do know what the contractual relationship requires for cost splitting. Big Rivers is obligated to pay its contractual share of capital and expense items. The breakdown of cost splits for capital projects are as follows:

For capital projects, Big Rivers will be obligated to pay the following percentage of each capital dollar based first on the below-specified megawatt splits and based further on whether the capital project is Station Two-related only, or is an item shared between Station Two and Reid, or is one shared between Station Two, Reid and Green.

Following is the listing of megawatt splits and the obligation Big Rivers will be responsible for on expenditures through May 31, 2009 based on the current megawatt split between Big Rivers and the City of Henderson (95 megawatts of the 312 megawatt capacity of HMP&L Station Two). Were the City of Henderson's reservation higher or lower, the calculated split percentage would change in accordance with the agreements.

	Split Percentage	Spending	Allocation	
Station Two Only - 217/312	0.6955	$1.00	$0.70	Big Rivers Obligation of each Capital Dollar
Station Two & Reid Common - 282/377	0.7480	$1.00	$0.75	Big Rivers Obligation of each Capital Dollar
Station Two, Reid & Green Common - 736/831	0.8857	$1.00	$0.89	Big Rivers Obligation of each Capital Dollar

Witness) David A. Spainhoward

Item 32) Please assume the Unwind Transaction closes as proposed. For each expense dollar that is necessary to rectify Henderson concerns regarding the operating condition of Station Two, how much of that is BREC obligated to pay?

Response) Big Rivers is not fully aware of the complete scope of Henderson's concerns regarding the operating condition of Station Two, what is necessary to rectify those concerns, or where expense expenditures would be made to rectify those concerns. However, we do know what the contractual relationship requires for cost splitting. Big Rivers is obligated to pay its contractual share of capital and expense items. The breakdown of cost splits for expense projects are as follows:

For expense items such as O&M Labor, O&M Non-Labor, SCR Costs, etc., the split percentage of costs attributable to Station Two that Big Rivers will be obligated to pay the following percentage of each expense dollar based on the following megawatt splits based on whether the expenditures are Station Two related only or if the expenditures are shared with Reid and Station Two or Reid/Station Two and Green on common facilities.

	Split Percentage	Spending	Allocation	
Station Two Only - 217/312	0.6955	$1.00	$0.70	Big Rivers Obligation of each Expense Dollar
Station Two & Reid Common - 282/377	0.7480	$1.00	$0.75	Big Rivers Obligation of each Expense Dollar
Station Two, Reid & Green Common - 736/831	0.8857	$1.00	$0.89	Big Rivers Obligation of each Expense Dollar

For Scrubber costs that are directly related to the Station Two Scrubber, Big Rivers will pay an allocated share of the cost using the 217/312 obligation split percentage. For Scrubber costs that will be shared based on Green Station Assets in common use with the HMP&L Scrubber, the following methodology is used to determine the percentage charged to Station Two each month. For O&M Labor and Non-labor related costs to the reagent prep area of the scrubber, a percentage attributable to Station Two is determined based on the additive flow meters. These flow meters determine the amount of lime used by each of Green and Station Two. This calculated percentage of Station Two lime usage is then applied to the costs incurred each month in the accounts for Reagent Prep Labor and Non-labor, and the resulting calculated Station Two costs will then be allocated between Big Rivers and HMP&L using the 217/312 split's split percentage of 0.6955 percent. For O&M labor and non-labor related costs in the waste treatment area, the allocation percentage between the various units is based on bleed flow meters. These bleed flow meters determine the amount of solid waste stacked out each month by each unit. For each unit, this percentage is then applied to the total costs incurred each month in the accounts for Waste Treatment Labor and Non-labor, and the allocated costs for Station Two's waste costs will then be allocated between Big Rivers and HMP&L using the 217/312 split's 0.6955 percentage. The percentages from the flow meters among the various units will change each month. Big Rivers will also pay its obligation for the hauling cost of the Station Two solid waste to the Landfill based on the 217/312 split percentage.

Reagent Prep allocation Example

	Tons	Percent	G/SII Allocation	Allocation
Reagent Lime Used in Month	12615			
Used by Green	7935	62 9%	$ 1 26	
Used by Station II	4680	37 1%	$ 0.74	$ 0.52

Reagent Prep Labor	$ 1.00
Reagent Prep Non-Labor	$ 1.00
Total	$ 2.00

Big Rivers Obligation 217/312 of the $0.74

The Waste Treatment obligation would follow the same methodology as the Reagent Prep.

The City of Henderson purchases its own coal and reagent lime. Big Rivers does not have an obligation for these costs

Witness) David A. Spainhoward