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Via Courier

May 24, 2013

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Docket CASE NO. 2012-00535

Dear Mr. Derouen:

Enclosed for the filing are an original and ten copies of the *Direct Testimony of Frank Ackerman on Behalf of the Sierra Club- Public Version* and a certificate of service in docket 2012-00535 before the Kentucky Public Service Commission. This filing contains no confidential information.

Sincerely,

Ruben Mojica
Sierra Club Environmental Law Program
85 2nd Street, 2nd Floor
San Francisco CA, 94105
(415)977-5737

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC	)	**Case No.**
CORPORATION FOR A GENERAL	)	**2012-00535**
ADJUSTMENT IN RATES	)	

DIRECT TESTIMONY
OF

FRANK ACKERMAN
SENIOR ECONOMIST
SYNAPSE ENERGY ECONOMICS

ON BEHALF OF

SIERRA CLUB

Date
May 24, 2013

BEN TAYLOR AND SIERRA CLUB

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

VERIFICATION

I, Frank Ackerman, verify, state, and affirm that I prepared or supervised the preparation of the testimony filed with this Verification, and that my testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Frank Ackerman

COMMONWEALTH OF MASSACHUSETTS)
COUNTY OF MIDDLESEX)

SUBSCRIBED AND SWORN TO before me by Frank Ackerman on this 24th day of May, 2013.

JANICE CONYERS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

Notary Public, Ma. State at Large
My Commission Expires 7/27/18

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position.

A. My name is Frank Ackerman. I am a senior economist at Synapse Energy Economics, Inc., 485 Massachusetts Avenue, Cambridge MA 02139.

Q. Please describe your professional experience before beginning your current position at Synapse Energy Economics.

A. Before coming to Synapse in late 2012, I worked for many years at two research institutes at Tufts University in Medford, Massachusetts, focusing on issues of energy, climate change, and policy analysis. I received a PhD in economics from Harvard University, and have taught economics at Tufts University and at the University of Massachusetts. A copy of my resume is attached as Exhibit Ackerman-1.

Q. Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government, and utilities.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Sierra Club.

Q. Have you filed testimony in other recent regulatory proceedings?

A. Yes. I filed testimony on behalf of the Sierra Club in Indiana, in the recent CPCN case filed by Duke Energy Indiana (Cause No. 44217).

Q. Have you testified previously in Kentucky?

A. No, I have not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the request by Big Rivers Electric Corporation ("BREC," or "the Company") for a rate increase, and to discuss alternative approaches to the underlying problem that has led to this request.

Q. Are you sponsoring any exhibits?

A. Yes. I have prepared the following exhibits to my prepared testimony:

1. Exhibit Ackerman-1	Professional CV for Frank Ackerman
2. Exhibit Ackerman-2	Evansville Courier & Press Article "Century Aluminum to buy Alcan's Sebree Smelter"
3. Exhibit Ackerman-3	Sargent & Lundy Study
4. Exhibit Ackerman-4	Wilson Direct Testimony
5. Exhibit Ackerman-5	Steinhurst Direct Testimony
6. Exhibit Ackerman-6	Metal Miner Article "Power Costs in the Production of Primary Aluminum"
7. Exhibit Ackerman-7	Evansville Courier & Press Article "UPDATE: Big Rivers seeking $74 Million annual increase in wholesale electric rates"

Q. How is your testimony organized?

A. My testimony is organized as follows:

1. Introduction and Qualifications.
2. Summary of Conclusions and Recommendation.
3. The Long-term Problem: Excess Capacity.
4. Costs to Maintain and Upgrade BREC's Power Plants.
5. Subsidies for Smelters: A Question for State Policy.
6. BREC's Options: Finding the Least Bad Choice.
7. Potential Revenue from Power Plant Sales.
8. Implications of Bankruptcy for Ratepayers.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATION

Q. Please summarize your conclusions.

A. My conclusions can be summarized by section, as follows. In Section 3, I demonstrate that BREC had more than enough capacity to serve its load, even before the departure of either of the smelters. Since the smelters represent two-thirds of BREC's load, their announced departure would leave BREC with vastly more capacity than is needed for its remaining customers. Off-system sales, and the search for new customers, do not appear able to produce enough revenue to justify keeping this excess capacity.

In Section 4, I evaluate the costs required to bring BREC's power plants into compliance with current and anticipated environmental regulations. The roughly $60 million for MATS compliance discussed by BREC witnesses in this case is only a small part of what will be needed. According to Sargent & Lundy, the Company's consultants in the Big Rivers 2012 CPCN case, the costs for environmental compliance at BREC's plants could exceed $500 million. This does not include the impact of any potential future greenhouse gas regulations, which could further decrease the profitability of coal plants.

In Section 5, I review the issue of subsidies designed to keep the smelters in business. If such subsidies are deemed appropriate, they should be provided by Kentucky state economic development funds, not by the utility that serves the smelters – or by its other ratepayers.

In Section 6, I describe BREC's choices in responding to the loss of the smelters. If off-system sales are not sufficient to support the existing capacity, then BREC will have to idle, sell, or decommission some of its plants. BREC has barely begun to face these choices, and is still relying on the unsupported hope that off-system sales will recover enough to avoid the hardest decisions.

In Section 7, I discuss the potential revenue from selling coal plants. The limited recent data suggests sale prices around $100 - $160/kw of capacity, a small fraction of the book value net of depreciation, or of the current value in rate base, of BREC's plants.

Finally, in Section 8, I explore the potential implications of bankruptcy for BREC's customers. This painful topic unfortunately cannot be avoided, due to the large debt borne by BREC and the relatively limited revenues available from either off-system electricity sales or from sales of assets. Reorganization following a bankruptcy could lead to BREC's remaining (non-smelter) customers paying rates based on the MISO market price of electricity, plus transmission, distribution, and administrative costs. If keeping BREC out of bankruptcy imposes rates much higher than this, it would not be in the customers' best interests.

Q. Please summarize your recommendation.

A. I recommend that the Commission reject the requested rate increase. It would impose substantial burdens on BREC's remaining customers, yet it would be far from enough to solve the underlying problem of excess capacity. Indeed, BREC has already announced its intention to promptly file another request for a rate increase in response to the second smelter's departure. Yet another rate increase would be required to cover the costs of bringing BREC's power plants into compliance with environmental regulations; only a small fraction of these costs are included in the current request. Instead of seeking an endless series of rate increases, BREC should be directed to explore other approaches that can resolve its long-term problems, reduce its total capacity, and offer stable, affordable rates to BREC's customers.

3. THE LONG-TERM PROBLEM: EXCESS CAPACITY

Q. Please describe the fundamental issue addressed in this case.

A. BREC is a generation and transmission cooperative, owned by and operated on behalf of three distribution cooperatives in western Kentucky. BREC's service territory includes about 112,000 rural and industrial customers – and two large aluminum smelters, Century and Alcan, which together represent more than two-thirds of BREC's load. (Although Century Aluminum has recently agreed to acquire the Alcan smelter, I will continue to use the traditional names to distinguish the two smelters.)

In August 2012, the Century smelter gave the required 12 months' notice that it intended to stop buying electricity from BREC in August 2013. BREC then filed its current request for a substantial rate increase on the remaining smelter and the non-smelter customers, in order to make up for its revenue losses. The Alcan smelter gave notice in January 2013 of its intention to stop buying electricity from BREC as of January 2014; BREC has stated that it will soon have to request an additional rate increase to compensate for the loss of the second smelter. In an April 29, 2013 *Evansville Courier & Press* article (attached as Exhibit Ackerman-2), BREC President and CEO Mark Bailey was cited as saying the two rate increases together could increase residential electric rates as much as 40 percent.[1]

Q. Has BREC proposed any reductions in capacity in response to this substantial loss of load?

A. They have not proposed any permanent reductions in capacity. They have proposed idling the Wilson plant – their newest and most efficient (lowest heat rate) plant – until 2019.

Q. Is BREC's proposal an appropriate response to the loss of one or both smelters?

A. No, it is not. With the loss of one or both smelters, BREC will have far more capacity than it needs to serve its remaining customers, as reflected in extraordinarily high reserve ratios. BREC's proposal in this case, responding to the loss of the first smelter, does not discuss sale or permanent retirement of any of its excess capacity, but asks its remaining customers to pay much higher rates in order to maintain and add selected new environmental controls to its plants.

BREC owns and operates 1444 MW of capacity and has contractual rights to another 375 MW (from Henderson and SEPA combined), for a total of 1819 MW (Berry testimony, p.5). With both smelters, the highest forecast monthly billing demand in 2013 is 1529 MW (Exhibit Barron-3, p.1), so BREC has an ample 19%

[1] Chuck Stinett, "Century Aluminum to Buy Alcan's Sebree Smelter," *Evansville Courier & Press*, April 29, 2013, http://www.courierpress.com/news/2013/apr/29/century-aluminum-buy-alcans-sebree-smelter/.

reserve margin. Even with both smelters on its system, BREC is well above MISO's planning reserve margin of 14.2% in 2013, declining to 13.4% in 2022.[2]

As the smelters leave, BREC's reserve margin will shoot up from ample to absurd. Without the Century smelter, BREC's 2013 highest monthly demand drops to 1047 MW, implying a 74% reserve margin; after the departure of Alcan a few months later, the corresponding peak demand would be 679 MW, and the reserve margin would be 168%.

The Wilson plant has a capacity of 417 MW, somewhat less than the 482 MW of demand from the Century smelter. If Wilson goes off-line when Century leaves, BREC will still have 1402 MW of remaining capacity to serve 1047 MW of demand, a 34% reserve margin. When Alcan leaves, BREC, with all current capacity except Wilson on-line, would have a 106% reserve margin.

Q. Is detailed modeling required to confirm that BREC will have excess capacity after the smelters depart?

A. No. BREC with both smelters has a (forecasted 2013) peak monthly demand of 1529 MW; without the Century smelter it would have 1047 MW; without both smelters, it would have 679 MW. It is simply not possible for a generation fleet that is appropriate to serve 1529 MW of load to be equally appropriate for 679 MW of load. When both smelters have departed, only 808 MW of capacity would be needed to achieve the same 19% reserve margin that BREC currently maintains.

Roughly this amount of capacity, or more, could be achieved by keeping any two of the following four generation resources: the Coleman Station, the Green Station, the Wilson Station, and the contractual rights to power from elsewhere. That is, any two of those four resources, as well as the Reid Station, could be retired or sold, and BREC would still have adequate capacity to serve its non-smelter load.

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[2] The planning reserve margin is an estimate of the reserve capacity needed to meet the one day in 10 years standard for loss of load expectation. MISO, "Planning Year 2013 LOLE Study Report," p.14, https://www.misoenergy.org/Library/Repository/Study/LOLE/2013%20LOLE%20Study%20Report.pdf, accessed May 21, 2013.

Q. Can BREC justify keeping some of its excess capacity in order to generate electricity for sale outside its service territory?

A. No. This strategy has failed, on multiple grounds. Even with both smelters present, BREC sold 18% of its MWh of generation in 2010 and 23% in 2011 to customers other than its members and smelter contracts (BREC 2011 financial statement, application tab 35, p.61). To replace the smelters, BREC would need very large increases in these off-system sales. In effect, BREC is gambling on the ability to either profitably sell into the market or sign up new customers for a massive amount of energy generation. This gamble is unjustified in light of market conditions and BREC's marketing experience (discussed in this section), BREC's apparent failure to account for the full set of costs facing its coal units (discussed in Section 4), and BREC's failure to produce any production cost modeling supporting its strategy (discussed in Section 6).

Q. Please describe the market conditions that are unfavorable for BREC's plans to increase off-system sales.

A. Ample capacity is available in neighboring states and service territories, and the market price of electricity in MISO is quite low. This is documented in the 2011 "State of the Market" report (published in June 2012, the latest available) by MISO's independent market monitor, Potomac Economics: MISO met its July 2011 all-time record peak demand, during a period of record high temperatures, without any emergency procedures or involuntary load reductions; "this is partly because MISO currently has a sizable capacity surplus, as is reflected in [near-zero] capacity prices."[3] In MISO's 2013-2014 planning resource auction, the clearing price for capacity was a mere $1.05/MW-day.[4] The MISO capacity surplus seems likely to last for some time; a recent NERC assessment of long-

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[3] Potomac Economics, "2011 State of the Market Report for the MISO Electricity Markets," June 2012, p.ii, http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, accessed May 20, 2013.

[4] "2013/2014 MISO Planning Resource Auction Results," https://www.midwestiso.org/Library/Repository/Report/Resource%20Adequacy/2013-2014%20MISO%20Planning%20Resource%20Auction%20Results.pdf, accessed May 22, 2013.

term reliability found that MISO's reserve margins will be at or above NERC's "reference margin level" through 2021.[5]

Other fundamental factors that depress the potential for BREC's off-system sales include the low price of natural gas, which leads to lower electricity prices, and the increasing recognition of the potential for energy efficiency and demand-side management (DSM) programs, which directly reduce the demand for electricity. (I will discuss energy efficiency and DSM options in Section 4, below.)

Q. How much of an increase in off-system sales would be required to replace the smelters?

A. In 2011, BREC sold 6,855 GWh of energy to the smelters, compared to 3,056 GWh in off-system sales (BREC 2011 annual report, p.61, application tab 35). Thus BREC would need to more than triple its off-system sales to replace the amount of energy sold to smelters. Since prices for off-system sales are currently lower than rates paid by the smelters in the recent past, an even greater increase would be needed to replace the dollars of revenue received from the smelters.

Q. Is BREC projecting a major increase in off-system sales and revenues in the near future?

A. No. In the response to AG 1-18, BREC stated, "Big Rivers' off-system sales margins are not forecasted to increase significantly for the next few years because depressed wholesale market prices will drive low sales volumes and margins per MWh." BREC's data and projections confirm this pessimistic outlook. In the forecasts developed for this case, BREC projects off-system sales volume of only [redacted] GWh in 2013 and [redacted] GWh in 2014, [redacted] (confidential response to PSC 1-57). Revenue per MWh of off-system sales declined to $33.30 in 2011, down from $37.90 in 2010 and $48.03 in 2007 (BREC 2011 financial statement, p.32). [redacted]

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[5] NERC, "2012 Long-Term Reliability Assessment," November 2012, pp.57-58, http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012_LTRA_FINAL.pdf, accessed May 21, 2013.

[redacted]

Q. How successful has BREC been in recent attempts to increase off-system sales?

A. In response to a request for information about recent off-system electricity marketing efforts (PSC 2-18), BREC listed [redacted] potential customers it had contacted. At least [redacted] of them appeared to have definitely turned down BREC's proposals, while [redacted] had definitely accepted, as of February 28, 2013 (the date of BREC's data response).

Q. Has BREC faced the problem of excess capacity before?

A. Yes, this is a longstanding problem for BREC. In its 2010 bond prospectus BREC says that its 1996 bankruptcy "was precipitated largely by our inability to sell our capacity in excess of that required to serve our Members at prices sufficient to cover all of our costs" (BREC application, tab 33, p.8).

Under the 1998 reorganization plan that resolved the bankruptcy, BREC leased its generation assets to Western Kentucky Energy Corporation (WKEC, then a subsidiary of LG&E Energy, later a subsidiary of E.ON), and purchased power to serve its customers from another LG&E subsidiary (bond prospectus, tab 33, pp.8-9). This agreement transferred the costs of maintaining and operating BREC's excess capacity to WKEC: BREC could buy the amount of power it needed, while WKEC bore the unprofitable burden of marketing the excess power from BREC's plants. This may explain the willingness of E.ON to compensate BREC with more than $860 million in the Unwind Transaction of 2009 (BREC bond prospectus, p.10). The Unwind eliminated the last 14 years of the 25-year reorganization plan; thus E.ON found it worthwhile to pay more than $60 million per year of early release from this agreement.

Since the Unwind, off-system electricity sales have been important to BREC, even with both smelters present. In view of the market conditions I described above, there is little prospect for revival in BREC's off-system sales revenues.

Q. Has the risk of adverse market conditions and declining load been brought to BREC's attention in the past?

A. Yes. The December 2011 report[6] by the Commission staff on the BREC 2010 IRP notes that

> "Big Rivers has experienced large declines in the demand for electricity in the past and is well aware of the price sensitivity of its direct-serve customers and other large customers. One purpose of a long-range load forecast's sensitivity analysis is to investigate how a utility will be affected by adverse conditions and then to plan accordingly. The EPA has been openly working on implementing new air and water quality regulations for some time. It seems short-sighted to update the load forecast biennially only and to not attempt to incorporate the effects of these new regulations, the effects of which could have serious impacts on Big Rivers' regional economy and on Big Rivers' service territory specifically. Waiting until events are known tends to defeat the purpose of prudent risk analysis and planning." (p.21)

The report then recommends that

> "Big Rivers should run forecast simulations in its sensitivity analysis in order to gain a better understanding of the probability of occurrence for the various scenarios, including the potential closure of one or both of the aluminum smelters on its system." (p.22)

Q. Are some BREC plants needed by MISO for reliability purposes?

A. MISO reliability studies that would answer this question are just beginning, and are not available to the public (see responses to SC 2-15 and 2-16). BREC has confirmed, however, that if the Company planned to idle or retire a unit that was found to be needed for reliability purposes, it would expect to receive

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[6] Kentucky Public Service Commission, "Staff Report On the 2010 Integrated Resource Plan of Big Rivers Electric Corporation, Case No. 2010-00443," December 2011, http://psc.ky.gov/agencies/psc/industry/electric/irp/201000443_122011.pdf, accessed May 23, 2013.

reimbursement from MISO to keep the plant operational until any necessary reliability fixes were made (see response to SC 2-17c).

MISO does not appear to be concerned about transmission issues involving BREC. In MISO's detailed 2012 Transmission Expansion Plan, there is only one comment on Big Rivers, in the section on "NERC Reliability Assessment Results Overview." That comment reads in full:

"Big Rivers Electric Corporation (BREC)
There are no thermal or voltage issues requiring network expansions."[7]

In response to PSC 2-21(f)(1), BREC provided a memo describing the results of power flow studies performed by the Company to evaluate the idling of either the Coleman station or the Wilson station. The memo indicates that if both smelters continue operating at current levels, there could be unacceptable line overload conditions if certain other major lines were out of service and the Coleman plant were idled. However, BREC acknowledges that it has not explored alternatives that could mitigate these potential reliability concerns (see response to SC 2-16(d)). BREC should work with MISO to develop cost estimates for transmission reinforcement and/or upgrade projects that could alleviate these reliability concerns. These transmission upgrades may be significantly more cost effective than continuing to run the Coleman plant—especially in light of the substantial control costs that will be needed to keep Coleman in compliance with current and future environmental regulations, as discussed in the next section.

4. COSTS TO MAINTAIN AND UPGRADE BREC'S POWER PLANTS

Q. How much will it cost to bring BREC's plants into compliance with current and anticipated environmental regulations?

A. BREC's proposed expenditure of about $60 million on MATS compliance is only the beginning of an extensive and expensive process of upgrades that will be

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[7] "MISO Transmission Expansion Plan 2012," p.43, https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP12/MTEP12%20Report.pdf, accessed May 21, 2013.

required to continue running these plants. The total cost, according to BREC's own consultant in a previous case, will likely be more than $500 million.

In its recent application for a Certificate of Public Convenience and Necessity (Case 2012-00063), BREC submitted an Environmental Compliance Study performed by the consulting firm Sargent & Lundy ("S&L Study", attached as Exhibit Ackerman-3).[8] The S&L Study assessed the potential impacts of various recently issued, proposed, and pending environmental regulations on BREC's fleet and recommended compliance strategies for meeting those future regulations. The S&L Study evaluated the impacts of several regulations, including the Cross-State Air Pollution Rule ("CSAPR"), the Ozone and Particulate Matter National Ambient Air Quality Standards ("NAAQS"), the Utility Maximum Achievable Control Technology rule (now called the Mercury and Air Toxics Standard - "MATS"), the Clean Water Act Section 316(b) cooling water intake structure regulation ("316(b)"), and the proposed rule regarding Coal Combustion Residuals ("CCR").

Q. Are compliance costs for CSAPR still relevant, since that regulation was overturned in the courts last year?

A. While CSAPR was vacated by the U.S. Court of Appeals for the D.C. Circuit in August 2012, the EPA is required to adopt a replacement rule to address the impact of transported pollutants on downwind states. Since EPA recently adopted a more stringent particulate matter NAAQS[9] and is expected to propose a more stringent Ozone NAAQS this year, the replacement for CSAPR is likely to be more stringent than the vacated rule. In the S&L Study, the impact of more stringent Ozone and PM NAAQS was accounted for by decreasing emission allocations available under CSAPR by 20 percent. At this time, this serves as a reasonable proxy for estimating the possible costs to BREC from the anticipated CSAPR replacement rule.

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[8] Sargent & Lundy, "Big Rivers Electrical Corporation Environmental Compliance Study," February 13, 2012, http://psc.ky.gov/pscscf/2012%20cases/2012-00535/20130306_Big%20Rivers_Response%20to%20AG%201-179.pdf.
[9] 78 Fed. Reg. 3806 (January 15, 2013).

Q. Please summarize the compliance costs estimated in the S&L study.

A. The table below summarizes the S&L Study's estimated capital costs (in millions of dollars) for the recommended strategy to bring the BREC units into compliance with the identified regulations:

Regulation	Coleman	Wilson	Green	HMP&L	Reid	TOTAL
CSAPR + NAAQS	29.6	139.0	162.0	6.3	1.2	**338.1**
MATS	28.3	11.2	18.5	0.5	N/A	**59.5**
316(b)	8.0	N/A	2.0	2.0	2.0	**14.1**
CCR	38.0	N/A	28.0	28.0	N/A	**94**
TOTAL	**103.9**	**150.2**	**210.5**	**36.8**	**3.2**	**505.8**

Q. Are there additional environmental regulations that may impose costs beyond those identified in the S&L Study?

A. The S&L Study estimates do not include costs necessary for compliance with the recently-proposed Effluent Limitation Guidelines and Standards (ELG) for steam electric power plants. However, the Study did find that limits on discharge of mercury, sulfates, chlorides, and other constituents could require the installation of advanced wastewater treatment/removal systems at all of BREC's plants. These systems represent costs BREC will have to incur to continue operating all of its plants, in addition to the $506 million identified in the S&L Study. In its response to SC 2-9, BREC acknowledged that it has no estimate of the cost of ELG compliance.

In addition, the S&L Study did not estimate the costs of complying with future regulations of CO_2 through federal legislation or EPA rulemaking. CO_2 regulation will have a significant impact on the economics of coal-fired units. While there is not currently a federal law or proposed rulemaking governing CO_2 emissions at existing power plants, discussions at the EPA and at the Congressional level are ongoing, and there is a real possibility of such regulations being adopted within the remaining lifetime of BREC's plants.

The most recent legislative proposal to reduce emissions of CO_2 has taken the form of a Clean Energy Standard (CES), as introduced by Senator Bingaman on March 1, 2012. A CES encourages the use of low-carbon power through the allocation of clean energy credits to those generation technologies that emit less CO_2, which generation owners would consider in their dispatch decisions. In Senator Bingaman's bill, credits are determined based on individual power plant emissions and generating sources are given a certain number of credits based on their carbon profile, with lower emitting sources rewarded with a larger number of clean energy credits. In any given year, electric utilities would be required to hold a certain number of clean energy credits for a specific percentage of their sales.

Furthermore, the EPA recently proposed the first ever greenhouse gas new source performance standards ("NSPS") under Clean Air Act Section 111(b). The NSPS sets unit-specific performance standards for significant new sources of greenhouse gases. EPA is also required to establish a NSPS program for *existing* sources of greenhouse gases under Clean Air Act Section 111(d). While EPA has yet to propose such a program, it is widely anticipated that performance standards for existing plants are on the horizon. The Edison Electric Institute recently produced a white paper describing possible scenarios for GHG regulation under 111(d) and anticipating a proposal "sometime in 2013."[10]

Q. Does BREC face additional costs of maintaining its plants, beyond the level required for compliance with environmental regulations?

A. Yes. In order to meet the minimum financial margins required by its loan agreements, BREC has drastically cut back on maintenance at its plants. Since the Unwind Transaction in July 2009, BREC has delayed, reduced in scope, or cancelled 22 of its 24 scheduled maintenance outages – solely for financial reasons (Berry testimony, pp.7-8). Catching up on the resulting agenda of deferred maintenance will require an expenditure of about [redacted] by 2016, in addition to $212 million of scheduled "asset replacement and capital improvements" and [redacted] of routine, non-outage maintenance costs over the next four years (Berry testimony, pp.14-16).

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[10] Edison Electric Institute, *Existing Source GHG NSPS White Paper*, November 19, 2012, available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf, accessed May 22, 2013.

Q. What conclusions do you draw from the costs of environmental compliance and deferred maintenance at BREC's power plants?

A. It is critical to factor in the full range of costs facing BREC's coal units in evaluating whether it is reasonable to project that they are going to be profitable again. The greater those costs are, the higher the hurdle facing the plants.

BREC has not submitted production cost modeling in this case that would allow a comprehensive evaluation of the economics of its power plants. In testimony in last year's CPCN case, however, my colleagues Rachel Wilson and William Steinhurst, both of Synapse Energy Economics, described numerous flaws and questionable assumptions in BREC's modeling of the costs of these plants (see Wilson and Steinhurst testimony in 2012 CPCN case, attached as Exhibits Ackerman-4 and Ackerman-5).

In one noteworthy error identified by Ms. Wilson, BREC used the PACE Global price forecast, which incorporated an assumed CO_2 price in into its projection of future electricity prices – but BREC's production cost modeling of its own plants, in the same case, assumed that there was no CO_2 price (Wilson testimony, p.23). I believe it is reasonable to assume that future electricity prices will include a CO_2 price; it is also reasonable to assume that this price will apply to BREC as well as everyone else. This, of course, increases the estimated costs of operating BREC's plants.

Ms. Wilson recalculated BREC's plant costs, correcting modeling flaws and using better input assumptions, such as the use of the Energy Information Administration's *Annual Energy Outlook 2012* natural gas price forecast in place of BREC's PACE Global forecast. In her recalculation, every one of BREC's coal units was uneconomic compared to replacement with a natural gas combined cycle plant. This suggests that BREC's plants will not be able to compete with natural gas plants in bidding for off-system electricity customers: natural gas plants, with lower costs than BREC, will be able to sell electricity at a lower price than BREC.

Q. What role should BREC include for energy efficiency, as it develops its future resource plans?

A. In the 2012 CPCN case, Dr. Steinhurst explained that BREC was inappropriately dismissive of the potential of demand-side management (DSM) and energy efficiency, arguing that BREC should be able to achieve much greater efficiency savings. He referred to BREC's projected savings of 0.01% of non-smelter sales as "barely a token amount," since industry leaders have been able to save energy equal to 1% of retail sales, and numerous states have programs saving more than 0.5% of sales (Steinhurst testimony, 2012 CPCN, pp.11-12). If future electricity prices rise as dramatically as BREC is hoping, more ambitious energy efficiency programs will become cost-effective – for BREC, as well as its prospective off-system customers.

In this case, in response to a question (SC 1-13) about its DSM budget of $1 million, BREC responded that the budgeted amount "was selected to represent approximately 1% of revenue from the rural load" (response to SC 1-13a), and "is not adequate to achieve all cost-effective energy savings from DSM" (response to SC 1-13b). In short, BREC acknowledges that its DSM spending is arbitrary in amount, and insufficient to maximize cost-effective energy savings. Increases in DSM effort and expenditure will be a bargain for BREC's customers, in contrast to continued investment in maintaining and retrofitting BREC's uneconomic coal plants.

Q. Has BREC responded appropriately to the costs it will incur to maintain its plants?

A. No; it appears to be gambling on future increases in electricity prices, offering only to idle one plant for a few years. In effect, BREC is now planning to double down on a bet it has been losing since the 1990s. Under BREC's proposal, its customers will have to pay the costs of maintaining an idled plant for some years to come, in order to continue making this bet. Market conditions, however, give no grounds for believing that BREC's luck is about to change. This is not a prudent gamble for a financially constrained utility to make.

Q. Is it reasonable to guess that capacity will soon become scarcer and electricity prices will rise, after the current wave of coal plant retirements resulting from tighter environmental regulations and cheap natural gas?

A. If there is such an opportunity, how many other utilities will anticipate the same trends, and will also see it as a reason to keep their coal plants on-line? If enough utilities keep their coal plants on-line in the hopes of being able to profit from a future capacity shortfall, then there will be no shortfall, and no future profits from this strategy.

Even if other utilities do not pursue this strategy, hopes of future price increases appear to be exaggerated. As I noted above, MISO has substantial excess capacity at present, so that some retirements can occur without creating shortfalls; this is all the more true because new renewable and gas capacity is being added by some MISO utilities. Also, if electricity prices rise, energy efficiency and demand reduction measures will become increasingly cost-effective; many utilities, including BREC, have only begun to explore the potential of this resource. As efficiency measures are more widely adopted, the demand for electricity will be curtailed.

In short, it is imprudent for a utility with resources as limited as BREC's to gamble the ratepayers' money on a (chronically inaccurate) hunch about future electricity markets and prices.

5. SUBSIDIES FOR SMELTERS: A QUESTION FOR STATE POLICY

Q. There have been suggestions in the media that the smelters may want to negotiate a return to BREC under new or improved terms. Should BREC preserve the capacity needed to serve the smelters, to allow their return?

A. Not unless the smelters are willing to commit to return, on terms that do not unreasonably shift costs and risk to other ratepayers. As I explained in Section 3, the generation resources needed to serve BREC's remaining (non-smelter) customers as of 2014 are vastly different in scope from the resources needed to serve BREC's current customers, including the smelters. It is an unreasonable burden on BREC's non-smelter customers to charge them for carrying the excess capacity that might be needed if the smelters change their mind at some future date.

Q. Under what terms should BREC be willing to take the smelters back into its system?

A. BREC, like any regulated utility, has one primary responsibility: to provide least-cost, reliable service to its customers. To avoid cross-subsidization and unfair burdens on any categories of customers, each customer class should pay the incremental costs of the service it receives, plus a fair share of the common, fixed costs of utility operation.

If the smelters want to return to BREC, then BREC should calculate the revenue requirements for serving them as well as the rural and industrial customers. The smelters should be charged rates that recover the difference between BREC's with-smelters and without-smelters revenue requirements, plus the smelters' share of BREC's fixed costs that serve all customers. Charging them anything less forces the other customers to subsidize the smelters. To make the remaining customers whole, the smelters – like any other group of customers – must pay the full cost that they add to revenue requirements, plus their proportionate share of common costs.

If, as seems likely, the optimal without-smelters BREC system involves shedding excess capacity, then the cost to accept the smelters back into BREC could rise over time. As BREC progresses toward resizing itself for its non-smelter load, it may become more expensive to reverse course and serve the additional smelter load. This provides a financial incentive for the smelters to return promptly (if they intend to return), before BREC reduces its capacity.

Q. Is BREC adopting this approach in negotiations about the potential return of one or both smelters?

A. It is impossible to answer this question at present, due to BREC's initial refusal to discuss the negotiations. In response to questions about a tentative agreement between BREC and Century Aluminum – an agreement that was announced in a recent press release from Century Aluminum – BREC made the implausible assertion that such questions "are not reasonably calculated to lead to the discovery of admissible evidence" (see the responses to SC 2-24, 2-25, and 2-26). A motion to allow supplemental discovery on this issue was granted by the Commission on May 22, so I anticipate receiving more information about this topic soon. Once BREC's responses have been received, it may be appropriate to supplement my testimony.

Q. Is it important to subsidize the smelters, in order to preserve jobs and incomes in Kentucky?

A. The commonwealth of Kentucky could make such a decision; many states have made similar decisions about major industries. In that case, the subsidy should be provided by the state government, not by the small fraction of the state's households and businesses that happen to fall in the same service territory as the smelters. That is, a subsidy intended to preserve jobs should be made from state economic development funds, not from increases in neighboring ratepayers' electric bills.

Indeed, the current agreements are already very favorable to the smelters, to the potential detriment of BREC's financial health. As explained by BREC witness Billie Richert, the existing smelter agreements effectively limit BREC's margins to 1.24 times their interest obligations (Richert testimony, pp.6-9). This is a lower margin than is achieved by numerous other generation and transmission cooperatives (see exhibit Richert-2). There is a very narrow window between the minimum margin of 1.10 times interest payments that is required to comply with BREC's financial obligations and be eligible for further financing, and the maximum margin of 1.24 times interest that is imposed by the smelter agreements (Richert testimony, pp.23-25). There appears to be little or no slack remaining to offer an even better deal to the smelters – except by imposing additional costs on the non-smelter customers.

Q. Are you endorsing state subsidies to keep the smelters in business?

A. I am not expressing a position for or against such subsidies; that is a complex question of state policy, involving considerations that extend well beyond the scope of this hearing. I would, however, note two concerns in relation to subsidies for smelters.

First, the argument that the smelters need lower electric rates to remain internationally competitive should be carefully examined. Information about electric rates paid by smelters elsewhere is difficult to obtain. An article in the trade press in 2009 (attached as Exhibit Ackerman-6) concluded that at that time, aluminum smelters in China and Australia were paying $0.050 - $0.055 per kwh for electricity, i.e. $50 - $55 per MWh.[11] [redacted]

Second, the Kentucky state government has recently produced a thoughtful economic development plan, which does not place a priority on, or even mention, the aluminum industry. Adopted in 2012 after incorporating extensive stakeholder input, *Kentucky's Unbridled Future* identifies 10 strategic sectors for Kentucky's economic development, in the areas of advanced manufacturing (much of it automobile-related), sustainable manufacturing (much of it related to energy efficiency and renewable energy), technology (focusing on life sciences), transportation, and healthcare services.[12] The low cost of electricity is mentioned at the end of the list of Kentucky's advantages in most of these sectors; other advantages such as research strengths, clusters of complementary industries, the state's central location, and excellent transportation logistics are featured more prominently.

In view of this detailed statement of priorities, it is possible but by no means certain that the state would decide to subsidize aluminum smelters. One of the strongest arguments for such subsidies, from this perspective, might be that the state's aluminum industry is an important supplier to the high-priority automobile and renewable energy industries. In any case, this is a decision that belongs in the

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[11] Stuart Burns, "Power Costs in the Production of Primary Aluminum," *MetalMiner*, February 26, 2009, http://agmetalminer.com/2009/02/26/power-costs-the-production-primary-aluminum/.

[12] For the official announcement of *Kentucky's Unbridled Future,* see http://www.thinkkentucky.com/newsroom/NewsLetters/Jan2012/NLJan2012.htm. For the document itself, see http://boyettestrategicadvisors.com/wp-content/uploads/2012/07/Kentuckys-Unbridled-Future-REVISED2.pdf. (Both accessed May 9, 2013). The word "aluminum" literally does not appear in *Kentucky's Unbridled Future*.

realm of Kentucky's statewide economic development planning and funding, not in electric rate design for one limited part of the state.

6. BREC'S OPTIONS: FINDING THE LEAST BAD CHOICE

Q. If BREC's off-system sales are not sufficient to support its current capacity after the departure of one or both smelters, what should it do?

A. There are three choices, none of them good. The question is: which choice is least bad? BREC could idle, or mothball, some of its plants, planning to bring them back into service in the future. Or it could sell some of its coal plants at whatever price it can get for them, even if this is far below book value. Finally, it could retire and decommission some of its plants. While none of these paths is attractive, BREC has an obligation to its remaining customers to evaluate any options that would result in lower rates.

Q. Has BREC considered any of the choices you have proposed?

A. BREC has continued to engage in what I consider wishful thinking about the potential for increased off-system sales (see response to PSC 2-18 on the failure, to date, of expanded off-system sales marketing). As discussed earlier, there is no evidence that this will be fruitful for them.

BREC has proposed mothballing the Wilson plant, a proposal that seems puzzling. Wilson is their newest, most efficient plant; it might therefore seem like the last, not the first, plant to idle. A news story on this rate case (attached as Exhibit Ackerman-7) suggests that the choice may have been somewhat arbitrary. The story quotes Marty Littrell, BREC Manager of Communications and Community Relations, as saying about the proposal to mothball a plant, "We still don't know if it would be Wilson or not. We had to put something down for the rate case, and that's what we put down. But that could change."[13] If accurately quoted, that statement suggests a remarkable lack of rigorous analysis in preparation of the application for a major rate increase.

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[13] Chuck Stinnett, "Big Rivers seeking $74 million annual increase in wholesale electric rates," *Evansville Courier & Press,* January 16, 2013, http://www.courierpress.com/news/2013/jan/16/big-rivers-seeking-74-million-increase-in-rates/.

BREC has also rejected the option of retirement of any coal units. Explaining this position, in response to SC 1-23(b), BREC stated:

> "Big Rivers has not evaluated the retirement, rather than idling, of any of its generating units as an option for mitigating the impact of the termination of the Century contract and/or the decline in off-system sales. Despite the fact that current wholesale electricity market prices are low, Big Rivers' generating units have significant remaining useful life and Big Rivers' members would be unduly harmed if Big Rivers were to retire assets instead of temporarily idling them. Although Big Rivers' members will continue to incur some costs over the next three years associated with idled units, Big Rivers' members will be able to reap significant benefits from the units in the future, either by selling wholesale power and using the proceeds to reduce member rates or by supporting the Western Kentucky economy by supplying power to industries."

In other words, BREC is proposing to throw good money after bad on the projection that it will be able to profitably sell energy into the market or to new customers in a few years, yet they have provided no evidence to support that assumption and there is little reason to expect that to be true. BREC has engaged in relatively little long-range planning; it acknowledges performing 15-year production cost model runs to determine when idled plants would return to service, but refuses to provide such model runs on the grounds that they are not relevant to this proceeding (response to SC 2-2).

Q. Is long-run analysis, such as 15-year modeling, normally required for utility planning?

A. Yes. Power plants and transmission lines are large, long-lived investments; it is not possible to make good decisions about them in the absence of long-term planning. The Kentucky statute governing integrated resource planning by electric utilities, 807 KAR 5:058, repeatedly makes this clear. Sections 7 and 8 of 807 KAR 5:058, specifying the data requirements for integrated resource planning, identify 7 separate categories of information that must be forecast for 15 years, including base load, summer and winter peak demand, energy sales and generation, detailed description of available generating facilities, energy inputs by fuel type, and actions to be taken to comply with the Clean Air Act.

In this context, it should be noted that BREC requested to delay its IRP filing until 2014 (a request granted by the Commission) so that it can first figure out how to respond to the smelter terminations. If this delay to allow better analysis and planning makes sense for the IRP filing, it is equally sensible for any rate increase that responds to the smelter terminations.

Q. Has BREC performed any long-run analyses in this case?

A. Although BREC has argued that this rate case is only concerned with revenue requirements for the next few years, it has also supplied a longer-term analysis in response to AG 1-89. That analysis, the "Load Concentration Analysis and Mitigation Plan" (LCAMP) of June 2012, [redacted]

[redacted]

[redacted]

[redacted]

Q. What support does BREC offer for its projection that the Wilson plant, if idled, could profitably return to service in 2019?

A. In response to SC 1-21d, BREC says, "Based on the present ACES market price forecasts, Wilson is currently scheduled to re-start in 2019…" However, BREC also seems to deny the use of any price projections beyond 2014 in the current rate case. In response to SC 1-21e, asking about "any forecasted market prices in MISO for 2015, 2016, and any future years beyond 2016" and the use of such forecasts in this application, BREC responded, "The process for 2015, 2016, and any future year beyond 2016 are not incorporated into this application because the forecasted test period includes September 1, 2013 through August 31, 2014 exclusively."

[redacted]

[redacted]

[redacted]

Q. Do you have any comments on the PACE Global energy price projections?

A. I have not had an opportunity to examine these price projections. However, in the 2012 CPCN case, my colleague Rachel Wilson examined the PACE Global forecast of natural gas prices, used by BREC in that case. She recommended against use of that forecast, since it is higher than other forecasts developed in 2011 and 2012. For example, the PACE Global natural gas price forecast is higher than the Energy Information Administration's *Annual Energy Outlook* 2011 and 2012 gas price forecasts (Wilson testimony in 2012 CPCN case, pp.21-22.) Since the price of electricity is based, to a significant extent, on the price of natural gas, an excessively high forecast for natural gas translates directly into an excessively high forecast for electricity prices.

7. POTENTIAL REVENUE FROM POWER PLANT SALES

Q. How much could BREC expect to receive from the sale of some of its coal plants?

A. There are only a handful of recent transactions involving sale of existing coal plants between separate companies.[15] The individual transactions are often large and complex, allowing some difference of opinion in estimating the actual price paid for the plants. In the recent cases, it appears that the price per kw of capacity has been around $100 - $160, even for relatively large coal plants with scrubbers.

Q. Please describe those recent sales of coal plants, and the prices paid for them.

A. In August 2012, Exelon sold three Maryland power plants with a total capacity of 2,648 MW, of which more than 2,000 MW is coal (the remainder consists of oil

[15] Much higher prices have been proposed at times for internal sales, for instance between regulated and non-regulated subsidiaries of the same parent corporation. Such sales, however, may not reflect true market prices, since the parent corporation is effectively paying itself, and may benefit financially from moving assets from one subsidiary to another.

and gas-fired units at those plants), for $400 million.[16] The average price was thus $151/kw.

In March 2013, Dominion Resources sold three power plants, the Brayton Point and Kincaid coal-fired plants (totaling 2,628 MW) and a 50% interest in the Elwood gas-fired plant (the plant's total capacity is 1,424 MW) to Energy Capital Partners. According to Dominion, its after-tax proceeds will amount to about $650 million.[17] A *Platts* financial newsletter story estimated the true purchase price at about $450 million, or $132/kw of capacity.[18] A *Wall Street Journal* article commented on this transaction that "after stripping out tax benefits, the implied underlying price paid per kilowatt of capacity was just over $100."[19]

Also in March 2013, Ameren agreed to divest an Illinois-based subsidiary to Dynegy; that subsidiary owns five coal-fired plants totaling 4,100 MW, 80% of another 1,186 MW coal- and gas-fired plant, an energy marketing business, and a retail energy business. Dynegy did not making any cash payment to Ameren, but has assumed $825 million in debt associated with the coal plants. If $825 million is interpreted as the purchase price for the 5,050 MW of capacity that Dynegy acquired, then the price was $163/kw.[20]

Q. How does BREC's current valuation of its plants compare to their potential sale prices?

A. In the cost of service study submitted in this rate case, BREC calculates its total utility plant rate base, excluding transmission, and net of accumulated depreciation, at $978,881,050 (Exhibit Wolfram-3, p.2). For 1444 MW of

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[16] See Exelon's press release, August 9, 2012, at http://www.exeloncorp.com/newsroom/PR_20120809_EXC_Mdcoalplantsale.aspx (accessed May 15, 2013).
[17] See Dominion's press release, March 11, 2013, at http://dom.mediaroom.com/2013-03-11-Dominion-To-Sell-Three-Merchant-Power-Stations-To-Energy-Capital-Partners (accessed May 15, 2013).
[18] "Recent plant sales establish new floor for coal assets," *Platts,* March 14, 2013, http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/6260790 (accessed May 15, 2013).
[19] Liam Denning, "There is Life After Death for Coal Power," *Wall Street Journal*, March 31, 2013, http://online.wsj.com/article/SB10001424127887323361804578390561956760382.html (accessed May 15, 2013).
[20] See Dynegy's press release, March 14, 2013, http://phx.corporate-ir.net/phoenix.zhtml?c=147906&p=irol-newsArticle_Print&ID=1796097&highlight= (accessed May 15, 2013).

capacity, this amounts to $678/kw, or more than 4 times the price per kw of recent coal plant sales. The net book value of the Reid, Coleman, Green, and Wilson coal-fired units, at the start of 2013, was $791,986,950 (SC 2-6). This amounts to $548/kw, or more than 3 times the price per kw of recent sales.

8. IMPLICATIONS OF BANKRUPTCY FOR RATEPAYERS

Q. If BREC sells or closes some of its plants, would it be forced back into bankruptcy?

A. This is a difficult question which depends on many unknowns, including the choice of which units to dispose of, and the prices at which they can be sold. It depends, as well, on BREC's ability to renegotiate any of its current debts. The risk of bankruptcy, however, is real and cannot be ignored. At the end of 2012 BREC had long-term debt of $925 million, owed to CFC, RUS, CoBank, and Ohio County (Kentucky) bonds sold on BREC's behalf; against these debts BREC had $189 million of cash, investments, and reserves, excluding the reserves from the Unwind that are pledged to ratepayers (KIUC 2-45, attachment pp.29, 31). Thus BREC appears to have net debts of $736 million. Selling all of its generation capacity at $160/kw would bring in an amount equal to only about one-third of BREC's net debt.

Q. BREC voluntarily assumed these debts, in some cases quite recently. Isn't the company obligated to do whatever is necessary to repay its debts – even if that means much higher rates for its remaining ratepayers?

A. Under ordinary circumstances, this would certainly be true. A small loss of load or temporary reduction in sales would not provide legitimate grounds for contemplating bankruptcy.

On the other hand, consider an extraordinary worst-case scenario, in which an unpredictable event such as an earthquake suddenly removes 99% of a utility's customers and sales. (Something close to this happened to Entergy New Orleans in the aftermath of Hurricane Katrina, leading to a bankruptcy that lasted almost two years.) Assume that the utility has substantial debts, incurred to provide and maintain service to the former customer base. In such a case, it seems clear that the remaining 1% of post-earthquake customers should not be expected to pay hugely inflated rates to repay the utility's debts. Those debts were undertaken to serve the vastly greater pre-earthquake load, and cannot be repaid by the survivors. Instead, the utility should eliminate the debts by selling most of its assets and/or declaring bankruptcy. This would allow the survivors to receive electric service at rates that are based on their current cost of service, not on debts that were only needed to serve the ghosts of the past.

Q. What is the relevance of this worst-case scenario to BREC's situation today?

A. The twin earthquakes of the two smelters' departures are taking BREC more than two-thirds of the way from the earlier status quo to my worst-case scenario (when measured by loss of load). In 2014, after both smelters depart, BREC's remaining customers are in danger of being forced to pay for debts incurred to serve BREC's two giant ex-customers. If, as seems unfortunately likely, off-system energy sales and asset sales cannot pay off these debts, then the option of bankruptcy must be considered in the discussion of strategies for serving BREC's remaining customers.

Q. Did BREC's previous bankruptcy impose economic hardships on its customers?

A. Not compared to more recent years. In fact, BREC's electric rates were lower in the years soon after the bankruptcy than they have been since the Unwind Transaction. From 2000 to 2008, under the agreement that resolved the bankruptcy, wholesale rates to members were low and stable, roughly \$35-\$36/MWh for rural customers and \$30-\$31/MWh for industrial customers (BREC 2008 Annual Report, p. 18, application tab 35). Since the Unwind, rates have shot upward; average wholesale rates reached \$46.78/MWh for rural customers and \$41.68 for industrial customers by 2011, prior to application of the reserves set up in the Unwind[21] (BREC 2011 Annual Report, p.32, application tab 35).

[21] The Unwind Transaction set aside funds reserved for rate reduction for BREC's customers, so the rates actually paid in 2011 were lower than the figures reported here; these reserves provide only temporary rate relief, and will be exhausted within a few years.

Other factors are also involved in the recent increase in rates: BREC's revenue from off-system sales has dropped due to the economic downturn and the decline in market prices for electricity; and the 2009 smelter agreements, as discussed above, have placed great pressure on BREC's finances. Yet the fact remains that BREC's previous bankruptcy did not impose high rates or unreliable service on BREC's customers.

Q. Have you calculated the cost of post-bankruptcy service for BREC's customers?

A. No, I have not. Such calculations were not possible within the tight time frame of this case. I recommend, however, that post-bankruptcy rates be estimated, in order to provide a standard against which to judge the proposals for rescuing BREC.

Q. How should the hypothetical post-bankruptcy rates be estimated?

A. Suppose, in the worst case, that bankruptcy resulted in the retirement or sale of all of BREC's generation assets. A reorganized BREC could still buy power from MISO and deliver it to the distribution cooperatives. The new BREC would need to charge its customers the MISO market price, plus the cost of transmission, plus reasonable administrative and general expenses and margin. The distribution cooperatives would add distribution costs, as at present. Calculation of such "no-generation" rates would be much simpler than BREC's current rate design process. If the rates required to keep BREC in business today are significantly higher than the no-generation rates based on MISO prices, then the ratepayers could experience lower rates after another bankruptcy.

Calculation of the no-generation costs and rates would also provide a useful benchmark against which BREC's power plants could be evaluated. Should a reorganized, post-bankruptcy BREC retain and operate a reduced generation fleet, sized appropriately for its reduced customer base? This should be allowed only if it would lead to rates comparable to or lower than the no-generation rates.

Q. Would retirement or sale of BREC's generation assets expose its customers to greater risks?

A. The only increased risk for customers from loss of BREC's plants would occur if MISO electricity prices rise well above BREC's costs of generation (including the substantial costs to bring BREC's plants into compliance with environmental regulations, described above). In that case, BREC customers would have to pay MISO prices, rather than having access to BREC's own generation. This is the future scenario – a dramatic rise in electricity prices, making old coal plants newly profitable – which BREC has been gambling on, without success, for years. As I have explained, current market conditions and projections do not provide any reason to think that BREC will do better on this gamble in the future.

Q. Does this conclude your testimony?

A. Yes, it does.

CERTIFICATE OF SERVICE

I certify that I mailed a copy of Direct Testimony of Frank Ackerman on Behalf of the Sierra Club- Public Version via US Mail on May 24, 2013 to the following:

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Editor of GDAE's *Frontier Issues in Economic Thought* book series, a coauthor of GDAE's macroeconomics textbook, and director of the institute's Research and Policy program. Taught courses in the Tufts Department of Urban and Environmental Policy and Planning.

Tellus Institute, Boston, MA. Senior Economist, 1985 – 1995.
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EXHIBIT 2

courier .com Read more at courierpress.com

Century Aluminum to buy Alcan's Sebree smelter

Century, Big Rivers, Kenergy reach 'framework' on Hawesville smelter's power

By Chuck Stinnett

Originally published 09:50 a.m., April 29, 2013
Updated 11:03 a.m., April 29, 2013

Century Aluminum Co. announced today that it has entered into a definitive agreement to acquire substantially all of the assets of the Sebree aluminum smelter from Rio Tinto Alcan.

The Sebree smelter employs more than 500 people and has an annual production capacity of 205,000 metric tons of primary aluminum. It has a $200 million economic impact on the region in salaries, purchases and taxes, according to Rio Tinto Alcan.

The announcement was made minutes after Century and power providers Big Rivers Electric Corp. and Kenergy Corp. jointly announced they have come to a framework for an agreement under which power for Century's 650-employee aluminum smelter at Hawesville, Ky., will be purchased on the open market instead of generated by Big Rivers.

Without such a deal, Century would be forced to close the Hawesville smelter on Aug. 20, exactly 12 months after the company notified Big Rivers that it was terminating their existing power contract.

Big Rivers President and CEO Mark Bailey emphasized that details of an agreement still need to be hammered out, and approval must be sought from the Kentucky Public Service Commission and Big Rivers' chief creditor, the federal Rural Utilities Service.

However, Bailey emphasized that with the departure of its two biggest customers — Century's Hawesville smelter and Alcan's Sebree smelter — over the next several months, Big Rivers will still be forced to seek a pair of large rate increases to make up for the loss of revenue. Alcan notified Big Rivers earlier this year that it will terminate its power contract effective Jan. 31, 2014.

Bailey estimated that combined, the two requested rate increases "could" increase residential electric rates as much as 40 percent for customers of Kenergy Corp. and two other rural electric co-ops that distribute Big Rivers' power. Big Rivers has already filed an application with the state PSC for a rate increase to make up for Century leaving its system, and Bailey said an application for a second increase to make up for the departure of the Sebree smelter next year will be submitted by late June.

Concerning the pending acquisition of the Alcan smelter, Century President and CEO Michael Bless said in a statement, “We are well acquainted with the Sebree smelter and its excellent management team and talented group of employees. We believe that, with these facilities under common ownership, we will derive real benefits in better serving customers and through improving both operations with the sharing of best practices in safety, technical and operational practices and procedures. My colleagues and I are anxious to welcome Sebree’s men and women into the Century group of companies.”

“We believe Sebree, like Hawesville, is globally competitive in every area other than the cost of power,” Bless said. “Maintaining operations at these plants, and the thousands of direct and indirect jobs they provide and support, is critical for the entire western Kentucky community. Gaining access to competitive energy is a crucial for the continued viability of these plants, and we hope that the tentative agreement we have reached for Hawesville will be the first step towards obtaining market priced power.”

“Sebree has been a solid operation over the years and this is expected to continue under the ownership of Century Aluminum,” Rio Tinto Alcan declared in a news release. However, following a strategic review of its aluminum operations in 2013, Rio Tinto decided that the Sebree smelter “no longer fits with the company’s long-term strategy.”

Pursuant to the terms of the agreement, Century will acquire the smelter for $61 million in cash (after $4 million in purchase price deductions) and will receive $71 million in working capital, subject to customary adjustments. As part of the transaction, RTA will retain all historical environmental liabilities of the Sebree smelter and has agreed to fully fund the pension plan being assumed by Century’s subsidiary at closing.

The transaction is subject to certain closing conditions, including the consent of Kenergy Corp. to the assignment of the smelter’s existing power contract, which will terminate on Jan. 31, 2014.

Still to be resolved is how the Sebree smelter will obtain power after that date.

“We’ve not been asked to deal with that,” Bailey said. “The framework we’ve reached is specific to Hawesville. However, if there is a request, we’d be happy to discuss that relative to Sebree, too.”

Century would become the fourth company to operate the Sebree smelter. The plant, located in southeastern Henderson County near the Webster County line, was opened in the early 1970s by Anaconda Aluminum. It became part of ARCO Metals (a division Atlantic Richfield) in the early 1980s, then was purchased by the former Alcan Aluminum in early 1985. International mining giant Rio Tinto acquired Alcan in 2007 as part of a $38 billion deal, saddling Rio Tinto with a large debt just as the global recession was beginning. Rio Tinto has been selling businesses and cutting costs since then; as part of that, Rio Tinto Alcan — the aluminum division of Rio Tinto — in October 2011 announced that it had determined that 13 operations, including the Sebree smelter, were "non-core assets" that would be either sold or closed.

Sebree was among the operations that a Rio Tinto Alcan spokesman said at the time were "sound businesses," but were "no longer aligned with our strategy and we believe they have a bright future under new ownership."

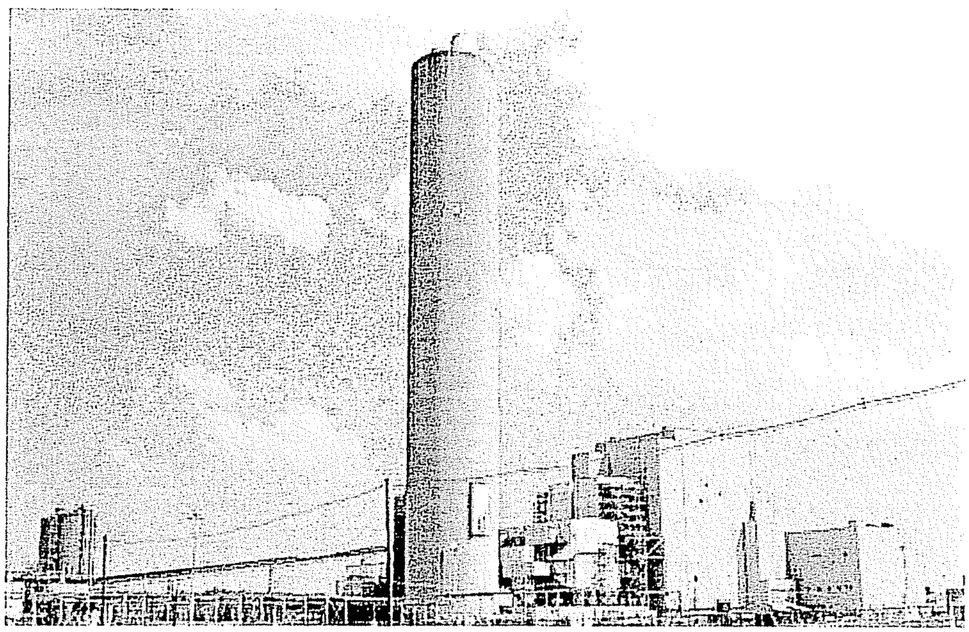
Century Aluminum owns primary aluminum capacity in the United States and Iceland. Century's corporate offices are located in Monterey, Calif.

Century stock is traded on the NASDAQ exchange under the ticker symbol CENX.

More information can be found at www.centuryaluminum.com.

EXHIBIT 3

Big Rivers Electrical Corporation Environmental Compliance Study



Prepared by: Sargent & Lundy, LLC
Revision: Final
Date: February 13th, 2012

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

Green, Henderson, Reid, Coleman & Wilson Stations

Environmental Compliance Study

Prepared for
Big Rivers Electric Corporation

SL-010881
February 2012
Project 12845-001

55 East Monroe Street

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GLOSSARY OF TERMS

ACI - Activated Carbon Injection: A mercury reduction process system that involves the injection of a very fine dry powdered form of carbon into the flue gas stream of coal burning power plants.

AFUDC – Allowance for Funds Used During Construction: Interest that occurs on capital project loans during the construction period.

BACT – *Best Available Control Technology:* BACT is a pollution control standard detailed in the Clean Air Act in which the Environmental Protection Agency (EPA) determines what air pollution control technology should be applied to control a specific pollutant to a specified limit.

BREC – Big Rivers Electric Corporation

BTA – *Best technology available*

CAIR – Clean Air Interstate Rule: A rule issued by the EPA in 2005 that was intended to implement the Clean Air Act requirements concerning the transport of air pollutants across state boundaries, and assist downwind states to attain and maintain the National Ambient Air Quality Standards for ozone and fine particulate matter. The rule was vacated by the U.S. Court of Appeals in 2008. See CATR – Clean Air Transport Rule.

CCR - Coal Combustion Residuals: Byproducts of the coal combustion process, including but not limited to fly ash, bottom ash, and wet flue gas desulfurization waste streams.

Cl – Chloride: Constituent of Coal.

CO - Carbon Monoxide: A flue gas pollutant.

CPM – Condensable Particulate Matter: See PM.

CSAPR – Cross-State Air Pollution Rule: Rule issued by the EPA that replaces the previously issued 2005 Clean Air Interstate Rule.

DSI - Dry Sorbent Injection: A process system that involves the injection of a dry sorbent into the flue gas stream of coal burning power plants. May be used for reduction of sulfur trioxide (SO_3) or other acid gases.

EGU MACT - Electric Generating Utility Maximum Achievable Control Technology: Proposed rule issued in March 2011 by the EPA setting emissions standards for certain pollutants, including mercury, particulate matter, acid gases, and several others. MACT standards for air pollution require a maximum reduction of hazardous emissions, considering cost and feasibility, and are set based on a review of existing sources.

EPA – United States Environmental Protection Agency

GLOSSARY OF TERMS (cont.)

ESP - Electrostatic Precipitator: A particulate matter control device installed in boiler flue gas systems.

FGD – Flue gas desulfurization

FPM – Filterable Particulate Matter: See PM.

fps – Feet per Second: Unit of measure.

HAP – Hazardous Air Pollutants: Hazardous emissions from power plants or other sources.

HCl – Hydrochloric Acid: An acid byproduct of coal combustion.

Hg – Mercury: Constituent of certain coals.

ICR - Information Collection Request: A request by the EPA for operating data from electric generating unit operators. Used to support the development of emission limits.

IM&E - Impingement Mortality and Entrainment: Injury, death, or entrainment of fish and other organisms. See 316 (b).

KPDES - Kentucky Pollutant Discharge Elimination System

lb/MMBtu - Pounds per Million British Thermal Units: A unit of measure.

lb/TBtu – Pounds per Trillion British Thermal Units: A unit of measure.

LNB – Low-NO_X burner

LNCFS - Low NO_X Concentric Firing System: A proprietary combustion system arrangement for Alstom (formerly Combustion Engineering) cyclone boilers. The equipment may include low NO_X burners, separated overfire air systems (see OFA definition, as well as other technologies depending on the generation of LNCFS system being considered. Currently there are four generations of this system that have been developed (LNCFS I, II, III, and IV).

MACT – Maximum Achievable Control Technology

MGD – Million gallons per day

MMBtu – Million British Thermal Units: A unit of measure.

NAAQS – National Ambient Air Quality Standards: Standard developed by the EPA to set the required levels of air quality.

GLOSSARY OF TERMS (cont.)

NO_X – Nitrogen Oxides

NPV -- Net Present Value: A present value is the value now of a stream of future cash flows, negative or positive, including initial costs of purchasing an asset.

O&M - Operating and Maintenance

OFA – Overfire Air: Also SOFA or Separated Overfire Air System. Various methods of staging combustion in a boiler for enhanced NO_X reductions.

ORSANCO – Ohio River Sanitation Commission: Discharges to the Ohio River are also regulated by ORSANCO. It sets Pollution Control Standards for industrial & municipal waste water discharges to the Ohio River.

pH: A measure of the acidity or basicity of an aqueous solution.

PM – Particulate Matter: Condensable or filterable particulate matter in flue gas stream. PM2.5 refers to fine particulate matter with diameters less than 2.5 micrometers; PM10 to matter with diameters less than 10 micrometers.

RCRA -- Resource Conservation and Recovery Act: The RCRA Act gives the EPA the authority to control hazardous waste from the "cradle-to-grave." This includes the generation, transportation, treatment, storage, and disposal of hazardous waste. Sets the framework for management of non-hazardous wastes.

ROFA – Rotating overfire air

S&L – Sargent & Lundy, LLC

SCR - Selective Catalytic Reduction: A NO_X reduction system that uses a reagent such as ammonia in conjunction with a catalyst reactor to convert NO_X into harmless nitrogen.

Sebree Generating Station: Encompasses the Robert D. Green Station, Robert A. Reid Station, and the HMP&L Station.

SNCR - Selective Non-Catalytic Reduction: A NO_X reduction process technology that involves the injection of a NO_X reduction agent such as ammonia or urea solution into a boiler.

SO_2 – Sulfur Dioxide

SO_3 – Sulfur Trioxide

SSC – Submerged Scraper Conveyor: A dry bottom ash handling technology.

GLOSSARY OF TERMS (cont.)

TBtu -- Trillion British Thermal Units: A unit of measure.

Title V: Operating permits for air pollution sources are issued under Title V of the EPA's Clean Air Act

TPM – Total Particulate Matter

tpy – Tons per year

WFGD - Wet Flue Gas Desulfurization: A wet scrubbing process for removing SO_2 from flue gas streams that uses an alkaline reagent introduced as a fine spray in an absorber vessel.

316(b) Regulations: Environmental regulations being developed by the EPA that require the cooling water intake structures to reflect the best technology available for minimizing adverse environmental impact. Adverse environmental impacts include the impinging of fish and other organisms on cooling system intake screens or pumping equipment, as well as the entrainment of fish and other organisms in the cooling systems. See Impingement Mortality and Entrainment (IM&E).

EXECUTIVE SUMMARY

Environmental regulations currently in place and being actively developed by the U.S. Environmental Protection Agency (EPA) and the U.S. Congress are expected to require additional reductions of several air pollutants for many electric utilities. These include sulfur dioxide (SO_2) and nitrogen oxides (NO_X), which are addressed under the Cross-State Air Pollution Rule (CSAPR) regulations, and total particulate matter (TPM), mercury (Hg), and hydrochloric acid (HCl), which are addressed under the EPA's proposed Electric Generating Utility Maximum Achievable Control Technology (EGU MACT) regulations. Additional EPA regulations are proposed to reduce impingement mortality and entrainment of fish, eggs, larvae, and other aquatic organisms that come in contact with a station's cooling water intake system. (Since this study was completed, the EGU MACT was replaced the Mercury and Air Toxins Standard (MATS). This report has not been updated to reflect the new MATS rule.)

The EPA is also proposing alternative approaches for regulating coal combustion residual (CCR) waste products. It is likely that CCR regulatory requirements for pond modification and operation, along with the pending wastewater discharge effluent guideline requirements, will make continued operation of the dewatering ponds impractical. Wastewater discharge effluent guidelines being proposed by the EPA will likely also impact the station's ability to discharge large volumes of ash sluice water to the environment, due to limits on total dissolved solids, metals, pH and other parameters, further necessitating the dry bottom ash conversions.

Phase I of this study provides a thorough assessment of the various expected future regulations as they apply to BREC. Phase II of this study draws on the conclusions developed in the Phase I regulatory assessment, and provides an evaluation of possible compliance strategies, using existing technologies, new technologies, or a combination of technologies. Phase III screens the viable technology selections based on an evaluation using order of magnitude capital and O&M costs. Where the screening results in multiple compliance strategies being proposed, a net present value (NPV) analysis is used to provide the optimal selection. The impact of any changes between the proposed or predicted rules considered in this study and the final rules that are promulgated should be evaluated and the conclusions adjusted accordingly.

The results are summarized along with the associated net present value (NPV). Currently planned O&M improvements are not considered in the costs described in this evaluation since S&L understands them to be already accounted for in the operating budget for current or upcoming fiscal years.

SULFUR DIOXIDE (SO_2)

In order to achieve compliance with their 2012 and 2014 CSAPR allocations, BREC will need to reduce their current SO_2 fleet-wide emissions from 27,286 tpy to 26,478 tpy in 2012–2013 and to 13,643 tpy for 2014 and beyond. Although potential reductions are speculative at this time, additional allocation reductions of 20% may follow the CSAPR regulations as part of National Ambient Air Quality Standards (NAAQS), which will require an even greater reduction in emission to meet the potential 10,914-tpy allocation in 2016–2018. To meet the forthcoming CSAPR emission allocations and the potential NAAQS reductions, BREC will need to make modifications to reduce emissions. A summary of the baseline emissions data, recommended modifications for CSAPR and NAAQS compliance, expected emission reductions, and the estimated NPV associated with the technology selections is provided below.

Table ES-1 — SO_2 CSAPR and NAAQS Compliance Strategy

Unit	Baseline SO_2 Emissions (tpy)	Current Annual SO_2 Emission Rate (lb/MMBtu)	Technology Selection	Estimated New SO_2 Emissions (tpy)	Estimated New Annual SO_2 Emission Rate (lb/MMBtu)	Net Present Value at Baseline Credit Value (2011$ Million)
Coleman Unit C01	1,473	0.250	None**	1,473	0.250	N/A
Coleman Unit C02	1,473	0.250	None**	1,473	0.250	N/A
Coleman Unit C03	1,571	0.250	None**	1,571	0.250	N/A
Wilson Unit W01	9,438	0.510	New Tower Scrubber - 99% removal	1,049	0.057	$82.5
Green Unit G01	1,873	0.186	None	1,873	0.186	N/A
Green Unit G02	1,414	0.139	None	1,414	0.139	N/A
HMP&L Unit H01	2,227	0.347	Run both pumps & spray levels, install 3rd pump as	788	0.123	-$2.1
HMP&L Unit H02	2,745	0.415	Run both pumps & spray levels, install 3rd pump as	835	0.126	-$2.1
Reid Unit R01	5,066	4.522	Natural Gas with Existing Burners	1	0.001	$8.9
Reid Unit RT	5	0.117	None	5	0.117	N/A
Fleet Total	**27,286**	**0.384**	**N/A**	**10,482**	**0.148**	**$87.2**

**Note SO2 emissions in this scenario have been adjusted to reflect data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%

UNIT 1 NITROGEN OXIDES

To achieve compliance with their 2012 and 2014 CSAPR NO_X allocations, BREC will need to reduce their current fleet-wide emissions from 12,074 tpy to 11,186 tpy in 2012–2013 and to 10,142 tpy for 2014 and beyond. Potential additional allocation reductions of 20% may follow the CSAPR regulations as part of NAAQS which will require an even greater reduction in emission to meet the potential 8,114 tpy allocation in 2016–

2018. To meet the forthcoming CSAPR emission allocations and the potential NAAQS reductions, BREC will need to make a number of modifications to reduce NO_X emissions. A summary of the baseline emissions data, recommended modifications for CSAPR and NAAQS compliance, expected emission reductions, and the estimated NPV associated with the technology selections is provided below.

Table ES-2 — NO_X CSAPR Compliance Strategy (2014)

Unit	Baseline NO_X Emissions (tpy)	Current Annual NO_X Emission Rate (lb/MMBtu)	Technology Selection	Estimated New NO_X Emissions (tpy)	Estimated New Annual NO_X Emission Rate (lb/MMBtu)	Net Present Value at Baseline Credit Value (2011$ Million)
Coleman Unit C01	1,858	0.330	Advanced Burners	1,672	0.297	$0.32
Coleman Unit C02	1,585	0.332	Advanced Burners	1,427	0.299	$0.32
Coleman Unit C03	2,044	0.335	Advanced Burners	1,840	0.302	$0.32
Wilson Unit W01	934	0.052	None	934	0.052	N/A
Green Unit G01	2,050	0.206	None	2,050	0.206	N/A
Green Unit G02	2,168	0.215	SCR @ 85% Removal	325	0.032	$43.90
HMP&L Unit H01	460	0.071	None	460	0.071	N/A
HMP&L Unit H02	418	0.069	None	418	0.069	N/A
Reid Unit R01	512	0.522	Natural Gas with Existing Burners	292	0.298	See SO_2
Reid Unit RT	45	0.708	None	45	0.708	N/A
Fleet Total	**12,074**	**0.177**	**N/A**	**9,462**	**0.139**	**$44.9**

Table ES-3 — NO_X NAAQS Compliance Strategy (2016–2018)

Unit	Baseline NO_X Emissions (tpy)	Current Annual NO_X Emission Rate (lb/MMBtu)	Technology Selection	Estimated New NO_X Emissions (tpy)	Estimated New Annual NO_X Emission Rate (lb/MMBtu)	Net Present Value at Baseline Credit Value (2011$ Million)
Coleman Unit C01	1,858	0.330	Advanced Burners	1,672	0.297	$0.32
Coleman Unit C02	1,585	0.332	Advanced Burners	1,427	0.299	$0.32
Coleman Unit C03	2,044	0.335	Advanced Burners	1,840	0.302	$0.32
Wilson Unit W01	934	0.052	None	934	0.052	N/A
Green Unit G01	2,050	0.206	SCR @ 85% Removal	307	0.031	$46.50
Green Unit G02	2,168	0.215	SCR @ 85% Removal	325	0.032	$43.90
HMP&L Unit H01	460	0.071	None	460	0.071	N/A
HMP&L Unit H02	418	0.069	None	418	0.069	N/A
Reid Unit R01	512	0.522	Natural Gas with Existing Burners	292	0.298	See SO_2
Reid Unit RT	45	0.708	None	45	0.708	N/A
Fleet Total	**12,074**	**0.177**	**N/A**	**7,720**	**0.113**	**$91.4**

IMPLEMENTATION TIMELINE FOR CSAPR AND MACT COMPLIANCE (SO_2 AND NO_X)

Since BREC has a total of nine plants where potential modifications can affect overall fleet-wide compliance with CSAPR and potential NAAQS regulations, a running summation of emissions above and (below) their allocations was plotted along with the startup dates of the recommended modifications. Implementing the strategies below will allow BREC to achieve fleet-wide compliance with minimal credit purchases while major modifications are completed.

Figure ES-1 — Cumulative Emissions Above or Below CSAPR SO_2 and NO_X Allocations

(Adjusted Outage Schedule)

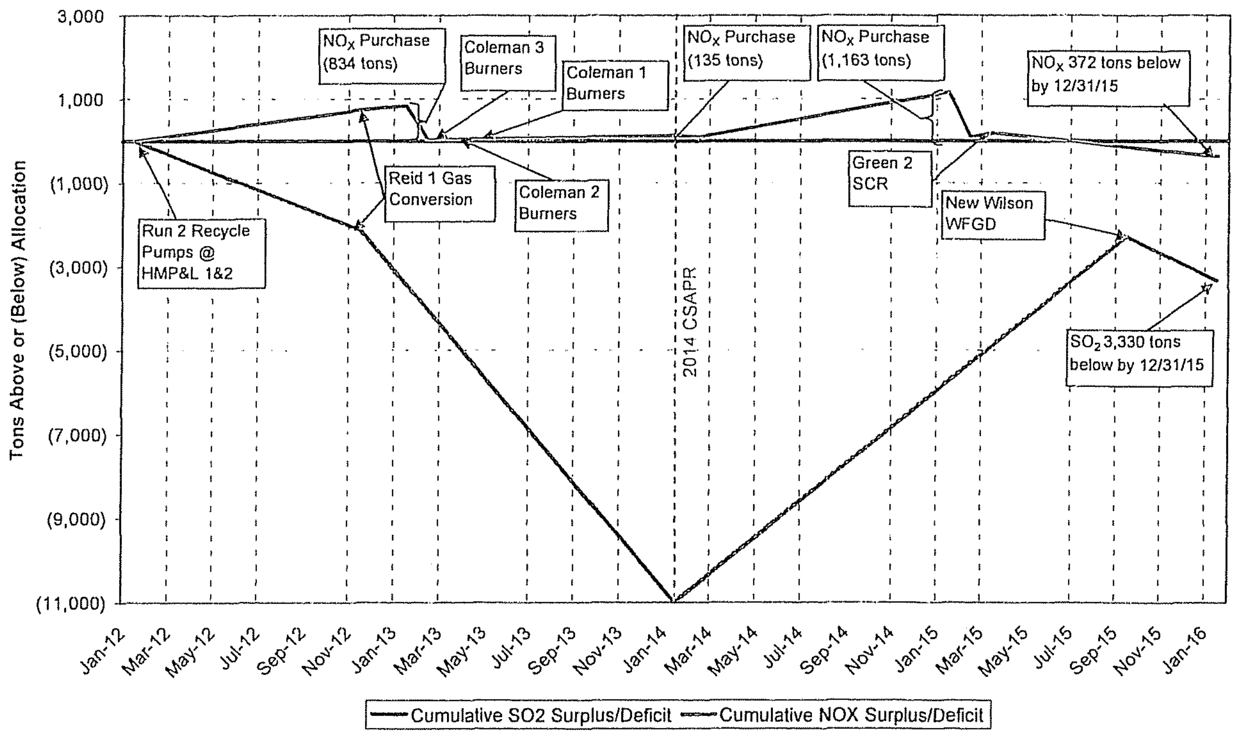
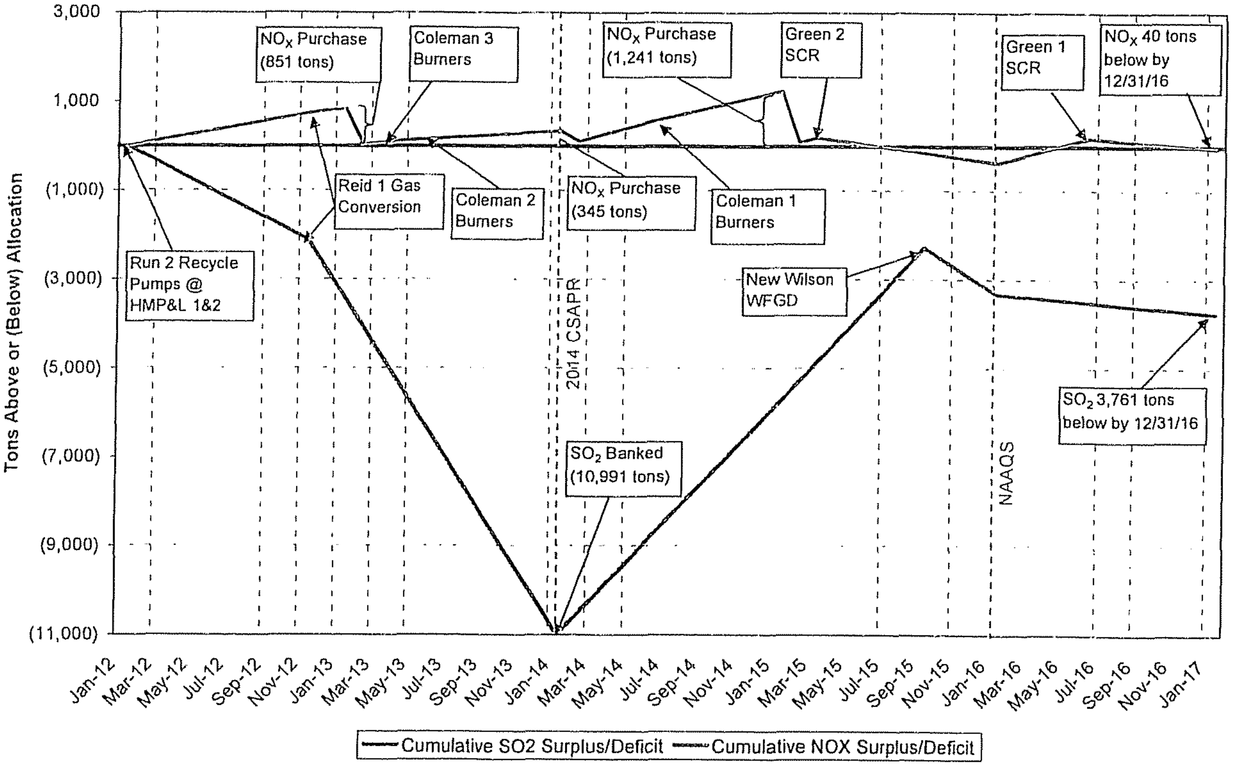


Figure ES-2 — Cumulative Emissions Above or Below CSAPR and NAAQS SO_2 and NO_X Allocations



MERCURY

Baseline mercury emissions at all BREC units except Henderson (HMP&L) are above the proposed MACT limit of 1.2 lb/TBtu and will need to be reduced to achieve compliance. It is anticipated that that activated carbon injection (ACI) systems will be required at each of the over-emitting units to lower emission rates to the required levels. A summary of each unit's baseline emissions, required reduction, recommended modification, and associated NPV are provided below.

Table ES-4 — MACT Hg Compliance Summary

Unit	Baseline Elemental Hg Emission Rate (lb/TBtu)	Baseline Oxidized Hg Emission Rate (lb/TBtu)	Baseline Total Hg Emission Rate (lb/TBtu)	Required Percent Reduction for MACT Compliance	Technology Selection	NPV (2011$ Million)
Coleman Unit C01	2.67	0.85	3.52	66%		$11.9
Coleman Unit C02					Activated Carbon Injection	$11.9
Coleman Unit C03						$11.9
Wilson Unit W01	1.56	0.21	1.77	32%	Activated Carbon Injection	$26.7
Green Unit G01	2.73	0.36	3.09	61%	Activated Carbon Injection	$15.3
Green Unit G02	2.46	0.12	2.58	53%	Activated Carbon Injection	$15.3
HMP&L Unit H01	0.34	0.28	0.62	N/A	None	N/A
HMP&L Unit H02	0.22	0.24	0.47	N/A	None	N/A
Reid Unit R01	N/A	N/A	6.5	82%	Natural Gas Conversion	N/A
TOTAL						$93.0

PARTICULATE MATTER

High condensable emission levels at Coleman and HMP&L a largely contributing to emission levels above the proposed limit of 0.030 lb/MMBtu. A reduction in condensable PM levels >50% can be achieved by adding a dry sorbent (hydrated lime) injection system, which would provide a large improvement in total PM emissions. To improve filterable removal efficiencies, it is suggested that BREC modify the existing electrostatic precipitators (ESPs) with advanced electrodes and high frequency transformer rectifier (TR) sets. The combination of these two modifications at HMP&L and Green should result in PM emissions below the MACT limit. Other BREC units that are considering ACI systems for mercury control and dry sorbent injection (DSI) systems for improved ACI efficiency and acid gas control should also consider upgrading the existing electrodes and installing high frequency TR sets to remain in compliance. However, testing on the affects of adding these systems should be conducted before implementing these strategies. Baseline TPM emissions, required reductions compliance, recommended equipment upgrades/modifications, and associated NPV to meet the anticipated MACT limits are provided below.

Table ES-5 — MACT TPM Compliance Summary

Unit	Baseline Total PM Emission Rate (lb/MMBtu)	Required Percent Reduction for MACT Compliance	Technology Selection	NPV (2011$ Million)
Coleman Unit C01	0.0398	25%	Hydrated Lime DSI & ESP Upgrades	$10.3
Coleman Unit C02				$10.3
Coleman Unit C03				$10.3
Wilson Unit W01	0.0196	N/A	Low Oxidation Catalyst & ESP Upgrades	$11.2
Green Unit G01	0.0195	N/A	Hydrated Lime DSI & Potential ESP Upgrades	$11.2
Green Unit G02	0.0169	N/A	Hydrated Lime DSI & Potential ESP Upgrades	$11.2
HMP&L Unit H01	0.0319	6%	Hydrated Lime, Low Oxidation Catalyst & ESP Upgrades	$11.2
HMP&L Unit H02	0.0324	7%	Hydrated Lime, Low Oxidation Catalyst & ESP Upgrades	$11.2
Reid Unit R01	0.269(1)	~90%	Natural Gas Conversion	N/A
TOTAL				$86.9

(1) Condensable particulate emission data was not available for Reid. Value shown is filterable particulate matter only.

AIR QUALITY COMPLIANCE RECOMMENDATION SUMMARY (CSAPR 2014 & MACT)

The table below provides the complete BREC fleet-wide recommended compliance strategy to meet the 2014 CSAPR and potentially forthcoming MACT regulations. Technologies selected along with estimated project capital costs are shown.

Table ES-6 — Air Quality Compliance Strategy Summary

BREC Unit	Technology Selection						Capital Cost (Millions $)						Total Projected Capital Cost (2011$)
	CSAPR - Selection		MACT - Selection										
	SO_2	NO_x	HCl	Hg	CPM	FPM	SO_2	NO_x	HCl	Hg	CPM	FPM	
Coleman Unit C01	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	0.00	5.94	0.32	4.00	5.00	2.72	$18,000,000
Coleman Unit C02	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	0.00	5.94	0.32	4.00	5.00	2.72	$18,000,000
Coleman Unit C03	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	0.00	5.94	0.32	4.00	5.00	2.72	$18,000,000
Wilson Unit W01	New Tower Scrubber - 99% removal	None	Higher L/G or new tower for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	Advanced Electrodes & High Frequency TR Sets	139.00	0.00	0.00	4.50	6.50	4.54	$154,500,000
Green Unit G01	None	None	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	0.00	0.00	0.00	4.00	5.00	3.34	$12,300,000
Green Unit G02	None	SCR @ 85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000
HMP&L Unit H01	Run both pumps & spray levels, Install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000
HMP&L Unit H02	Run both pumps & spray levels, Install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000
Reid Unit R01*	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	1.20						$1,200,000
Reid Unit RT	None	None	None	None	None	None	0.00						$0
TOTAL							146.5	98.8	1.0	24.5	43.5	24.4	$339,000,000

**Note SO2 emissions in this scenario have been adjusted to reflect recent data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%
***Note four (4) HCl monitors are required for Coleman One (1) for the common WFGD stack and one (1) for each unit bypass stack

EPA 316(b) REGULATIONS FOR COOLING WATER INTAKES

The existing intake screens at Coleman and Sebree are not equipped with fish buckets or return systems, and the intake velocities approaching the screens are approximately 1.8 and 2.3 feet per second (fps), respectively, at the low water level. This study evaluated several different technologies that provide for compliance with these proposed regulations, including new screen designs and conversion to closed cycle cooling. Since the proposed regulations do not mandate a conversion to closed cycle cooling, it is recommended that replacement intake screens be installed. The recommended screen technology based on an evaluation of capital and O&M costs is a rotating circular intake screen with fish pumps to meet the expected impingement mortality reduction. The estimated capital cost of these screens is $1.33M for each of the Coleman units and $2.05M for Sebree. Projected annual O&M costs are estimated to be $250,000 per unit at Coleman and $370,000 at Sebree.

COAL COMBUSTION RESIDUAL HANDLING & WASTE WATER EFFLUENTS

Assuming Subtitle D is promulgated, modifications would be required at Coleman, HMP&L, and Green to comply. Although continued operation of the existing bottom ash dewatering ponds may be possible under the new regulations, this is not expected to be practical due to requirements for pond modifications (liner and groundwater monitoring system installation) and pending wastewater discharge standards that will likely necessitate treatment or elimination of the ash pond discharge streams. As such, a conversion to a dry bottom ash system using submerged scraper conveyors (SSCs) is recommended. The resulting NPV associated with SSC installation and closure of the existing ash ponds is provided below.

Table ES-7 — Coal Combustion Residue Compliance Summary

Station	Technology Selected	Capital Cost (2011$ Millions)	NPV (2011$ Millions)
Coleman	Dry Bottom Conversion – Remote SSC & Fly Ash Conversion to Dry Pneumatic	$38.0	$45.6
Wilson	None	N/A	N/A
Green	Dry Bottom Conversion – Remote SSC	$28.0	$37.0
HMP&L	Dry Bottom Conversion – Remote SSC	$28.0	$34.1
Reid	None	N/A	N/A

Last page of Executive Summary.

1. OBJECTIVES AND APPROACH TO STUDY

The U.S. Environmental Protection Agency (EPA) and the U.S. Congress have been actively developing environmental regulations and legislation that will impact coal and oil-fired power plant operations. Air pollution regulations are aimed at requiring reductions of the criteria air pollutants including sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM, including PM10 and PM2.5), and will likely compel additional control of other air pollutants including mercury, acid gases, trace metals, and potentially carbon dioxide (CO_2). Additional EPA regulations are being developed for cooling water intakes that will reduce impingement mortality and entrainment of fish, eggs, larvae, and other aquatic organisms that come in contact with a station's cooling water system. These regulations, referred to as the EPA's 316(b) regulations, are expected to require modifications to a plant's cooling water system. The EPA is also proposing alternative approaches for regulating coal combustion residual (CCR) waste products. It is expected that the regulatory requirements will make continued operation of dewatering ponds impractical, necessitating conversions from wet to dry bottom ash systems and the subsequent closures of the dewatering ponds. Wastewater discharge effluent guidelines being proposed by the EPA will likely also impact the station's ability to discharge large volumes of ash sluice water to the environment, due to limits on total dissolved solids, metals, pH and other parameters, further necessitating the dry bottom ash conversions.

1.1 OBJECTIVES

Big Rivers Electric Corporation (BREC) requested Sargent & Lundy, L.L.C. (S&L) to perform a comprehensive compliance study addressing the recently issued, proposed and pending environmental regulations and legislation, and the potential impacts these initiatives may have on operations at BREC's Kenneth C. Coleman, D.B. Wilson, and Sebree (Reid, Henderson and Green units) generating stations.

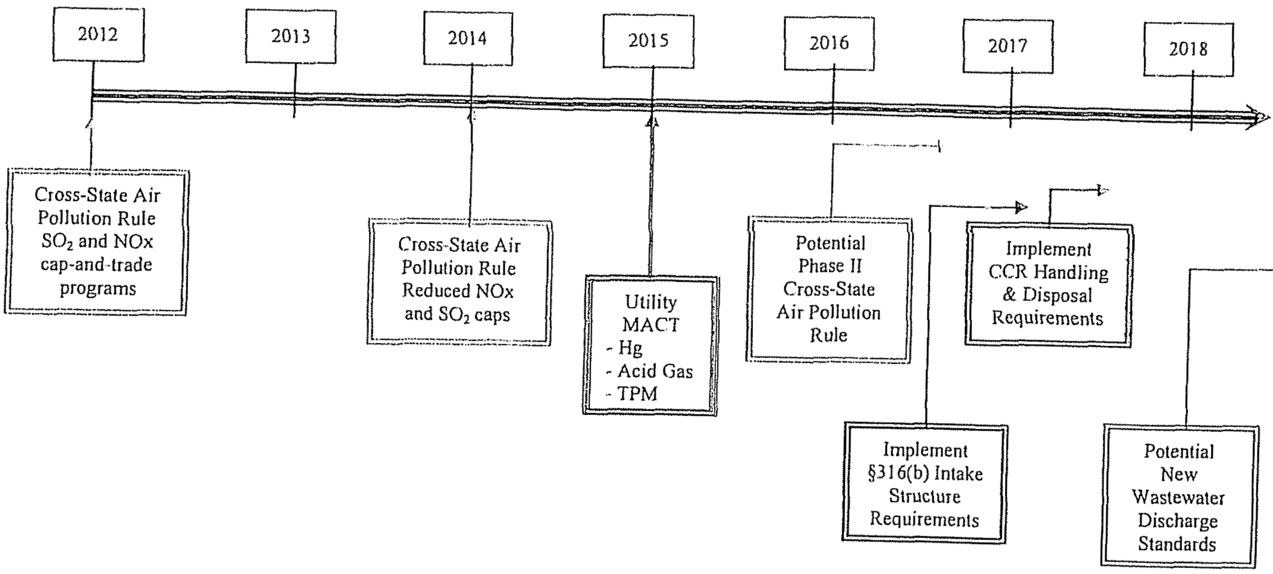
This study examines the compliance requirements of the Cross-State Air Pollution Rule (CSAPR), the anticipated compliance requirements of the EPA's proposed Electric Generating Utility Maximum Achievable Control Technology (EGU MACT) regulation, and the pending CCR and 316(b) regulations. The study was completed in three phases, as follows:

- **Phase I.** A review of the potential regulatory outcomes for pending rules.

- **Phase II.** A review of candidate technologies to meet the anticipated regulations
- **Phase III.** A technology evaluation, including a net present value (NPV) analysis where necessary, based on capital and O&M costs to determine the optimum solution for BREC.

This evaluation was conducted to provide BREC with technology recommendations that will economically comply with the current and pending regulatory requirements. The technologies reviewed included upgrades to existing environmental control systems and the installation of new technologies. Figure 1-1 provides a timeline showing the anticipated promulgation and implementation of the various environmental regulatory initiatives currently imposed or being considered by EPA that will affect operation of the Big River units.

Figure 1-1 — Environmental Regulatory Implementation Timeline



Although several environmental initiatives are currently being advanced by EPA, the regulatory initiatives that will have the most immediate impact on the BREC generating units are the CSAPR and the proposed Utility MACT Rule.

1.2 BASIS OF STUDY

The design basis values and assumptions for this study are summarized in Table 1-1 below. Historical plant data, emission test reports, and other key input data received from BREC are included in Appendix 5 for reference.

Table 1-1 — Economic Evaluation Parameters

Economic Parameter	Value
Installation Year	2014
Cost Estimate Basis Year	2011
Operating Life of the Facility, starting 2014 (years)	20
Discount Rate (%)	7.93%
Capital Cost Escalation Rate (%)	2.5%
Operating and Maintenance (O&M) Escalation Rate (%)	2.5%
Levelized Fixed Charge Rate (20 years) (%)	10.13%
Operating Labor Rate - Pay Includes Benefits ($/hr)	70
Auxiliary Power Cost ($/MWh)	40
Delivered Cost of Sorbent - Hydrated Lime ($/ton)	100
Delivered Cost of Activated Carbon ($/ton)	2000
Delivered Cost of Fuel Additive - Calcium Bromide ($/ton)	2200
Delivered Cost of Ammonia ($/ton)	866
Delivered Cost of Urea ($/ton)	540
Delivered Cost of Lime ($/ton)	120
Delivered Cost of Limestone ($/ton) – Wilson	18
Delivered Cost of Limestone ($/ton)	21
Additional Ash Disposal Costs Under Proposed Regulations for Coal Combustion Residuals (Subtitle D) ($/ton)	2.5
SO_2 Allowance Estimated Cost ($/ton)	500
NO_X Allowance Estimated Cost ($/ton)	2500
Natural Gas Cost ($/MMBtu)	4.50
Coal Cost ($/ton)	48

1.2.1 Estimating Basis

Capital and O&M costs estimates were developed for the various technology selections using S&L historical project information, escalated as required to reflect 2011 dollars. In order to provide BREC with the lowest-cost approach and highest level of control over schedule and design, the capital costs estimates provided are based on a minimal-contracts approach to project execution,. The costs provided include all direct and indirect construction costs, engineering, escalation, and 10%–20% contingency (depending on technology) based on project cost source similarity, project execution date, and other factors relating to price confidence. However, owner's costs are not included. Since these estimates are not based on detailed takeoffs or project-specific bid information, the typical range of accuracy is approximately ±20%. This is consistent with a Class 4 study or feasibility estimate, as defined by the Association for the Advancement of Cost Estimating (AACE) International Recommended Practice 18R-97.

1.2.2 Study Basis Input Parameters and Assumptions

Study basis input parameters were established based on a review of historical plant operating data and input received directly from BREC, including recent emissions tests performed in July/August 2011. A summary of key input parameters are provided in Table 1-2 through Table 1-4.

Table 1-2 — Facility Baseline Summary for Coleman & Wilson

Parameter	Coleman Unit C01		Coleman Unit C02		Coleman Unit C03		Wilson Unit W01	
Gross Unit Output (MW)	160		160		165		440	
Full Load Heat Input (MMBtu/hr)	1,800		1,800		1,800		4,585	
Primary Fuel	Illinois Basin bituminous		Illinois Basin bituminous		Illinois Basin bituminous		Illinois Basin bituminous	
Secondary Fuel	N/A		N/A		N/A		Pet Coke Pelletized Fines #2 Fuel Oil	
Unit Description	Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler	
NO_X Control	LNB & ROFA		LNB & OFA		LNB & OFA		LNB/OFA/SCR	
PM Control	ESP		ESP		ESP		ESP	
SO_2 Control	Wet Limestone FGD		Wet Limestone FGD		Wet Limestone FGD		Wet Limestone FGD	
Condenser Cooling System	Once-through cooling		Once-through cooling		Once-through cooling		Closed cycle cooling	
Baseline Average Annual Heat Input(1) (MMBtu)	11,784,789		11,787,242		12,570,106		37,043,481	
2010 Annual Heat Input (MMBtu)	11,254,853		9,544,382		12,195,952		36,221,670	
Baseline Annual SO_2 Emissions(2) (tpy) / (lb/MMBtu)	1,473	0.25	1,473	0.25	1,571	0.25	9,438	0.51
Annual NO_X Emissions (2010) (3) (tpy) / (lb/MMBtu)	1,858	0.33	1,585	0.33	2,044	0.34	934	0.053
Ozone Season NO_X Emissions (2010) (3) (tons) / (lb/MMBtu)	733	0.33	735	0.34	857	0.34	378	0.050

(1) Baseline average annual heat inputs provided in this table represent the average of the three highest heat input years during the baseline years 2006-2010.

(2) Baseline annual SO_2 emissions represent the average of the three highest emission years (2006 – 2010); however, baseline SO_2 emissions from Coleman Units C01, C02, and C03 were adjusted to an annual average emission rate of 0.25 lb/MMBtu based on information provided by BREC.

(3) Baseline NO_X emission rates are calculated using 2010 NO_X emissions and 2010 heat inputs.

Table 1-3 — Facility Baseline Summary for Sebree

Parameter	Green Unit G01		Green Unit G02		Henderson Unit H01		Henderson Unit H02		Reid Unit R01		Reid Unit RT	
Gross Unit Output (MW)	252		244		172		165		72		70	
Full Load Heat Input (MMBtu/hr)	2,569		2,569		1,624		1,624		911		803	
Primary Fuel	Illinois basin bituminous		Illinois basin bituminous		Illinois basin bituminous		Illinois basin bituminous		Illinois basin bituminous		natural gas	
Secondary Fuel	Pet Coke		Pet Coke		N/A		N/A		N/A		Oil	
Unit Description	Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Dry bottom wall-fired boiler		Combustion Turbine	
NO_X Control	LNB		LNB		LNB/SCR		LNB/SCR		LNB			
PM Control	ESP		ESP		ESP		ESP		Cyclone ESP			
SO_2 Control	Wet Lime FGD		Wet Lime FGD		Wet Lime FGD		Wet Lime FGD					
Condenser Cooling System	Closed cycle cooling		Closed cycle cooling		Closed cycle cooling		Closed cycle cooling		Once-through cooling			
Baseline Average Annual Heat Input(1) (MMBtu)	20,128,359		20,347,531		12,823,005		13,214,893		2,240,807		87,379	
2010 Annual Heat Input (MMBtu)	19,866,020		20,128,970		13,003,466		12,118,692		1,962,424		126,361	
Baseline Annual SO_2 Emissions(2) (tpy) / (lb/MMBtu)	1,873	0.19	1,414	0.14	2,227	0.35	2,745	0.42	5,066	4.52	5	0.12
Annual NO_X Emissions (2010)(3) (tpy) / (lb/MMBtu)	2,050	0.21	2,168	0.22	460	0.071	418	0.069	512	0.52	45	0.71
Ozone Season NO_X Emissions (2010)(3) (tons) / (lb/MMBtu)	789	0.20	890	0.21	208	0.074	179	0.066	193	0.47	33	0.70

(1) Baseline annual heat inputs shown in this table represent the average of the three highest heat input years during the years 2006 – 2010.

(2) Baseline annual SO_2 emissions shown in this table represent the average of the three highest emission years during the years 2006 – 2010.

(3) Baseline NO_X emission rates are calculated using 2010 NO_X emissions and 2010 heat inputs.

Table 1-4 — MACT Emission Test Data

Proposed MACT Emission Limits		Stack Emission Test Data[1]						
		Coleman	Wilson	Green 1	Green 2	HMP&L 1	HMP&L 2	Reid 1
a. Total particulate matter (TPM)	0.030 lb/MMBtu	0.0398	0.0196	0.0195	0.0169	0.0319	0.0324	0.269[2]
OR								
Total non-Hg HAP metals	0.000040 lb/MMBtu	0.0000910	0.0000591	0.0000906	0.0000678	0.0000959	0.0001203	N/A
b. Hydrogen chloride (HCl)	0.0020 lb/MMBtu	0.000236	0.000074	0.000281	0.000334	0.001670	0.001370	0.068
OR								
Sulfur dioxide (SO_2)	0.20 lb/MMBtu	0.250	0.510	0.186	0.139	0.347	0.415	4.52
c. Mercury (Hg)	1.2 lb/TBtu	3.52	1.77	3.09	2.58	0.62	0.47	6.5

(1) Green cells indicate baseline emissions below the applicable MACT emission limit. Yellow cells indicated emissions below, but within 15% of the proposed emission limit. Red cells indicate baseline emissions above the applicable MACT emission limit.

(2) Condensable particulate emission data was not available for Reid. Value shown is filterable particulate matter only.

Per discussions with BREC, it is understood that approximately 70% of load generating capacity is used by two local aluminum smelters. Being that a majority of output is consumed by this group, it was agreed that a load-forecasting study would not be developed. Furthermore, BREC requested that S&L assume the BREC units will continue to operate in a manner similar to that demonstrated over IRC data collection years (2006-2010).

Existing acid gas emissions were based on recent test data at the various units stack outlets. Acid gas emissions for Reid Unit 1 are estimates only and are not based on tests.

It is assumed that the existing wet flue gas desulfurization (WFGD) systems at Green Units 1 & 2 will consistently perform up to the historical peak removal efficiency.

It is assumed that Wilson station will maintain its current intake water demands and continue to operate with a through-screen velocity at or below the required 0.5 fps per the provided Kentucky Pollutant Discharge Elimination System (KPDES) fact sheets.

Since the Henderson (HMP&L) units are owned by the City of Henderson, BREC has requested that the HMP&L units be able to meet their own CSAPR allocations and stand alone if need be.

Per discussions with BREC, HMP&L 1 and 2 and Wilson have already committed to upgrading their existing Low-NO_X burners due to high O&M costs associated with the current burners.

Technology selection for CSAPR compliance was based on the most economic method for achieving compliance with BREC's 2014 allocations.

Last page of Section 1

2. PHASE I – ENVIRONMENTAL REGULATORY REVIEW

Compliance with EPA's existing and proposed regulations will require a review of the following regulations:

- CAIR – Clean Air Interstate Rule (2010-2012)
- CSAPR – Cross-State Air Pollution Rule (2012-2014/2016)
- MACT – Maximum Available Control Technology for controlling mercury, acid, non-mercury metallic pollutants and organic air toxics including dioxin/furnas.(2015/2016)
- 316 (b) Cooling Water Intake Regulations.
- Waste Water Discharge Standards
- Coal Combustion Residue Regulation

2.1 AIR POLLUTION CONTROL SUMMARY

2.1.1 Clean Air Interstate Rule

CAIR includes an annual SO_2 cap-and-trade program, an annual NO_X cap-and-trade program, and an ozone season NO_X cap-and-trade program. CAIR went into effect in its entirety on January 1, 2009, and will remain in effect until the recently published CSAPR takes effect on January 1, 2012.

Actual SO_2 and NO_X emissions from the BREC generating units are currently very close to the corresponding CAIR Phase I SO_2 and NO_X allocation requirements. Annual SO_2 emissions from all units averaged 27,280 tpy (average of highest three years) between 2006 and 2010 (or 54,560 CAIR SO_2 allowances) compared to an allocation of 52,470 allowances. Thus, based on average historical emissions, BREC should be slightly above their CAIR Phase I SO_2 allocations without providing additional SO_2 emission controls. If SO_2 emissions exceed the CAIR allocations in any individual year, banked CAIR allocations and banked pre-2009 Acid Rain Program SO_2 allocations can be used to off-set any allocation deficit.

Systemwide annual and ozone season NO_X emissions were also slightly above the CAIR Phase I NO_X allocations. In 2010, annual NO_X emissions from all units were approximately 6% above the CAIR Phase I allocation of 11,351 tons, and ozone season NO_X emissions from all units were approximately 3.4% above the CAIR Phase I allocation of 4,824 tons. Relatively small NO_X reductions on the non-SCR controlled units (e.g., C01, C02, C03, G01, and G02) could provide the emissions reductions needed for systemwide NO_X emissions to maintain emissions at or below the CAIR Phase I NO_X allocation requirements.

Table 2-1 below provides a summary of CAIR Phase I allowance requirements and corresponding emission reduction requirements for each BREC generating unit:

Table 2-1 — CAIR Phase I Summary

Pollutant	Station	Baseline Emissions (Required Allocations - 2x Emissions)	CAIR Phase I Allocations (per year)	Reductions Needed to Meet Allocations
SO_2	Coleman	4,517 (9,034)	15,709	NA
	Wilson	9,438 (18,876)	12,461	(6,415)
	Sebree	13,325 (26,650)	24,300	(2,350)
	Systemwide	27,280 (54,560)	52,470	(2,090)
NO_X (Annual)	Coleman	5,487	2,679	(2,808)
	Wilson	934	3,210	NA
	Sebree	5,653	5,462	(191)
	Systemwide	12,074	11,351	(723)

2.1.2 *Cross-State Air Pollution Rule*

The CSAPR will replace CAIR in 2012. The rule includes a new SO_2 cap-and-trade program and new annual and ozone-season NO_X trading programs. Potential impacts of the CSAPR are summarized in Table 2-2 below:

Table 2-2 — BREC CSAPR SO_2 and NO_X Reduction Requirements (2012 and 2014)

Fleet-Wide Emission	Annual Allowances (tpy)		Baseline Annual Emission (tpy)	Required Reduction	
	2012	2014		2012	2014
SO_2	26,478	13,643	27,286	3%	50%
Annual NO_X	11,186	10,142	12,074	7%	16%
Ozone Season NO_X	4,972	4,402	4,995	0.5%	12%

Reductions of approximately 50% and 16% from BREC's baseline emissions are needed to meet the 2014 SO_2 and NO_X annual allocations. The largest contributors to the overall SO_2 deficit are the Wilson W01 and Reid R01 units, which have emission rates of 0.51 lb/MMBtu and 4.522 lb/MMBtu, respectively. The largest contributors to the overall NO_X deficit are Reid RT, Reid R01, and Coleman C03, which have baseline emission rates of 0.71 lb/MMBtu, 0.52 lb/MMBtu and 0.34 lb/MMBtu respectively.

2.1.3 Maximum Achievable Control Technology

The Proposed Utility MACT rule includes emission limits for mercury, acid gases (HCl or SO_2), and trace metal HAP emissions (which includes TPM, total non-Hg metals, or individual non-Hg metals). Based on the HAP emissions data available from the BREC coal-fired units, and taking into consideration Information Collection Request (ICR) emissions data from similar sources, it is foreseen that modifications are required throughout the BREC fleet to meet the proposed Utility MACT emission limits. Tables below compare existing emissions from each unit to the proposed emission limits and identify the emission reductions that may be needed to comply with the proposed MACT standards.

Since this study was completed, the MACT rule was replaced by the Mercury and Air Toxins Standard (MATS). This report has not been revised to reflect the new MATS rule.

Table 2-3 — Comparison of Baseline Hg Emissions to the Proposed MACT Hg Emission Limit

BREC Unit	Hg		
	Baseline (lb/TBtu)	Proposed MACT (lb/TBtu)	Required Reduction
Coleman Unit C01	3 5	1.2	66%
Coleman Unit C02			
Coleman Unit C03			
Wilson Unit W01	1 77	1.2	32%
Green Unit G01	3.1	1.2	61%
Green Unit G02	2.6	1.2	53%
HMP&L Unit H01	0 62	1.2	None
HMP&L Unit H02	0.47	1 2	None
Reid Unit R01	6.5 (one test)	1.2	82%

Table 2-4 — Comparison of Baseline Acid Gas Emissions to the Proposed MACT Acid Gas Limits

BREC Unit	Acid Gas Emissions					
	HCl (lb/MMBtu)			SO_2 (lb/MMBtu)		
	Baseline	MACT	Required Reduction	Baseline	MACT	Required Reduction
Coleman Unit C01	0.24×10^{-3}	2.0×10^{-3}	None	0.25	0 20	20%
Coleman Unit C02						
Coleman Unit C03						
Wilson Unit W01	0.07×10^{-3}	2.0×10^{-3}	None	0 51	0.20	61%
Green Unit G01	0.28×10^{-3}	2.0×10^{-3}	None	0.19	0.20	None
Green Unit G02	0.33×10^{-3}	2.0×10^{-3}	None	0.14	0.20	None
HMP&L Unit H01	1.67×10^{-3}	2.0×10^{-3}	None	0.35	0.20	43%
HMP&L Unit H02	1.37×10^{-3}	2.0×10^{-3}	None	0.42	0.20	52%
Reid Unit R01*	68.0×10^{-3}	2.0×10^{-3}	97%	4.52	0 20	96%

* Baseline HCl emissions summarized above represent estimated emission rates based on limited available stack test data. Additional stack test data would be needed to more accurately predict HCl emissions from each unit.

Table 2-5 — Comparison of Baseline TPM Emissions to the Proposed MACT TPM Emission Limit

BREC Unit	Total PM Emissions		
	Baseline (lb/MMBtu)	Proposed MACT (lb/MMBtu)	Required Reduction
Coleman Unit C01	0.0398	0.030	25%
Coleman Unit C02			
Coleman Unit C03			
Wilson Unit W01	0.0196	0.030	None
Green Unit G01	0.0195	0.030	None
Green Unit G02	0.0169	0.030	None
HMP&L Unit H01	0.0319	0.030	6%
HMP&L Unit H02	0.0324	0.030	7%
Reid Unit R01	0.269(1)	0.030	~90%

(1) Condensable particulate emission data was not available for Reid. Value shown is filterable particulate matter only.

2.1.4 Phase II Cross-State Air Pollution Rule

The 8-hour ozone and PM2.5 National Ambient Air Quality Standards (NAAQS) are the regulatory drivers for CSAPR. As discussed in section 3.5 of Appendix 1, EPA is considering revising the existing 8-hour ozone and PM2.5 NAAQS, making the ambient air quality standards more stringent. If revisions to the NAAQS are finalized, it is almost certain that more areas in Kentucky, and other downwind states, will be designated as ozone and PM2.5 non-attainment areas.

EPA could revise the CSAPR to address the new 8-hour ozone and PM2.5 NAAQS. If so, it is likely that Phase II CSAPR would address the new ozone and PM2.5 NAAQS standards by reducing each state's CSAPR allocation budget. EPA would conduct ambient air quality impact modeling to identify emissions that contribute to the new non-attainment area designations and then revise the emission budgets to eliminate each state's contribution to downwind non-attainment. For this analysis, it was assumed that the Phase II CSAPR allocations will be 20% below the Phase I allocations and that the Phase II rule will take effect in the 2016–2018 timeframe.

Projected emission allocations, baseline annual emissions, and potential required reductions are shown in Table 2-6 below.

Table 2-6 — BREC CSAPR Phase II SO_2 and NO_X Reduction Requirements

Fleet-Wide Emission	Annual Allowances (tpy)	Baseline Annual Emission (tpy)	Required Reduction
SO_2	10,914	27,286	60%
Annual NO_X	8,114	12,074	33%
Ozone Season NO_X	3,522	4,995	30%

Assuming a total systemwide annual heat input of 136,400,000 MMBtu and a total ozone season heat input of 57,200,000 MMBtu, NO_X emissions from all BREC units would have to average approximately 0.12 lb/MMBtu to match the projected Phase II CSAPR allocations. A systemwide average emission rate of 0.12 lb/MMBtu is approximately 33% below the current systemwide average NO_X emission rate of 0.177 lb/MMBtu.

2.2 316(B) WATER INTAKE IMPINGEMENT MORTALITY & ENTRAINMENT – REGULATORY SUMMARY

As detailed in Appendix 1, on April 20, 2011, the EPA published in the Federal Register proposed regulations implementing §316(b) of the Clean Water Act (CWA) at all existing power generating facilities and all existing manufacturing and industrial facilities that withdraw more than 2 million gallons per day (MGD) of water from waters of the U.S. and use at least 25% of the water they withdraw exclusively for cooling purposes. The newly proposed rule, as applicable to BREC's units, proposes reductions in impingement mortality by selecting one of two options for meeting Best Technology Available (BTA) requirements. Option 1 requires the owner or operator of an existing facility to install, operate, and maintain control technologies capable of achieving the following impingement mortality limitations for all life stages of fish:

Table 2-7 — Impingement Mortality Not-to-Exceed Values

Regulated Parameter	Annual Average	Monthly Average
Fish Impingement Mortality	12%	31%

The proposed impingement mortality performance standards are based on the operation of a modified course mesh traveling screen with technologies such as fish buckets or pumps, a low-pressure spray wash, and dedicated fish return lines implemented. However, the proposed rule does not specify any particular screen configuration, mesh size, or screen operations, so long as facilities can continuously meet the numeric impingement mortality limits.

Under Option 2, facilities may choose to comply with the impingement mortality standards by demonstrating to the permitting agency that its cooling water intake system has a maximum intake velocity of 0.5 fps. The maximum velocity must be demonstrated as either the maximum design intake velocity or the maximum actual intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh. Typically, this intake velocity will correspond to the through-screen velocity. The maximum velocity limit must be achieved under all conditions, including during minimum ambient source surface elevations and during periods of maximum head loss across the screens during normal operation of the intake structure.

The Proposed 316(b) Rule also includes entrainment mortality performance standards applicable to existing units with a design intake flow >2 MGD, existing units with a design intake flow >125 MGD, and new units. Proposed entrainment performance standards are summarized below. For entrainment mortality, the proposed rule establishes requirements for studies as part of the permit application, and then establishes a process by which BTA for entrainment mortality would be implemented at each facility on a case-by-case basis. These case-by-case performance standards must reflect the permitting agency's determination of the maximum reduction in entrainment mortality warranted after consideration of all factors relevant for determining the BTA at each facility. Factors that the permitting agency must consider when making a case-by-case entrainment mortality determination include the following:

- Number and types of organisms entrained
- Entrainment impacts on the water body
- Quantified and qualitative social benefits and social costs of available entrainment technologies, including ecological benefits and benefits to any threatened or endangered species
- Thermal discharge impacts
- Impacts on the reliability of energy delivery within the immediate area

- Impact of changes in particulate emissions or other pollutants associated with entrainment technologies
- Land availability inasmuch as it relates to the feasibility of entrainment technology
- Remaining useful plant life
- Impacts on water consumption

In addition, existing facilities with an actual intake flow of greater than 125 MGD must conduct the following additional entrainment mortality studies and evaluations as part of the BTA determination:

- Entrainment Mortality Data Collection Plan (with peer reviewers identified)
- Peer-reviewed Entrainment Mortality Data Collection Plan
- Completed Entrainment Characterization Study
- Comprehensive Technical Feasibility and Cost Evaluation Study, including—
  - — Benefits Valuation Study
  - — Non-water Quality and Other Environmental Impacts Study

2.3 WASTEWATER DISCHARGE

EPA has indicated in the October 2009 *Detailed Study Report* that wastewaters from air pollution control devices are of primary concern, in particular, mercury and other heavy metals. At this point, it is difficult to accurately anticipate what affect these regulations may have on coal-fired generating station operations. A brief summary of the potential wastewater discharge requirements is provided in Table 2-8 below.

Table 2-8 — Potential Wastewater Effluent Discharge

BREC Station	KPDES Permit No.	Receiving Water	Facility Summary
Coleman	KY001937	Ohio River	Because this plant discharges directly to the Ohio River, Ohio State Sanitation Commission (ORSANCO) requirements will apply to the effluent. Even though the effluent guidelines have not yet been promulgated, the concentration of mercury in water entering the river will be required to meet the ORSANCO limit of 0.000012 mg/L (in addition to other metals limitations) The permit also requires the Coleman plant to monitor for total recoverable metals and hardness. The results of this monitoring will be incorporated into the next permit application and may result in numeric discharge limits for these substances. The FGD wastewater and other wastewaters generated by the plant will have to meet the Steam Electric Power Effluent Guidelines, which are expected to be similar to ORSANCO standards. Depending upon the discharge limits for mercury and other constituents in the KPDES permit it may become necessary to install advanced wastewater treatment/removal systems for mercury and other metals.
Wilson	KY0054836	Green River and Elk Creek	The KPDES permit requires monitoring for hardness, sulfate, and chloride. The results of this monitoring may be used to demonstrate the need for numeric effluent standards for these parameters in future permits. Further, the required monitoring for total recoverable metals indicates a potential for future limits based on the data developed. It is expected that the new Steam Electric Power Effluent Guidelines will result in more stringent effluent requirements for this facility. The existing permit fact sheet relied heavily on the requirements of 40 CFR 423. Depending upon the discharge limits for sulfates, chlorides, mercury and other constituents in the KPDES permit it may become necessary to install advanced wastewater treatment/removal systems for mercury and other metals.
Sebree	KY001929	Green River	The Green and Henderson facilities are equipped with cooling towers that contribute 1.9 MGD and 7.20 MGD respectively to the overall discharge Because the facilities discharge to the Green River, it is expected that the new Steam Electric Power Effluent Guidelines will drive the effluent limits. The facility currently has a 1,200 ppm chloride limit. Cooling tower blowdown and FGD blowdown may contain high levels of chloride, which is difficult and expensive to remove The permit also requires monitoring for total recoverable metals and hardness, indicating a potential for numeric effluent standards for metals in the next round of permitting. It is not known whether the potential numeric standards will be more or less stringent than any that may be proposed in the update of 40 CFR 423. Depending upon the discharge limits for sulfates, chlorides, mercury, and other constituents in the KPDES permit, it may become necessary to install advanced wastewater treatment and/or removal systems for mercury and other metals

2.4 COAL COMBUSTION RESIDUE – REGULATORY SUMMARY

Two alternate regulations for the management of coal combustion residuals (CCR) have been issued for public comment. Both options fall under the Resource Conservation and Recovery Act (RCRA). Under the first proposal, EPA would list these residuals as special wastes under the hazardous waste provisions of Subtitle C of RCRA, when destined for disposal in landfills or surface impoundments. With Subtitle C, the waste products would need to be trucked by specially licensed hazardous waste carriers and be taken to an alternate landfill suitable for hazardous waste at significant additional cost. Although not specifically addressed in the proposed Subtitle C regulations, existing ash ponds used strictly for dewatering would likely require significant improvements to meet Subtitle C regulations, even though they are not used for long-term storage of CCRs. Product handling, transportation, and disposal costs under Subtitle C are substantial due to the hazardous material classification resulting in higher costs for insurance, taxes, licensing, manifesting, documentation, and training.

Under the second proposal, EPA would regulate coal ash under Subtitle D of RCRA, the section for non-hazardous wastes. If the Subtitle D regulations are promulgated (i.e., non-hazardous waste), the existing manner in which the waste materials are transported is considered acceptable; however, some additional landfill costs may still be incurred by BREC's units due to Subtitle D requirements for lining of landfills and ongoing groundwater monitoring.

Pending revisions to the wastewater discharge standards for steam electric power plants may have a significant impact on the bottom ash systems operations at the Green, HMP&L, Reid, and Coleman stations. It is difficult to predict the specific type of treatment and associated costs that will be required; however, given the large volume of ash sluicing water that discharges through the stations' ponds, the costs of any treatment mandated by pending regulations will be substantial. As such, even if the Subtitle D (non-hazardous) regulations are promulgated, continued operation of the existing ash dewatering ponds may not be possible. Since the specific water quality parameters (e.g., selenium, mercury, total suspended solids) and compliance limits of the future wastewater discharge standards are unknown, a conversion to a dry bottom ash system is recommended and included as the study basis. Table 2-9 below gives a brief summary of the existing facilities and potential impacts of the proposed regulations.

Table 2-9 — Coal Combustion Residue Summary

Station	Bottom Ash Handling	Economizer Ash Handling	Pyrites Handling	Fly Ash Handling	Modifications Required for Subtitle C	Modifications Required for Subtitle D
Coleman	Sluiced to Pond	Sluiced to Pond	Sluiced to Pond	Sluiced to Pond	Maintain Piping System and Add Dewatering Equipment to Eliminate Pond Storage & Install Pneumatic Transport System for Fly Ash	Maintain Piping System and Add Dewatering Equipment to Eliminate Pond Storage. Landfill waste product
Wilson	SSC under Boiler	Sluiced to Bottom Ash SSC	Handled Dry	Pressurized Pneumatic System to Storage Silo	Convert Pressurized Pneumatic Fly Ash Transport System to Vacuum System	None
Green	Sluiced to Pond	Sluiced to Pond	Sluiced to Pond	Pressurized Pneumatic System to Storage Silo	Eliminate Ash Storage Ponds and Install Dewatering Equipment & Convert Pressurized Pneumatic Fly Ash Transport System to Vacuum System.	Maintain Piping System and Add Dewatering Equipment to Eliminate Pond Storage. Landfill waste product.
HMP&L	Sluiced to Pond	Sluiced to Pond	Sluiced to Pond	Vacuum Pneumatic System to HMP&L Silo & Pressure Pneumatic System to Green Silo	Eliminate Ash Storage Ponds and Install Dewatering Equipment & Convert Pressurized Leg of Transport Piping to Green Silo to Vacuum System	Maintain Piping System and Add Dewatering Equipment to Eliminate Pond Storage Landfill waste product
Reid	Sluiced to Pond	Sluiced to Pond	Sluiced to Pond	Pressurized Pneumatic System to HMP&L Silo	Eliminate Ash Storage Ponds and Install Dewatering Equipment & Convert Pressurized Portion of System to Vacuum Pneumatic	Maintain Piping System and Add Dewatering Equipment to Eliminate Pond Storage Landfill waste product

Last page of Section 2

3. PHASE II – IDENTIFICATION OF COMPLIANCE TECHNOLOGIES

3.1 EXISTING TECHNOLOGIES

The BREC units currently operate a number of pollution control technologies that can help to provide a means of regulatory compliance. The existing equipment is either sufficient to comply with the expected regulatory limits, or it may be applied in combination with other new technologies to provide the most cost effective approach. In some cases, the existing equipment has been demonstrated to be incapable of meeting the regulatory limits, in which case all new technology must be explored.

3.1.1 Air Pollution Control

As shown in Table 1-2 and Table 1-3, the BREC units have a variety of air pollutant control technologies implemented at the units across their fleet. All BREC units except Reid Unit 1 are equipped with wet flue gas desulfurization (WFGD) systems. All of the units except Reid RT are equipped with first generation low-NO_X burners. Coleman Units 1-3 and Wilson Unit 1 have overfire air. Wilson Unit 1 and Henderson Units 1&2 are equipped with selective catalytic reduction (SCR) systems for NO_X removal. Each BREC unit also has an electrostatic precipitator (ESP) installed (cyclone ESP for Reid 01) for filterable particulate removal. The capability of the existing air pollution control equipment was evaluated against the anticipated regulatory limits to determine whether these systems can comply. Details regarding existing technology effectiveness are discussed in Phase I of this report and included in Attachment 1 of this report. Exploration of new technologies and implementation of various upgrades to support the existing systems are discussed in detail in Sections 3.2 and 4 of this report.

3.1.2 Intake Structure Impingement Mortality and Entrainment (316(b))

Currently, the maximum through-screen velocity of 0.5 fps at Wilson station meets the expected 316(b) requirements. However, the maximum through-screen velocities at Coleman and Sebree are not capable of meeting the expected 316(b) requirements. Screens at Coleman and Sebree are not currently equipped with any systems that reduce impingement mortality or entrainment sufficiently to meet the proposed regulation.

3.1.3 Coal Combustion Residual Handling

If the Subtitle C regulations are promulgated, significantly higher costs will be incurred because the products will need to be transplanted as hazardous waste, as described in Section 2.4. It would also be recommended that BREC convert any existing positive-pressure pneumatic ash transport systems to negative-pressure (vacuum) systems to avoid potential out-leakage. If the Subtitle D regulations are promulgated (i.e., CCR as non-hazardous waste), BREC units will incur additional landfill costs for fly ash and WFGD waste products due to Subtitle D requirements for lining of landfills and ongoing groundwater monitoring.

Although Subtitle C and Subtitle D make some provision for continued operation of on-site ash ponds, the current method of using the ash ponds to dewater the bottom ash material before loadout and trucking offsite is not considered to be practical for the following reasons:

- High cost of retrofitting the on-site ash ponds with the required composite liners and groundwater monitoring systems.
- Impact on station operations and outage time necessary for retrofit of composite liners into the ash ponds.
- The use of front-end loaders and/or drag chain equipment to dewater the ponds following installation of liners, which could result in damage to the required composite lining system.

As a result, conversion of the existing wet bottom ash sluicing systems to one of several dry bottom ash technologies is recommended and included as the study basis.

3.2 CANDIDATE TECHNOLOGIES FOR COMPLIANCE

This section highlights the potential control technologies for each of the CSAPR and proposed Utility MACT regulated pollutants and the proposed technologies for potential forthcoming CCR and 316(b) regulations. S&L screened the potential control technologies and identified the technologies that are the most practical to be implemented at the various BREC stations for compliance with the new regulations.

3.2.1 SO_2 and Acid Gas Control Options

3.2.1.1 SO_2 Control Technologies

3.2.1.1.1 Dry Sorbent Injection Technology

Dry sorbent injection (DSI) technology is a low-capital-cost option for controlling SO_2 emissions; however, DSI systems typically have much higher variable O&M costs than FGD systems. DSI uses a sodium sorbent, such as trona or sodium bicarbonate (SBC), to react with the SO_2 present in the flue gas. Trona and SBC are injected as a dry product into the flue gas, typically upstream of the air preheater (APH) for trona and downstream of the APH for SBC. The reagents then react with SO_3, HCl, and SO_2 in the flue gas. DSI technology has been proven to achieve overall SO_2 reductions up to 90% for low sulfur applications. However, unlike FGD, DSI performance is highly unit-specific and depends on several factors, including fuel sulfur content, temperatures at the injection locations, available residence times, and the type of particulate collector.

It is recommended that before installing a full-scale system, DSI technology be demonstrated on that particular unit to confirm the achievable performance and determine its effect on ESP performance.

3.2.1.1.2 Wet Flue Gas Desulfurization Technology

WFGD technology uses a lime or limestone slurry to react with the SO_2 present in the flue gas. WFGD systems consist of multiple levels of spray nozzles, where the alkaline slurry contacts the flue gas, and liquid tray level(s) that removes the SO_2. The slurry simultaneously quenches the flue gas as the water evaporates and reduces SO_2 emissions by reacting to form $CaSO_3$ and $CaSO_4$. WFGD technologies can typically achieve up to 98%–99% SO_2 removal with an outlet emission of 0.05 lb/MMBtu or less.

3.2.1.2 SO_2 Control Strategies

Based on review of the provided data and the anticipated CSAPR limits, only slight improvements from the BREC stations are required to meet the 2012 SO_2 Allocations. However, since Kentucky is part of the Group 1 compliance states (see Attachment 1 for details), significant improvements will need to be implemented to meet the 2014 SO_2 allocations. Except for Green Units 1 & 2, SO_2 emissions from all other BREC units are above their site-specific allocations and are candidates for SO_2 emission reduction improvements. For all units except Coleman, it is expected that the necessary CSAPR 2014 SO_2 reductions will result in unit emission rates below 0.20 lb/MMBtu, which would also allow for use of SO_2 emissions data as a surrogate for demonstrating compliance with the MACT acid gas regulations. Although emissions data for those units indicate that current HCl emissions are below the proposed MACT limits, this approach would eliminate the need for installation of HCl monitors to demonstrate acid gas compliance. Table 3-1 below provides a list of the various new technologies and equipment improvements that were explored for improved SO_2 control.

Table 3-1 — Candidate SO_2 Control Technologies

Unit	Technology	Comments
Coleman 1/2/3	Existing WFGD (Common)	Recent operational data indicate that the existing WFGD is operating at approximately 93.5% SO_2 removal, resulting in an annual emission of around 7,150 tons of SO_2 per year. Based on interviews with the Coleman plant staff, the WFGD system has recently been operated using a lower quality limestone This indicates that the existing system performance can readily be improved
	Increase L/G	Increasing the liquid-to-gas ratio of the current WFGD by upgrading the existing pumps and nozzles will significantly increase the efficiency of the scrubber. In discussions with the WFGD manufacturer, it was acknowledged that an increase in liquid to gas flow of approximately 20% would result in SO_2 removal efficiencies near 98%.
	Additives	Either dibasic acid or sodium formate could be used to improve removal efficiencies of the current FGD system
Wilson	Existing WFGD	Currently Wilson has a Kellogg horizontal scrubber in service Recent operational data suggest the absorber is operating at approximately 91% SO_2 removal efficiency with use of dibasic acid (DBA) and sodium bisulfite, resulting in an annual emission of around 9,450 tons of SO_2 per year.
	Increase L/G	Increasing the liquid to gas ratio of the current WFGD by upgrading pumps and spray nozzles may result in removal rates low enough to satisfy the proposed emission limits. However, based on limited number of similar installed technologies and insufficient supporting data, it is recommended that flow modeling be conducted before implementation of this strategy
	New Absorber	Replacement of the existing horizontal flow absorber vessel with a vertical flow absorber while maintaining use of the supporting reactant preparation systems. Increase in flue gas pressure drop across WFGD system and additional duct losses necessitate need for booster fans. New scrubber technology will allow for 99% SO_2 removal, which results in excess credits to be sold or shared amongst other BREC units.
Green 1&2	Existing WFGD	Unit 1 and Unit 2 have dual absorber, dedicated WFGDs, The existing WFGDs achieve high SO_2 removal efficiencies and are not a major contributor to BREC's overall fleet deficit Current emissions are at approximately 3,300 tpy, which is below the proposed CSAPR 2014 allocations. Furthermore, recent stack test data show an SO_2 emission rate of 0 186 lb/MMBtu for Unit 1 and 0 139 lb/MMBtu for Unit 2, which is below the anticipated MACT limit of 0.2 lb/MMBtu, allowing SO_2 emissions data to be used as a surrogate for HCl emissions. It is anticipated that any additional modifications at green would not provide any substantial additional reductions.
HMP&L 1&2	Existing WFGD	Unit 1 and Unit 2 currently both have dedicated WFGDs. Currently, operational data suggest that they are achieving SO_2 removal efficiencies of approximately 93% (Unit 1) and 90% (Unit 2). Based on these removal rates and the recent operational data, emissions will be around 2,227 tpy (Unit 1) and 2,745 tpy (Unit 2).

Unit	Technology	Comments
	Increase L/G	Currently, the absorbers at HMP&L operate with one out of two recycle pumps in service. Data collected from the plant where both recirculating pumps are used show that SO_2 removal efficiencies of >97% can be achieved. However, the dual pump operation inherently leads to loss of system redundancy and increased pressure drop across the absorber in an already fan-limited system. As a result, increasing the liquid-to-flue gas ratio at HMP&L will also require tipping of the existing ID fans, new fan motors, and installation of a third recycle pump to be used as a spare for each unit
	Additives	Either dibasic acid or sodium formate could be used to improve removal efficiencies of the current FGD system
Reid 1	Existing	Currently, Reid 01 has no SO_2 control technologies installed at its facility. As currently configured, the unit emits approximately 4,560 tpy of SO_2. The historical emissions from Reid 01 show that continuing current operation will significantly contribute to BREC overall fleet-wide SO_2 deficit
	New WFGD	Installation of a new WFGD system at Reid 01 would result in operational compliance with the proposed regulatory emission limits. Currently available FGD technology has been proven to achieve removal efficiencies of >99%
	Trona Injection	Injection of Trona into the flue gas stream has been proven to provide up to 80% SO_2 removal in some cases. However, due to the high volumetric flow required to produce such removal efficiencies, significant increase in ESP loading is to be expected, resulting in PM emission rate increases beyond allowable limits without significant ESP modifications or installation of a baghouse.

3.2.2 SO_3 Mitigation

The coupling of SCR and WFGD systems has resulted in unintentionally increasing the production and emission of sulfuric acid mist. The vanadium in SCR catalyst aids in the oxidation of SO_2 to SO_3. This results in a fraction of the SO_2 in the flue gas being oxidized to SO_3. When this SO_3 cools along with the flue gas, both going through the air heater and the WFGD, it combines with moisture, creating H_2SO_4 (sulfuric acid). The sulfuric acid mist forms into sub-micron aerosols that are not efficiently collected by conventional WFGD systems, and consequently pass through the FGD system and into the chimney. The resulting emission of sulfuric acid creates a blue plume and can bring a unit out of compliance for total particulate since the proposed MACT rule includes condensable particulate.

3.2.2.1 SO_3 Control Technologies

Removal of SO_3 from flue gas is accomplished by using a DSI system. The dry sorbent that is used for SO_2 capture (hydrated lime) can also capture SO_3 by injecting the sorbent into the flue gas stream after the air heater. The solid is then removed from the flue gas by use of a particulate removal system, such as an ESP or baghouse.

It has also been shown that it is cost effective to control the SO_3 with sorbent injection, which thereby reduces the activated carbon requirements for mercury removal. Less carbon is needed after reducing the SO_3 because SO_3 competes with Hg for adsorption in the pores of the activated carbon. However, the effect of sorbent injection on ESP performance should be tested before implementation.

3.2.3 NO_X Control Options

3.2.3.1 NO_X Control Technologies

3.2.3.1.1 Selective Catalytic Reduction Technology

In an SCR system, ammonia (NH_3) is injected into the flue gas at the exit of the economizer. This ammonia in the flue gas reacts with NO_X in the presence of a catalyst to form nitrogen and water. The catalyst enhances the reaction between NO_X and ammonia and results in high NO_X removal efficiencies with an economical use of the ammonia. The injected ammonia is adsorbed on the catalyst surface in the SCR reactor and reacts with the oxygen and NO_X present in the flue gas. SCR systems can typically achieve 80%–90% NO_X removal with outlet emissions of as low as 0.04 lb/MMBtu.

3.2.3.1.2 Selective Non-Catalytic Reduction Technology

The SNCR process uses a urea-based reagent that reacts with NO_X in the flue gas to form elemental nitrogen and water vapor. The driving force of the reaction is the high temperature within the boiler. Urea solution is injected into the boiler at locations in the unit that provide optimum reaction temperature and residence time. SNCR systems can typically achieve 15%–40% NO_X removal depending on the baseline NO_X emissions, injection temperature, residence time, and other factors.

3.2.3.1.3 State-of-the-Art Low-NO_X Burners (Third Generation)

Low-NO_X burners (LNBs) reduce emissions of NO_X by separating the air flow into two paths, staging the mixing of coal and air. This provides a fuel-rich region for char combustion, longer flames, and lower peak flame temperatures that helps limit the formation of thermal NO_X. LNBs generally use dual air registers in parallel to delay the mixing of air with coal injected through a coal nozzle in the center of the burner. While LNBs reduce NO_X, they may result in higher levels of unburned carbon as a result of incomplete combustion that occur from the staging of mixing. LNBs do not affect the emissions of other pollutants such as CO_2, SO_2, or particulates.

3.2.3.1.4 Overfire Air,, ROFA® and ROTAMIX ®

Conventional overfire air (OFA) systems cause intense turbulence in the upper part of the boiler and can effectively mix oxygen and flue gas in the upper furnace for effective completion of combustion and an overall reduction of NO_X. Selective non-catalytic reduction (SNCR) also may be combined with LNB or OFA to provide deeper emissions reductions for moderate capital investment. Addition of SNCR with an OFA system will add urea or ammonia to some or all of the OFA ports so that the ammonia is conveyed into the furnace where the temperature is most favorable for NO_X removal. Nalco-Mobotec USA refers to their combination of OFA/SNCR as ROFA (Rotating Overfire Air)/ROTAMIX, which is a patented technique by the developers of ROFA for mixing of NO_X-reducing chemicals in the furnace through their ROFA nozzles. In this technique, the same kind of asymmetrical air nozzles used for ROFA are used in the ROTAMIX technique. A booster fan is generally necessary for the OFA depending upon forced-draft fan characteristics. (A minimum of 8 in. H_2O pressure between the windbox and the upper furnace needs to be available.)

3.2 3.1.5 FMC PerNOxideSM Process

The PerNOxide process has been proposed by FMC and URS for a full-scale demonstration/installation of this NO_X removal process at Green Unit 1 or 2. The PerNOxide process involves the injection of hydrogen peroxide into the flue gas between the economizer and the air heater. The hydrogen peroxide oxidizes the nitric oxide (NO) into other nitrogen-oxygen compounds. Once these nitrogen compounds are formed, they must be captured to effectively remove them from the flue gas stream. Based on the estimates by URS/FMC of collection in the Green lime-based FGD system, there would be between 55% and 65% NO_2 removal in the scrubbers.

3.2.3.2 NO_X Control Strategies

Based on review of the provided data and the CSAPR limits, a reduction in fleet-wide NO_X removal is required. Except for Wilson and the Henderson units, all the other BREC units are large contributors to the BREC CSAPR emissions deficit and are preferred candidates for NO_X control technologies. The Green and Coleman units offer the greatest potential reduction improvements to meet the upcoming regulations. Overall fleet-wide NO_X emissions will need to be reduced by nearly 16% to meet BREC's 2014 allocations by means of various improvements through new equipment and retrofits. Table 3-2 below provides a list of the various new technologies and equipment improvements that were explored for improved NO_X control.

Table 3-2 — Candidate NO_X Control Technologies

Unit	Technology	Comments
Coleman 1/2/3	Existing LNB & (R)OFA	Coleman Units 1, 2, and 3 are all equipped with first-generation low-NOx burners. Units 2 and 3 have a conventional OFA system while Unit 1 has a second-generation ROFA system. With the currently implemented technologies, Units 1, 2, and 3 emit approximately 1,860, 1,590, and 2,050 tpy respectively and are a major contributor to the overall fleet-wide deficit.
	LNCFS III	Installation of the latest generation of Low-NOx Concentric Firing System (LNCFS) is expected to reduce formation of NOx more effectively than the current system. Supplementary technologies would need to be installed in conjunction with the LNCFS to reach acceptable emission rates.
	SNCR	Installing the latest SNCR technology will provide a significant improvement compared the currently installed technology. NOx reductions of approximately 20% can be expected for the Coleman units with the implementation of an SNCR. Although the units are short of their 2014 allocations by 47%–56%, the reduction significantly helps the overall fleet-wide allocation deficit.
	ROTAMIX (Unit 1)	ROTAMIX is a second-generation SNCR technology that can provide similar NOx reductions as the traditional SNCR but requires fewer modifications for units that have ROFA systems in place. Emission reductions of 20% can be expected with this technology.
	SCR	SCR could provide the Coleman units with significant reduction in NOx emissions However, based on plant walk downs conducted early in the project, there appears to be limited available space for the technology's anticipated footprint, thus increasing overall project cost Furthermore, because of the existing control technologies installed, the overall benefit of an SCR installation would not be as great as other units
Wilson	Existing LNB/OFA/SCR	Wilson currently has multiple technologies implemented for NOx control including SCR. Based on their existing systems and recent emission data, it is expected that Wilson will not require any additional upgrades to meet the anticipated emission limits
	Advanced Low-NOx Burners	In discussions with plant staff, it was noted that Wilson currently spends a large amount of O&M budget on maintaining their existing burners Upgrade to state-of-the-art low-NOx burners will provide some O&M relief, but is not expected to provide a reduction in NOx emissions.
HMP&L 1&2	Existing LNB/SCR	The existing low-NOx burners and SCR currently installed at HMP&L Units 1 and 2 are producing removal efficiencies adequate to meet the projected 2014 limits. If operation continues in a manner similarly to the baseline time period, BREC can expect excess NOx credits of approximately 520 tpy as compared to their 2014 allocations that can be shared to offset other facilities' deficits Plant staff noted that there are a number of issues causing excessive O&M efforts and costs with the existing burners.
	Advanced Low-NOx Burners	Although it is not anticipated BREC will significantly reduce NOx emissions by installation of third-generation low-NOx burners, the will provide relieve from their current O&M issues and may potentially offer some reduction in emissions.
Green 1&2	Existing LNB	Both Green units are equipped with first generation low-NOx burners. With the currently implemented NOx control technology, Units 1 and 2 emit approximately 2,050 and 2,170 tpy respectively and will need to reduce emissions significantly to comply with their anticipated allowance.
	SNCR	Installing the latest SNCR technology will provide an improvement compared the technologies installed currently at Green NOx reductions of approximately 20% can be expected for the Green units with the implementation of an SNCR.

Unit	Technology	Comments
	SCR	SCR would provide sufficient reduction in NO_x emissions and would result in excess credits to be shared amongst the other BREC units. Typical removal efficiencies for units comparable to Green are around 85%. Based on current operational data, installation of SCR at both Green units would result in an excess of approximately 2,250 tpy compared to the 2014 allocations. This excess would cover nearly all of the BREC fleet's shortage for 2014.
	Advanced Low-NO_x Burners with OFA	Upgrade to state-of-the-art low-NO_x burners along with OFA will provide some O&M relief as well as provide an approximate reduction of 432 tpy in NO_x emissions.
Reid 01	Existing LNB	Reid 01 is equipped with first-generation low-NO_x burners. With the currently implemented NO_x control technology, the unit emits approximately 5,066 tpy and would need to reduce emissions significantly (≈69%) to comply with their 2014 allowance.
	SNCR	Installing the latest SNCR technology will provide a significant improvement compared the NO_x technologies installed currently at Reid 01. NO_x reductions of approximately 20% can be expected for the unit with the implementation of an SNCR system
	SCR	SCR would provide sufficient reduction in NO_x emissions and would result in excess credits to be shared amongst the other BREC units. Typical removal efficiencies for units comparable to Reid 01 are around 85%. Based on current operational data, installation of SCR at Reid 01 would still result in a shortage of credits compared to the 2014 allocations.

3.2.4 PM Control Options

3.2.4.1 PM Control Technologies

3.2.4.1.1 Electrostatic Precipitator Upgrades

There are several available ESP upgrades which may be capable of reducing the filterable PM emissions from the existing ESPs. The potential ESP upgrades include the following:

- Installation of high frequency transformer-rectifier (TR) sets
- Rebuilding the ESP internals
- Adding an additional collection field to the ESP
- Converting part of the ESP to a baghouse (COHPAC II)

After reviewing the filterable PM emission rates from the BREC ESPs and based on S&L's engineering experience it was determined that upgrades to the existing ESP will achieve the required performance.

3.2.4.1.2 Dry Sorbent Injection for Condensable Particulate Matter

A significant contributor to condensable particulate matter is sulfuric acid (H_2SO_4). Dry sorbent injection (DSI) technology (previously explained as an SO_2 control technology) is the current industry standard to control acid gases including H_2SO_4; therefore, it may be a potential control technology for condensable PM emissions as a means of reducing the total PM. The use of DSI for compliance with the proposed Utility MACT limits for total PM is entirely dependent on the makeup of condensable PM which is currently unknown. Several sorbents are used for condensable PM control in the Utility Industry, these being Trona, sodium bicarbonate, and hydrated lime. Although hydrated lime is not as reactive as the sodium based sorbents (Trona and sodium bicarbonate) it will not affect the character of the fly ash being collected or the disposal of wastes, fixated or otherwise. In addition, BREC has familiarity with hydrated lime injection as it has been used for acid mist control for several years at the Wilson Station.

3.2.4.1.3 Baghouse Technology

There are several forms of baghouse technology which may be installed to achieve the required reduction in filterable PM emissions; these include:

- Converting part of the ESP to a baghouse
- Converting the existing ESP to a baghouse
- Adding a polishing baghouse
- Replacement of the ESP with a full baghouse

For those units that do not appear to be in compliance with the proposed Utility MACT limits for PM, an alternate approach to ESP upgrades or DSI may be required. If ESP upgrades or DSI are not capable of reducing emissions to below the Utility MACT limit, the unit will be required to install a baghouse. Baghouse technology would be capable of meeting a filterable PM outlet emission rate of 0.01-0.012 lb/MMBtu. It is not foreseen that the BREC units will require a baghouse to meet the anticipated MACT TPM emissions limits.

3.2.4.2 Particulate Matter Control Strategies

With the existing electrostatic precipitators and WFGD systems in service at the various BREC units, PM emissions are currently below the anticipated limits at the Green and Wilson facilities. TPM emission data collected for HMP&L, Reid 01 the Coleman Units shows that additional control or upgrade of the existing control systems will be required. Furthermore, because of the technology choices being considered to eliminate other pollutants (ACI, DSI, etc.) it is anticipated that modifications to the existing particulate controls will also be required for units that are currently below the 0.030 lb/MMBtu total PM limit and will be determined on a case-by-case basis based on overall required system upgrades.

3.2.5 Mercury Control Options

3.2.5.1 Mercury Control Technologies

When coal is combusted in a boiler, the mercury contained in the coal is released predominantly in three forms; particulate Hg, ionic (or oxidized) Hg, and elemental Hg. The quantity of each form of Hg that develops during combustion depends on a number of factors, including other constituents of the coal itself, such as the halogen content. The various types of mercury formed are called its speciation.

The speciation of mercury plays a significant role in the ease of its capture. The conversion of elemental mercury to oxidized mercury depends upon several factors;

- Cooling rate of the gas,
- Presence of a catalyst such as those found in an SCR,
- Presence of halogens (chlorides, bromides, fluorides, etc.) or SO_3 in the flue gas,
- Amount and composition of fly ash, and
- The presence of unburned carbon.

Particulate mercury exists in solid form and is removed to a significant degree by conventional particulate control equipment such as ESPs and baghouses.

Elemental mercury is insoluble in water and is generally not removed in normal particulate control devices or in an FGD system. In contrast to elemental mercury, oxidized mercury is highly water soluble. Wet FGD systems downstream of particulate control devices readily capture oxidized mercury.

Some technologies for mercury removal involve converting elemental mercury to water soluble, ionic mercury for capture in a downstream FGD. Others involve adsorption of mercury on activated carbon by the injection of carbon in the flue gas.

3.2.5.1.1 Fuel Additives

Halogen fuel additives, such as calcium bromide, are a low capital cost option for improving mercury capture for units equipped with mercury control technologies that have a low proportion of oxidized mercury to elemental mercury. Bituminous fuels, similar to that burned at BREC facilities, typically have higher (than PRB fuels) chloride concentrations in the coal, which inherently help in oxidizing elemental mercury. Halogen additives can be added to the coal (target approximately 100 ppm bromide in coal) to increase the amount of oxidized mercury to greater than 90% of the total mercury present in the flue gas. The oxidized mercury is more readily captured by carbon in the flue gas; in addition, lower injection rates or less expensive non-brominated carbon may be used to capture the mercury downstream.

It is recommended that before installing a permanent fuel additives system, a portable system be used to test the effect these additives have on the overall mercury capture and potential re-emission.

3.2.5.1.2 Activated Carbon Injection

Activated Carbon Injection (ACI) is a proven technology for mercury (Hg) reduction downstream of coal-fired boilers. ACI technology can achieve >90% reduction in total Hg. ACI has been proven effective in removing both oxidized and elemental mercury. The drawback to ACI use is the high cost of activated carbon.

Some flue gas constituents, especially SO_3, reduce the effectiveness of ACI. Operation of a DSI system before an ACI system may be required to reduce the SO_3 concentration to 3–5 ppm to improve the overall ACI effectiveness while maintaining high enough SO_3 concentrations to aid ESP performance. In addition, fuel additives can be combined with non-brominated carbon to potentially provide the required removal efficiency while using less carbon.

It should be noted that with the addition of an ACI system, the particulate loading to the ESP will be increased and that S&L recommends testing of the PM emissions with ACI to determine if any upgrades to the ESP are necessary.

3.2.5.2 Mercury Control Strategies

Mercury emissions testing at the BREC units indicate that HMP&L 1 & 2 currently meet the proposed MACT standard with no additional mercury controls. Mercury from units Coleman 1-3 and Green units 1-2 must be reduced by approximately 53% to 66% to meet the proposed MACT emission limits. Mercury emissions from Wilson 1 must be reduced by nearly 32% to meet the proposed MACT standard. Mercury from Reid 01 must be reduced by approximately 80% to meet MACT standard. Mercury control options capable of achieving the required removal efficiencies include Fuel additives to promote mercury oxidation and mercury capture in the units' ESP/FGD control systems, and activated carbon injection control system.

3.2.6 Intake Structure Impingement Mortality and Entrainment (316(b))

3.2.6.1 316(b) Compliance Technologies

Although 316(b) regulations have yet to be finalized there are several equipment suppliers that are actively developing various technological means of meet the proposed rule. Although none of the technologies discussed below have been implemented beyond test applications, there are specific operational characteristics that make certain technologies more viable than others at a particular site. Technologies that either reduce through-screen velocity to 0.5 fps or less or provide a means of returning impinged fish back to the supply body of water within the acceptable mortality rates are actively being considered by utilities for compliance along with other alternative means.

3.2.6.1.1 Replacement Screens with Fish Buckets / Return Systems

Test installations of traveling screen designs that are equipped with fish bucket and fish return systems have been shown to reduce impingement mortality to levels that would comply with the proposed regulations. It is expected that the entrainment portion of the standard can be met via the studies and testing described in Section 2.2 of this report. The traveling screens can be operated continuously, and any fish impinged on the screen will be lifted up in a horizontally mounted fish bucket and discharged safely into a trough as the bucket rotates up and over the top of the screen. Low pressure water provides for safe flushing of the fish back into the river. The scope of work involved in a traveling screen replacement such as this involves the removal of the existing traveling screens, replacement with new screens equipped with fish buckets and a fish return system, electrical and controls installation, and 316(b) approval Testing. Significant structural modifications are not expected since the new screens would be designed to fit into the existing screen guide channels of the intake structure(s).

3.2.6.1.2 Rotating Circular Intake Screens with Fish Pump

Rotating circular intake screens are designed to meet the 316(b) requirements by safely returning impinged fish to the river through the use of fish pumps. It is expected that the entrainment portion of the standard can be met via the studies and testing described in Section 2.2 of this report. These screens would be designed to match the size of the mesh in the existing traveling screen intake wells, or this mesh could be reduced somewhat if the entrainment compliance studies indicated this is necessary.

The scope of work involved in a rotating circular screen installation retrofit includes the removal of the existing traveling screens, existing intake structure concrete and channel modifications to accept the new screens, screen installation including fish pump and return systems, electrical and controls installation, and 316(b) approval testing

3.2.6.1.3 Cylindrical Wedgewire Screens

Another approach to meeting the target reduction in impingement is to retrofit the existing intake structure with cylindrical wedgewire screens in order to reduce the intake entrance velocity to a maximum of 0.5 fps. The existing intake structure would be modified to take suction through large screen headers that extend out into the river.

For river installation such as those being reviewed for BREC, the screen will require periodic cleaning due to debris buildup. To accomplish this, a compressed air system installed near the intake structure releases a large volume of compressed air to backflush any debris from the screen surface back into the river. The river current flowing across the cylindrical wedgewire aids in transporting the backflushed debris downstream away from the intake structure, helping to avoid re-entrainment onto the screen surface. Once a screen mesh size is selected, it is difficult to retrofit a different screen mesh size to address a new potential entrainment portion of pending legislation, since the surface area and size of the screens is determined based on mesh size.

The scope of work involved in a cylindrical wedgewire installation involves significant modification of the existing intake structure to accept the cylindrical wedgewire headers, mounting of cylindrical wedgewires underwater, including any required support structures, backflushing compressed air system installation, electrical and controls installation, and 316(b) approval testing.

3.2.6.1.4 Conversion to Closed Cycle Cooling

Closed-cycle wet cooling systems can reduce cooling water intake volume, and consequently IM&E impacts, by approximately 95% compared to once-through cooling, and would most certainly meet all anticipated 316(b) performance standards. Closed-cycle wet cooling will effectively reduce entrainment and, assuming the though-screen velocity of the make-up water intake structure does not exceed 0.5 fps, will effectively reduce impingement mortality. In addition to special constraints at Coleman and Sebree, when evaluating the feasibility of a retrofit closed-cycle wet cooling system, consideration must be given to collateral environmental impacts, including air emissions, visual impacts, and noise impacts. Due to the size of the cooling tower structure and their visible vapor plume, cooling towers have a visual and aesthetic impact on the surrounding area. Noise emissions during operation of the cooling tower must also be considered, particularly with mechanical draft cooling towers.

Based on a review of the intake velocities at Coleman and Sebree, which can potentially reach 2.4 fps, this study considers installation of a full-sized mechanical-draft cooling tower since even a partial-capacity closed-cycle system would be nearly the same size to reduce intake velocities by the required margin. Due to large capital and O&M costs when compared to the other available compliance technologies this option was not considered further.

3.2.6.1.5 Other Technologies - Behavioral Barriers

Behavioral barriers reduce impingement by triggering a behavioral response in fish causing them to avoid the intake flow. Behavioral barriers have been used with varying success, as behavioral responses are a function of fish species, age and size, as well as environmental factors at specific locations. Recent tests using advanced acoustic barrier technology have successfully reduced alewife impingement at intake structures located in the Great Lakes. Although behavioral barriers, including light and sound, have been used with some success at certain locations, studies would have to be conducted to determine the effectiveness of sound, light, and/or other behavioral barriers at Coleman and Sebree stations. Although it provides a potentially low-cost solution, behavioral barriers will not be considered for further screening and cost estimate purposes since extensive local testing would be needed to establish this as a best technology available.

3.2.6.2 316(b) Compliance Strategy

The proposed regulations for 316 (b) do not mandate a cooling tower as the required technology selection. As such, this study will evaluate practical, relatively low cost screen options for installation at the Coleman and Sebree stations. Technologies described above that will be considered for further screening and cost estimating evaluation are as follows:

- Replacement Screens with Fish Buckets / Return Systems
- Rotating Circular Screens with Fish Pump
- Cylindrical Wedgewire Screens

3.2.7 Coal Combustion Residual Options

3.2.7.1 Coal Combustion Residual Technologies

All BREC units (except Reid 01) are equipped with WFGD and fly ash waste product handling and disposal operations. These systems can continue as-is, although potentially significant (Subtitle C) or minor (Subtitle D) increases in handling and disposal costs may occur. With exception of Wilson which currently has dry bottom ash disposal with an existing SSC, new bottom ash technologies evaluated are as follows:

3.2.7.1.1 Submerged Scraper Conveyor

A submerged scraper conveyor (SSC) provides for removal of the bottom ash by transporting the bottom ash up an inclined dewatering ramp before discharging into a bottom ash enclosure for removal by front end loader and trucks. If the bottom ash is going to be stored in a silo before disposal, then the SSC discharges through a crusher, then the crusher discharges to a vertically inclined drag-type chain conveyor or belt conveyors for transport to the bottom ash storage silo.

A closed loop recirculating system is used for supplying cooling water to the chain conveyor trough. The recirculating system includes a holding tank, heat exchanger, pump and water treatment (pH control) system. The horizontal section of the drag chain conveyor is adequate for three (3) hours of storage during periods of peak bottom ash production rates. The conveyor flights are designed with replaceable abrasion resistant wear strips to allow for wear resistance on both the conveying and return cycles. The conveyor flights are moved by two strands (or a double strand) of carburized chain. New pumps and electrical equipment would be housed in new buildings located by the SSCs.

Depending on the space constraints underneath the boiler, the SSC may be either mounted directly under the hopper or it may be mounted remotely. The remote submerged scraper conveyor (SSC) system provides for removal of the bottom ash from the boiler hopper(s) using the existing sluice system to transport the ash to the SSC, before discharging into a bottom ash enclosure for removal by front end loader and trucks. Based on a review of the plant general arrangement drawings and site walkdowns, the available space adjacent to the boiler buildings at the BREC stations is limited due to existing structures. As such, a remote SSC installation is considered as the basis for this study.

3.2.7.1.2 Dry Ash Cooler / Conveyor

The main component of the dry ash conveyor system is the extractor, which is designed to operate in harsh conditions including exposure to high temperature and shock loads caused by the fall of large clinkers. The extractor is connected to the boiler throat through a refractory-lined hopper or a transition chute, which provides a volume for temporary ash storage. The hopper is available with bottom doors which can be closed to isolate the extractor and for ash storage. The hopper or transition chute is connected to the boiler throat by a high temperature mechanical seal that allows for boiler expansion. The key element of the extractor is the hardened steel belt conveyor, which receives and extracts bottom ash falling from the boiler. The belt is enclosed inside the sealing casing of the extractor.

During the conveying of ash on the belt, ash is cooled by a small, controlled amount of ambient air that flows by natural draft into the casing through inlet valves. In addition the air provides oxygen to the unburned ash allowing a more complete combustion and return of heat to the boiler. Data from existing installations indicate reverse air flow does not disturb the combustion process and does not influence NO_X formation. From the extractor, the cooled ash is discharged into a crusher, which reduces the large ash clinkers to a size suitable for conveying to a silo. Any ash fines that fall on the casing floor are swept off by the spill chain, a small scraper conveyor installed under the belt.

There are currently only two manufacturer's of the dry ash conveyor, Magaldi Industries and United Conveyor Corporation (UCC). This system can only be used when installed directly under the boiler hopper(s). Based on a review of the BREC site general arrangements and site walkdowns, there does not appear to be sufficient space on either side of the boilers at Coleman, HMP&L and Green for installation of a dry bottom ash cooler / conveyor.

3.2.7.1.3 Dewatering Bin System

This type system is also referred to as a closed-loop recirculation system which converts a wet sluice system into a "dry" ash system without change to the existing bottom ash hopper. A complete recirculation system replaces the ash pond with dewatering bins which separates the water and ash, a clarifying (settling) tank and surge (storage) tank and associated pumps and piping. The dewatering bin is designed to remove and drain water from solid materials that have been pumped into the bin in a slurry form. The dewatering bin, a cylindrical steel tank with a conical bottom, is custom sized for various material tonnage capacity requirements. Typically constructed of mild steel plate, the bin can also be constructed with alloy materials for exceptionally corrosive conditions.

The clarifying (settling) tank, is a cylindrical steel tank with a conical bottom, is used to remove the remaining fines from the water, return the fines to the dewatering bin and send the decanted water to the surge tank. The settling tank is custom sized for various material tonnage capacity requirements. Typically constructed of mild steel plate, the bin can also be constructed with alloy materials for exceptionally corrosive conditions. The surge (storage) tank, is a cylindrical steel tank with a conical bottom that is used to store the decanted water and provide a suction head for the recirculation system return pumps. The surge tank is custom sized for various material tonnage capacity requirements. Typically constructed of mild steel plate, the bin can also be constructed with alloy materials for exceptionally corrosive conditions.

This system reuses the conveying water and only requires a small amount of make-up water. The recirculation system is ideal when water supplies are available and minimal outage time is required to make the conversion. The ash is unloaded from the dewatering bins into transport vehicles for disposal.

3.2.7.2 Coal Combustion Residual Strategies

Data collected during site walkdowns and discussions with plant staff indicate that modifications will be necessary at Coleman, Wilson (pneumatic transport modifications for Subtitle C only), Green, Reid 01 and the HMP&L units. Elimination of the existing ash ponds at Coleman, Green, Reid 01 and HMP&L is expected with either Subtitle C or D. The technologies discussed above will be considered for further screening and cost estimating evaluation.

3.3 OTHER COMPLIANCE STRATEGIES

3.3.1 Purchase of Emission Allowance Credits

The purchasing of emission allowance credits may be an economically justifiable compliance strategy, or part of a compliance strategy involving lower cost equipment or system than would otherwise be required. This study evaluates this approach by estimating the future cost of credits under the proposed regulations, and then reflecting these costs as operating expenditures that can be compared with the capital and O&M costs associated with new technology installation. It should also be noted that such a strategy is highly sensitive to credit market costs and availability and may not be economically justifiable on a long-term basis.

3.3.2 Conversion to Natural Gas

In addition to the compliance methods explored for various pollutants above, there is also the possibility of converting a coal-fired boiler to operate on natural gas. Conversion to natural gas would greatly reduce SO_2 emissions and also exclude the EGU from any potential MACT compliance. NO_X emissions would also be reduced from uncontrolled levels by approximately 40%. Due to lack of slagging, tube temperature limitations and other inherent design differences between natural gas and coal-fired boilers, it is typical that a 20% derate must be applied. Furthermore, modifications to the existing burners and installation of a flue gas recirculation system should be implemented to improve overall system performance and reduce NO_X emissions. Because of limited natural gas supply infrastructure near several of the BREC facilities, conversion was considered to only be viable at Sebree, specifically at Reid 01 and the Green Units. If additional supply is required for conversion of those units, BREC has indicated that an existing main trunkline is within approximately five (5) miles of the Sebree Station.

3.3.2.1 Reid 01

Half of the burners at Reid 01 were previously retrofitted with new natural gas burners and a natural gas supply fuel system. Based on interviews with plant staff, the system has never been permitted for operation. Although most of the infrastructure is in place, it is recommended that the existing system be inspected and tested before putting into operation. If a heat input near the baseline is maintained, Reid 01 should expect nearly untraceable SO_2 emissions and NO_X emissions reductions of approximately 220 tpy. The nearly 5,000 tpy reduction in SO_2 emissions would be available to the other BREC units to aid in achieving overall fleet-wide compliance.

3.3.2.2 Green 1 & 2

The Green units are the second most appropriate candidates for natural gas conversion. For each unit conversion, BREC can expect an approximate reduction of 1,400 tpy of SO_2 and 1,000 tpy of NO_X emissions provided a heat input similar to the baseline is maintained. It should also be noted that if BREC were to decide to convert either or both of the Green units for natural gas operation, an additional gas supply line would need to be routed from the existing off-site supply header to support the increased demand.

3.3.3 Retirement of Existing Units

Unit retirement is another potential strategy for compliance with the various EPA regulations. By retiring an existing unit, BREC will continue to receive that unit's CSAPR credit allocations for four years after the unit's last date of operation. Once the four year time period has elapsed, BREC will no longer have access to those credits and will have to adjust remaining plant operations to meet the reduced fleet-wide limits.

Because Reid 01 has minimal NO_X and SO_2 controls in place and it is one of BREC's smallest units, it becomes the best candidate for such a strategy. The unit's overall relative contributions to BREC's CSAPR deficit are larger than the other units and would require improvements to both SO_2 and NO_X controls. Being that the unit is 72 MW it also poses less of an impact to overall fleet-wide capacity than potentially retiring other units. If Reid 01 were retired, BREC would reduce their fleet-wide SO_2 and NO_X emissions by 5,066 tpy and 512 typ respectively and could use those to offset other station emissions.

Last page of Section 3

4. PHASE III – TECHNOLOGY SCREENING AND SELECTION

4.1 SO_2 AND ACID GAS CONTROL OPTIONS

4.1.1 Existing SO_2 and Acid Gas Controls

All Big River Units except Reid 01 are equipped with WFGD air quality control systems. Based on their present operation the BREC fleet with the exception of Wilson and Reid 01 will meet their station specific 2012 allocations limits. Fleet-wide, BREC needs to reduce its yearly baseline SO_2 emissions by 3% (808 tons) to comply with the 2012 CSAPR allocations. A much greater fleet-wide reduction of 50% (13,643) is needed compared to the baseline emissions of 27,286 tpy to comply with the 2014 CSAPR limits. As stated in Section 3.2.1, it is anticipated that the SO_2 emission rates resulting from modifications at some BREC units will be at or below 0.20 lb/MMBtu which will allow SO_2 stack emissions data to be reported as a surrogate for compliance with the proposed acid gas MACT limits. Units above the SO_2 limits will require HCl monitors for compliance.

Recent operational data from Coleman Units 1-3 suggests that the existing WFGD is operating at approximately 93.5% SO_2 removal, resulting in an average annual emission of around 7,150 tpy. CSAPR allowances for Coleman are 8,195 tons for 2012 and 3,526 tons for 2014. Similarly, current HMP&L data suggests a removal efficiency of 93% for Unit 1 and 90% for Unit 2 which implies emissions of 2,227 tpy and 2,745 tpy for Units 1 and 2 respectively. These levels are within the 2012 CSAPR emission limits of 2,518 tons and 2,997 tons but are above the 2014 allocations of 1,251 tpy and 1,289 tpy.

Green units 1 and 2 current average of 3,290 tpy, is adequate removal for 2012 CSAPR emission limit of 3,849 tpy along with 3,735 tpy for 2014. Similarly, data for Reid RT suggests average emissions of 5 tpy which will stay within compliance for 2012 limits of 11 tpy and 9 tpy for 2014.

Wilson currently uses a Kellogg-Weir horizontal scrubber and recent data approximates SO_2 removal efficiency at 91% resulting in an average annual emission of around 9,450 tpy which is significantly over the emission limit of 8,400 tons for 2012 and 3,614 tons for 2014. Reid unit 1 currently has no SO_2 control technologies implemented. The unit on average emits approximately 4,560 tpy and predictions increase emissions to 5,066 tpy for 2012. The 2012 CSAPR limits emissions to 508 tpy. Historical emissions predict that continuing current operations will significantly contribute to BREC' overall fleet-wide SO_2 emission deficit.

S&L reviewed the entire EPA information collection request (ICR) database covering HCl and HF emissions from coal fired power plants. All Big River Units except Reid unit 1 are equipped with both ESPs and WFGD air quality control systems which are capable of removing HCl and HF. It is expected that if WFGD SO_2 removal efficiencies of ~97% or higher are achieved, the HCl emissions will meet the EGU MACT requirements without any further modifications. Furthermore, current emissions of the Green units are below the anticipated MACT limit of 0.2 lb/MMBtu, which would allow SO_2 emissions to be used as a surrogate for HCl emission monitoring.

4.1.2 Improved Spray Nozzles and Increased Liquid-to-Gas Ratio

Increasing the L/G (Liquid to Gas Ratio) in the wet FGD provides an environment for higher SO_2 absorption from the flue gas by the increased amount of liquid spray. The additional liquid slurry spray provides more surface area contact for the flue gas to react with, resulting in further removal of SO_2.

Increasing the L/G in the HMP&L units would be implemented by running both recirculating pumps on each absorber. Installation of a third pump for each absorber will provide use as a spare for reliability purposes. Tests at HMP&L were performed and the data collected confirms the ability for two pump operation to increase SO_2 removal to ~97%. Averaged SO_2 baseline data showing average SO_2 removal of single pump operation from July, 2011 and test trial data showing operation of two recirculating pumps is shown in Table 4-1. Feedback from plant staff indicated that while the tests were being conducted with two pumps the ID fans were at maximum capacity and unstable due to the increase in pressure drop across the FGD. Because the unit experienced limited fan capacity, ID fan modifications, including tipping the fan blades and installing new motors, will be considered as part of this modification.

Table 4-1 — HMP&L Scrubber Pump Test Data

	Inlet (lb/MMBtu)		Outlet (lb/MMBtu)			
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2
Test	SO_2	SO_2	SO_2	SO_2	Removal (%)	Removal (%)
Single Pump	5.20	5.34	0.341	0.503	**93.5**	**90.3**
Dual Pump	5.50	5.51	0.127	0.162	**97.7**	**97.1**

The data from the testing confirms sufficient increase in SO_2 removal with the addition of the second recycle pump to comply with the anticipated 2014 CSAPR and 2015 MACT limits. SO_2 removal percentage increases, on average, from 93.5 to 97.7 in HMP&L Unit 1 and from 90.3 to 97 for Unit 2 based on the 24 hour testing with a second pump in service.

4.1.3 Additives

Organic acid additives have been known to improve the SO_2 removal efficiency in WFGD systems by about 5%. SO_2 efficiency improvements can generally be achieved with as low as 500 ppm acid in the absorber slurry. The most common organic acids used in WFGD applications are dibasic acid (DBA), Adipic acid, Formic acid, and Sodium Formate. The addition of organic acids will require capital investment in storage and injection systems. There will also be an annual operating cost associated with the additive addition. The Wilson station currently uses organic acid to enhance FGD performance.

4.1.4 New WFGD Absorber

The Wilson plant currently operates a horizontal scrubber system that is one of only six built. Four of the six scrubbers are currently being decommissioned or are no longer in operation. This is a result of their inability to achieve high SO_2 removal standards of current and future regulations, even with modifications. Replacing the existing horizontal flow absorber vessel with a vertical flow absorber is a proposed SO_2 control strategy due to the minimal probability of achieving higher removal efficiencies with the existing technology. Installation of a new vertical scrubber would increase overall removal from ~91% up to ~99%.

Unit 1 at the Reid station currently does not use any SO_2 control technologies. Installation of a new WFGD system at this station would result in operational compliance with the proposed regulatory emission limits. Currently available wet FGD technology has been proven to achieve removal efficiencies of up to 99%.

4.1.5 Natural Gas Conversion

Converting an existing coal-fired unit to natural gas almost eliminates SO_2 emissions. For instance, Reid 01 has a baseline annual emission of 5,066 tons and after a gas conversion would emit approximately 1 tpy. Similarly, converting Green 1 and 2 to natural gas would reduce their overall annual emissions by 1,870 tpy and 1,411 tpy respectively. Conversion usually requires installation of new burners and a flue gas recirculation system to improve boiler efficiency and typically necessitates a derate of the unit.

4.1.6 Other Recommendations

Because the three Coleman units share a common WFGD there are operational scenarios when the absorber is out of service and the operating units must bypass the absorber and discharge into existing unit specific stacks. This operational mode causes uncontrolled SO_2 flue gas to be emitted and increases the overall emissions of the plant. For instance, if the scrubber were to be out of service along with one of the three units and the other two units were operating in bypass at an 85% capacity factor for eight (8) hours, an estimated 66 tons of additional SO_2 would be released from those two units than if they were operating with the WFGD in service. Regardless of approach for reducing SO_2 emissions, BREC should conduct a condition assessment to determine methods of improving WFGD system reliability to reduce the likelihood and duration of WFGD outages. In addition, BREC may also want to consider implementing a planned and forced outage strategy that prevents WFGD bypass operation to prevent uncontrolled emissions.

4.2 SO_3 MITIGATION

It is recommended that DSI systems be installed for CPM capture purposes at all BREC units except for units that are potentially converting to natural gas. Installing a technology to reduce SO_3 concentrations in the flue gas can provide a number of benefits. The air preheater pluggage and duct corrosion downstream of the air preheater is an operational concern for the Big River units. These problems are most likely the result of high SO_3 concentrations in the flue gas. In addition, the removal of NO_X on the SCR is limited by the interaction of SO_3 with the ammonia slip. SO_3 reduction will also reduce CPM emissions which reduces TPM limits that are regulated by the EGU MACT. If activated carbon injection is used as a mercury reduction technology, SO_3 reduction can reduce activated carbon usage, since SO_3 competes with Hg for adsorption sites on the activated carbon.

4.3 NO_X CONTROL OPTIONS

4.3.1 Existing NO_X Controls

All BREC units are currently operating with first-generation low-NO_X burners. The Coleman and Wilson units are each equipped with over-fire air systems. Wilson and HMP&L units also have SCRs installed. With the current control technologies, the BREC fleet's annual emissions are approximately 12,074 tpy. The 2014

CSAPR NO_X emission limits for the fleet total is 10,142 tpy, which would leave BREC with a deficit of 1,930 tpy in NO_X credits.

The current low NO_X burners in combination with over fire air system (Unit 2-3) and rotating over fire air system (Unit 1) at the Coleman and HMP&L units do not achieve sufficient NO_X reduction to comply with 2014 CSAPR emissions requirements. If no additional NO_X removal is achieved, credits will need to be purchased to meet the future regulatory requirements. For the combination of Coleman units, NO_X credits would need to be purchased to cover the difference between the actual NO_X emissions. The total Coleman NO_X emission is estimated to be 5,488 tpy while the anticipated 2014 Phase II CSAPR emissions limit is 2,065 tpy. Based on EPA's distribution of credits, Coleman would be short 3,423 tpy when compared to the site Phase II allocations.

The current technology at the Green units does not sufficiently reduce NO_X emissions for the 2014 CSAPR limits. Units 1 and 2 emit approximately 2,050 and 2,170 tpy respectively, while their combined limit is 2,890 tpy. Green units will need to significantly reduce NO_X emissions to comply with their anticipated allowance or they will be forced to purchase over 1,300 tpy in NO_X credits. Reid units will also have to reduce their annual emissions of around 560 tpy by 69% to be within compliance for their anticipated 2014 limits of 166 tpy.

Currently, the HMP&L SCR in combination with low NO_X burners is providing enough NO_X removal to give BREC an emission surplus, thus does not need any modifications. The amount of potential excess NO_X credits available would be approximately 982 tpy. Wilson also operates low NO_X burners in combination with an SCR, which would provide a NO_X emission surplus of 1,711 tpy for the 2014 CSAPR limits.

4.3.2 Advanced Burners

The low-NO_X concentric firing system (LNCFS) was developed for tangentially fired systems. The advanced technology separates the fuel and air streams for the tangential fired arrangement. This system applied to the Coleman station would reduce emissions approximately 10% in comparison with their current LNBs. However, it is foreseen that supplementary technologies would need to accompany the LNCFS to reach acceptable emission rates.

The Wilson station already has first generation LNB, OFA, and SCR technology implemented and meets the anticipated emission limits. There are planned upgrades for implementation of third generation LNB to reduce

O&M costs. Similarly, the HMP&L units currently have LNB and SCR technologies implemented and meet the anticipated emission limits but have a planned upgrade to install third generation LNB to alleviate O&M issues. Installation of third generation LNB at the Wilson and HMP&L units are not anticipated to provide any substantial reduction in NO_X emissions.

4.3.3 FMC PerNOxideSM Process

The PerNOxide process has been proposed by FMC and URS for a full-scale demonstration/installation of this NO_X removal process at Green Unit 1 or 2. The PerNOxide process involves the injection of hydrogen peroxide into the flue gas between the economizer and the air heater. The hydrogen peroxide oxidizes the nitric oxide (NO) into other nitrogen-oxygen compounds including

- NO_2
- N_2O_5
- HNO_2
- HNO_3

with a series of reactions that includes

$$H_2O_2 + NO \rightarrow H_2O + NO_2$$

$$2H_2O_2 + 2NO_{2+} \rightarrow H_2O + 2HNO_3 + \frac{1}{2} O_2$$

Once these nitrogen compounds are formed, they must be captured to effectively remove them from the flue gas stream. This is especially important with NO_2 since a high enough concentration of NO_2 can cause a brown plume to form at the chimney exit and with HNO_3 (nitric acid) due to its corrosivity. For implementation at the Green Station, the process would depend on the wet lime scrubbers to capture the nitrogen compounds. These compounds would be captured as soluble calcium nitrite ($Ca(NO_2)_2$) and calcium nitrate ($Ca(NO_3)_2$) and would need to be immobilized by the Pozotec process used at Sebree for wastes disposal. To date, there has not been any published test results that show that nitrates and/or nitrites can be immobilized in a fixated flyash/scrubber sludge matrix.

and below were presented by FMC/URS to BREC as an example of the PerNOxide process applied to the units at R. D. Green. It was projected that a reagent molar ratio of 1.5:1 would be used and therefore, based on the economizer outlet temperature, would oxidize approximately 55% of the NO to NO_2 producing about 60 ppm of NO_2 exiting the air heater. Based on the estimates by URS/FMC of collection in the Green lime-based FGD system, there would be between 55% and 65% NO_2 removal in the scrubbers. It should be noted that URS stated that the NO_2 removal was a projection based on laboratory data and that pilot-scale testing would be needed to validate the laboratory results. Even if the removal projections were correct, this would result in an emission of about 25 ppm of NO_2. A paper by G. Blythe and C. Richardson of URS at the 2003 EPA/DOE/EPRI/AWMA Megasymposium stated "NO_2 has a brown color that can lead to flue gas plume coloration and increased opacity at concentrations as low as 10 ppm."

The experimental nature of the PerNOxide process, coupled with the potential for both a brown plume and a waste material with soluble nitrates and nitrites, does not recommend itself for implementation at the Green Units. Accordingly, S&L did not consider this process further in the technical evaluation.

Figure 4-1 — PerNOxide Oxidation of NO by Hydrogen Peroxide

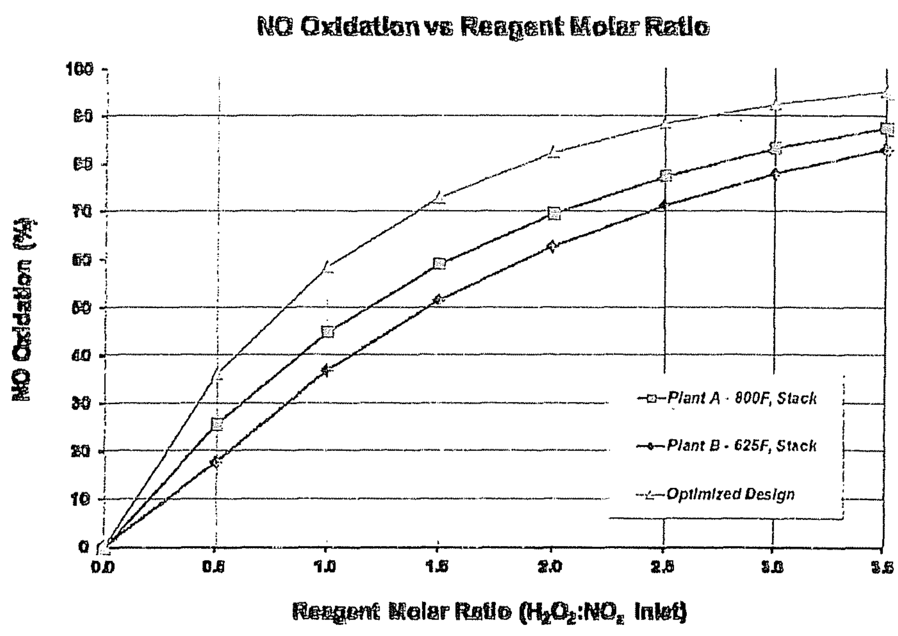
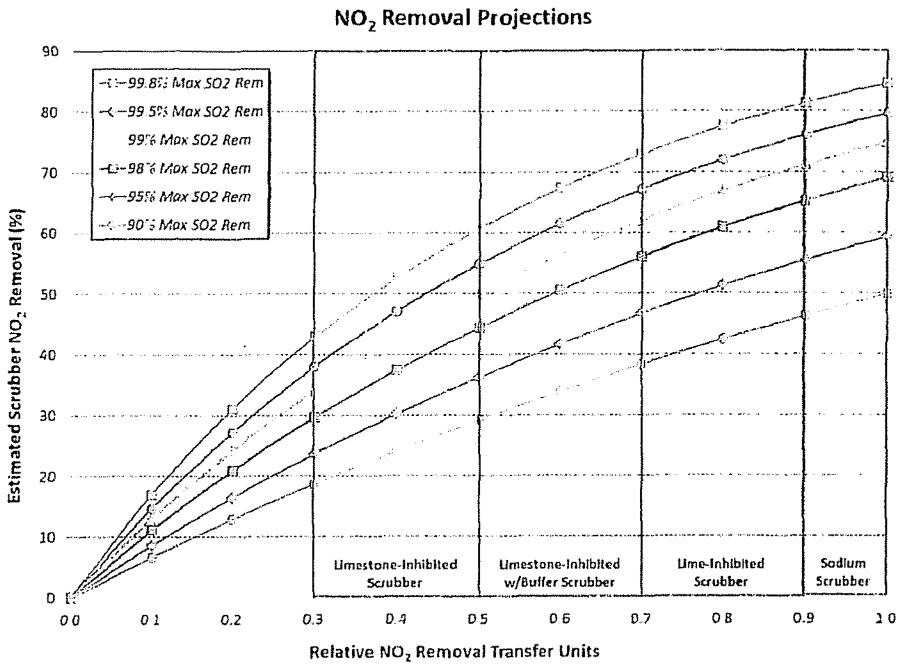


Figure 4-2 — Projected NO_2 Removal in FGD Systems Based On Laboratory Bench-Scale Results



4.3.4 Selective Non-Catalytic Reduction

The SNCR process does not require catalyst to drive the reaction; instead the driving force of the reaction is the high temperature within the boiler. NH_3 is injected into the hot flue gas at a location in the unit that provides optimum reaction temperature and residence time. The overall reactions of the SNCR process are as follows:

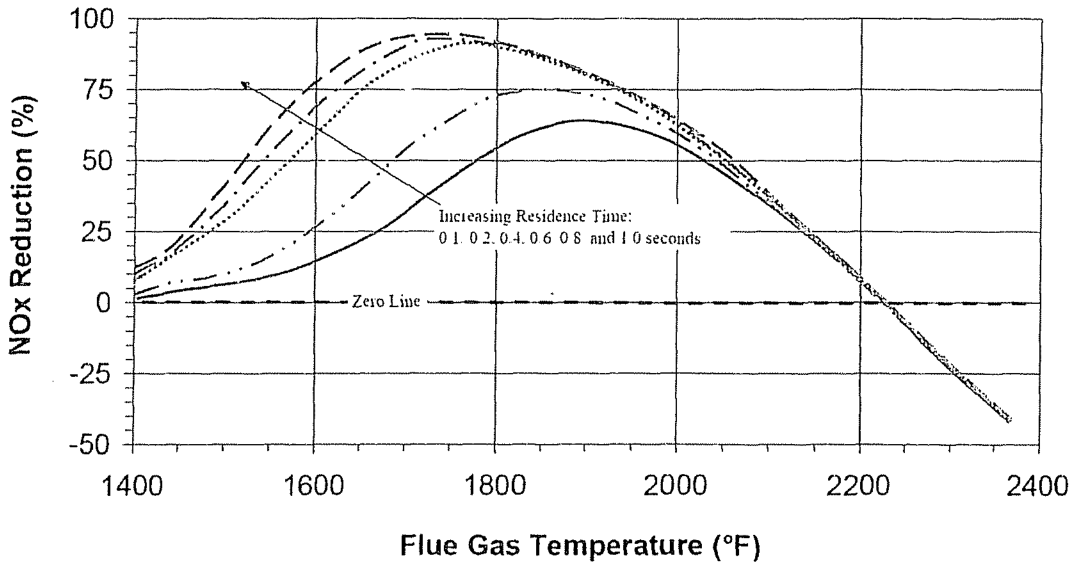
$$NH_2CONH_2 + H_2O \longrightarrow 2NH_3 + CO_2$$ (occurs between 1600°F and 2200°F)

$$2NH_3 + 2NO + 0.5O_2 \longrightarrow 2N_2 + 3H_2O$$

$$2NH_3 + 2.5O_2 \longrightarrow 2NO + 3H_2O$$ (occurs above 2000°F)

The preferred temperature range for this reaction is within 1600 and 2000°F, as shown in Figure 4-3. The best NO_X removal is achieved between 1700°F and 1850°F. At temperatures over 2000°F, NH_3 will oxidize and increase NO_X emissions. At temperatures below 1700°F, there will be more un-reacted NH_3, leading to higher ammonia slip.

Figure 4-3 — Theoretical NO_X Removal with SNCR Technology



Source: EPRI TR-102414, 1993 Report

Typically, NO_X removal efficiencies of 10-40% can be achieved with SNCR technology. While it is possible to achieve 40% NO_X reduction with SNCRs, 20% was chosen because factors such as ammonia slip, CO production, CO baseline values, and boiler temperatures all contribute to NO_X reduction capabilities. Without having boiler baseline test data, S&L conservatively estimates that SNCR can achieve 20% removal.

ROTAMIX® is a second generation SNCR technology provided by Nalco-Mobotec. It is a system that improves reagent mixing in the flue gas which in turn decreases the total chemical usage. The system also uses compressed air to increase penetration instead of water. The installation of ROTAMIX on Coleman Unit 1 instead of a traditional SNCR will incorporate significantly fewer modifications since the ROFA system is already in place. For Coleman units 2 and 3, that currently have conventional OFA systems, the addition of traditional SNCRs were assumed.

While SNCR systems are generally a lower capital cost option to reduce NO_X, the technology has certain disadvantages. For example, SNCR can result in increases in CO emissions. When water is injected in the boiler, it creates lower localized temperatures that inhibit the carbon in the coal from fully oxidizing to CO_2; instead a portion stays in the form of CO.

In addition, the effectiveness of SNCR is limited in regions with low oxygen, which is indicated by the presence of high amounts of CO in the boiler. If CO levels are above approximately 500ppm at the throat of the boiler, the NO_X removal can be severely limited. If boiler tuning does not bring CO levels down to an acceptable level, SNCR technology may not significantly reduce NO_X emissions. Testing would need to be conducted prior to selecting SNCR technology to ensure that SNCR would be effective at Coleman and Green stations.

Compared to SCR technology discussed in Section 4.3.5 below, SNCR systems have higher ammonia slip values. SCR is capable of achieving up to 90% NO_X removal with slip values of less than 2ppmvd NH_3 at 3% O_2, and that high of ammonia slip is only reached at the end of catalyst life. SNCR systems can achieve 5ppm slip, but to achieve higher NO_X removal it may be necessary to operate around 10ppm. SNCR slip can also vary more in load following units. Higher ammonia slip levels can lead to ammonium bisulfate (ABS) formation that can cause fouling of air heaters and precipitators. ABS pluggage can be a significant maintenance expense. In addition, higher ammonia slip values from SNCR can preclude ash sales for those units that market their ash.

The final concern with SNCR technology is its load-following capabilities. In general, SNCRs have a slow response to load shifts because the reactions are so dependent on temperature. As load increases or decreases, the optimum reaction temperature shifts up or down in the boiler. To minimize this effect, three levels of injection lances can be installed; although it is not always physically possible to do. This would allow greater opportunity to utilize the optimum temperature region by shifting which level is being used for injection.

4.3.5 Selective Catalytic Reduction

SCR technology allows for significantly higher reduction of NO_X in the flue gas than SNCRs due to the addition of the catalyst. However, the implementation of the system would include a much larger footprint, due to the additional space that the catalyst and duct work require. Coleman units are in the highest need of NO_X reduction in comparison with the rest of the fleet. Installation of SCRs at Coleman stations would significantly increase NO_X removal efficiencies (≈85%), however there does not appear to be enough room for the anticipated footprint of the technology.

Addition of SCR technology at the Green units also predicts NO_X reduction of approximately 85%. This would reduce emissions to below the anticipated 2014 allocation limits. Based on current operational data, installation of an SCR at either Green unit would result in reduced emission rates of approximately 1,800 tpy. This emission reduction would nearly cover the 1,932 tpy fleet-wide 2014 CSAPR allocation shortage.

Reid Unit 1 would also receive around 85% removal efficiency with the installation of an SCR system. However, based on current operational data, Reid 1 would still operate in a deficit compared to its 2014 allocations.

4.4 PARTICULATE MATTER CONTROL OPTIONS

4.4.1 Existing Electrostatic Precipitators and Wet Flue Gas Desulfurization Systems

All BREC units, except for Reid, are already equipped with ESPs and WFGD technologies. Unlike SO_2 and NO_X, which are under CSAPR regulation, particulate matter is under regulation by the MACT ruling. It is not possible to buy and sell emissions credits to stay in compliance with MACT. Therefore it is necessary for each site to be under 0.03 lb PM/MMBtu to comply with the anticipated allowance. Under the proposed regulations, either periodic stack testing or an installed PM continuous emission monitoring system (CEMS) will be needed to verify compliance.

Currently, Coleman Units 1, 2, and 3 are each equipped with an ESP and routed to a shared WFGD. Together the units emit approximately 0.0398 lb/MMBtu of PM and will need to reduce their total PM emissions by nearly 25% to comply with the anticipated MACT allowance. HMP&L units also are equipped with an ESP and WFGD system, yet still are not within compliance of the anticipated MACT limits. Current data suggests Unit 1 emits 0.0319 lb/MMBtu and Unit 2 emits 0.0324 lb/MMBtu of PM. Emissions would have to be reduced by approximately 6% to comply with their anticipated allowance.

The Wilson station is equipped with an ESP along with a Kellogg horizontal scrubber. With use of the current technologies, emissions are approximately 0.02 lb/MMBtu, which is within proposed MACT compliance limits. Each Green unit is also within compliance levels with emissions levels below 0.02 lb/MMBtu. These levels are achieved with the current ESP and WFGD systems in place.

4.4.2 Electrostatic Precipitator Upgrades

Recent stack and ESP test data suggests that the Coleman ESPs are currently achieving approximately 94% overall removal efficiency for particulates. Upgrading the current ESPs by installing advanced electrodes and high frequency transformer-rectifier (TR) sets will decrease particulate emissions to approximately 0.029 lb/MMBtu to keep within MACT compliance. HMP&L units are also equipped with ESPs that are currently achieving around 98% removal efficiency. By installing the same ESP upgrades as described for Coleman, data suggests PM emissions would be reduced to 0.029 lb/MMBtu for each unit.

Stack data was also collected for the Wilson unit that is currently operating an ESP. The data suggests that this unit is achieving approximately >99% removal efficiency for PM. Upgrades to the ESP will not further affect the removal efficiencies, since they are already achieving 99% removal. The same is true for the units at Green. However, potential ESP upgrades may be required if ACI and DSI systems are implemented upstream, due to the increased particulate loading.

4.4.3 Sorbent Injection

Condensable particulate matter (CPM) is also a major factor in PM compliance. These particulates are not removed by ESP or baghouse filter techniques. Since total PM is measured by adding CPM with filterable PM emissions, reduction of CPM is just as important as removing the filterable particulates. All BREC units except Wilson would benefit from the addition of a Hydrated Lime DSI system. Wilson currently has a DSI system installed and has demonstrated CPM emissions of 0.010 lb/MMBtu. CPM emissions are responsible for 45% of the total particulate emissions at the Coleman stations, 57% at Green Unit 1 and 73% at Unit 2, and nearly 45% at HMP&L Unit 1 and 63% at Unit 2. With the addition of a DSI system, CPM emissions can be expected to reduce approximately 50% at each of these units.

4.4.4 Baghouse

Baghouses for the BREC stations are not expected to be necessary for compliance with the total PM limits or mercury limits proposed in the EGU MACT rules. With the expectation that other lower cost technology combinations can achieve the proposed EGU MACT compliance; an estimated capital cost for installation of a baghouse at the Green station will be provided for informational purposes only. In the event that the final regulations were to mandate individual non-mercury HAP metals emissions for compliance, a more detailed study would need to be conducted.

4.4.5 Conclusions

The testing that BREC performed at the Coleman and HMP&L systems showed that the PM emissions were above the proposed MACT limits primarily due to condensable PM emissions.

The recommended use of dry sorbent (hydrated lime) injection will reduce the condensable PM emissions with only a slight increase in inlet dust loading to the ESP. The upgrade plans involve replacement of the discharge electrodes (DE) with newer advanced designs with more discharge points and also replacement of the existing T/R sets with high frequency T/R sets permitting more power to charge the fly ash in the ESP. Coupled with replacement of the conventional T/R sets will be some increased sectionalization of the existing precipitators for both power (less plate area be "served" by a single T/R set) and reliability reasons (loss of a T/R set has less of an effect on overall ESP performance). Similar upgrades have been completed by S&L on ESP's that are over 30 years old which are the same age range as the ESP's at HMP&L and Coleman.

In addition, S&L has recently participated in a number of activated carbon injection tests where PM was measured both baseline and during the tests. With activated carbon injection rates as high as 9 lb/million acf there was minimal increases in the outlet PM loading. Testing with hydrated lime has also shown minimal increases in particulate loading. Any lime that penetrates the ESP will pass through to the wet FGD systems at HMP&L and Coleman and will aid in SO2 removal.

The existing ESPs in conjunction with the WFGD systems and the previously described dry sorbent injection systems for SO_3 mitigation are expected to provide adequate control to meet the proposed EGU MACT total PM emission limits. If activated carbon injection systems are implemented for mercury emission reduction, then the ESP upgrades described above are expected to be required, subject to the results of existing ESP performance testing.

4.5 MERCURY CONTROL

4.5.1 Existing Electrostatic Precipitators and Wet Flue Gas Desulfurization Systems

ESP and other particulate reduction technologies are effective at reducing particulate mercury, while wet FGD systems typically only effectively capture ionic mercury. Without an inherently high level of halogens in the coal that is fired, there will still be high levels of mercury due to elemental mercury. The EGU MACT is expected to regulate mercury emissions to below 1.2 lb/TBtu.

All units at Coleman, Wilson, Green and HMP&L are equipped with both ESP and WFGD systems. However, HMP&L is the only station that has baseline mercury emissions that are below the anticipated MACT limit. HMP&L Unit 1 emits approximately 0.62 lb/TBtu and 0.47 lb/TBtu for Unit 2. The lower overall mercury level is due to the higher oxidation of elemental mercury to oxidized mercury that can be captured in the WFGD. The rest of the stations do not experience this increased oxidation and therefore are not within compliance with the anticipated limits. Current mercury emissions are 3.52 lb/TBtu combined at Coleman units, 1.77 at Wilson, and 3.09 and 2.58 at Green unit 1 and 2 respectively. Additional mercury control technologies are necessary for all BREC units, except the HMP&L units.

4.5.2 Activated Carbon Injection

Activated carbon injection (ACI) systems are capable of removing both elemental and oxidized mercury, reaching a total mercury reduction of 90%. All BREC units will benefit from the addition of an ACI system and will see reduction of mercury emissions from their current levels to the MACT requirement limit of 1.2 lb/TBtu. Since HMP&L is already witnessing compliance levels of mercury emissions, installation of an ACI system is not recommended due to the high cost of activated carbon compared to the unnecessary mercury removed.

4.5.3 Fuel Additives and Activated Carbon Injection

If there is not an inherently high level of halogens in the coal and brominated PAC is not used, addition of halogen additives to the coal can help oxidize elemental mercury. Since Coleman units are witnessing the highest levels of mercury, the units will benefit from addition of fuel additives in conjunction with an ACI system. The fuel additives will oxidize elemental mercury into a water soluble compound that can then be removed in the wet FGD, which will increase overall removal of mercury. Fuel additives should be able to oxidize greater than 90% of the mercury in the fuel.

4.5.4 Conclusions

If the existing air pollution control equipment is supplemented with the addition of an ACI system (except at HMP&L), the resulting system will be able to meet the proposed EGU MACT mercury limit of 1.2 lb/TBtu. Field testing can establish the capabilities of this technology. Since this reduction level is at the upper limit of what fuel additives and WFGD additives are expected to achieve, the cost summaries in this study are based on ACI, sorbent injection, and ESP upgrades.

4.6 AIR EMISSION TECHNOLOGY BENEFITS

4.6.1 CSAPR Technology Benefits

After reviewing the various potential options for establishing compliance with BREC's CSAPR allocations and eliminating outliers based on feasibility, existing plant configuration and potential cost savings benefits, the potential compliance technologies were reviewed against each other to determine emission reductions by unit. Estimated NO_X and SO_2 reductions, as compared to baseline emissions, are provided in Table 4-2 and Table 4-3 below.

Table 4-2 — SO_2 Emission Reductions by Technology

Plant / Unit	SO_2 Reduction from Baseline (tpy)			
	Return to Design Lime/Operation	Increase L/G for ~97% Removal	New Scrubber	Natural Gas Conversion
Coleman 1	858			
Coleman 2	937			
Coleman 3	835			
Wilson 1			8,389	
Green 1				1,870
Green 2				1,411
HMP&L 1		1,439		
HMP&L 2		1,910		
Reid 01				5,065

Returning the Coleman scrubber back to as-designed operation conditions and lime produces a reduction of approximately 2,630 tpy when compared to the baseline output. Increasing the liquid-to-gas ratio in the HMP&L

scrubbers to achieve ~97% removal provides a reduction of about 3,350 tpy. The current Wilson scrubber has undergone upgrades and uses additives to increase performance and is achieving an SO_2 removal efficiency of 91%. Because of the low operating efficiencies and high operating costs, Wilson has the greatest potential benefit with installing a new scrubber and will experience an approximate reduction in SO_2 emissions of 8,389 tpy. Converting the Reid 01 unit to natural gas is another choice for compliance with substantial emission reduction potential. Since Reid 01 currently has no technologies implemented for SO_2 control, a reduction of about 5,065 is to be expected.

Table 4-3 — NO_X Emission Reductions by Technology

Plant / Unit	NO_X Reduction from Baseline (tpy)			
	Advanced Burners	SNCR	SCR	Natural Gas Conversion
Coleman 1	186	372		
Coleman 2	159	317		
Coleman 3	204	409		
Wilson 1				
Green 1		410	1,742	815
Green 2		434	1,843	1,003
HMP&L 1				
HMP&L 2				
Reid 01				220

Several options were considered for reducing NO_X to achieve compliance with BREC's CSAPR allocations. Installation of an SCR at Green 1 and 2 will reduce NO_X emissions by 1,742 tpy and 1,843 tpy respectively. Retrofitting the Coleman units with SNCRs will reduce yearly NO_X emissions by nearly 1,100 tons. There is also potential for lower NO_X emissions by upgrading the existing low-NO_X burners at a number of plants. If the burners are upgraded for all the Coleman units, BREC should expect an overall reduction of approximately 549 tpy.

Each of the options given above is mutually exclusive except for natural gas conversion and will be selected from to achieve necessary reductions to meet forthcoming regulations. A complete fleet-wide CSAPR and

NAAQS compliance strategy using the technologies above will be developed in Section 5 of this report based on economic viability and estimated project schedules.

4.6.2 MACT Technology Benefits

Unlike SO_2 and NO_X emission reduction strategies for achieving CSAPR compliance, the potential options for MACT are more straightforward but also dependant on the technologies selected to meet CSAPR emissions. It's anticipated that ACI systems will be required at each unit except HMP&L 1 and 2 and that DSI systems will be required where ACI systems are installed to lower SO_3 emissions and improve Hg removal efficiency. Furthermore, due to increased particulate loadings from the ACI and DSI systems, it's anticipated that these units will also require ESP upgrades to achieve the MACT allowable limits. Since selection of these technologies is dependant on the implemented CSAPR technologies, a final recommendation of what is necessary for compliance will be determined after the cost benefits (NPV) of each CSAPR technology has been explored and compliance plan has been developed.

4.6.3 Summary

The compliance technologies discussed above have various pros and cons in their ability to meeting the anticipated CSAPR allocations. Although CSAPR allows significant flexibility in selecting technologies to implement because of credit sharing, MACT simply requires site-specific emissions limits. It is foreseen that all of the Units that continue to operate as coal-fired will need to install DSI systems to help mitigate formation of SO_3 as well as reduce overall PM emissions to levels compliant with MACT. ACI systems are also expected to be required on each of the coal-fired units except for HMP&L to reduce mercury emissions to MACT allowable rates. Capital, O&M, credit purchase and sales and fuel costs will be developed and discussed for a final compliance plan based on the economic evaluations in Section 5 of this report.

4.7 316(b) IMPINGEMENT MORTALITY AND ENTRAINMENT

4.7.1 Existing Intake Structure and Screen Technology

Based on the proposed 316(b) regulations and a review of all BREC units, this study considered new technology selections that may be able to meet an impingement reduction standard of 80% to 90%, or result in an intake velocity at the screen that is less than 0.5 feet per second for the Coleman and Sebree stations.

4.7.2 Compliance Technologies

Based on a review of the available technologies and data supporting the compliance viability of each technology, the following three were chosen to be considered for further evaluation and screening with regards to complying with these pending regulations for the Sebree and Coleman station:

Table 4-4 — Intake Structure 316(b) Compliance Technologies

Units	Technology	Target Compliance Level Based on Selected Technology (%)	Comments
Coleman & Sebree	Replacement Screens (WIP) with Fish Pumps / Return Systems	Impingement: 0.5 fps at screens or impingement mortality not to exceed 12% annual average, 31% monthly average. Entrainment. Demonstrate Best Technology Available (BTA)	Velocity through screens would not be reduced, but fish would be returned to the river to meet the reduction in impingement. 3/8" mesh could be used. Weekly testing would be required to confirm acceptable mortality rates.
	Cylindrical Wedgewire Screens		Velocity through screens would be reduced to 0.5 fps to meet the reduction in impingement. 3/8" mesh or 2-mm mesh could be used. However, once the entrainment piece of the regulation is finalized, retrofitting the screens would be difficult
	Traveling Screen with Fish Return		Velocity through screens would not be reduced, but fish would be returned to the river to meet the reduction in impingement. Weekly testing would be required to confirm acceptable mortality rates.

The Coleman and Sebree stations will need of modifications to their existing intake structures to meet the proposed 316(b) regulations. In addition, it should also be noted that if Units were to alter their current operational practices or shut down, strategies could vary significantly. For instance, preliminary calculations show that if Reid were to discontinue operation, the circulating water pumps could be downsized for makeup to the HMP&L cooling towers, HMP&L sluice water make up, and to supply Henderson Water Utilities' South Water Treatment facility and overall intake velocity would be reduced to approximately 0.55 fps. Since this is relatively close to the anticipated regulatory limit of 0.5 fps, further analysis would need to be conducted if BREC would like to explore this means of compliance. Technology selection of the three proposed options for compliance will be chosen based lowest lifetime cost accounting for associated capital and O&M costs. Details of this analysis covered in Section 5 of this report.

4.8 COAL COMBUSTION RESIDUALS

4.8.1 Existing Operation and Technology

Either Subtitle C or Subtitle D will result in an increase in O&M disposal costs for BREC due to groundwater monitoring requirements that will be imposed on the existing landfill that receives these wastes. Several of the BREC facilities will need to implement upgrades to their exist waste/ash handling systems. If Subtitle D is chosen, Wilson would not require any modifications but would still potentially incur additional disposal fees. All other stations would require significant modifications to convert the existing sluiced systems. If Subtitle C is chose, each station would still need to perform the modifications necessary for Subtitle D compliance and would also need to convert the existing pressurized pneumatic transport systems to vacuum systems.

4.8.2 Conclusions and Recommendations

This study will consider a conversion of the existing bottom ash handling systems to one of the dry technologies discussed in Section 3.2.7. The recommended technology (dewatering bin system or remote submerged scraper conveyor) will be selected based on net present value (NPV) analysis based on estimated capital and O&M costs. Future ash disposal will then be conducted by hauling the bottom ash waste to landfill, along with the fly ash and WFGD waste product. Upper bound estimates for the transportation costs for CCR waste products under Subtitle C (hazardous waste) and Subtitle D (non-hazardous waste) are provided. It is assumed for the purpose of this study that the moisture content of the dewatered bottom ash that currently exists before truck loading is approximately the same as that which occurs with a dewatering bin system or submerged scraper conveyor. In order to close the existing ponds, BREC would have to take the following four steps:

1. Eliminate free liquids or solidify the remaining waste and residue
2. Stabilize the remaining wastes sufficiently to support final cover
3. Construct the final cover
4. Provide maintenance and monitoring for a 30-year period.

An additional step involving the redirection of miscellaneous waste streams that currently flow into the ash ponds, including boiler blowdown, limestone pile runoff, WFGD blowdown, etc. may also be necessary. It is estimated that if such regulations were to be implemented, wastewater stream treatment facilities would be costly. A detailed water balance study should be performed once the EPA's wastewater effluent guidelines are published to better assess the necessary process changes and impacts of this redirection, as well as assess possible beneficial reuse of the redirected waste streams.

Last page of Section 4.

5. CAPITAL AND O&M COST DEVELOPMENT FOR PHASE III SELECTIONS

5.1 TECHNOLOGY COSTS

5.1.1 Capital Costs

The estimated capital costs provided are based on a total installed cost that includes the following:

- Equipment and materials
- Direct field labor
- Indirect field costs and engineering
- Contingency
- Initial inventory and spare parts
- Startup and commissioning

The capital costs do not include; sales taxes, property taxes, license fees and royalties, owner costs, or AFUDC (Allowance for Funds Used During Construction). The costs are based on a minimal-contracts lump-sum project approach. The total installed costs are factored from recent projects and quotes obtained by S&L. No specific quotes or engineering was completed for any of the projected upgrades for the BREC units. The costs provided herein reflect an approximate accuracy of +/-20% and are not indicative of costs that may be negotiated in the current marketplace. These costs should not be used for detailed budgeting or solicitation of pollution control bonds.

5.1.2 Operation and Maintenance Costs

The O&M costs are a combination of variable and fixed costs. The O&M costs are reported in fourth quarter 2011 dollars.

The variable O&M costs include applicable items such as the following:

- Reagent and Disposal
- Auxiliary Power

- Makeup Water
- Bag replacement

The fixed O&M costs include the following:

- Operating Labor
- Maintenance Labor
- Maintenance Materials

5.1.3 Air Pollutant Control Capital Cost Summary

Table 5-1 shows estimated capital and O&M costs for all of the screened technologies considered in this evaluation. O&M costs are shown as the additional cost to current budgets and expenses.

Table 5-1 — Estimated Costs for Technologies Considered (Air Pollution Compliance)
(Additional Costs to the Current Budgets and Expenses)

Pollutant	Station / Unit	Technology	Capital Cost (2011$ Millions)	O&M Cost (2011$ Millions)	Comments
SO_2 Control	Wilson	New WFGD Absorber Vessel	139 0	0 69	Replacement of the existing horizontal scrubber with a new state-of-the-art vertical scrubber. Existing limestone preparation and dewatering systems would be reused to support new vessel (Capital cost estimate was based on SESS budget proposal number 4296 provided 11/11/11)
	Green 1/2	Natural Gas Conversion	25.6 – 27.6 (per unit)	47.2(1) (per unit)	The available gas supply line near green currently has capacity for conversion of one (1) of the green units. If both are converted, the higher capital value would need to be applied to both for a new supply line. The conversion cost includes installation of new burners, a flue gas recirculation system and a natural gas supply system.
	HPM&L 1/2	Existing WFGD with Increased L/G Upgrades	3.15 (per unit)	0.38 (per unit)	Based on received data the current HMP&L scrubbers are capable of increasing removal efficiency by operating a second recirculation pump. The capital cost for this modification includes installation of a third recycle pump to maintain system redundancy and tipping of the existing ID fans with installation of new motors to account for additional system pressure losses as a result of increased removal spray flow.

Pollutant	Station / Unit	Technology	Capital Cost (2011$ Millions)	O&M Cost (2011$ Millions)	Comments
	Reid 1	Natural Gas Conversion	1.2	3.84[1] (Fuel Cost: 5.61, Other: -1.77)	Reid already has natural gas supply and burners in place. Based on discussions with BREC these have not been placed into service. The capital allowance is an approximation of maintenance, testing and other incurred fees to startup the existing system.
NO_x Control	Coleman 1/2/3	SNCR (Unit 1)	2.4	1.56	Unit 1 currently has the ROFA system installed for NO_x control. Installation of a SNCR system would provide the desired removal efficiencies at a reduced cost over conventional SNCR technologies.
		SNCR (Unit 2 & 3)	2.7 (per unit)	1.58 (per unit)	Cost is based on a complete system with necessary piping, valves, heating units, reagent preparation equipment, etc.
		Advanced (third Generation) Low-NO_x Burners	5.94 (per unit)	0	Upgrade includes replacement of existing first generation Low-NO_x burners with new advanced burners.
	Wilson	Advanced (third Generation) Low-NO_x Burners	8.61	0	Upgrade includes replacement of existing first generation Low-NO_x burners with new advanced burners.
	Green 1/2	SNCR	3.5 (per unit)	1.61 (per unit)	Cost is based on a complete system with necessary piping, valves, heating units, reagent preparation equipment, etc.
		SCR	81 (per unit)	1.47 (per unit)	Capital cost for installation of an SCR at Green includes foundations, duct modifications, steel structures, SCR catalyst and new ID fans for the increased pressure loss.
		SCR Catalyst	2.43	0	The catalyst cost for replacement of all three (3) layers (not including labor). It's anticipated that a single layer would have to be replaced every two (2) years and the remaining layers would be rotated. A new set of catalyst would be required every six (6) years. $0.41M is the annualized cost for the 6-year cycle life of the catalyst.
		Natural Gas Conversion	See SO_2 Above	See SO_2 Above	Conversion to natural gas will provide a reduction in NO_x emissions in addition to the SO_2 reductions. See SO_2 section above for details of installation.
		Advanced (third Generation) Low-NO_x Burners + OFA	8.64	0	Upgrade includes replacement of existing first generation Low-NO_x burners with new advanced burners and over fire air.
	Reid 1	Natural Gas Conversion	See SO_2 Above	See SO_2 Above	Conversion to natural gas will provide a substation reduction in NO_x emissions in addition to the SO_2 reductions. See SO_2 section above for details of installation.

Pollutant	Station / Unit	Technology	Capital Cost (2011$ Millions)	O&M Cost (2011$ Millions)	Comments
HCl	All Units	HCl Monitor	0.24 (per stack)	0.02 (per stack)	Typical cost for installation of an HCl monitor is shown. Installation is not usually dependant on unit size or other operational parameters. Required for units not able to use SO_2 emissions for MACT compliance.
Hg	Coleman 1/2/3	Activated Carbon Injection System	4.0 (per unit)	0.81 (per unit)	Complete carbon injection systems are included in the estimated capital costs provided. System includes foundations, silo, transport piping, injection lances, blowers and all other necessary components of a complete activated carbon injection system
	Wilson		4.5	2.19	
	Green 1/2		4 (per unit)	1.14 (per unit)	
Condensable Particulates	Coleman 1/2/3	Hydrated Lime DSI	5.0 (per unit)	0.27 (per unit)	Complete dry sorbent injection systems are included in the estimated capital costs provided. System includes foundation, silo, transport piping, injection lances, blowers and all other necessary components of a complete hydrated lime injection system.
	Green 1/2		5.0 (per unit)	0.32 (per unit)	
	Wilson	Hydrated Lime DSI + Low Oxidation Catalyst	6.5	0.50	Complete dry sorbent injection systems as well as upgrading the existing catalyst are included in total cost estimate. The costs are on a per unit basis and include complete unitized systems with all necessary components (silo, blowers, piping, lances, etc.)
	HMP&L 1/2		6.0 (per unit)	0.29 (per unit)	
Filterable Particulates	Coleman 1/2/3	Upgrade Existing with Advanced Electrodes and High Frequency TR Sets	2.4 (per unit)	0.06 (per unit)	Implementation of advanced electrode technology and the addition of high frequency transformer rectifier sets may be needed for each of the units listed. Choice of modification of the existing ESP at each unit will be decided based on the particular unit's present performance capability and the chosen technologies for mitigating other regulated pollutants
	Wilson		4.3	0.15	
	Green 1/2		3.1 (per unit)	0.05 (per unit)	
	HMP&L		2.5 (per unit)	0.08 (per unit)	
Total Particulates	Coleman 1/2/3	Particulate Matter Monitor	0.24 (per stack)	0.02 (per stack)	Particulate monitors will be needed at the listed sites to demonstrate compliance with the anticipated MACT regulations. Typical cost for installation of an PM monitor is shown. Installation is not usually dependant on unit size or other operational parameters.
	Wilson				
	Green 1/2				

(1) Natural gas O&M cost includes fuel cost and were developed based on baseline heat inputs and the economic parameters show in Table 1-1. O&M savings that are associated with day-to-day operation and outage work from conversion to natural gas have been estimated based on information provided by BREC and S&L's experience

Conversion of an existing coal-fired unit to natural gas increases fuel costs. However, expected maintenance and day-to-day operational costs are expected to decline after converting an existing coal unit to natural gas. The fixed O&M for a typical coal unit is about $25 per kilowatt per year, based on several variables, e.g., number of units, age of units, degree of unionization, management practices, and other factors. S&L estimates that about one third of that cost would be eliminated for a coal plant converted to operation on natural gas. The cost reduction would include elimination of the ash handling and coal handling, WFGD reagent savings and a reduction in water treatment and other expenses. The total savings are estimated to be approximately $9/kW/year in fixed O&M cost. Current BREC O&M costs have been adjusted accordingly and are reflected in the costs shown above.

5.1.4 Options Not Considered for Air Compliance

Although it is not anticipated, initial testing may require that an EGU meet non-Hg HAP metal emission limits in addition to TPM. The highest probability of achieving compliance with possible non-Hg HAP emission limits is with a baghouse. Provided below is an order of magnitude capital cost estimate for installation of a baghouse at BREC's Green and HMP&L stations. This estimate is provided for information only and a more detailed cost estimate would need to be conducted to confirm overall project capital and O&M costs.

Table 5-2 — Baghouse Capital Cost Estimates

Station / Unit	Capital Cost (2011$ Millions)
Green / 1&2	75 (per unit)
HMP&L / 1&2	51 (per unit)

5.1.5 Non-Air Pollutant Technology Cost Summary

Table 5-3 shows capital and O&M costs for compliance with 316(b) regulations and coal combustion residual handling (CCR) regulations, for all of the screened technologies considered in this evaluation. For future CCR transport and disposal under Subtitle C (hazardous waste classification for all fly ash, bottom ash, and WFGD waste product), transportation and disposal costs could be in excess of $80/ton, it is not expected that the Subtitle C regulations will be promulgated. As such, future CCR transport and disposal costs are estimated based on Subtitle D (non-hazardous waste classification) being promulgated.

Table 5-3 — Estimated Technology Costs (316(b) and CCR Compliance (Additional Costs to the Current Budgets and Expenses)

Regulation	Station / Unit	Technology	Capital Cost (2011$ Millions)	O&M Cost (2011$ Millions)	Comments
316(b) IM&E	Coleman 1/2/3	Replacement Screens (WIP) with Fish Pumps / Return System	1.33 (per unit)	0.25 (per unit)	Cost is on a per unit basis for the six intake bays (two per unit). Estimated mortality testing costs have been included in the provided O&M
		Traveling Screens with Fish Return	1.87 (per unit)	0.25 (per unit)	Cost is on a per unit basis for the six intake bays (two per unit) Estimated mortality testing costs have been included in the provided O&M
		Cylindrical Wedgewire Screens	2.15 (per unit)	0.27 (per unit)	Wedgewire technology will reduce through-screen velocity to or below the proposed 0.5 fps. Compliance will not require weekly mortality testing O&M cost includes use of a purge-air system to prevent debris from gathering on the screens.
	Sebree	Replacement Screens (WIP) with Fish Pumps / Return System	2.05	0.37	Cost is on a per unit basis for the three intake structures Estimated mortality testing costs have been included in the provided O&M.
		Traveling Screens with Fish Return	2.80	0.37	Cost is on a per unit basis for the three intake structures. Estimated mortality testing costs have been included in the provided O&M.
		Cylindrical Wedgewire Screens	2.45	0.38	Wedgewire technology will reduce through-screen velocity to or below the proposed 0.5 fps. Compliance will not require weekly mortality testing. O&M cost includes use of a purge-air system to prevent debris from gathering on the screens
CCR (Conversion to Dry Bottom Ash)	Coleman 1/2/3	Submerged Scraper Conveyor (Remote)	28.0	1.25	Currently bottom ash is sluiced to a pond on site. Cost is to provide two 100% remote SSCs to be shared between the three units
		Dewatering Bin System	38.0	0.86	Bottom ash will be routed to three new dewatering bins before it is collected and taken offsite to a landfill.
	HPM&L 1/2	Submerged Scraper Conveyor (Remote)	28.0	0.97	Currently bottom ash is sluiced to a pond on site. Cost is to provide two 100% remote SSCs to be shared between the two units
		Dewatering Bin System	38.0	0.68	Bottom ash will be routed to three new dewatering bins before it is collected and taken offsite to a landfill.

	Green 1/2	Submerged Scraper Conveyor (Remote)	28.0	1.25	Currently bottom ash is sluiced to a pond on site. Cost is to provide two 100% remote SSCs to be shared between the two units
		Dewatering Bin System	38.0	0.87	Bottom ash will be routed to three new dewatering bins before it is collected and taken offsite to a landfill.
Pressurized Pneumatic Transport System Conversion (Subtitle C or D for Coleman, Subtitle C only for HMP&L, Green and Wilson)	Coleman 1/2/3	Convert Pressurized Fly Ash System to Vacuum	10.0	0	Currently Coleman fly ash is sluiced to an onsite waste ash pond. Conversion of existing system to vacuum pneumatic system
	HPM&L 1/2	Convert Pressurized Fly Ash System to Vacuum	6.0	0	HMP&L currently has a vacuum pneumatic system to storage silo then pressurized system to Green storage silo. Conversion of pressurized portion of system to vacuum.
	Green 1/2	Convert Pressurized Fly Ash System to Vacuum	6.0	0	Green currently has a pressurized pneumatic system to storage silo. Conversion of pressurized system to vacuum.
	Wilson	Convert Pressurized Fly Ash System to Vacuum	5.0	0	Wilson currently has as pressurized fly ash transport system that takes ash to an onsite silo and is used for stabilizing scrubber waste. Conversion of pressurized pneumatic transport system to vacuum

5.2 NET PRESENT VALUE COST COMPARISON

Based on the factors detailed in Section 1.2 and costs from Section 5.1, a net present value (NPV) analysis was conducted to compare the screened technologies on the same lifetime cost basis. The O&M portion of the analysis included escalation from the time the technology options are commissioned in 2014 through the end of the operating life of each system and accounts for the benefits associated with assumed credit costs. The net present value for the capital charges and O&M costs, over the operating life, are discounted back to the commercial operating date of 2014.

5.2.1 Lifetime Cost of Individual CSAPR Control Technologies

Based on the economic parameters of Table 1-1, an install date of 2014, developed capital and O&M cost estimates and the predicted performance of implementing each CSAPR related technology, the relative payback point was determined for all applicable screened technologies. Table 5-4 and

Table 5-5 below show the relative value of each modification by determining a "break even" point at which the NPV of a given modification is equivalent to $0 and thus establishing an economically hierarchy for developing a implementation and scheduling strategy.

Table 5-4 — SO_2 Break Even Credit Cost by Technology

Station / Unit	Compliance Technology	SO_2 Credit Reduction (Tons Per Year)	"Break Even" SO_2 Credit Cost	NPV at Baseline Credit Cost (2011$ Million)
HMP&L 1&2	Run Two Recycle Pumps (Increase L./G)	3,349	$382	($4.13)
Reid 01	Natural Gas Conversion(1)	5,065	$669	$8.91
Wilson	New WFGD Absorber	8,389	$1,445	$82.55
Green 1&2	Natural Gas Conversion(1)	3,281	$28,593	$989.58
Green 2	Natural Gas Conversion(1)	1,411	$32,775	$474.01

(1) Conversion to natural gas also reduces NO_X emissions and excludes the unit from any potential MACT compliance issues. Conversion inherently makes the unit susceptible to changes in natural gas pricing but eliminates dependency on coal and other reagent markets.

Based on the results of the NPV analysis shown above, it is most cost effective for BREC to upgrade the existing HMP&L scrubbers, convert Reid 01 to natural gas and then build a new WFGD at Wilson. SO_2 emission reductions resulting from implementation of these three lowest break-even cost technologies/upgrades will allow BREC to meet their CSAPR 2014 SO_2 allocations.

Table 5-5 — NO_X Break-Even Credit Cost by Technology

Station / Unit	Compliance Technology	NO_X Credit Reduction (Tons Per Year)	"Break Even" NO_X Credit Cost	NPV at Baseline Credit Cost (2011$ Million)
Coleman 1/2/3	Advanced Low- NO_X Burners	549	$2,670	$1 0
Green 1&2	SNCR	844	$4,500	$17.6
Coleman 1	SNCR	372	$4,729	$8.6
Green 2	SCR	1,843	$4,788	$43 9
Coleman 2&3	SNCR	726	$4,965	$18.6
Green 1	SCR	1,742	$5,064	$46.5
Reid 01	Natural Gas Conversion(1)	220	$6,392	$8 9
Green 2	Natural Gas Conversion(1)	1,003	$47,905	$474 0
Green 1&2	Natural Gas Conversion(1)	1,818	$53,214	$989.6

(1) Conversion to natural gas also reduces SO_2 emissions and excludes the unit from any potential MACT compliance issues Conversion inherently makes the unit susceptible to changes in natural gas pricing but eliminates dependency on coal and other reagent markets.

The NPV analysis shown above indicates that it is most cost effective to upgrade the existing upgrade the Coleman Low-NO_X burners install SNCR systems at Green and/or Coleman and install an SCR at Green. NO_X emission reductions resulting from implementation of these lowest break-even cost technologies/upgrades will allow BREC to meet their CSAPR 2014 SO_2 allocations.

Table 5-6 shows two possible strategies for complying with CSAPR in 2014. Fleet-wide NO_X compliance for 2014 can be achieved by installing a total of three SNCR systems or a single SCR system at Green Unit 2. Comparing the NPV values for these two strategies favors SNCR technology.

Table 5-6 — CSAPR 2014 NO_X Compliance Strategies

	Strategy 1 SNCR at Coleman 1 & Green 1/2 and Reid 1 Natural Gas Conversion	**Strategy 2** SCR at Green 2 and Reid 1 Natural Gas Conversion
Total NO_X Reduction (tpy)	1,436	2,063
Net Present Value (2011$ Millions)	$35.1	$52.8

However, Table 5-7 shows two possible strategies for complying with potential revisions to CSAPR in the 2016 or 2018 timeframe as a result of potential NAAQS revisions as described in section 2.1.4. To meet the estimated requirements to comply with Phase II of CSAPR, a total of four SNCR systems plus an SCR at Green 2 would be required, or two SCR systems could be installed at Green. Comparing the NPV values for these longer-term compliance strategies are nearly equal. This is because while the SCR system is significantly higher in capital cost, only the stoichiometric amount of urea is injected to achieve high NOX removal, and it therefore has lower O&M costs compared to four SNCR systems. In contrast, SNCRs have lower capital cost but significantly higher operating costs due to the amount of urea consumed to achieve lower NOX removal efficiencies.

Table 5-7 — NAAQS 2016/18 NO_X Compliance Strategies

	Strategy 1 SNCR at Coleman 1/2/3 & Green 1, SCR at Green 2 and Reid 1 Natural Gas Conversion	**Strategy 2** SCR at Green 1 & 2 and Reid 1 Natural Gas Conversion
Total NO_X Reduction (tpy)	3,517	3,805
Net Present Value (2011$ Millions)	$88.8	$90.4

While the immediate compliance targets can be met with three SNCR systems at a lower NPV, S&L recommends implementing SCR technology at the Green units as part of a lower risk, longer-term compliance strategy. As discussed in section 4.3.4, SNCR performance capabilities may be limited by higher levels of CO in the boiler. In addition, operation of the SNCR system can increase CO emissions. The higher ammonia slip values that result from SNCR compared to SCR may cause increased fouling of downstream equipment and add to maintenance costs. SNCR systems are also slow to respond to load changes, which can cause problems on load-following units. The Green units use coal-reburn, and there is no known SNCR experience in conjunction with coal-reburn. Given that the impacts of these items have not been tested at Coleman or Green, and given that increasingly stringent regulations may eventually require at least 1 SCR at Green Station, implementing SCR systems at both units is an overall lower risk strategy. Furthermore, it is likely that many, if not all, of the design elements for the two SCR systems would be identical. This could potentially lead to lower overall capital costs for the second SCR and would simplify operations and maintenance requirements since the entire compliance strategy would be implemented at a single station.

It is also important to note that although converting Reid 01 to natural gas has a larger "break even" point than burner upgrades, SNCR or SCR options, the benefits go beyond those noticed in a NOX credit cost sensitivity analysis and must be considered further. Natural gas conversions for the Green units appear to be beyond what is economically justifiable at present time.

Justification for conversion of an existing BREC unit to natural gas is highly dependent on future fuel cost assumptions. As such, a sensitivity analysis was conducted on natural gas fuel price while holding SO_2 and NO_X credit prices constant at their baseline value. NPV for the Reid 1 gas conversion will reach equilibrium when natural gas prices are $4.12/MMBtu whereas Green 1 and 2 natural gas conversion will require a natural gas price of $2.23/MMBtu. Given that the fluctuations in the natural gas market are highly unpredictable over the twenty year lifetime of the project, consideration should be given to the uncertainty associated with such a strategy.

Table 5-8 — Natural Gas Pricing Sensitivity

Modification	"Break Even" Gas Pricing at Baseline NO_X & SO_2 Credit Cost (2011$)
Reid 1 Conversion	$4.12
Green 1 & 2 Conversion	$2.23

5.2.2 Fleet-Wide Air Pollutant Compliance Strategy (2014 CSAPR)

Based on examination of the relative value added of each technology, an overall air pollutant compliance strategy was developed. This strategy includes the minimal technologies required to meet both the CSAPR and

MACT emission limits. The technologies selected as well as the emission surpluses and deficits are shown in Table 5-9 below.

Table 5-9 — Air Pollutant Compliance Strategy (2014 CSAPR)

BREC Unit	Technology Selection: CSAPR - Selection: SO_2	Technology Selection: CSAPR - Selection: NO_X	Technology Selection: MACT - Selection: HCl	Technology Selection: MACT - Selection: Hg	Technology Selection: MACT - Selection: CPM	Technology Selection: MACT - Selection: FPM	Emission Surplus / (Deficit) vs. Allocation: CSAPR II - 2014 (Tons): SO_2	Emission Surplus / (Deficit) vs. Allocation: CSAPR II - 2014 (Tons): NO_X	Emission Surplus / (Deficit) vs. Allocation: Projected NAAQS (Tons): SO_2	Emission Surplus / (Deficit) vs. Allocation: Projected NAAQS (Tons): NO_X
Coleman Unit C01	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	(323)	(831)	(553)	(1000)
Coleman Unit C02	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	(323)	(585)	(553)	(753)
Coleman Unit C03	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	(345)	(842)	(590)	(1121)
Wilson Unit W01	New Tower Scrubber - 99% removal	None	Higher L/G or new tower for increased SO2 removal to below 0.2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	Advanced Electrodes & High Frequency TR Sets	2565	1711	1843	1182
Green Unit G01	None	None	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	91	(613)	(302)	(900)
Green Unit G02	None	SCR @ 85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	357	1128	3	837
HMP&L Unit H01	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0 2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	463	456	213	273
HMP&L Unit H02	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0 2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	454	526	196	337
Reid Unit R01*	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	218	(132)	174	(164)
Reid Unit RT	None	None	None	None	None	None	4	(39)	2	(40)
TOTAL							3161	680	432	(1349)

**Note SO2 emissions in this scenario have been adjusted to reflect recent data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%

***Note four (4) HCl monitors are required for Coleman One (1) for the common WFGD stack and one (1) for each unit bypass stack

The complete compliance strategy above takes several of the individual technologies and implements them based on value added and 2014 CSAPR compliance. Although break-even costs for installation of an SNCR is near that of an SCR, installation of an SCR has increased reliability and operational flexibility compared to an SNCR. The strategy has also accounted for necessary upgrades to achieve MACT compliance given the proposed CSAPR modifications are put in place. Because this compliance strategy is near BREC's exact NO_X CSAPR allocation limit, it is minimally affected by credit market price fluctuations.

A sensitivity analysis was also conducted on the CSAPR technologies as a whole. Holding NO_X credit prices constant, the "break even" credit cost for SO_2 was found to be approximately $1,000. Holding SO_2 credit prices constant, the "break even" credit cost for NO_X was found to be approximately $4,440. The suggested CSAPR compliance strategy is more sensitive to the price of NO_X credits as a result of the large lifetime costs associated with upgrading NO_X control technologies and that the current NO_X emission surplus is 16% over as apposed to SO_2 being 50% over their 2014 allocations. However, BREC should consider implementing a strategy of technologies such as that shown in Table 5-9 to meet the upcoming CSAPR regulatory limits in order to avoid the uncertainties that come with prediction of future market credit costs.

5.2.3 Fleet-Wide Air Pollutant Compliance Strategy (Potential 2016 NAAQS)

Although it is unclear what, if any, reductions will be necessary with any forthcoming regulations, an additional compliance strategy was developed to demonstrate necessary modifications required to meet a 20% reduction beyond the 2014 CSAPR as part of NAAQS in 2016.

Table 5-10 — Air Pollutant Compliance Strategy (2016 NAAQS)

	Technology Selection									
	CSAPR - Selection		MACT - Selection				CSAPR II - 2014 (Tons)		Projected NAAQS (Tons)	
BREC Unit	SO_2	NO_X	HCl	Hg	CPM	FPM	SO_2	NO_X	SO_2	NO_X
Coleman Unit C01	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from ROTOMIX	Advanced Electrodes & High Frequency TR Sets	(323)	(831)	(553)	(1000)
Coleman Unit C02	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from SNCR	Advanced Electrodes & High Frequency TR Sets	(323)	(585)	(553)	(753)
Coleman Unit C03	None**	Advanced Burners	HCl level is below anticipated MACT limits Installation of an HCl monitor is needed since SO2 can not be used as a surrogate.***	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from SNCR	Advanced Electrodes & High Frequency TR Sets	(345)	(942)	(590)	(1121)
Wilson Unit W01	New Tower Scrubber - 99% removal	None	Higher L/G or new tower for increased SO2 removal to below 0 2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	Advanced Electrodes & High Frequency TR Sets	2565	1711	1843	1182
Green Unit G01	None	SCR @ 85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	91	1130	(302)	842
Green Unit G02*	None	SCR @ 85% Removal	HCl Montior is not required since SO2 is below 0.2 lb/mmBtu	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	357	1128	3	837
HMP&L Unit H01	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0 2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	463	456	213	273
HMP&L Unit H02	Run both pumps & spray levels, install 3rd pump as spare	None	Higher L/G for increased SO2 removal to below 0 2 lb/mmBtu will permit reporting SO2 data as prima facia evidence of compliance with HCl emission limits	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	454	526	196	337
Reid Unit R01*	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	218	(132)	174	(164)
Reid Unit RT	None	None	None	None	None	None	4	(39)	2	(40)
TOTAL							3161	2422	432	394

**Note SO2 emissions in this scenario have been adjusted to reflect recent data received from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and reaching removal rates of approximately 95%

***Note four (4) HCl monitors are required for Coleman One (1) for the common WFGD stack and one (1) for each unit bypass stack

The compliance strategy above has identical SO2 control technologies as the CSAPR 2014 approach but the NOX technologies have been altered to include a second SCR at Green 1. With these upgrades BREC will be approximately 394 tpy below the projected NAAQS NOX allocations. As with the 2014 CSAPR strategy, necessary upgrades for MACT have also been accounted for given the proposed CSAPR modifications are put in place.

A sensitivity analysis was also conducted on the NAAQS technologies as a whole. The "break even" credit cost for SO2 was identical to the CSAPR approach. Holding SO2 credit prices constant, the "break even" credit cost for NOX was found to be approximately $4,713. As with the CSAPR approach, the suggested NAAQS strategy is more sensitive to the price of NOX credits as a result of the large lifetime costs associated with NOX control technologies. Implementing a strategy to comply with future predicted regulations is a high risk approach and may not offer any pay back over the project lifetime. If a reduction such as those predicted for NAAQS is executed by EPA, a strategy similar to that shown in Table 5-10 may be warranted.

5.2.4 316(b) Impingement Mortality and Entrainment

The circular replacement screens (WIP) with fish pumps, traveling screens with fish return system and the cylindrical wedgewire screen are all considered to be technically acceptable technologies for meeting the anticipated 316(b) regulation. Since the rotating circular replacement screens (WIP) with fish pumps had the lowest capital impact also had the lowest O&M cost, an NPV analysis was not conducted. Therefore, installation of the rotating screens (WIP) with fish pump technology is recommended as the compliance technology to meet the pending 316(b) regulations.

5.2.5 Coal Combustion Residuals

Both the remote submerged scraper conveyor (SSC) and dewatering bin systems are considered technically acceptable technologies. The SSC has higher O&M costs than a dewatering bin system due to higher maintenance costs as well as additional operators and equipment needed for front end loader operation to load ash into trucks for transport. Net present value comparison is detailed as follows:

Table 5-11 — Bottom Ash Conversion Lifetime Cost Comparison

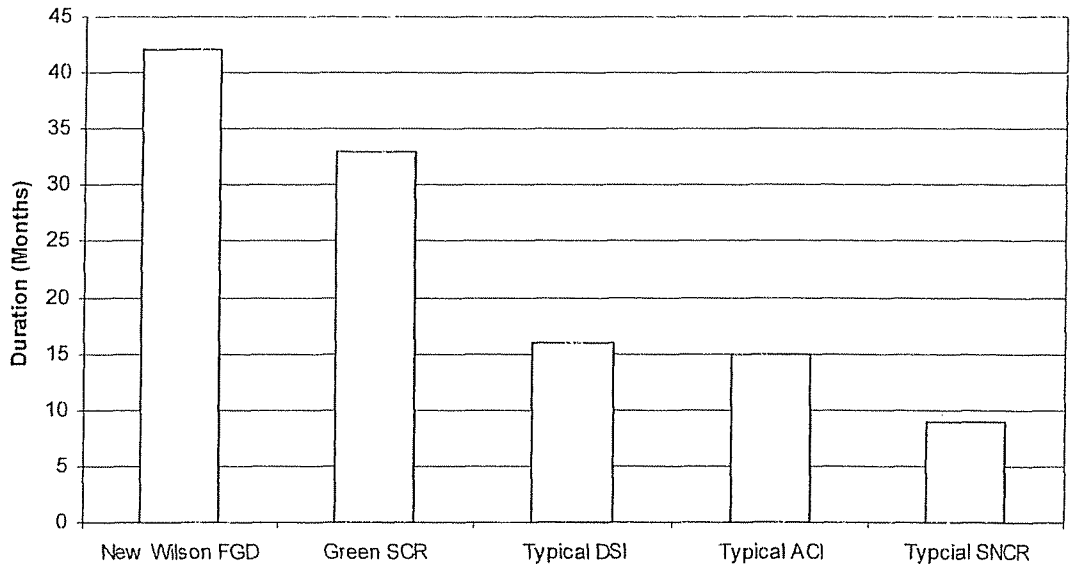
Station	Remote SSC NPV (2011$ Millions)	Dewatering Bin NPV (2011$ Millions)
Coleman	45.6	50.1
HMP&L	34.1	39.6
Green	37.0	41.6

Based on this comparison, installation of remote SSC systems are recommended as the compliance technology selection at Coleman, HMP&L and Green for pending CCR regulations.

5.3 COMPLIANCE TECHNOLOGY PROJECT SCHEDULES

For each of the major anticipated modifications proposed, a level 1 project schedule was developed. The schedules show major administrative, engineering, procurement, construction and start up tasks. These schedules are based on S&L's past project experience and current 2011 equipment lead times. The anticipated durations, milestones and links were developed based on a minimal contracts approach to project execution. Schedules for installation of a new absorber at Wilson, an SCR at Green (1 or 2) and typical schedules for installation of DSI and ACI systems are provided in Appendix 4. A summary of anticipated durations from the start of engineering to system start up for the four major technologies is provided in Figure 5-1 below.

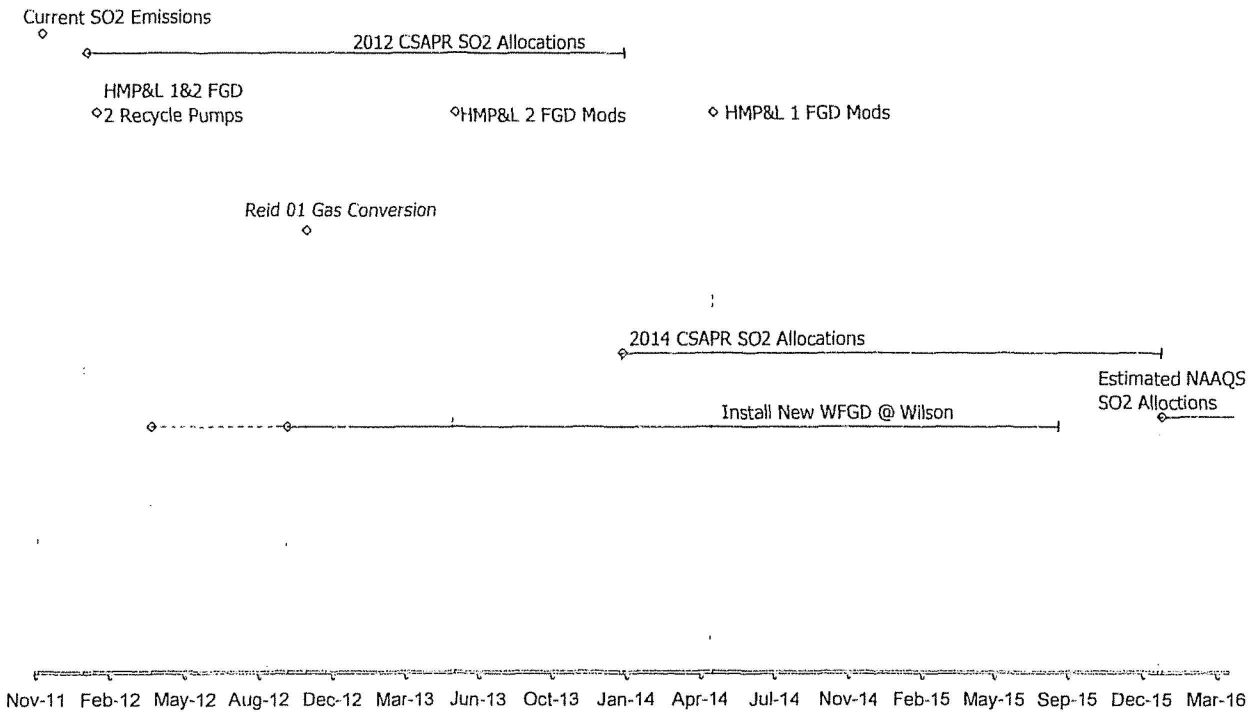
Figure 5-1 — Project Duration by Technology



5.3.1 Technology Implementation Timeline

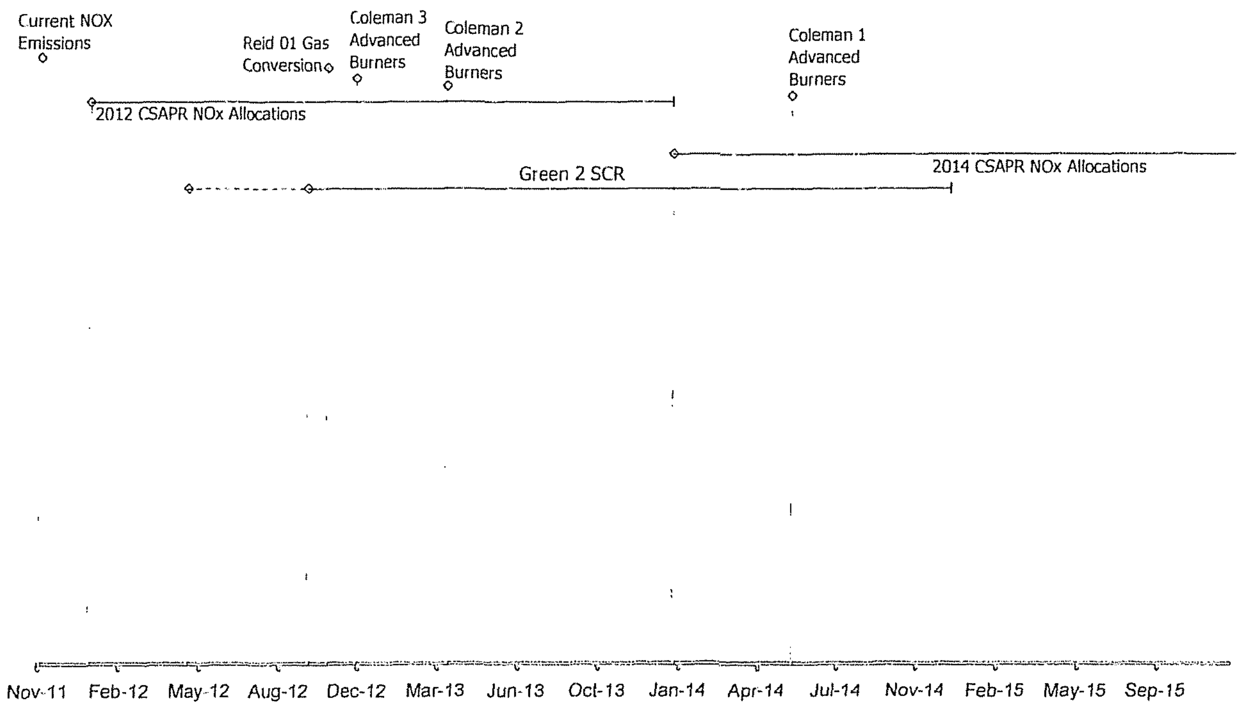
In order to meet the upcoming 2012 and 2014 CSAPR, 2015 EGU MACT and potential 2016 NAAQS dates, a timeline showing when each technology should be implemented at the various BREC sites was developed for the two strategies detailed above. The timelines show the desired installation dates as well as the overall surplus or deficit of credits that will need to be bought for compliance or overall surplus available to sell to other Group 1 states.

Figure 5-2 — CSAPR / NAAQS SO_2 Compliance Technology Timeline



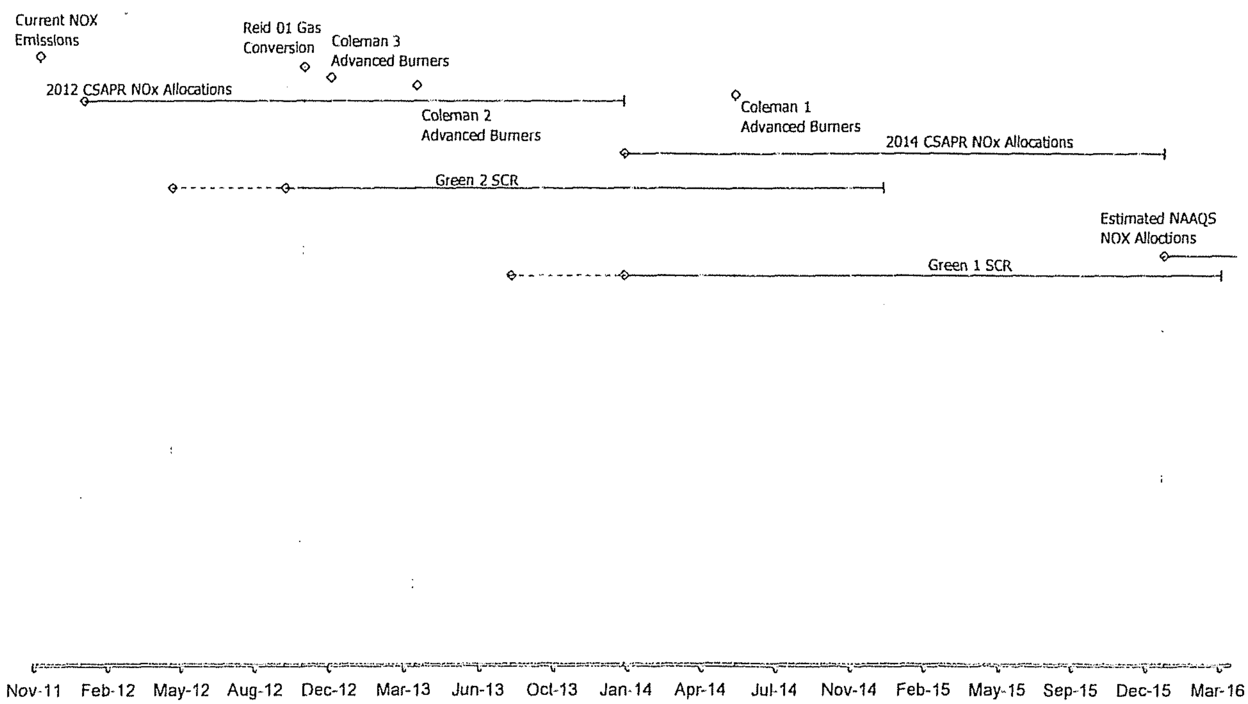
Based on an estimated equipment award date of October 1, 2012, it is anticipated that the new Wilson scrubber would be in service by September 2015. Reid 1 gas conversion would take place during the next major scheduled outage in October 2012. Operating the HMP&L scrubbers with two recycle pumps would start in January 2012 with installation of spare recycle pumps and ID fan upgrades taking place during the March-May 2013 HMP&L 2 and April–May 2014 HMP&L outages. During periods of high load demand and/or high ambient temperatures the HMP&L Units may need to derate or return to single-pump WFGD operation to avoid overheating the existing fan motors until the fan upgrades are completed. Project durations for typical ACI and DSI technologies are 15 and 16 months, respectively, and should be completed before the MACT compliance deadline. In addition, the anticipated ESP modifications have not been shown in this timeline but should be completed based on available outage schedules to meet the anticipated MACT compliance date of January 1, 2015.

Figure 5-3 — CSAPR NO_X Compliance Technology Timeline



Installation advanced burners at all Coleman units, an SCR at Green 2 and converting Reid 1 to natural gas will reduce annual NO_X emissions below BRECs 2012 CSAPR allocation level. The Reid 1 gas conversion would take place during the next major outage in October 2012. The Coleman advanced burner upgrades will take place in 2013, 2014, and 2015 according to BREC's schedule already in place. Completion of the Green 2 SCR for 2014 CSAPR compliance is based on an equipment award date of October 1, 2012.

Figure 5-4 — NAAQS NO_X Compliance Technology Timeline

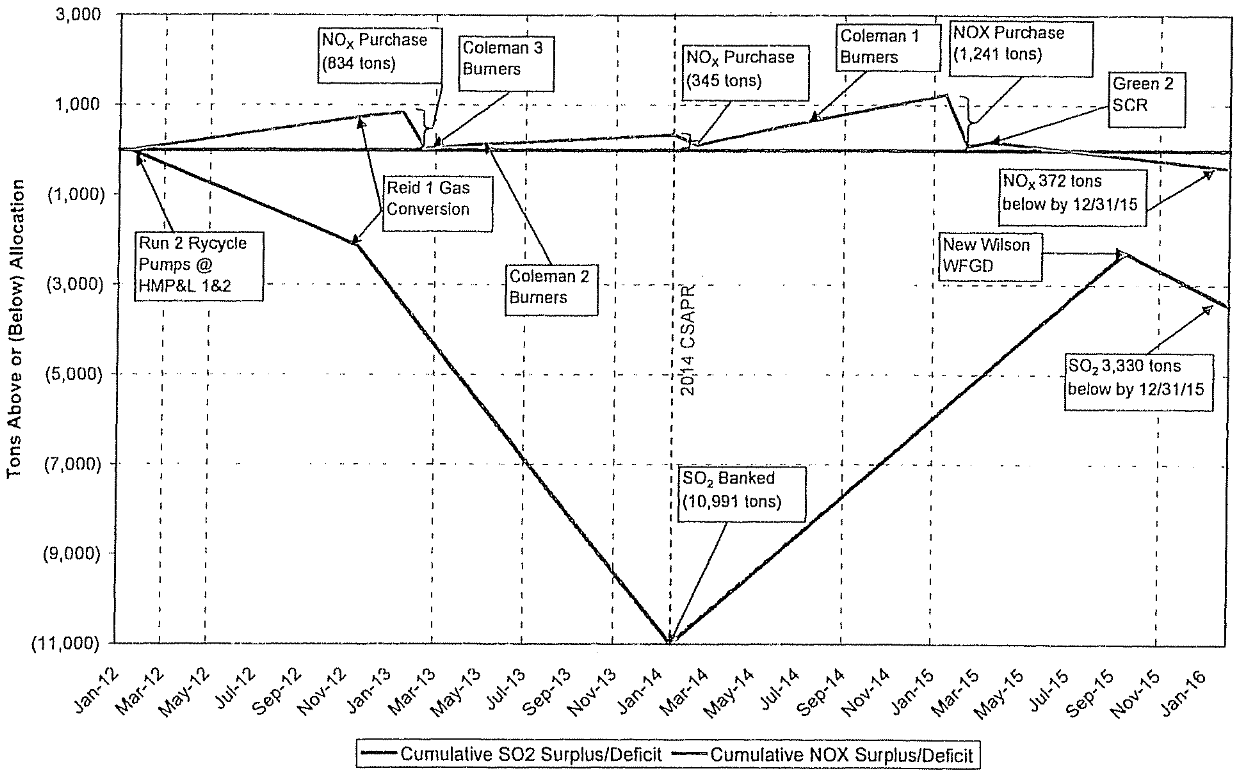


To comply with the potential 20% reductions foreseen by NAAQS, additional technologies would be required. Installation of an SCR at Green 1 will be responsible for making up the additional 1,349 tpy of required NO_X reductions. Engineering of the Green 1 SCR would need to start in August 2013 in order to comply with the predicted 2016 allocations.

5.3.2 Banked and Purchased Credits for Strategies

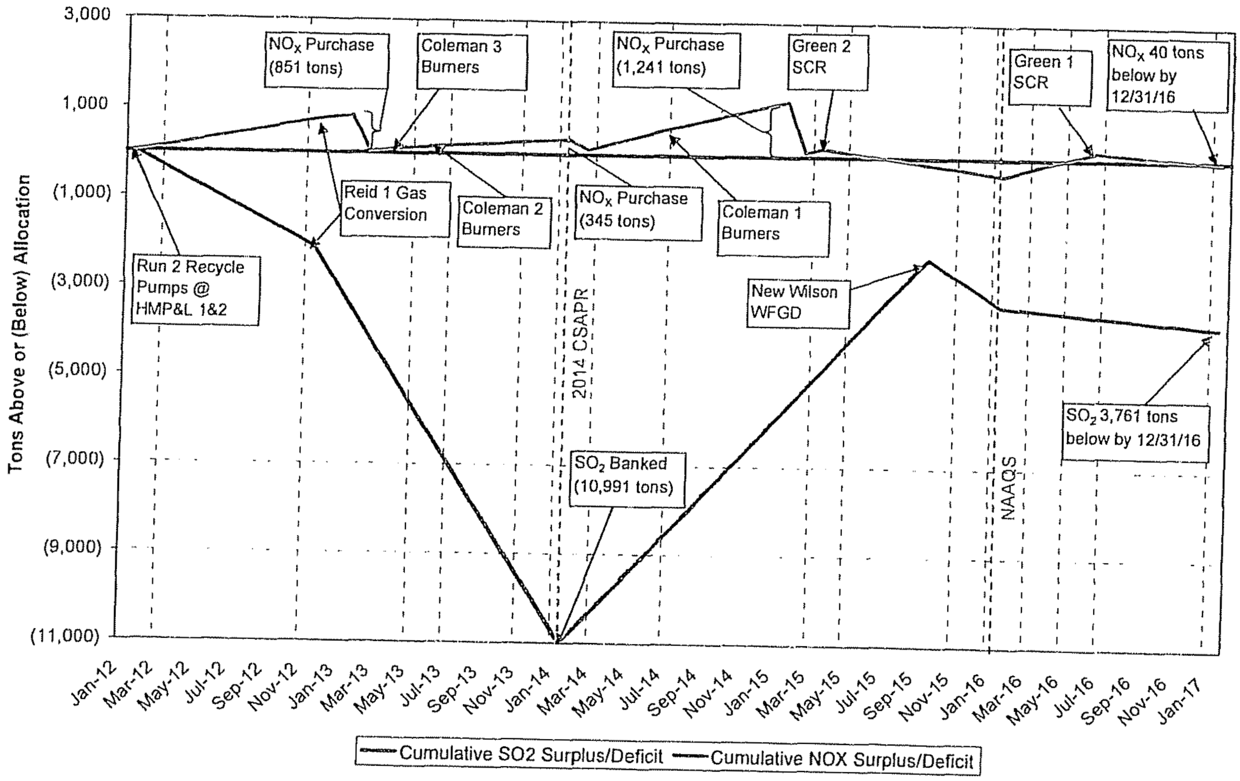
Based on the implementation strategy timeline detailed above, the cumulative deficit or surplus generated by implementing the proposed strategies compared to the 2012 and 2014 CSAPR and projected 2016 NAAQS was determined. Figure 5-5 below shows the total cumulative SO_2 and NO_X emission deficits and/or surpluses compared to CSAPR allocations from January 2012 through December 2015.

Figure 5-5 — Cumulative Emissions Above or Below CSAPR SO_2 and NO_X Allocations



Implementing the compliance schedule shown in Figure 5-2 and Figure 5-3, BREC will consistently have adequate SO_2 credits to maintain operation within their CSAPR allocation limits. NO_X emissions continue to be above allocation limits each year until startup of the Green 2 SCR. Based on these completion dates for NO_X technologies, BREC will be able to meet their 2014 CSAPR allocations limits by 2015 but will need to purchase additional credits to cover surplus emissions for 2012 (843 tons), 2013 (345 tons) and 2014 (1,241 tons). Starting in 2015 with startup of the Green 2 SCR, the NO_X control strategies will lower emission levels below the 2014 CSAPR allocations. Implementing the WFGD modifications at HMP&L and converting Reid 01 will reduce SO_2 emission below the 2012 levels and allow BREC to bank approximately 11,000 credits over two years (2012-2013) for use to offset yearly overages while the new Wilson FGD is being constructed.

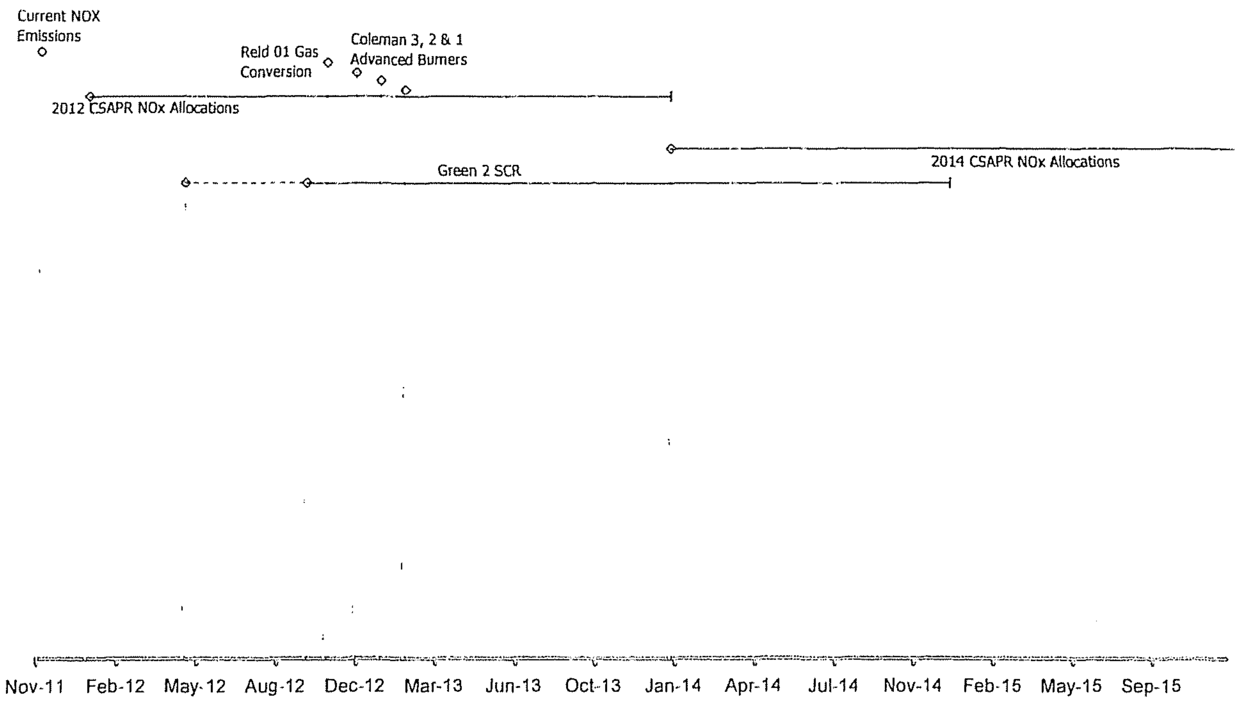
Figure 5-6 — Cumulative Emissions Above or Below NAAQS SO_2 and NO_X Allocations



Using the installation timelines shown in Figure 5-2 and Figure 5-4, BREC will be able to meet their predicted 2016 NAAQS allocations. Both NO_X and SO_2 will remain at levels below the anticipated NAAQS limits after 2014. NO_X credit purchase of approximately 851, 345 and 1,241 tons would be required for 2012, 2013 and 2014 respectively.

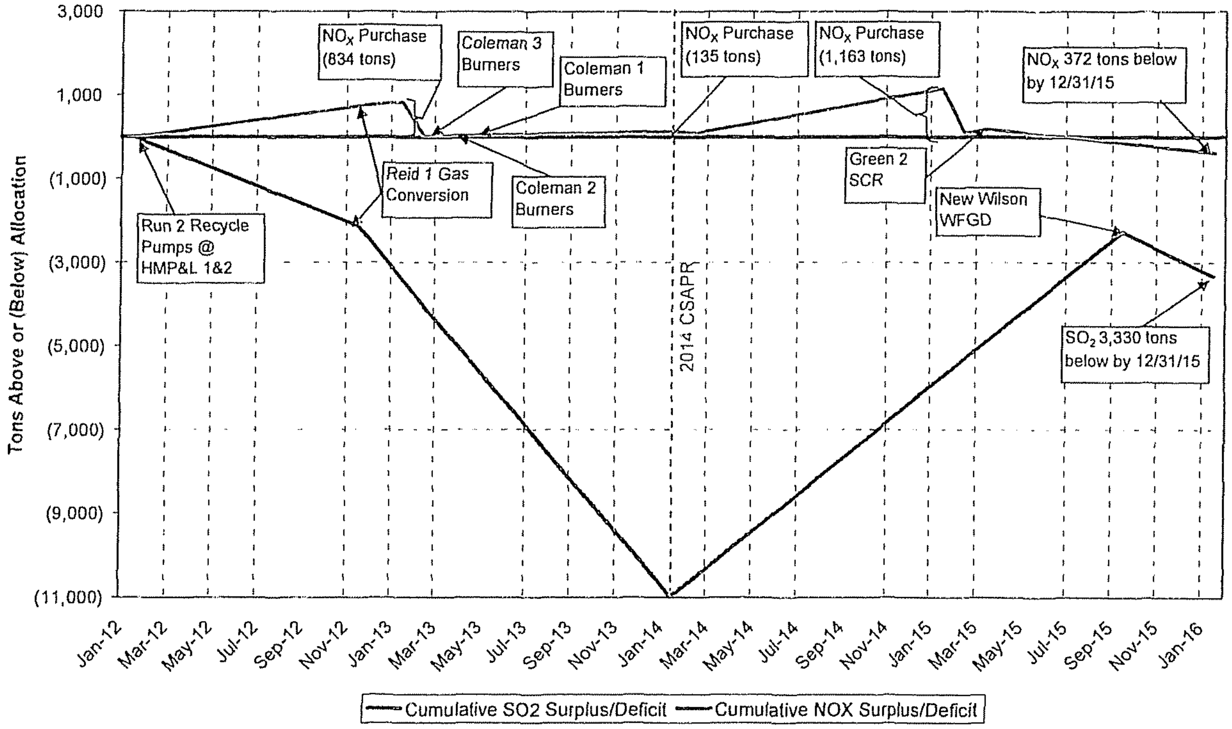
Cumulative deficits and surpluses shown in Figure 5-5 and Figure 5-6 represent installation and startup dates that parallel BREC's current outage schedules. To minimize potential NO_X overages and purchase of credits, BREC should consider adjusting some planned outage dates. Figure 5-7 below adjusts post 2012 scheduled outages to reduce yearly NO_X overages after 2013.

Figure 5-7 — CSAPR NO_X Compliance Technology Timeline (Adjusted)



Adjusting the installation date for the Coleman 1 and 2 advanced burners to the start of 2013 will reduce BREC's overall exceedence of their 2013 and 2014 NO_X allocations by 210 and 78 tons and help to avoid uncertainties of the credit market. The resulting cumulative surplus and deficit associated with implementing the above NO_X timeline and the previous SO_2 timeline of Figure 5-2 is shown in Figure 5-8 below.

Figure 5-8 — Cumulative Emissions Above or Below CSAPR SO_2 & NO_X Allocations (Adjusted)



Purchase of approximately 834, 135 and 1,163 tons of NO_X credits will be needed to offset excess 2012, 2013 and 2014 emissions. Installation of third generation low-NO_X burners at Coleman 1, 2 and 3 and start up of the Green 2 SCR in 2015 will enable BREC to achieve NO_X compliance for 2015. After switching the HMP&L scrubbers to operate with two recirculation pumps, SO_2 emissions will continuously be lower than BREC's 2012 allocations and should be banked to offset excess emissions in 2014 and 2015 before the new Wilson WFGD starts up.

Should BREC exceed their allowance, they will be required to settle any credit deficits on a calendar year basis. If below their yearly allocations, BREC will have the option to either sell or bank their excess credits for use at a later date. Credits that have been banked do not expire and can be used to offset in any future CSAPR emission overage. Table 5-12 below shows the anticipated excess or shortage of credits per year (2012-2017) for each of the proposed strategies and installation schedules.

Table 5-12 — Fleet-Wide Yearly Allocation Surplus and Deficit

Year	End of Year SO_2 Surplus or (Deficit)			End of Year NO_X Surplus or (Deficit)		
	CSAPR	CSAPR (Adjusted)	NAAQS	CSAPR	CSAPR (Adjusted)	NAAQS
2012	3,385	3,385	3,385	(834)	(834)	(834)
2013	7,606	7,606	7,606	(345)	(135)	(345)
2014	(5,229)	(5,229)	(5,229)	(1,241)	(1,163)	(1,241)
2015	(2,433)	(2,433)	(2,433)	372	372	372
2016	3,160	3,160	431	679	679	(332)
2017	3,160	3,160	431	679	679	394
TOTAL	9,650	9,650	4,192	(688)	(401)	(1,986)

Regardless of the approach taken, BREC will need to purchase credits to offset excess NO_X emissions in 2012, 2013 and 2014. Should BREC choose to implement the "CSAPR Adjusted" implementation schedule, the early burner upgrades at Coleman 1 and 2 will reduce necessary credit purchases by a total of 288 tons for 2013 and 2014. The NAAQS approach requires NO_X credit purchases in 2012, 2013, and 2014 but will provide excess credits to be banked in 2016 to offset potential overages in 2017. SO_2 credit surplus and deficit remains the same regardless of strategy. Excess SO_2 credits from 2012 and 2013 will need to be banked to offset deficits in 2014 and 2015. Startup of the new Wilson WFGD will return overall fleet-wide SO_2 emissions to below their allocations by 2016.

Last page of Section 5

6. CONCLUSIONS AND RECOMMENDATIONS

Based on the results of the technology screening and cost estimating performed in this study, the recommended compliance strategies for meeting future regulations on air quality, coal combustion residual handling, and 316(b) impingement mortality and entrainment are summarized as follows:

6.1 SULFUR DIOXIDE

The projected emission limit under the final version 2014 Cross-States Air Pollution Rule (CSAPR) is 13,643 tpy for the BREC fleet. Using this limit and the annual average heat input, the calculated emission rate for 2014 is 0.192 lb/MMBtu compared to the current fleet-wide rate of 0.384 lb/MMBtu. A total fleet-wide reduction in SO_2 emissions of 50% is needed to comply with the 2014 allocations. This limit will require BREC to upgrade existing WFGD systems and address units such as Reid 01 which has no SO_2 control technology in place. After completing an NPV comparison of the various improvements available, the most economical solutions to reduce BREC's emissions to the 2014 limits were chosen.

BREC should replaced the existing Wilson horizontal scrubber which has been operating at about 91% removal efficiency with new absorber vessel capable of increasing removal rates to 99% and reduce emission by approximately 8,400 tpy. Operating the existing HMP&L scrubbers with two (2) recirculation pumps will increase removal efficiency to about 97% and reduce emissions by nearly 3,350 tpy. It's recommended that HMP&L install third recycle pump in each absorber to increase redundancy and tip the existing ID fans to offset the increased pressure drop caused by an increase in slurry flowrate. Converting Reid 01 to natural gas will further reduce fleet-wide SO_2 emissions by 5,065 tpy. BREC should also return the Coleman scrubber back to as-designed operation to achieve 96% removal rates, perform a condition assessment to determine how best to improve reliability and consider implementing simultaneous Coleman unit outages when the WFGD is offline to avoid bypass operation. Implementing the modifications given in Table 6-1 below, BREC will be under their 2014 CSAPR allocation allowance and a potentially forthcoming ruction of 20% for NAAQS compliance.

Table 6-1 — SO_2 Compliance Summary

Unit	Baseline Heat Input (MMBtu)	Baseline SO_2 Emissions (tpy)	Current Annual SO_2 Emission Rate (lb/MMBtu)	Technology Selection	Estimated New SO_2 Emissions (tpy)	Estimated New Annual SO_2 Emission Rate (lb/MMBtu)	Net Present Value (2011$ Million)
Coleman Unit C01	11,784,789	2,331	0 396	Return to As-Designed Operation	1,473	0.250	N/A
Coleman Unit C02	11,787,242	2,411	0.409	Return to As-Designed Operation	1,473	0 250	N/A
Coleman Unit C03	12,570,106	2,406	0 383	Return to As-Designed Operation	1,571	0 250	N/A
Wilson Unit W01	37,043,481	9,438	0.510	New Tower Scrubber - 99% removal	1,049	0 057	$82.5
Green Unit G01	20,128,359	1,873	0.186	None	1,873	0.186	N/A
Green Unit G02	20,347,531	1,414	0 139	None	1,414	0 139	N/A
HMP&L Unit H01	12,823,005	2,227	0.347	Run both pumps install third pump as spare	788	0.123	-$2 1
HMP&L Unit H02	13,214,893	2,745	0.415	Run both pumps install third pump as spare	835	0 126	-$2 1
Reid Unit R01	2,240,807	5,066	4.522	Natural Gas with Existing Burners	1	0 001	$8.9
Reid Unit RT	87,379	5	0 117	None	5	0.117	N/A
TOTAL	142,027,592	29,916	0.421	N/A	10,482	0.148	$87 2

To achieve CSAPR compliance BREC should execute a fleet-wide project schedule similar to that show in Figure 5-2. Operating the HMP&L WFGDs with both recirculation pumps starting in January 2012 along with converting Reid 1 to natural gas in November 2012 will result in excess allocations that can be used to offset SO_2 deficits after the 2014 allocations go into effect until startup of the new Wilson scrubber in 2015. It is anticipated that the new Wilson scrubber will take forty-two months from the start of engineering to the startup and would need to be in service by the end of 2015 to avoid any potential credit purchase.

6.2 ACID GAS MITIGATION (SO_3 AND HCL)

In order to promote effective mercury capture, DSI systems should be installed at each unit where ACI systems are installed. Activated carbon requires SO_3 concentrations to be in the range of 3-5 ppm for maximum effectiveness. At these concentration levels, ESP performance should be unaffected by the reduced SO_3 and remain near their current removal efficiencies. Installation of a DSI system typically takes 16 months from the start of engineering to system operation. Lifetime cost of the recommended sorbent injection systems is included in the particulate matter strategy summary of Section 6.5.

Although each of the BREC units currently has HCl emissions that are below the proposed MACT limits, some facilities will not have SO_2 emission rates low enough to be used as a surrogate for MACT acid gas compliance. In cases where SO_2 emission rates are greater that 0.20 lb/MMBtu (Coleman), HCl stack monitors will be required to demonstrate compliance. Net present value for a monitor is approximately $414k.

6.3 NITROGEN OXIDES

BREC's NO_X allocation under the final version 2014 CSAPR is 10,142 tpy for the fleet. Using this limit and the annual average heat input, the calculated emission rate for 2014 is 0.149 lb/MMBtu compared to the current fleet-wide rate of 0.177 lb/MMBtu. A total fleet-wide reduction in SO_2 emissions of 16% is needed to comply with the 2014 allocations. To meet their allocation limit BREC will need to install an SCR at Green, convert Reid 1 to natural gas and upgrade existing Low-NO_X burners at Coleman. After completing an NPV comparison of the various improvements available, the most economical solutions to reduce BREC's emissions to the 2014 limits were chosen. BREC should install SCR system at Green 2 to reduce emission by 1,843 tpy. Planned upgrades at the three Coleman units to third generation Lox-NO_X burners will provide 549 tpy of reduction and converting Reid to natural gas will provide an additional 220 tpy reduction. Implementing all of these modifications will reduce BREC's annual NO_X emissions to approximately 9,462 tpy and achieve compliance with their 2014 CSAPR allocations. Table 6-2 provides a summary of the suggested modifications for compliance.

Table 6-2 — NO_X CSAPR Compliance Summary

Unit	Baseline Heat Input (MMBtu)	Baseline NO_X Emissions (tpy)	Current Annual NO_X Emission Rate (lb/MMBtu)	Technology Selection	Estimated New NO_X Emissions (tpy)	Estimated New Annual NO_X Emission Rate (lb/MMBtu)	Net Present Value (2011$ Million)
Coleman Unit C01	11,254,853	1,858	0.330	Advanced Burners	1,672	0.297	$0.32
Coleman Unit C02	9,544,382	1,585	0.332	Advanced Burners	1,427	0.299	$0.32
Coleman Unit C03	12,195,952	2,044	0.335	Advanced Burners	1,840	0.302	$0.32
Wilson Unit W01	36,221,670	934	0.052	None	934	0.052	N/A
Green Unit G01	19,866,020	2,050	0.206	None	2,050	0.206	N/A
Green Unit G02	20,128,970	2,168	0.215	SCR @ 85% Removal	325	0.032	$43.9
HMP&L Unit H01	13,003,466	460	0.071	None	460	0.071	N/A
HMP&L Unit H02	12,118,692	418	0.069	None	418	0.069	N/A
Reid Unit R01	1,962,424	512	0.522	Natural Gas with Existing Burners	292	0.298	See SO_2
Reid Unit RT	126,361	45	0.708	None	45	0.708	N/A
TOTAL	136,422,791	12,074	0.177	N/A	9,462	0.139	$44.9

In order to achieve compliance with potential NAAQS emission reductions, BREC would need to alter their compliance strategy. Assuming that an additional 20% reduction beyond the 2014 CSAPR allocations will be required, BREC will need to reduce its fleet-wide NO_X emission rate from 0.177 lb/MMBtu to 0.119 lb/MMBtu in order to meet their allocation of 8,114 tpy. Advanced burner upgrades would be required at all three Coleman units and both Green units would require a SCRs. Like the CSAPR approach, converting Reid 1 to natural gas would provide additional reduction. A summary of the suggested modifications, net present value and resulting emissions for this approach are provided in Table 6-3 below.

Table 6-3 — NO_X NAAQS Compliance Summary

Unit	Baseline Heat Input (MMBtu)	Baseline NO_X Emissions (tpy)	Current Annual NO_X Emission Rate (lb/MMBtu)	Technology Selection	Estimated New NO_X Emissions (tpy)	Estimated New Annual NO_X Emission Rate (lb/MMBtu)	Net Present Value (2011$ Million)
Coleman Unit C01	11,254,853	1,858	0 330	Advanced Burners	1,672	0.297	$0 32
Coleman Unit C02	9,544,382	1,585	0 332	Advanced Burners	1,427	0 299	$0 32
Coleman Unit C03	12,195,952	2,044	0.335	Advanced Burners	1,840	0.302	$0 32
Wilson Unit W01	36,221,670	934	0.052	None	934	0.052	N/A
Green Unit G01	19,866,020	2,050	0.206	SCR @ 85% Removal	307	0 031	$46.5
Green Unit G02	20,128,970	2,168	0 215	SCR @ 85% Removal	325	0.032	$43.9
HMP&L Unit H01	13,003,466	460	0.071	None	460	0.071	N/A
HMP&L Unit H02	12,118,692	418	0.069	None	418	0 069	N/A
Reid Unit R01*	1,962,424	512	0.522	Natural Gas with Existing Burners	292	0 298	*See SO_2*
Reid Unit RT	126,361	45	0.708	None	45	0.708	N/A
TOTAL	136,422,791	12,074	0 177	N/A	7,720	0 113	$91.4

Project schedules and implementation timelines for the recommended NO_X control modifications are shown in Figure 5-7. These strategies produce NO_X allocation deficits in 2012, 2013 and 2014 which will need to be purchased from other Group 1 utilities. Installation of new advanced low-NO_X burners at Coleman 1, 2, and 3 and the startup of the Green 2 SCR reduce emissions sufficiently for 2015 compliance. To meet potential NAAQS reductions, an implementation timeline similar to Figure 5-4 should be executed.

6.4 MERCURY

Currently the only BREC units that are compliant with the proposed MACT regulation of 1.2 lb/TBtu are HMP&L 1 and 2. All units at Coleman, Wilson and Green will require ACI systems to achieve compliance by 2015. Emission reductions of 66% at Coleman, 32% at Wilson, 61% at Green 1 and 53% at Green 2 will be needed. If any unit is converted to natural gas it will no longer be required to meet the MACT Hg requirements. Typical duration for installation of an ACI system is fifteen (15) months from the start of engineering to system startup. BREC should install the ACI systems across their fleet before the anticipated MACT compliance date of January 1, 2015. A summary of current mercury emission levels, proposed compliance technology and net present value for the recommended modifications is provided below.

Table 6-4 — MACT Hg Compliance Summary

Unit	Baseline Elemental Hg Emission Rate (lb/TBtu)	Baseline Oxidized Hg Emission Rate (lb/TBtu)	Baseline Total Hg Emission Rate (lb/TBtu)	Required Percent Reduction for MACT Compliance	Technology Selection	NPV (2011$ Million)
Coleman Unit C01	2 67	0 85	3 52	66%	Activated Carbon Injection	$11.9
Coleman Unit C02						$11 9
Coleman Unit C03						$11 9
Wilson Unit W01	1 56	0.21	1.77	32%	Activated Carbon Injection	$26 7
Green Unit G01	2.73	0.36	3 09	61%	Activated Carbon Injection	$15.3
Green Unit G02	2 46	0.12	2 58	53%	Activated Carbon Injection	$15.3
HMP&L Unit H01	0.34	0.28	0.62	N/A	None	N/A
HMP&L Unit H02	0 22	0.24	0.47	N/A	None	N/A
Reid Unit R01	N/A	N/A	6.5	82%	Natural Gas Conversion	N/A
TOTAL						$93 0

6.5 PARTICULATE MATTER AND ACID GAS CONTROL

PM emissions are made up of condensable emissions and filterable emissions. The existing ESPs and WFGD systems at Wilson and Green 1 and 2 are currently achieving filterable and condensable emissions below the anticipated MACT level of 0.030 lb/MMBtu. Total particulate emissions at Coleman and HMP&L are above the MACT proposed limit and will required upgrades. Current emission levels, recommended modifications and net present value for each station are summarized below.

Table 6-5 — MACT TPM Compliance Summary

Unit	Baseline Filterable PM Emission Rate (lb/MMBtu)	Baseline Condensable PM Emission Rate (lb/MMBtu)	Baseline Total PM Emission Rate (lb/MMBtu)	Required Percent Reduction for MACT Compliance	Technology Selection	Net Present Value (2011$ Million)
Coleman Unit C01	0.0220	0.0178	0.0398	25%	Hydrated Lime DSI & ESP Upgrades	$10.3
Coleman Unit C02						$10.3
Coleman Unit C03						$10.3
Wilson Unit W01	0.00912	0.01043	0.0196	N/A	Low Oxidation Catalyst & ESP Upgrades	$11.2
Green Unit G01	0.0084	0.0111	0.0195	N/A	Hydrated Lime DSI & Potential ESP Upgrades	$11.2
Green Unit G02	0.0046	0.0123	0.0169	N/A	Hydrated Lime DSI & Potential ESP Upgrades	$11.2
HMP&L Unit H01	0.0177	0.0142	0.0319	6%	Hydrated Lime, Low Oxidation Catalyst & ESP Upgrades	$11.2
HMP&L Unit H02	0.0120	0.0204	0.0324	7%	Hydrated Lime, Low Oxidation Catalyst & ESP Upgrades	$11.2
Reid Unit R01	0.269	N/A	>0.030	90%	Natural Gas Conversion	N/A
TOTAL						$86.9

Although current Wilson and Green TPM emission levels are below 0.030 lb/MMBtu, upgrades to the ESPs will likely be required to offset increased particulate loading from the ACI and DSI systems that are required for mercury control. In addition, installation of DSI systems at HMP&L and Coleman will reduce the high condensable emissions while minimally increasing filterable emissions. Testing should be conducted at all units to determine how the existing ESP performance is affected by activated carbon and sorbent injection systems before any upgrades.

6.6 COOLING WATER INTAKE IMPINGEMENT MORTALITY AND ENTRAINMENT (316(b))

Proposed EPA 316(b) regulations for cooling water intakes will limit intake velocities to 0.5 fps or require cooling system modifications to limit impingement mortality of fish, eggs, larvae, and other aquatic organisms to a maximum of 12% annual average. In addition, the compliance technology installed should be demonstrated to be a Best Technology Available (BTA) for entrainment reduction. This study evaluated several different technologies that provide for compliance with these proposed regulations, including new screen designs and conversion to closed cycle cooling. Since the proposed regulations do not mandate a conversion to closed cycle cooling, it is recommended that replacement intake screens be installed. The recommended screen technology based on an evaluation of capital and O&M costs is a rotating circular intake screen with fish pumps to meet the expected impingement mortality reduction. The expected capital and O&M cost of these screens is provided in the table below.

Table 6-6 — 316(b) Compliance Summary

Unit	Selected Technology	Estimated Capital Cost ($2011 Million)	Estimated O&M Cost ($2011 Million)
Coleman Unit C01	Rotating Circular Intake Screen with Fish Pump	$1.33	$0.25
Coleman Unit C02		$1.33	$0.25
Coleman Unit C03		$1.33	$0.25
Sebree		$2.05	$0.37

It is recommended that BREC engage a screen supplier to discuss the site specific installation requirements and compliance verification methods for new screen technology that will meet the proposed EPA 316 (b) requirements. Ongoing EPA 316(b) testing that is being performed in the industry on the various new designs of replacement screens should be monitored as well.

6.7 COAL COMBUSTION RESIDUAL HANDLING AND DISPOSAL

Two alternate regulations for the management of CCRs including fly ash, WFGD waste product, and bottom ash, have been issued for public comment. Under the first proposal, EPA would list these residuals as special wastes under the hazardous waste provisions of Subtitle C of the Resource Conservation and Recover Act (RCRA). Under the second proposal, EPA would regulate coal ash under Subtitle D of RCRA, the section for non-hazardous wastes. It is expected that the less stringent Subtitle D regulations will be promulgated, which will result in additional O&M cost for landfilling costs due to Subtitle D requirements for lining of landfills and ongoing groundwater monitoring. Although continued operation of the existing bottom ash dewatering ponds may be possible under the new regulations, this is not expected to be practical due to requirements for pond modifications (liner and ground water monitoring system installation) as well as pending wastewater discharge standards that will likely necessitate treatment or elimination of ash pond discharge streams. As such, a conversion to a dry bottom ash system using remote submerged scraper conveyors (SSCs) is recommended. The resulting capital costs associated with remote SSC installation and O&M costs is estimated and provided below. Depending on the local landfill options available to BREC under Subtitle D, additional CCR disposal O&M costs of approximately $2.50/ton may be incurred due to liner and groundwater monitoring requirements that will be imposed on landfill operators.

Table 6-7 — CCR Compliance Summary

Station	Technology Selected	NPV (2011$ Millions)
Coleman	Dry Bottom Conversion – Remote SSC & Fly Ash Conversion to Dry Pneumatic	$45.6
Wilson	None	N/A
Green	Dry Bottom Conversion – Remote SSC	$37.0
HMP&L	Dry Bottom Conversion – Remote SSC	$34.1
Reid	None	N/A

Last page of Section 6.

Appendix 1 – Expanded Compliance Strategy Matrices

Technology Selection & Results - CSAPR & MACT

logy Selection				Emission Surplus / (Deficit) vs. Allocation				Capital Cost (Millions $)						Total Projected Capital Cost (2011$)	Additional O&M Cost (Millions $)						Fuel Cost Increase (2011$)	Total Yearly O&M Cost Increase (2011$)
	MACT - Selection			CSAPR II - 2014 (Tons)		Projected NAAQS (Tons)																
	Hg	CPM	FPM	SO_2	NO_x	SO_2	NO_x	SO_2	NO_x	HCl	Hg	CPM	FPM		SO_2	NO_x	HCl	Hg	CPM	FPM		
d MACT monitor be	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	(323)	(831)	(553)	(1000)	0.00	5.94	0.32	4.00	5.00	2.72	$18,000,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
d MACT monitor be	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	(323)	(585)	(553)	(753)	0.00	5.94	0.32	4.00	5.00	2.72	$18,000,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
d MACT monitor be	Activated Carbon Injection	Hydrated Lime - DSI	Advanced Electrodes & High Frequency TR Sets	(345)	(942)	(590)	(1121)	0.00	5.94	0.32	4.00	5.00	2.72	$18,000,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
elow 0.2 g SO2 of n limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	Advanced Electrodes & High Frequency TR Sets	2565	1711	1843	1182	139.00	0.00	0.00	4.50	6.50	4.54	$154,500,000	0.69	0.00	0.00	2.19	0.00	0.17		$3,100,000
ince	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	91	(613)	(302)	(900)	0.00	0.00	0.00	4.00	5.00	3.34	$12,300,000	0.00	0.00	0.00	1.14	0.32	0.07		$1,500,000
ince	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	357	1128	3	837	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000	0.00	2.16	0.00	1.14	0.32	0.07		$3,700,000
2 Btu will prima with	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	463	456	213	273	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
2 Btu will prima with	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	454	526	196	337	3.15	0.00	0.00	0.00	6.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
rners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	218	(132)	174	(164)	1.20						$1,200,000	(1.77)						$5,610,000	$3,800,000
	None	None	None	4	(39)	2	(40)	0.00						$0	0.00							$0
				3161	680	432	(1349)							$339,000,000							$5,610,000	$17,300,000

parts have been extimated based on S&L exprence due to lack of available operational data.
eceived from BREC confirming that the Coleman FGD is capable of producing emission rates of 0.25lb/MMBtu and

WFGD stack and one (1) for each unit bypass stack.

Technology Selection & Results - NAAQS / CSAPR & MACT

logy Selection								Capital Cost (Millions $)						Total Projected Capital Cost (2011$)	Additional O&M Cost (Millions $)						Fuel Cost Increase (2011$)	Total Yearly O&M Cost Increase (2011$)
	MACT - Selection			CSAPR II - 2014 (Tons)		Projected NAAQS (Tons)																
	Hg	CPM	FPM	SO_2	NO_x	SO_2	NO_x	SO_2	NO_x	HCl	Hg	CPM	FPM		SO_2	NO_x	HCl	Hg	CPM	FPM		
:d MACT l monitor x be	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from ROTOMIX	Advanced Electrodes & High Frequency TR Sets	(323)	(831)	(553)	(1000)	3.93	5.94	0.32	4.00	5.00	2.72	$21,900,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
:d MACT l monitor x be	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from SNCR	Advanced Electrodes & High Frequency TR Sets	(323)	(585)	(553)	(753)	3.93	5.94	0.32	4.00	5.00	2.72	$21,900,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
:d MACT l monitor x be	Fuel Additive & Activated Carbon Injection or Activated Carbon Injection	Hydrated Lime - DSI Control NH3 slip from SNCR	Advanced Electrodes & High Frequency TR Sets	(345)	(942)	(590)	(1121)	3.93	5.94	0.32	4.00	5.00	2.72	$21,900,000	0.00	0.00	0.03	0.81	0.27	0.09		$1,200,000
elow 0.2 ng SO2 e of on limits	Activated Carbon Injection & New SCR Catalyst	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	Advanced Electrodes & High Frequency TR Sets	2565	1711	1843	1182	139.00	0.00	0.00	4.50	6.50	4.54	$154,500,000	0.69	0.00	0.00	2.19	0.00	0.17		$3,100,000
since	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	91	1130	(302)	842	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000	0.00	2.16	0.00	1.14	0.32	0.07		$3,700,000
since	Activated Carbon Injection	Hydrated Lime - DSI	Potential ESP Upgrades Due to ACI and DSI	357	1128	3	837	0.00	81.00	0.00	4.00	5.00	3.34	$93,300,000	0.00	2.16	0.00	1.14	0.32	0.07		$3,700,000
)2 Btu will s prima e with	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	463	456	213	273	3.15	0.00	0.00	0.00	0.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
)2 Btu will s prima e with	None needed due to oxidation across SCR and WFGD	Low Oxidation SCR catalyst + Hydrated Lime - DSI Control NH3 slip from SCR	ESP Maintenance / Possible Upgrade	454	526	196	337	3.15	0.00	0.00	0.00	0.00	2.50	$11,700,000	0.38	0.00	0.00	0.00	0.29	0.08		$800,000
rners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	Natural Gas with Existing Burners	218	(132)	174	(164)	1.20						$1,200,000	(1.77)						$5,610,000	$3,600,000
	None	None	None	4	(39)	2	(40)	0.00						$0	0.00							$0
				3161	2422	432	394							$432,000,000							$5,610,000	$19,500,000

parts have been extimated based on S&L expience due to lack of available operational data
eceived from BREC confirming that the Coleman FGD is capable of producing emission rates of 0 25lb/MMBtu and

WFGD stack and one (1) for each unit bypass stack.

Appendix 2 -- Level 1 Project Schedules

	Orig Dur	Activity
	0	Start Engineering
	66	Project Execution Plan & Schedule
	130	Engineering Studies
	131*	WFGD Spec/Bid/Award
t	195	WFGD Vendor Engineering & Procurement
	273	WFGD Fabrication & Delivery
	85	Booster Fans / Motors Spec/Bid/Award
ery	372	Booster Fans / Motors Fabrication & Delivery
	87	Electrical Equip Spec/Bid/Award
	87	Electrical Equip Fabrication & Delivery
	66	DCS Spec/Bid/Award
	66	DCS Fabrication & Delivery
	66	Structural Steel Spec/Bid/Award
	66	Flue Gas Ductwork Spec/Bid/Award
	44	Site Plot Plan / General Arrangement
	130	Sitework & U/G Utilities Design
	130*	Design FGD / BOP Foundations
	130	Ductwork / Steel Design
	336	Mechanical Design
	325	Electrical Design / I & C Design
	44	Substructure Spec/Bid/Award/Mobilize
	110	GWC Spec/Bid/Award/Mobilize
	65*	Sitework & U/G Utilities
	68	WFGD Foundations
	326	WFGD Erection
	21	WFGD Tie-in Outage
	60	System Tuning
	5	Testing
	128	ID Fans
	253	Ductwork
	130	Electrical Check Out & Start Up
	110	Mechanical Check Out & Start Up

Months 1–48

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Big Rivers
Wet FGD
Level I Study Schedule

Sheet 1 of 1

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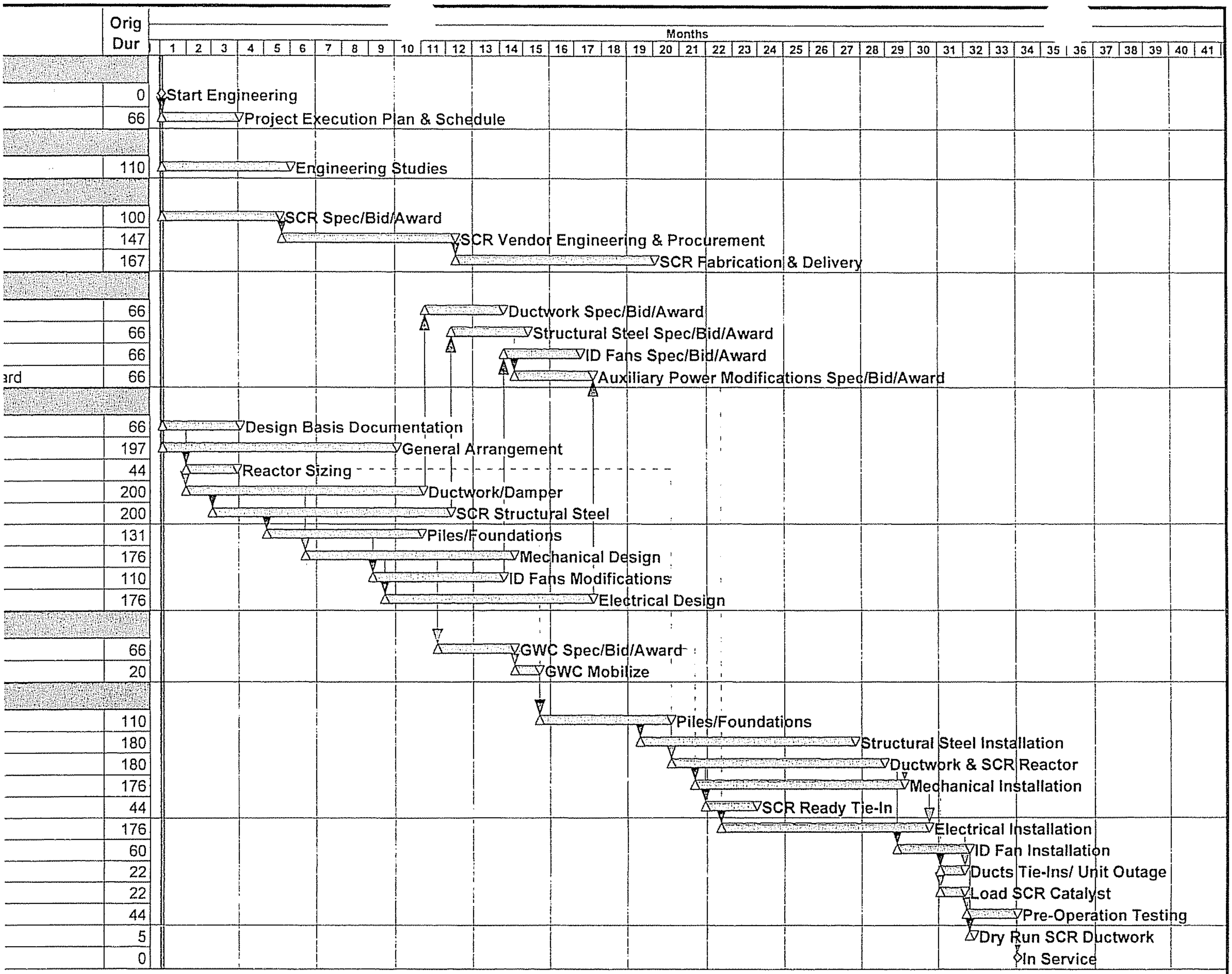

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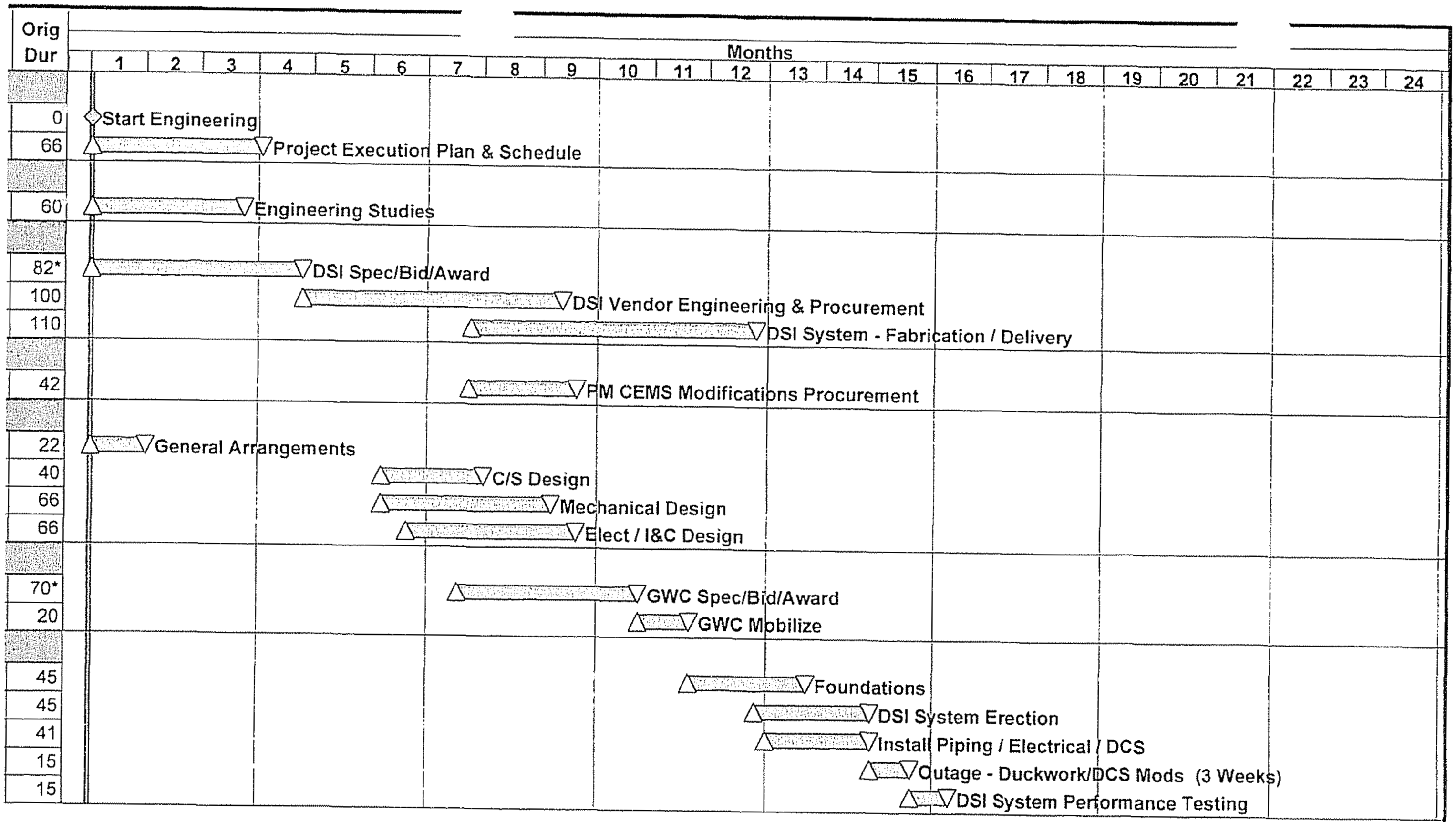

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Big Rivers
DSI
Level I Study Schedule

Sheet 1 of 1

Sargent & Lundy LLC

Orig Dur	AREA	Activity
0	00	Start Engineering
66	00	Project Execution Plan & Schedule
60	12	Engineering Studies
82*	20	ACI Spec/Bid/Award
100	20	ACI Vendor Engineering & Procurement
108	20	ACI System - Fabrication / Delivery
42	50	HG CEMS Modifications Procurement
22	55	General Arrangements
30	55	C/S Design
66	55	Mechanical Design
66	55	Elect / I&C Design
70*	70	GWC Spec/Bid/Award
20	70	GWC Mobilize
44	80	Foundations
41	80	ACI System Erection
41	80	Install Piping/Electrical/DCS
15	80	Outage (3 Weeks)
15	80	ACI System Performance Testing

Months: 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

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Big Rivers
ACI
Level I Study Schedule

Sheet 1 of 1

Sargent & Lundy LLC

Appendix 3 – NPV Calculations

CSAPR & NAAQS Compliance Technology NPV & LRR Calculations

SO2					NOx											
	NOx=	$2,500							SO_2=	$500		NOx=	$2,500			
2 Natural onversion	Green 1&2 Natural Gas Conversion	Reid Natural Gas Conversion	CSAPR 2014 Strategy	NAAQS Strategy	C1 SNCR	C2/3 SNCR	Green 1 SCR	Green 2 SCR	Green 1&2 SCR	Green 2 Natural Gas Conversion	Green 1&2 Natural Gas Conversion	Reid Natural Gas Conversion	Coleman 1,2&3 Advanced Burners	Green 1&2 SNCR	CSAPR 2014 Strategy	NAAQS Strategy
20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011
011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011
014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014
13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%
1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013
8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563
.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101
00,000	55,100,000	1,200,000	146,500,000	146,500,000	2,400,000	5,400,000	81,000,000	81,000,000	162,000,000	25,600,000	55,100,000	1,200,000	17,810,000	7,000,000	98,820,000	181,020,000
40,000	93,830,000	3,840,000	5,290,000	5,290,000	1,560,000	3,160,000	2,160,000	2,160,000	*4,320,000*	*46,640,000*	*93,830,000*	*3,840,000*	*0*	3,220,000	*6,000,000*	8,160,000
27,542	87,645,405	757,452	-3,661,798	-3,661,798	630,905	1,345,262	-2,196,146	-2,446,790	-4,642,936	-43,427,542	87,645,405	757,452	-1,372,500	1,111,074	-3,061,255	-5,257,401
.411	3,281	5,065	16,804	16,804	0	0	0	0	0	1,411	3,281	5,065	0	0	5,065	5,065
3,406	$1,640,565	$2,532,548	$8,401,798	$8,401,798	$0	$0	$0	$0	$0	$705,406	$1,640,565	$2,532,548	$0	$0	$2,532,548	$2,532,548
.003	1,818	220	220	220	372	726	1,742	1,843	3,585	1,003	1,818	220	549	844	2,611	4,354
07,033	$4,544,030	$550,000	$550,000	$550,000	$929,095	$1,814,739	$4,356,146	$4,606,790	$8,962,936	$2,507,033	$4,544,030	$550,000	$1,372,500	$2,105,926	$6,528,706	$10,884,852
48,000	1,023,961,000	41,002,000	180,524,000	180,524,000	18,295,000	37,520,000	91,850,000	91,850,000	183,700,000	507,448,000	1,023,961,000	41,002,000	15,260,000	39,515,000	147,085,000	239,962,000
06,000	959,579,000	8,913,000	87,335,000	87,335,000	8,623,000	18,629,000	46,502,000	43,893,000	90,395,000	474,006,000	959,579,000	8,913,000	972,000	17,561,000	52,756,000	100,286,000
2,775	$28,593	$669	$1,090	$1,090	$4,729	$4,965	$5,064	$4,788	$5,162	$47,905	$53,214	$6,392	$2,670	$4,500	$4,197	$4,795
027,342	$97,226,678	$903,085	$8,848,976	$8,848,976	$873,702	$1,887,532	$4,711,686	$4,447,336	$9,159,022	$48,027,342	$97,226,678	$903,085	$98,485	$1,779,320	$5,345,355	$10,161,201
9,898	$19,069	$171	$615	$615	$2,351	$2,600	$2,704	$2,413	$2,555	$19,898	$19,069	$171	$179	$2,109	$1,055	$2,006

CCR & 316(b) Compliance Technology NPV & LRR Calculations

Coleman					Sebree			HMP&L			Green			Wilson
Fish Retun Buckets	Wedgewire	Remote SSC	Dewatering Bin	Vacuum Conversion	WIP Screens	Fish Retun Buckets	Wedgewire	Remote SSC	Dewatering Bin	Vacuum Conversion	Remote SSC	Dewatering Bin	Vacuum Conversion	Vacuum Conversion
20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011
2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011
2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014
10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%
0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013
0.8563	0.8563	0.8563	-0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563
10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101
5,610,000	6,450,000	38,000,000	48,000,000	10,000,000	2,050,000	2,800,000	2,450,000	28,000,000	38,000,000	6,000,000	28,000,000	38,000,000	6,000,000	5,000,000
750,000	810,000	1,250,000	860,000	0	365,000	365,000	380,000	970,000	680,000	0	1,250,000	870,000	0	0
750,000	810,000	1,250,000	860,000	0	365,000	365,000	380,000	970,000	680,000	0	1,250,000	870,000	0	0
12,612,000	13,956,000	45,554,000	50,057,000	8,563,000	5,555,000	6,197,000	6,054,000	34,075,000	39,620,000	5,138,000	36,990,000	41,598,000	5,138,000	4,282,000

MACT Compliance Technology NPV & LRR Calculations

		Hg			TPM			
fication		Coleman ACI	WIlson ACI	Green ACI	Coleman DSI and ESP Upgrades	Wilson Low Oxidation Catalyst & ESP Upgrades	Green DSI & ESP Upgrades	HMP&L DSI, Low Oxidation Catalyst and ESP Upgrades
eters:								
	Years	20	20	20	20	20	20	20
	%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%	7.93%
n Rate	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
	%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
		2011	2011	2011	2011	2011	2011	2011
		2011	2011	2011	2011	2011	2011	2011
		2014	2014	2014	2014	2014	2014	2014
ge Rate		10.13%	10.13%	10.13%	10.13%	10.13%	10.13%	10.13%
		0.1013	0.1013	0.1013	0.1013	0.1013	0.1013	0.1013
		0.8563	0.8563	0.8563	0.8563	0.8563	0.8563	0.8563
		10.4101	10.4101	10.4101	10.4101	10.4101	10.4101	10.4101
	S	4,000,000	4,500,000	4,000,000	7,720,000	11,040,000	8,340,000	8,500,000
l)	S/yr	810,000	2,190,000	1,140,000	352,667	170,000	391,000	374,000
	S/yr	810,000	2,190,000	1,140,000	352,667	170,000	391,000	374,000
	S	11,858,000	26,652,000	15,293,000	10,282,000	11,224,000	11,212,000	11,172,000

EXHIBIT 4

Commonwealth of Kentucky

Before the Public Service Commission

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF ITS 2012 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, FOR CERTIFICATES OF PUBLIC CONVIENENCE AND NECESSITY, AND FOR AUTHORITY TO ESTABLISH A REGULATORY ACCOUNT.	)	Case No. 2012-00063

Direct Testimony of
Rachel S. Wilson

On Behalf of
Sierra Club

Public Version

July 23, 2012

Table of Contents

1. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, business address, and position.

A My name is Rachel S. Wilson and I am an associate with Synapse Energy Economics, Inc. (Synapse). My business address is 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct research and write testimony and publications that focus on a variety of issues relating to electric utilities, including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; environmental compliance technologies, strategies, and costs; electrical system dispatch; and valuation of environmental externalities from power plants.

I also perform modeling analyses of electric power systems. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electricity dispatch models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the Strategist, Promod, Prosym/Market Analytics, and Plexos models, and have reviewed input and output data for a number of other industry models.

Prior to joining Synapse in 2008, I worked for the Analysis Group, Inc., an economic and business consulting firm, where I provided litigation support in the form of research and quantitative analyses on a variety of issues relating to the electric industry.

I hold a Master of Environmental Management from Yale University and a Bachelor of Arts in Environment, Economics, and Politics from Claremont McKenna College in Claremont, California.

A copy of my current resume is attached as Exhibit RSW-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Kentucky Public Service Commission?

A Yes. On September 16, 2011, I filed direct testimony in the joint application of Kentucky Utilities Company/Louisville Gas & Electric for Certificates of Public Convenience and Necessity (CPCN) in Case Numbers 2011-00161 and 2011-00162. I also filed direct testimony on March 12, 2012 in the application of Kentucky Power for CPCN in Case Number 2011-00401.

Q What is the purpose of your testimony?

A My testimony reviews the regulatory requirements and economic justifications of specific environmental retrofits made by Big Rivers Electric Corporation ("BREC" or the "Company"), for which capital recovery is requested in this case. I review the current and expected running costs of the Company's coal-fired units, and compare these costs to different alternatives. I conclude that the Company's economic justification for these environmental retrofits, in the form of its financial modeling analysis, did not consider a full range of alternative compliance options and contained several flaws that bias its analysis in favor of installation of emission control retrofit projects.

Q Please identify the documents and filings on which you base your opinion regarding the Company's analysis of the environmental compliance costs affecting its fleet of coal plants.

A In addition to the application, Company witness testimonies, and discovery responses in this case, I have reviewed the Sargent & Lundy input assumptions and calculations relating to environmental retrofit options, the PACE Global input and assumptions and resulting market prices, the ACES Planning and Risk model inputs and outputs, and the BREC financial modeling calculations.

2. Conclusions and Overview of Testimony

Q In your opinion, do the facts and evidence presented in this case support the Company's request for CPCN?

A No, they do not. There are a number of assumptions in the modeling presented by the Company in this docket that are incorrect, which bias the Company's results in favor of the installation of pollution control retrofits and the continued operation of the BREC coal fleet. These include, but are not limited to: 1) modeling of only some of the controls expected for future regulatory compliance rather than the entire suite of anticipated controls; 2) a natural gas price forecast that is out-of-date and higher than current forecasts; 3) use of a carbon dioxide (CO_2) emissions price in the determination of market energy prices, but not in unit running costs; 4) exclusion of ongoing capital expenditures and operating and maintenance (O&M) costs at each of the coal units; 5) failure to examine the forward going costs of each of the BREC units on an individual basis; and 6) failure to model any alternative options (e.g. natural gas combined-cycle (NGCC), energy market purchases, etc.) for comparison to the retrofit case.

Synapse created a cash flow model that calculates the forward going costs of each of the BREC units on a stand-alone basis, and discounts those costs to determine the total net present value revenue requirement (NPVRR) of the retrofits selected by the Company for each unit individually. The "Retrofit" option is then compared to a natural gas combined-cycle replacement option.

The scenario used in our cash flow model represents what I believe is most likely to occur and includes the entire suite of pollution controls that are expected to bring the BREC coal units into compliance with both existing and expected U.S. Environmental Protection Agency (EPA) regulations. Second, it updates the Company's natural gas price forecast and instead uses the U.S. Energy Information Administration's (EIA) natural gas forecast from the *2012 Annual Energy Outlook*. Third, the CO_2 emissions price used by BREC's consultant PACE Global in modeling market energy prices is added in to the analysis of the future cost of operating BREC's generating units, as are the ongoing capital expenditures and O&M costs at each of the units. NPVRR at each of the units is then calculated under these revised assumptions for the "Retrofit" option. We then compare these results to the NPVRR associated with a natural gas combined-cycle replacement option.

The results of this case – the "Synapse Recommended Case" – are shown in Table 1 (also in Exhibit RSW-2), below. These results indicate that all of the BREC coal units are uneconomic when compared to a natural gas replacement option and should be considered for retirement.

Table 1. Comparison of Natural Gas Combined Cycle (NGCC) Replacement to BREC Unit Retrofits. Includes all pollution control retrofits, the AEO 2012 natural gas price forecast, and the PACE CO_2 price forecast (millions 2012$).

	NGCC Replacement 2015 minus Retrofit	% Difference from Retrofit
Wilson	($259)	-13.88%
Green 1	($204)	-18.53%
Green 2	($213)	-19.83%
HMPL 1	($82)	-12.47%
HMPL 2	($107)	-15.56%
Coleman 1	($108)	-15.84%
Coleman 2	($90)	-13.74%
Coleman 3	($103)	-14.92%
Total	($1,165)	-15.73%

The next sections of my testimony describe in more detail the errors that I believe were made by BREC in its modeling analysis and the scenarios modeled by Synapse in our cash flow analysis.

3. Characteristics of Units that Affect Their Running Costs

Q Please describe the characteristics of electric generating units that affect their running costs.

A Running costs of electric generating units are made up of two components – fixed and variable costs. Fixed costs include investment capital, property taxes, and fixed O&M expenses. Variable costs include fuel costs, emissions costs, and variable O&M expenses.

Characteristics unique to individual generating units affect their running costs, in particular generating unit size, age, heat rate, and installed pollution controls. Unit heat rate is a measure of the efficiency of the plant, with lower heat rates indicating that a generating unit is converting heat input (in the form of fuel) to energy output at a more efficient rate. Heat rate is related to age, and tends to degrade over time as units get older. It is also related to size, as smaller units tend to operate less efficiently than larger units. Higher heat rates, indicating a lower efficiency, lead to increased fuel and emissions costs, and increase the running costs of a generating unit.

As units get older, component parts degrade and require replacement. These replacements represent ongoing capital expenditures, which may increase as units age.

Pollution control technologies affect the running cost of a unit in various ways. First, they require investment capital and increase the fixed costs at a unit in a given year. Size of the unit matters when installing pollution controls due to economies of scale; smaller units are more expensive to retrofit on a $/kW (dollar/kilowatt) basis. Emission control equipment requires electricity to run, lowering the net output of a generating unit, which is called "parasitic load," meaning that the same fuel and emissions costs are incurred but result in less electricity output. Many emission controls also require the use of a reagent, the cost of which increases variable O&M.

4. ENVIRONMENTAL REQUIREMENTS FACING THE BREC COAL FLEET

Q What are the recent and emerging EPA requirements with which the Company's coal fleet will have to comply?

A The EPA has recently proposed a number of rules to protect human health and the environment. These rules are in various states of promulgation and, taken together, may have a significant economic implications for coal-fired generation. There are six rules that will have an effect on the coal-fired units in the United States, and the units in the BREC fleet:

A. Cross-States Air Pollution Rule (CSAPR)

B. Mercury and Air Toxics Standards (MATS)

C. National Ambient Air Quality Standards (NAAQS)

D. Coal Combustion Residuals (CCR)

E. Cooling Water Intake Rule (316(b))

F. Effluent limitation guidelines

In addition, regulation of CO_2 through federal legislation or EPA rulemaking will have a significant impact on the economics of coal-fired units.

Q Were all of these rules described sufficiently in Company witness testimony?

A No. Company witness Thomas Shaw describes CSAPR, MATS, CCR, and 316(b) rules. He does not discuss the NAAQS or the Effluent Limitation Guidelines, nor does he discuss the possibility of a CO_2 emissions allowance price.

Q Please briefly describe the purpose and impact of NAAQS.

A NAAQS set maximum air quality limitations that must be met at all locations across the nation. Compliance with the NAAQS can be determined through air quality monitoring stations, which are located in various cities throughout the

U.S., or through air quality dispersion modeling. If, upon evaluation, states have areas found to be in "nonattainment" of a particular NAAQS, states are required to set enforceable requirements to reduce emissions from sources contributing to nonattainment such that the NAAQS are attained and maintained. EPA has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide, ozone, particulate matter, and lead. EPA is required to periodically review and evaluate the need to strengthen the NAAQS if necessary to protect public health and welfare. For example, EPA is currently evaluating the NAAQS for ozone and particulate matter. Utilities are expecting new compliance requirements stemming from these anticipated NAAQS revisions as early as 2016, but no later than 2018. Sargent & Lundy confirms this in Table ES-3 of Exhibit DePriest-2, which lists a NAAQS compliance window of 2016-2018.

Q Please briefly describe the purpose and impact of the expected Effluent Limitation Guidelines.

A Following a multi-year study of steam-generating units across the country, EPA found that coal-fired power plants are currently discharging a higher-than-expected level of toxic-weighted pollutants. Current effluent regulations were last updated in 1982 and do not reflect the changes that have occurred in the electric power industry over the last thirty years, and do not adequately manage the pollutants being discharged from coal-fired generating units. Coal ash ponds and flue gas desulfurization (FGD) systems used by such power plants are the source of a large portion of these pollutants, and are likely to increase in the future as environmental regulations are promulgated and pollution controls are installed. No new rule has yet been proposed, but EPA intends to issue the proposed regulation in November 2012 and a final rule in April 2014.[1] New requirements

[1] *See* U.S. Environmental Protection Agency website. Accessed July 20, 2012. Available at: http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm

will be implemented in 2014-2019 through the 5-year National Pollutant Discharge Elimination System (NPDES) permit cycle.[2]

Q Please describe the purpose and impact of regulation of emissions of CO_2.

While there is not currently a federal law or proposed rulemaking requiring a control technology, cap-and-trade program, or tax on emissions of CO_2, discussions at the EPA and at the Congressional level are ongoing. The most recent legislative proposal to reduce emissions of CO_2 has taken the form of a Clean Energy Standard (CES), as introduced by Senator Bingaman on March 1, 2012. A CES encourages the use of low-carbon power through the allocation of clean energy credits to those generation technologies that emit less CO_2, which generation owners would consider in their dispatch decisions. In Senator Bingaman's bill, credits are determined based on individual power plant emissions and generating sources are given a certain number of credits based on their carbon profile, with lower emitting sources rewarded with a larger number of clean energy credits. In any given year, electric utilities would be required to hold a certain number of clean energy credits for a specific percentage of their sales.

Q Have there been any third-party analyses that evaluate the economic effect of the rules listed above on the U.S. coal fleet?

Yes, there have been several. The studies evaluate different combinations of the rules listed above. Study authors include the following organizations:

A. Investment and research firms (Credit Suisse and Bernstein Research)

B. Consulting firms (MJ Bradley, Charles River Associates, Brattle Group, and NERA Economic Consulting)

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[2] *See* U.S. Environmental Protection Agency. *Steam Electric ELG Rulemaking*. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf

C. Government and industry groups (North American Electric Reliability Corporation (NERC)), Edison Electric Institute (EEI), Electric Power Research Institute (EPRI), U.S. Department of Energy, and Bipartisan Policy Center)

Q Can you draw any conclusions about the effect of the EPA rules on coal economics based on the results of these studies?

Yes. There are two very important conclusions that one can draw when looking at the results of these studies. The first is that the forward-going economics of the coal fleet changes based on the number of rules that are taken into consideration when doing the analysis. A coal unit might still be economic to run when retrofit with controls that would allow it to comply with CSAPR and MATS, but if costs for compliance with the CCR rule are added, the forward-going costs of that same unit may at that point be higher than a natural gas or market alternative. In a 2010 study presented by ICF Consulting for the Edison Electric Institute (EEI) entitled *EEI Preliminary Reference Case and Scenario Results*, three scenarios are examined. The first looks at the effects of MATS, the second looks at the combined effect of MATS, CCR and 316(b), and the third scenario looks at the effects of those three rules with the addition of a CO_2 emissions price. A copy of this study is provided as Exhibit RSW-3.

Table 2, below, shows the number of expected gigawatts (GW) retired under the draft EPA rules as reported by ICF under the three scenarios.

Table 2. Coal Retirements in the ICF/EEI Analysis.

Scenario	Coal Retired (GW)	
	Low Estimate	High Estimate
MATS	25	50
MATS, CCR, 316(b)	30	60
MATS, CCR, 316(b), CO_2	70	120

As seen in Table 2, when regulations are examined in combination rather than independently, the effect on coal unit retirements is greater. The high estimate goes up by 10 GW when CCR and 316(b) are considered along with MATS. That estimate doubles with the addition of CO_2 regulation. As costs of emission control retrofits are compounded to comply with the EPA rules, the forward-going costs of running previously cost-effective coal units increase to the point at which they are uneconomic when compared to replacement options.

The second conclusion that one can draw when reviewing these studies is that lower natural gas prices lead to more coal retirements. As natural gas prices fall, the costs of operating natural gas-fired replacement generation decline, causing natural gas replacement capacity to look more favorable when compared to coal units with installed emission controls. EPRI's 2012 study, entitled *Analysis of Current and Pending EPA Regulations on the U.S. Electric Sector* evaluates the number of coal retirements/repowerings resulting from the combination of the CSAPR, MATS, ozone and haze, SO_2 NAAQS, CCR, and 316(b) rules at five different forecasts of natural gas prices. A copy of this study is provided as Exhibit RSW-4.

Table 3, below, shows the number of coal retirements/repowerings that might be expected at each natural gas forecast. EPRI's Reference case natural gas price forecast begins at approximately \$5.90/mmBtu in 2010 and rises to approximately \$7.30/mmBtu in 2035 (2009\$).

Table 3. Coal Retirements/Repowerings in EPRI's 2012 Analysis.

Scenario	Coal Retired/Refueled (GW)
Gas Plus \$2	30
Gas Plus \$1	50
Reference	57
Gas Minus \$1	75
Gas Minus \$2	120

As shown in Table 3, a lowering of the natural gas forecast has a more dramatic effect on the number of coal retirements/repowerings than does an increase in the natural gas price forecast. The Gas Plus \$2 scenario causes the number of retirements/repowerings to drop by 27 GW from the Reference case, while the Gas Minus $2 scenario increase coal retirements/repowerings by 63 GW. Similarly, the Gas Plus $1 scenario causes the number of retirements/repowerings to drop by 7 GW from the Reference case, while the Gas Minus $1 scenario increase coal retirements/repowerings by 18 GW. Natural gas price is therefore a significant determinant of the number of coal plant retirements that will occur as a result of EPA rules.

5. Effect of EPA Regulations on BREC Units

Q Which of the EPA regulations were considered by BREC when the Company determined which environmental retrofits were necessary to install on its units?

A In the 2012 Environmental Compliance Plan submitted in this docket, BREC plans to install environmental retrofits that would bring its coal-fired units into compliance with CSAPR and MATS only. Sargent & Lundy made recommendations for technologies intended to also bring the units into compliance with the NAAQS revisions, the CCR, 316(b), and Effluent rules, but these recommendations were ignored by BREC in its analysis.

Q Do you agree with the Company's assessment of CSAPR and the control technologies needed to bring its units into compliance with the rule?

A Yes, generally. I do have some issues of concern, however. First, according to page 9 of Mr. Berry's direct testimony, BREC is assuming that the new FGD system that it intends to install at the Wilson unit will have 99% SO_2 removal efficiency, but in Response to Data Request Sierra Club 2-23a, the Company states that it's the overall control efficiency included in its permit application is 98%. The Wilson plant is able to meet its CSAPR SO_2 limits, but the Company may be assuming that the extra 1% in control efficiency may result in additional allowances that could be used at another one of its units, and if control efficiency of 98% occurs, these bonus allowances may not materialize.

Additionally, Sargent & Lundy recommended advanced low NO_x burners at the Coleman units, as shown on page 15 of the direct testimony of Mr. DePriest, in order to provide BREC with a degree of margin in its NO_x compliance strategy and to reduce the NO_x burden until the selective catalytic reduction technology (SCR) at Green comes online in 2015. Advanced low NOx burners could be installed at a capital cost of $5.94 million per unit, according the Sargent & Lundy workbook entitled "Capital and O&M.xls," provided by the Company on June 14 as part of the folder entitled "Sargent and Lundy Production to Big Rivers." BREC elected not to install the advanced low NO_x burners, and instead plans to rely on the allowance market. There is some degree of risk involved in reliance on the allowance market, as the availability of allowances depends on whether or not other utilities install control technologies that gives them the ability to sell excess allowances into the market. It also assumes that these allowances will be available at a reasonable price. Historically, allowances of SO_2 and NO_x have been subject to some price volatility[3] and it is possible that future prices may rise above what BREC has estimated for future compliance.

Q Do you agree with the Company's assessment of MATS and the control technologies needed to bring its units into compliance with the standards?

A No. The Company provided "limited available stack test data"[4] to Sargent & Lundy, and this data was used by S&L to develop the MATS compliance recommendations. In the Company's Response to Sierra Club Data Request 1-36, BREC states that the stack test was performed at operational loads with pollution control equipment in service. A single stack test, however, represents nothing more than a snapshot, often taken under optimal operating conditions, that tells little about the emissions from that unit when the stack test is not occurring. This is especially true during periods of startup and shutdown, when control equipment

[3] *See* U.S. Environmental Protection Agency. *Allowance Market Assessment: A Closer Look at the Two Biggest Price Changes in Federal SO_2 and NO_x Allowance Markets.* White Paper. April 23, 2009. Available at: http://www.epa.gov/airmarkt/resource/docs/marketassessmnt.pdf

[4] Exhibit DePriest-2. Page 2-4.

may not be fully operational. Emissions, therefore, are likely higher than indicated by the stack test. Installation of Continuous Emissions Monitors (CEMs) would determine whether or not the limited stack test data is truly representative of unit emissions.

On page 28, lines 7-18 of Mr. DePriest's testimony and on page 4-12 of Exhibit DePriest-2, it is stated that retrofitting the BREC units with ACI and/or DSI technologies for MATS compliance will lead to additional loading of particulate matter, and upgrades of existing electro static precipitators (ESPs) may be required for units to remain in compliance with the rule. BREC has yet to conduct the testing necessary to determine if ESP upgrades are necessary. As the Company states in its Response to Sierra Club Data Request 2-10, if these upgrades are required, BREC would return to the Commission in early 2013 to seek CPCN and rate recovery for these controls. It is possible that installation of the combination of ACI, DSI and ESP upgrades may still not bring some or all of BREC's units into compliance with MATS. As the Company states in its Response to Sierra Club Data Request 2-10, it would then evaluate polishing baghouse (and full baghouse technologies, if necessary) retrofits, and would again return to seek CPCN and rate recovery in early 2013.

In its workbook entitled "Capital and O&M.xls," provided by the Company on June 14 as part of the folder entitled "Sargent and Lundy Production to Big Rivers," Sargent & Lundy gives the capital and annual O&M costs for the ESP upgrades that are shown in Table 4, below.

Table 4. Estimated Capital and Annual O&M Costs for ESP Upgrades.

	Capital Cost ($M)	Annual O&M ($M)
Coleman Unit 1	2.72	0.09
Coleman Unit 2	2.72	0.09
Coleman Unit 3	2.72	0.09
Wilson Unit 1	4.54	0.17
Green Unit 1	3.34	0.07
Green Unit 2	3.34	0.07
HMP&L Unit 1	2.5	0.08
HMP&L Unit 2	2.5	0.08

Sargent & Lundy also gave capital cost estimates for baghouse technologies, shown on page 5-5 of Exhibit DePriest-2, if they were to be required. Those estimates are shown in Table 5.

Table 5. Estimated Capital Costs for Baghouse Technologies.

	Per Unit Capital Cost ($M)
Green 1/2	75
HMPL 1/2	51

Q **Do you agree with the Company's assessment of the NAAQS revisions and the control technologies needed to bring its units into compliance with the expected standards?**

A No. In Table ES-2 of Exhibit DePriest-2, Sargent & Lundy presents a table of recommended NAAQS compliance retrofits, including an SCR at Unit 1 of the R.D. Green plant. BREC, however, chose to leave this SCR out of its 2012 Environmental Compliance Plan. The Company states in its Response to Sierra Club Data Request 2-7 that it expects that the ozone NAAQS will be finalized in 2013 and that states will be given three years from that date to comply with the revised limits. Thus, compliance with the revised NAAQS could occur as early as 2016. On page 19, lines 18-21 of Mr. Berry's direct testimony, he states that the expected in-service date of the SCR at Green 2 is July 1, 2015. Depending on when in 2013 the NAAQS revisions are finalized, the Company may return to this Commission as early as six months from now to seek CPCN and rate recovery for an SCR at Green 1 to comply with these rules. Given the recommendation from

Sargent & Lundy as well as the time frame for compliance, BREC should certainly include this additional SCR at Green 1 in its Environmental Compliance Plan and current financial analysis. In its workbook entitled "Capital and O&M.xls," provided by the Company on June 14 as part of the folder entitled "Sargent and Lundy Production to Big Rivers," Sargent & Lundy states that the capital cost of the SCR is $81 million and O&M costs are $2.16 million annually.

Q Do you agree with the Company's assessment of the CCR rule and the control technologies needed to bring its units into compliance with the expected standards?

A No, as BREC does not include the compliance options associated with the expected rule in its financial analysis. Mr. Shaw states on page 19 of his direct testimony that "the alternatives under consideration by the EPA are of such substantially different form that Big Rivers believes an immediate response to the proposal would not be appropriate." However, BREC does have some expectation of what compliance under the CCR rule might look like for its units. In the BREC presentation of its 2012 Environmental Compliance Plan at the Kenergy Board Meeting on May 8, 2012 (provided in Response to Sierra Club Data Request 1-57), slide 17 states that BREC is "not expecting the worst case."

BREC also has recommendations from Sargent & Lundy about the retrofits that might be expected for compliance. The Company need not move forward with plans to retrofit its units in order to comply with the CCR rule at this time, but it should include some assumption about expected costs of the rule in its financial analysis. In its workbook entitled "Capital and O&M.xls," provided by the Company on June 14 as part of the folder entitled "Sargent and Lundy Production to Big Rivers," Sargent & Lundy gives the capital costs for CCR compliance that are shown in Table 6, below.

Table 6. Estimated Capital Costs for CCR Compliance Technologies.

	S&L Recommended Tech	Capital Cost ($M)
Coleman Unit 1	Dry Bottom Conversion - Remote SSC & Fly Ash Conversion to Dry Pneumatic	38
Coleman Unit 2		
Coleman Unit 3		
Green Unit 1	Dry Bottom Conversion - Remote SSC	28
Green Unit 2		
HMP&L Unit 1	Dry Bottom Conversion - Remote SSC	28
HMP&L Unit 2		

Q Do you agree with the Company's assessment of the 316(b) rule and the control technologies needed to bring its units into compliance with the expected standards?

No, as BREC does not include the compliance options associated with the expected rule in its financial analysis. Again, Mr. Shaw states on page 20 of his direct testimony that "the alternatives described in this proposal are of such substantially different form that Big Rivers believes an immediate response to the proposal would not be appropriate." On slide 16 of that same May 8, 2012 presentation to the Kenergy Board, BREC states that the 316(b) rules could require a cooling tower at Coleman and modifications for intake structures at Reid/HMPL. Sargent & Lundy's recommendations for compliance are less stringent than these. On page 6-8 of Exhibit DePriest-2, Sargent & Lundy states that the intake screens at Coleman and Sebree are inadequate and recommends rotating circular intake screens with fish pumps to meet the expected impingement mortality reductions. BREC should, at a minimum, include the costs associated with these recommendations in its financial modeling. In its workbook entitled "Capital and O&M.xls," provided by the Company on June 14 as part of the folder entitled "Sargent and Lundy Production to Big Rivers," Sargent & Lundy gives the capital and annual O&M costs for 316(b) compliance that are shown in Table 7, below.

Table 7. Estimated Capital Costs for CCR Compliance Technologies.

<table>
<tr><td>316(b)</td><td>S&L Recommended Tech</td><td>Capital Cost ($M)</td><td>Annual O&M ($M)</td></tr>
<tr><td>Coleman Unit 1</td><td>Replacement Intake Screen</td><td>1.33</td><td>0.25</td></tr>
<tr><td>Coleman Unit 2</td><td>Replacement Intake Screen</td><td>1.33</td><td>0.25</td></tr>
<tr><td>Coleman Unit 3</td><td>Replacement Intake Screen</td><td>1.33</td><td>0.25</td></tr>
<tr><td>Green Unit 1</td><td rowspan="6">Replacement Intake Screen</td><td rowspan="6">2.05</td><td rowspan="6">0.37</td></tr>
<tr><td>Green Unit 2</td></tr>
<tr><td>HMP&L Unit 1</td></tr>
<tr><td>HMP&L Unit 2</td></tr>
<tr><td>Reid Unit 1</td></tr>
<tr><td>Reid Unit RT</td></tr>
</table>

Q Do you agree with the Company's assessment of the Effluent Limitations Guidelines and the control technologies needed to bring its units into compliance with the expected standards?

A No, as BREC does not include the compliance options associated with the expected rule in its financial analysis. On page 2-9 of Exhibit DePriest-2, Sargent & Lundy states that for the Coleman, Wilson, and Sebree units, "it may become necessary to install advanced wastewater treatment/removal systems for mercury and other metals." An estimate of potential costs of advanced wastewater treatment and removal should have been provided, and BREC should have included these costs in its financial modeling.

Q Do you agree that an emissions price for CO_2 should have been omitted from the BREC financial analysis?

A No. At a minimum, the presence of a CO_2 emissions price in the PACE Global output energy prices should have led the Company to also include a CO_2 price in the dispatch of its units in the ACES Planning and Risk (PaR) modeling, and in its financial modeling calculations.

While the future of CO_2 regulations is still somewhat unknown, an emissions allowance price, when it begins, will have a significant effect on coal-fired generation. Other utilities are planning for this by including a CO_2 allowance price in their optimization and dispatch modeling. Synapse has collected 21 different utility IRP and CPCN docket documents from 2010-2012 from utilities operating across the US. Nineteen of those utilities assume a price per ton for CO_2, and all but three of those reference CO_2 price forecasts are higher than the forecast used by PACE Global in its modeling. Figure 1 shows the range of utility forecasts as compared to the PACE Global forecast. The utilities included in this Figure are listed in Exhibit RSW-5.

[CONFIDENTIAL FIGURE REMOVED]

6. Description of Company Modeling

Q Please describe the modeling methods used by BREC in this docket.

A It is my understanding that three different modeling methodologies were used to support the BREC analysis. First, PACE Global used the Aurora model to determine hourly energy prices using input forecasts of coal prices, natural gas prices, CO_2 emissions, load, and capital costs for CC, CT, and wind generation technologies.

Those hourly energy prices were then given to ACES Power Marketing for use in production cost modeling using the PaR model. ACES did not use an input CO_2 emissions price in its dispatch when running the PaR model. Outputs from ACES production cost modeling included unit generation, capacity factor, fuel used and cost, emissions and emissions cost, and variable O&M. The PaR model also output wholesale market purchases and off-system sales.

BREC took the unit and system outputs from the ACES modeling and used them as inputs in its own spreadsheet financial model. The financial model calculates the NPVRR by first summing the production costs in a given year (start-up costs, fuel costs, costs for reagents, allowance purchases, purchased power, and off-system sales) with the fixed cost of capital in a given year (debt service, debt issuance cost, property tax, property insurance, and labor) to arrive at the revenue requirements in each of the years in the study period. The net present value of this stream of revenue requirements was then calculated.

BREC used this financial modeling methodology to calculate an NPVRR for three different scenarios: 1) a "Build" case, in which all of the emission control technologies deemed necessary for compliance with CSAPR and MATS are installed on the BREC units; 2) the "Partial Build" case, in which the same set of emission controls are installed as in the "Build" case, with the exception of the SCR on Green Unit 2; and 3) the "Buy" case, in which only MATS emission controls are installed, unit generation is curtailed to meet the CSAPR emissions limits, and power is purchased in the wholesale market to meet the remaining electricity demand.

7. Concerns with the BREC Financial Modeling Input Assumptions

Q Did you identify any problems with the Company's financial modeling?

A Yes, I have five major areas of concern with the BREC financial modeling. The first area of concern is that several of the Company's input assumptions are flawed, which I will address in this section. The remaining four areas of concern will be addressed in the next section.

Q Which of the Company's input assumptions do you believe are flawed?

A I believe that several of the Company's input assumptions are flawed, including:

A. The load forecast, which does not include the effects of DSM;

B. The input natural gas price forecast from the PACE Global modeling;

C. The use of a CO_2 emissions price to determine the energy market prices in the PACE Global modeling, but leaving it out of the ACES production cost modeling and the dispatch of generating units;

D. The resulting output energy prices from the PACE Global modeling/Use of inflated market prices;

E. The assumption that capacity, heat rates, forced outages, and availability factors stay constant over time;

F. The use of both real and nominal dollars in calculations of NPVRR in the BREC financial modeling.

A. Load Forecast

Q Why do you believe the load forecast used in the BREC analysis is incorrect?

A In its Response to Sierra Club Data Request 2-27, the Company essentially admits that its load forecast is overstated because it fails to account for various demand side management (DSM) efforts. In part c, subpart iv of the response, BREC states that the savings from energy efficiency programs that are currently being implemented in 2012 are not included in the load forecast used in its analysis. While level of participation and actual impacts are currently unknown, the Company should at the very least include a conservative estimate of the impacts of energy efficiency, or include a "low load" sensitivity analysis that reflects these impacts. The Company goes on to say in part c, subpart v, that the load forecast also does not explicitly include projected impacts of federal efficiency standards or programs, but only indirectly includes them to the extent they impact historical load data and economic forecast data. Overstating the load would likely cause the

BREC units to run more often than they otherwise would in the production simulation modeling, possibly improving the economics of those units as they are subject to fewer starts and less unit cycling. It might also lead to an overestimate of the size of any replacement energy needed if the coal units were to retire, either in the form of a NGCC replacement options, or market energy replacement.

B. Natural Gas Price Forecast

Q Why do you believe the natural gas price forecast used by PACE Global is incorrect?

The natural gas price forecast used by PACE Global to develop market energy prices appears to be higher than other natural gas prices developed in 2011 and 2012. Figure 2 shows the PACE forecast compared to the EIA's natural gas price forecast from its *Annual Energy Outlook* for the years 2010, 2011, and 2012.

[CONFIDENTIAL FIGURE REMOVED]

While the EIA forecast from 2010 is higher than the forecast from PACE Global, the forecasts from 2011 and 2012 are both lower than that used by PACE in its modeling.

In the near term, even the AEO 2012 natural gas price forecast is too high. The natural gas price at Henry Hub has been less than $3/mmBtu for all of 2012 thus far, as shown in Figure 3, below.

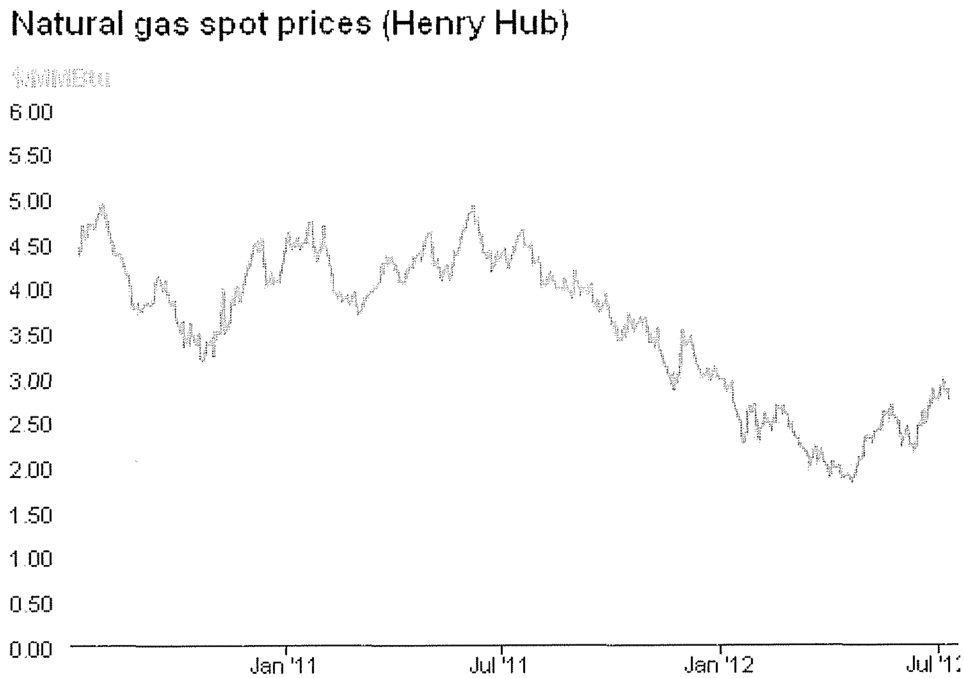

Figure 3. Natural gas spot prices at Henry Hub ($/mmBtu).[5]

Sources indicate that the drop in forecasts for both short and long-term natural gas prices represent a fundamental shift in the industry rather than a temporary anomaly, and are a result of recent growth in natural gas production due to shale gas and the related sale of natural gas liquids. In EPA's proposed New Source Performance Standards rule, the agency states that "technological developments and discoveries of abundant natural gas reserves have caused natural gas prices to

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[5] U.S. Energy Information Administration. *Natural Gas Weekly Update*. For week ending July 11, 2011. Accessed July 18, 2012. Available at: http://205.254.135.7/naturalgas/weekly/

decline precipitously in recent years and have secured those relatively low prices for the near future."[6]

C. CO_2 Emissions Price Forecast

Q How was a CO_2 emissions price used in the modeling performed in this docket?

A In its determination of hourly market prices, one of the inputs used by PACE Global was a CO_2 emissions price beginning in 2018. In the 200 Aurora iterations run by PACE, that CO_2 price was applied at varying levels in any given year to the emissions from all of the coal and natural gas generating units in MISO, raising the variable costs of operation accordingly, and thus raising the hourly bids of each generator into the MISO market. PACE's hourly energy prices are in fact the market clearing price in a given hour. All generator bid prices and associated generation are stacked from lowest to highest cost, and the market clearing price is the price of the last generator needed to meet the forecasted load in a given hour.

Those output market energy prices were then given to ACES for use in the PaR model, which dispatches each of the generating units on an hourly basis and calculates the resulting production costs. A CO_2 price is one of the variables that can be included as an operating cost of a generating unit, and if it is present, will affect the dispatch of that unit. It is my understanding, confirmed in the Company's Response to Sierra Club Data Request 3-17, that in the production cost runs produced by ACES and used by BREC in its financial modeling, a CO_2 emissions price was present in the market prices against which the generating units were dispatched, but was not present in the costs of generation at each unit.

Q Is this an appropriate way to account for likely future cost of CO_2 emissions?

A No. Because a CO_2 price was included in the PACE output market prices, it also should have been included in the ACES production cost modeling.

[6] 77 Fed. Reg. 22,392, 22,394-22,395 (April 13, 2012)

Q **Why should a CO_2 emissions price be used in both the PACE modeling and the ACES production cost modeling?**

A In the ACES production cost modeling, the CO_2 price has exerted an upward effect on market prices, but because the CO_2 price is not incorporated in the generating units' running costs, the units appear comparatively less expensive to run and thus run more hours of the day than they would otherwise.

D. Market Energy Prices

Q **Why are market energy prices important in this analysis?**

A Market energy prices are important for three reasons. First, because BREC bids its generation into the MISO market, the market energy prices have an effect on the units' dispatch. The higher the market prices, the more electricity output the BREC units will produce. Secondly, the market energy prices affect the "Buy" case that the Company modeled. BREC retrofits its units to comply with MATS, runs the units only enough so that they remain in compliance with CSAPR emissions limits, and buys the remainder of the energy necessary to meet load from the market. The higher the market prices in the "Buy" case, the more expensive the option. Third, market energy prices affect the calculation of a market replacement option, where one or more coal units retire and the generation from those units is replaced with market energy purchases.

Q **In other cases that have come before this Commission in the past year, both utilities and intervenors have done a calculation of the costs of a market replacement option. Why did you not present this calculation in your analysis?**

A I attempted to present a calculation of the costs of a market replacement option using the PACE energy prices, but in doing so, found that it always resulted in higher costs than that of an NGCC replacement option. In my experience in the past year, utility evaluations of a market replacement option have almost always resulted in a lower NPVRR than the NGCC replacement. The fact that in this case, the market option was coming out much higher indicated to me that the market price forecast was inaccurate.

Q **Do you have any other reason to believe that the output market prices from the PACE Global modeling are incorrect?**

A Yes. Coal and natural gas are typically the fuel types that are on the margin in any given hour in MISO. Thus fuel price has an effect on the market price, as does a CO_2 emissions price in later years. Using the Aurora output provided by PACE, one is able to remove the effect of the natural gas price and CO_2 emissions price on the hourly market price forecast. Removing these effects leaves you with the marginal emissions rate for the generating unit that is on the margin in a given hour. Coal-fired generators have a marginal emissions rate of about 1.0 – 1.1 tons CO_2/MWh. Natural gas-fired generators have a marginal emissions rate of about 0.6 – 0.7 tons CO_2/MWh. When the effects of natural gas and CO_2 prices were removed for the PACE forecast of market prices, the results suggested a marginal emissions rate of 1.8 tons CO_2/MWh (megawatt hour) in later years, which is not indicative of any type of generating unit that I know to be on the margin.

E. Capacity, Heat Rate, Forced Outages, and Availability

Q **What does BREC assume in its modeling about the capacity of its units over time?**

A BREC assumes that the capacity of its units stays constant. On page 24 of his direct testimony, Mr. Berry states that "the S&L study did not include calculating actual auxiliary power consumption for the recommended compliance strategies.

Q **Is it correct for BREC to assume a constant capacity rating over time?**

A No. Pollution control technologies require electricity to run. A portion of the electricity generated at a unit thus will go toward providing that electricity to run its emissions controls. This is known as parasitic load, and typically results in a capacity derating of a particular unit. This derating is important because it means that a smaller number of megawatts (MW) is then available to provide electricity to serve load.

Q **What does BREC assume in its modeling about unit heat rates over time?**

A In its Response to Sierra Club Data Request 2-5 part e, the Company states that it expects that unit heat rates will stay constant over time.

Q **Is it correct for BREC to assume a constant heat rate over time?**

A No. Heat rates often vary over time as generating unit component parts degrade and are replaced. Heat rates might be expected to rise gradually (units become less efficient) as components age, and then drop slightly when those aging parts are replaced (unit efficiency increases). Heat rate is important because it reflects the efficiency at which the generating unit converts fuel into electricity. A decline in unit heat rate over time means that it is producing fewer megawatt hours (MWh) of electricity over that period.

Q **What does BREC assume in its modeling about unit forced outages and availability over time?**

A In its Response to Sierra Club Data Request 2-5 parts a-d, the Company states that it expects that unit forced outages and availability will stay constant over time.

Q **Is it correct for BREC to assume constant forced outages and availability over time?**

A No. In its Response to PSC 2-5, BREC gives the historic availability of its units over the past five years. Availability varies from unit-to-unit and from year-to-year due to the number of outages in any given year. Unit outages can be planned, as when a unit undergoes routine maintenance or is taken offline for pollution control installations, or unplanned, as when a component part fails unexpectedly. Availability is the amount of time a generating unit is able to produce electricity in a given period. Outages might increase as units age, or as they require additional equipment replacement or retrofit, which would lead to a decrease in availability. Outages and availability are important because if a plant is offline, it is unable to generate electricity.

F. Real versus Nominal Dollars

Q Does the BREC financial modeling use both real and nominal dollars?

A Yes. The estimates of emission control capital and O&M costs developed by Sargent & Lundy are presented in Exhibit DePriest-2 in 2011 dollars. The PaR model used by ACES outputs the generation and operating costs for each of the BREC units in nominal dollars. The BREC financial modeling uses each of these values without converting them to the same base year dollars.

Q Why is this incorrect?

A BREC uses a discount rate of 7.93%, which I assume is a nominal discount rate and implies that the analysis was done in nominal dollars. Unit operating costs output by the PaR model are included in the BREC financial modeling in nominal dollars, which account for the effects of inflation over time. Estimates from Sargent & Lundy are in real 2011 dollars, and do not contain any effects of inflation. BREC does not spend all of the capital required for the emissions retrofits in 2011, but rather incurs it over time at some future start date. These 2011 dollar estimates should thus be multiplied by an inflation rate in order to determine how much an investment incurred in a future year will cost in that year's dollars. BREC does not convert these capital expenditures incurred in a future year into that future year's dollars. These capital expenditures are thus understated in the BREC financial modeling.

8. Additional Concerns with the BREC Financial Modeling

Q Please describe your additional concerns with the BREC financial modeling.

A My additional concerns with the financial modeling include the following: 1) that BREC does not model the full set of controls that will be required under the EPA rules; 2) that BREC does not model its units individually, but rather as a block, choosing to retrofit all of the units together rather than examining the economics of each unit on a standalone basis; 3) that the BREC financial modeling evaluates a selection of future costs associated with the retrofits rather than the actual forward going running costs of the units; and 4) that BREC does not model the emission control retrofits against a reasonable set of alternative options, including but not limited to: a natural gas-fired combustion turbine or combined cycle replacement, a replacement with market purchases, or a replacement with some combination of energy efficiency, renewables resources, natural gas units, and market purchases. I will address each of these concerns in turn.

Q Please explain what you mean when you say that BREC does not model the full set of controls required under the EPA rules.

A BREC models only the emission control retrofits that will be required under CSAPR and MATS, and includes only a subset of the controls recommended by Sargent & Lundy to comply with these rules. In addition to those technologies chosen by the Company, Mr. DePriest states on page 20, lines 9-16 that Sargent & Lundy recommended low NO_x burners on Coleman units 1-3 for CSAPR compliance. As I mention above, in section 5 of my testimony, it is possible, and even likely, that one or more of the BREC units will require additional retrofits to comply with MATS, whether in the form of ESP upgrades, a polishing baghouse, or a full baghouse.

In addition, Mr. Shaw and Mr. DePriest state in their direct testimonies that BREC will also be subject to the NAAQS revisions, the CCR rule, the Water Intake (316(b)) rule, and new limits on effluent. While the rules have yet to be finalized, BREC expects that capital expenditures will be necessary to bring their units into compliance. On page 19, lines 12-19 and page 20, lines 20-22 in the direct testimony of Thomas Shaw, Mr. Shaw states that the alternatives under consideration by the EPA for both the CCR and 316(b) rules are of such substantially different form that "an immediate response to the proposal would not be appropriate." It is correct that the Company cannot be expected to seek CPCN and begin construction of environmental projects before knowing what is required by the final rules. However, Sargent & Lundy made recommendations for those retrofits that it believes will bring the units into compliance with each of the rules in their expected final form. BREC could have easily incorporated those recommended capital expenditures associated with Sargent & Lundy's recommendations into an economic analysis of its coal-fired units. BREC uses a 20 year planning horizon, and to assume that these upcoming rules will have no effect on the capital expenditures or running costs at its coal units is unrealistic and favors a retrofit scenario.

As I mention above, third-party analyses of the EPA rules predict more coal retirements when all of the rules are considered together, as the cumulative capital additions cause the running costs of additional generating units to be higher than costs of a natural gas or market replacement option. Once BREC makes capital investments for the emission controls necessary for compliance with CSAPR and MATS, those costs are sunk and are no longer considered in the calculation of the units' forward going running costs when additional emission control retrofits are considered. By looking at the EPA regulations on a piecemeal basis as they become final, BREC is not considering the real forward economics of its coal units.

Q Please explain what you mean when you say that BREC models its units as a block and not individually.

A Compliance with CSAPR allows for allowance trading, with units that are not able to meet their emissions limits able to purchase SO_2 and NO_x allowances from the market. BREC models emissions compliance based on total fleet emissions, rather than installing retrofits such that each unit meets its individual emissions limit. This is an acceptable modeling practice.

When considering actual running costs of coal unit, however, it is not acceptable to model the BREC coal fleet as a whole instead of modeling each unit on a standalone basis. Larger, more efficient units may be less expensive and thus more economic to run, while smaller, less efficient units may be clearly uneconomic to run. Modeling the units individually would reveal this difference in running costs between the units. Modeling the units as a block would likely mask this difference, as the efficiencies of the larger unit would compensate somewhat for the poor economics of the smaller plant.

Certain units may also require additional capital expenditures to bring them into compliance with environmental regulations, and older units may face the need for more capital investments to continue operating. Taking all of the coal units as a whole spreads these capital expenditures over the entire fleet, hiding the fact that certain units require more investment capital and might be a candidate for retirement rather than retrofit.

Q **Please explain what you mean when you say that BREC models a selection of future costs associated with the retrofits rather than the actual forward going running costs of the units. Why is this an error?**

A As I mentioned above, the BREC financial modeling calculates revenue requirements based on the production costs in a given year (start-up costs, fuel costs, costs for reagents, allowance purchases, purchased power, and off-system sales) with the fixed cost of capital in a given year (debt service, debt issuance cost, property tax, property insurance, and labor) to arrive at the revenue requirements in each of the years in the study period.

The BREC financial modeling fails to take into account the ongoing capital costs associated with routine maintenance at each of the units, which the Company provided in its Confidential Response to Sierra Club Data Request 2-1a. [redacted] Costs have only been provided through 2015, but these costs will continue through the study period, and may increase as the units age.

Q **Please explain what you mean when you say that BREC does not model unit retrofits against alternative options.**

A BREC examines three options, but they are all variations on its "Build" case. In evaluating the economics of coal units with emission control retrofits, other utilities have evaluated the costs of the retrofits against replacement alternatives. These alternatives might include a NGCC replacement unit, replacement with market purchases, or a combination replacement option that looks at increased levels of energy efficiency, renewable energy, and some gas and market purchases. Without looking at such options for replacing any or all of BREC's coal units, there is simply no basis to conclude that retrofitting each such unit represents the least-cost option.

The Commission has seen in previous cases that the retrofit of a coal unit is often compared to the construction of a replacement natural gas-fired combined cycle unit, to the purchase of an existing NGCC, or to the cost of entering into a purchase power agreement (PPA) with the operator of an existing NGCC. BREC did not explore any of these options, as stated by the Company in Response to Data Request Sierra Club 1-50. Data from the EIA *2012 Annual Energy Outlook* (attached as Exhibit RSW-6) suggests that capacity factors for oil and natural gas generation are projected to be less than 20% through the BREC study period, indicating that it is highly likely that BREC could have entered into a long-term PPA for energy and capacity in MISO. A spreadsheet with this EIA data is attached to my testimony as Exhibit RSW-7.

The Commission has also seen in previous cases that utilities typically examine the cost of a coal unit retrofit against the cost of buying replacement power for that unit on the market, and that this option typically results in a lower NPVRR under current market conditions. The Company did not examine a market replacement scenario, and the fact that its "Buy" case results in a much higher NPVRR than its "Build" case suggests an error in its analysis.

Finally, the Company could have examined a combination replacement option. Had BREC done an energy efficiency market potential study, it could be currently achieving a high amount of savings. The Company then could have issued RFPs for a lower amount of replacement energy, and examined renewable energy sources as well natural gas and market energy purchases.

9. Description and Results of Synapse Energy Economics Financial Modeling

Q Did you perform any of your own financial modeling for this docket?

A Yes. Synapse created a cash flow model that calculates the forward going costs of each of the BREC units on an annual basis, and discounts this stream of costs to determine the total NPVRR of the suite of retrofits included in the analysis for each of the units on a standalone basis. The "Retrofit" option is then compared to a natural gas combined-cycle replacement option. Certain input assumptions are allowed to vary in the cash flow model and the user can create a number of scenarios to examine.

Q Please explain how you created your model and the inputs you used.

A The cash flow model was designed to compare the revenue requirements associated with the BREC 2012 Compliance Plan to a natural gas-fired combined cycle replacement option that provides similar rated capacity and generation. The model was created using as many of the inputs and assumptions found in modeling performed by the Company, ACES Power Marketing, and PACE Global as was possible. Any input that was not taken directly from BREC was taken from a public source, and where possible was a source referenced by the Company, e.g. the Energy Information Administration (EIA). The source for each input assumption is documented in the model.

The cash flow analysis creates the nominal revenue requirements for each environmental retrofit using the capital costs of the projects, AFUDC, book and tax depreciation, income and deferred taxes, return on rate base, property taxes and insurance costs. These capital revenue requirements are then combined with generating unit-specific, on-going non-environmental capital expenditures, generating unit-specific production costs (fuel costs, start costs, fixed and variable O&M costs, emissions costs), and environmental retrofit project-specific O&M costs, which sum to provide the nominal revenue requirements for each year, for each generating unit. These nominal revenue requirements are then summed and put in present value terms using the BREC nominal discount rate.

In calculating the NPVRR for the NGCC replacement option, we assumed retirement of the BREC units at the end of 2015 and assumed installation of the NGCC at the beginning of 2016. Similar to the calculation for the retrofit option, the NPVRR calculation for the NGCC option includes capital costs with AFUDC and unit production costs (fuel costs, fixed and variable O&M costs, emissions costs). The NPVRR of the retrofit option was then compared to the NPVRR for the NGCC replacement option on a unit-by-unit basis.

The cash flow spreadsheet model enables the creation of different scenarios through the use of certain different input values, e.g. natural gas price, CO_2 emissions price, and selection of additional environmental compliance retrofit technologies for each of the BREC units. The user can create different scenarios by selecting variations on each of these inputs.

Q What are the results of your financial modeling?

A The difference in NPVRRs between the coal retrofit and NGCC replacement option in the "Synapse Recommended Case" are shown in Table 4, below. Negative values in the "NGCC Replacement" column indicate that building a natural gas-fired unit is cheaper than installing pollution control retrofits on the BREC coal units. The results in Table 8 (also in Exhibit RSW-2) indicate that all of the BREC coal units are uneconomic when compared to a natural gas replacement option and should be considered for retirement.

Table 8. Synapse Recommended Case - Comparison of NGCC Replacement to BREC Unit Retrofits (millions 2012$).

	NGCC Replacement 2015 minus Retrofit	% Difference from Retrofit
Wilson	($259)	-13.88%
Green 1	($204)	-18.53%
Green 2	($213)	-19.83%
HMPL 1	($82)	-12.47%
HMPL 2	($107)	-15.56%
Coleman 1	($108)	-15.84%
Coleman 2	($90)	-13.74%
Coleman 3	($103)	-14.92%
Total	($1,165)	-15.73%

The Synapse Recommended Case includes the controls in the BREC 2012 Environmental Compliance Plan, and also includes those controls recommended by Sargent & Lundy for compliance with the revised NAAQS, the CCR rule, and the 316(b) rule. Costs of compliance with the Effluent Limitations Guidelines were also included, and were taken from the *2010 EPRI Cost Assessment of Coal Combustion Residuals* and the *2011 EEI Potential Impacts of Environmental Regulation.*

Q How does your Recommended Case compare to the BREC analysis?

A We put the input assumptions used by BREC (the BREC natural gas price forecast, a CO_2 emissions price of $0 in all years, and only those retrofits in the Company's 2012 Environmental Compliance Plan) into our cash flow model and got the results shown in Table 9 (also in Exhibit RSW-8) – the "Big Rivers Build Case."

Table 9. Company Case - Comparison of NGCC Replacement to BREC Unit Retrofits (millions 2012$).

	NGCC Replacement 2015 minus Retrofit	% Difference from Retrofit
Wilson	$152	10.06%
Green 1	$69	8.12%
Green 2	$4	0.50%
HMPL 1	$82	16.22%
HMPL 2	$65	12.27%
Coleman 1	$43	7.85%
Coleman 2	$61	11.73%
Coleman 3	$50	8.89%
Total	$527	8.91%

The results from the BREC Build Case show that retrofitting the units with select CSAPR and MATS compliance technologies only, under the Company's gas and CO_2 input assumptions, result in positive benefits of varying amounts for each of the units. Benefits of the Green 2 retrofits are smallest, at $4 million NPVRR and benefits of the Wilson retrofits are highest at $152 million NPVRR.

Q How do the results from your cash flow analysis go from a net benefit of $527 million under the BREC Build Case to a net cost of more than $1 billion in the Synapse Recommended Case when compared to an NGCC alternative?

A In order to help answer this question, I've prepared several tables that vary the input assumptions one at a time as I move between the BREC Build Case and the Synapse Recommended Case.

First, simply changing the CO_2 emissions price to be consistent throughout the BREC modeling[7] causes Green Unit 2 to become uneconomic to run, as shown in Table 10. It also causes the total net benefit of retrofitting the coal fleet to drop by $359 million. Table 10 is also attached as Exhibit RSW-9.

Table 10. Comparison of Company Build Case with and without CO_2 (millions 2012$).

	Company Build Case	Company Build + CO2
	Zero CO2 Price, BREC NG price, ECP Retrofits	BREC CO2 Price, BREC NG price, ECP Retrofits
Wilson	$151.56	$55.89
Green 1	$69.35	$21.46
Green 2	$4.44	($43.48)
HMPL 1	$82.38	$53.14
HMPL 2	$65.29	$31.36
Coleman 1	$43.18	$8.48
Coleman 2	$60.88	$26.58
Coleman 3	$49.72	$13.57
Total	$526.81	$167.00

Changing the PACE/BREC natural gas price forecast to the most up-to-date EIA AEO 2012 forecast has an even more dramatic effect on the economics of the retire and replace scenario. Five of the eight BREC units are now uneconomic to run under an updated natural gas price forecast, and the net benefits of retrofitting the entire fleet are now negative. These results are shown in Table 11, and also in Exhibit RSW-10.

[7] Of the 21 electric utilities we surveyed that have a public CO_2 price forecast, the PACE Global price forecast is the third lowest of the Reference cases.

Table 11. Comparison of Company Build Case with PACE/BREC and EIA 2012 Natural Gas Price Forecasts (millions 2012$).

	Company Build Case	Company Build, AEO NG
	Zero CO2 Price, BREC NG price, ECP Retrofits	Zero CO2 Price, AEO NG price, ECP Retrofits
Wilson	$151.56	($16.88)
Green 1	$69.35	($25.73)
Green 2	$4.44	($86.20)
HMPL 1	$82.38	$22.71
HMPL 2	$65.29	$3.80
Coleman 1	$43.18	($15.52)
Coleman 2	$60.88	$2.70
Coleman 3	$49.72	($12.22)
Total	$526.81	($127.35)

Changing the CO_2 and natural gas prices together yields even more dramatic results, shown in Table 12 (attached as Exhibit RSW-11) in the first and third columns, changing $526 million in net benefits in the Company Build Case to $487 million in net cost in the "Company Build + CO2, AEO NG" scenario.

Table 12. Comparison of Company Build Case with Changed Input Scenarios (millions 2012$).

	Company Build Case	Company Build + CO2	Company Build + CO2, AEO NG	All Retrofits but Effluent + CO2, AEO NG	Synapse Recommended
	Zero CO2 Price, BREC NG price, ECP Retrofits	BREC CO2 Price, BREC NG price, ECP Retrofits	BREC CO2 Price, AEO NG price, ECP Retrofits	BREC CO2 Price, AEO NG price, All Retrofits but Effluent	BREC CO2 Price, AEO NG price, All Retrofits
Wilson	$151.56	$55.89	($112.55)	($116.10)	($259.04)
Green 1	$69.35	$21.46	($73.62)	($135.37)	($203.80)
Green 2	$4.44	($43.48)	($134.12)	($144.63)	($213.05)
HMPL 1	$82.38	$53.14	($6.54)	($15.10)	($81.54)
HMPL 2	$65.29	$31.36	($30.13)	($38.69)	($106.72)
Coleman 1	$43.18	$8.48	($50.22)	($63.94)	($108.28)
Coleman 2	$60.88	$26.58	($31.60)	($45.33)	($89.67)
Coleman 3	$49.72	$13.57	($48.38)	($62.10)	($103.34)
Total	$526.81	$167.00	($487.16)	($621.25)	($1,165.44)

Adding in the costs of compliance with expected EPA regulations causes the economics of the fleet retrofits to look even worse. Compliance with the revised NAAQS, CCR, and 316(b) rules in addition to CSAPR and MATS would have a net total cost of $621 million. Finally, adding in Effluent Limitation Guidelines compliance costs leads to a net total cost of more than $1 billion when compared to a NGCC replacement option.

10. Conclusions

Q Please summarize your conclusions.

A Based on my review, I conclude that the errors present in the BREC modeling causes the Company to understate the costs associated with the continued operations of its coal fleet. Using corrected input assumptions and adding in the costs of compliance with expected EPA regulations causes the costs of coal unit retrofits to increase dramatically. When the complete retrofit scenario is compared to a NGCC replacement scenario, we see that the NGCC scenario is more than $1 billion cheaper than continued operation of the BREC coal fleet.

Q Does this conclude your direct testimony?

A Yes.

EXHIBIT 5

Commonwealth of Kentucky

Before the Public Service Commission

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF ITS 2012 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, FOR CERTIFICATES OF PUBLIC CONVIENENCE AND NECESSITY, AND FOR AUTHORITY TO ESTABLISH A REGULATORY ACCOUNT.	))))))))))	Case No. 2012-00063

Direct Testimony of William Steinhurst

On Behalf of Sierra Club

Public Version

July 23, 2012

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1. Introduction and Qualifications

Q Please state your name, business address, and position.

A My name is William Steinhurst, and I am a Senior Consultant with Synapse Energy Economics (Synapse). My business address is 32 Main Street, #394, Montpelier, Vermont 05602.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government and utilities.

Q Please summarize your work experience and educational background.

A I have over thirty years of experience in utility regulation and energy policy, including work on renewable portfolio standards and portfolio management practices for default service providers and regulated utilities, green marketing, distributed resource issues, economic impact studies, and rate design. Prior to joining Synapse, I served as Planning Econometrician and Director for Regulated Utility Planning at the Vermont Department of Public Service, the State's Public Advocate and energy policy agency. I have provided consulting services for various clients, including the Connecticut Office of Consumer Counsel, the Illinois Citizens Utility Board, California Division of Ratepayer Advocates, the D.C. and Maryland Offices of the Public Advocate, Delaware Public Utilities Commission, Regulatory Assistance Project, National Association of Regulatory Utility Commissioners (NARUC), National Regulatory Research Institute (NRRI), American Association of Retired Persons (AARP), The Utility Reform

Network (TURN), Union of Concerned Scientists, Northern Forest Council, Nova Scotia Utility and Review Board, U.S. Environmental Protection Agency (EPA), Conservation Law Foundation, Sierra Club, Southern Alliance for Clean Energy, Oklahoma Sustainability Network, Natural Resource Defense Council (NRDC), Illinois Energy Office, Massachusetts Executive Office of Energy Resources, James River Corporation, and Newfoundland Department of Natural Resources.

I hold a B.A. in Physics from Wesleyan University and an M.S. in Statistics and Ph.D. in Mechanical Engineering from the University of Vermont.

I have testified as an expert witness in over 30 cases on topics including utility rates and ratemaking policy, prudence reviews, integrated resource planning, demand side management policy and program design, utility financings, regulatory enforcement, green marketing, power purchases, statistical analysis, and decision analysis. I have been a frequent witness in legislative hearings, and represented the State of Vermont, the Delaware Public Utilities Commission Staff, and several other groups in numerous collaborative settlement processes addressing energy efficiency, resource planning and distributed resources.

I was the lead author or co-author of Vermont's long-term energy plans for 1983, 1988, and 1991, as well as the 1998 report *Fueling Vermont's Future: Comprehensive Energy* Plan and Greenhouse Gas Action Plan, and also Synapse's study *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers*. In 2008, I was commissioned by the National Regulatory Research Institute (NRRI) to write *Electricity at a Glance*, a primer on the industry for new public utility commissioners, which included coverage of energy efficiency programs. In 2011, NRRI commissioned a second edition of that work.

A copy of my current resume is attached as Exhibit WS-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Kentucky Public Service Commission?

A No, I have not. However, I did prepare prefiled testimony in Kentucky PSC Cases No. 2011-00161 and No. 2011-00162, which were settled.

Q What is the purpose of your testimony?

A Big Rivers Electric Corporation ("BREC" or the "Company") has requested that the Commission issue Certificates of Public Convenience and Necessity ("CPCN") for certain environmental upgrades at its coal fired power plants. *See* Berry prefiled direct at 39 and BREC Exhibit Berry-2. I will refer to those projects as the Environmental Retrofits. The purpose of my testimony is to provide an opinion, based on Synapse's analysis of the Environmental Retrofits and BREC's studies in support of its Application for the CPCNs, as to whether the proposed Environmental Retrofits are reasonable and cost-effective for complying with the environmental requirements the Company faces and providing least-cost service. Witness Wilson's accompanying testimony reviews the regulatory requirements and the Company's economic justifications for the Environmental Retrofits. For that purpose, she reviews the current and expected running costs of the Company's coal-fired units, and compares these costs to different alternatives. My testimony discusses the resource options BREC evaluated, the range of future scenarios it used to evaluate those resource options, its projection of revenue requirements for each resource option under those future scenarios and its conclusions regarding the merits of its proposed CPCN based upon its projections and analyses.

2. Findings and Overview of Testimony

Q In your opinion, do the facts and evidence presented in this case support the Company's request for a CPCN for the proposed environmental upgrades?

A No. The Company has not demonstrated that its proposed CPCN is reasonable and cost-effective for complying with the environmental requirements the Company is facing. That conclusion is based upon the results of our review which indicates that the Company has not evaluated the full range of resource options available to it, that its projections of revenue requirements for the resource options it did evaluate are not correct, that its evaluation of future scenarios does not include a reasonable projection of carbon prices and that its risk analysis is subjective and flawed As set out in the testimony of witness Wilson, the Company's economic justification for these environmental retrofits did not consider a full range of alternative compliance options and contained several flaws that bias its analysis in favor of installation of emission control retrofit projects. When a number of those errors are corrected, the results show that alternatives to the Environmental Retrofits are less costly and less risky.

Q What is your understanding of the standard for issuance of a CPCN in Kentucky?

A My understanding is that, before the Commission can grant such a certificate for a facility, it must determine that there is both a need for the facility and that construction of the new system or facility will not result in duplication. This standard requires more than just a showing that there is a need for new generation, as the statutory mandate to avoid "wasteful duplication" logically means that the new system or facility should not represent an excessive investment. Commission decision-making is guided by the overall requirement that utility rates are "fair, just, and reasonable." KRS § 278.030(1); KRS § 278.040. As a policy matter, I view these requirements as equating to the need for a showing that resources are the least-cost means of providing utility service since a resource plan that is not least cost cannot result in just and reasonable rates.

3. Expectation for Sound Utility Planning

Q HOW DOES BREC's DECISION MAKING PROCESS COMPARE WITH THE PROCESS A COMPANY WOULD FOLLOW TO INFORM A REASONABLE DECISION?

A BREC is conducting a business affected with the public interest. It should plan for the provision of utility service in a manner designed and implemented to provide adequate and reliable service consistent with public policy and in a manner designed to minimize long-term cost of service to customers while managing risk to customers in a reasonable way. I have discussed this approach at length elsewhere. (*See,* for example, *Portfolio Management: Tools and Practices for Regulators*, 9/29/2006, attached as Exhibit WS-2.) BREC's planning in regard to the subject matter of this proceeding should be held to that same standard: an assessment of all of its options for meeting customer needs and conducted in a manner that considers all of its options on a level playing field. Specifically, BREC should have done the following:

1. Identify All Currently Known Regulatory Requirements and Identify Emerging and Reasonably Likely Future Regulatory Requirements
2. Identify and Evaluate All Alternatives for Compliance and Alternatives to Compliance
3. Perform Correct Life-Cycle Economic Analyses, Including Sensitivity Cases and other Risk Analysis of All the Alternatives
4. Make a Decision Based on the Aforementioned Information
5. Re-Evaluate the Decision as Significant Milestones Are Reached
6. Balance Cost/Risk In Implementation Method
7. Actively Manage the Implementation To Assure Budget, Schedule and Performance Compliance

Unfortunately, BREC has failed in at least the first four of those requirements as explained below.

4. Description of Ways in which BREC Planning is Lacking

Q Was BREC's planning and economic analysis for its Environmental Retrofits correct? Was it consistent with least cost planning principles and good utility management?

A BREC's planning and economic analysis for its Environmental Retrofits was not correct, nor was it consistent with least cost planning principles and good utility management. Sierra Club witness Wilson summarizes the errors she identified as follows:

- The load forecast, which does not include the effects of demand side management (DSM);
- The input natural gas price forecast from the PACE Global modeling;
- The use of a carbon dioxide (CO_2) emissions price to determine the energy market prices in the PACE Global modeling, but leaving it out of the ACES production cost modeling and the dispatch of generating units;
- The resulting output energy prices from the PACE Global modeling/ Use of inflated market prices;
- The assumption that capacity, heat rates, forced outages and availability factors stay constant over time; and
- The use of both real and nominal dollars in calculations of net present value revenue requirement (NPVRR) in the BREC financial modeling.

Witness Wilson also describes BREC's failure to model all controls, failure to model units individually, and failure to compare to alternatives. Sensitivity analyses were extremely limited and did not cover the range of important input uncertainties. None of these practices is consistent with correct implementation of least-cost planning principles or with good utility management. I will discuss the utility planning implications of BREC's errors below.

a. Piecemeal Approach to Pending and Emerging Regulations

Q Does correct least-cost planning require treating emerging and reasonably expected regulatory requirements in a particular manner?

A Yes. Investments necessary to meet emerging and reasonably expected regulatory requirements must be considered as part of the forward going costs of any plant, just as with the investments necessary to meet currently known requirements. Unfortunately, BREC erred in at least two ways on this point by including in its economic modeling the costs of select control technologies rather than the entire suite of controls likely or reasonably expected for future compliance.

First, BREC chose to treat some emerging and reasonably expected regulatory requirements as "speculative" and ignored the risk of forward going costs for meeting those requirements. For example, BREC witness Berry states "potential NAAQS [national ambient air quality standards] reductions are not expected to be published until 2016 with compliance possibly due in 2018. At this time, anticipated NAAQS reductions are merely speculative and will be addressed in future environmental compliance plans." He also takes a similar position regarding "EPA-proposed regulations under §316(b) of the Clean Water Act - Waste Water Intake Impingement Mortality & Entrainment, Waste Water Discharge, and Coal Combustion Residuals (CCR)." Berry prefiled direct at 27-29.

Second, BREC failed to treat the alternatives on a level playing field with respect to potential carbon emission costs. BREC burdened market alternatives (mainly natural gas energy purchases) with carbon costs, but failed to similarly burden the forward going costs of the coal plants it proposes for Environmental Retrofits. This is a fundamental error in least cost planning.

This piecemeal and biased analysis is inconsistent with the principles of least cost planning and the requirements for a CPCN.

b. Creation of a Bias in Favor of Additional, Future Environmental Retrofits

Q Does BREC's failure to comprehensively plan for least-cost solutions to its regulatory requirements create any other concerns?

A Yes. Once the proposed Environmental Retrofits are made, their costs are sunk and not avoidable. Then, any incremental costs imposed by other regulations, such as emerging and reasonably expected regulations, would be evaluated on their incremental economics. However, from today's point of view that distorts the true economics of decisions about the proposed Environmental Retrofits vs.

the alternatives. Again, a piecemeal approach to economic evaluations distorts the economic analysis of alternatives. While some emerging and reasonably expected regulations are in flux and costs may be uncertain, totally ignoring those potential costs biases the analysis in favor of the proposed Environmental Retrofits.

Q As a general matter, how should BREC approach planning for environmental regulation?

A Under EPA's multi-faceted approach, plant owners can and should comprehensively plan for compliance. While BREC retained Sargent and Lundy to perform the initial steps in a comprehensive plan for compliance, BREC failed to follow through. As an example of this lack of follow through, BREC modeled only the emission control retrofits for Cross State Air Pollution Rule (CSAPR) and Mercury Air Toxics Standard (MATS) and, then only a subset of the controls recommended by Sargent & Lundy to comply with these rules. Also of importance, BREC did not consider forward going costs for compliance with NAAQS revisions, the CCR rule, the Water Intake (316(b)) rule, and new effluent limits despite its expectation that those regulations will drive further capital expenditures. Berry direct prefiled at 27 ff.; DePriest direct prefiled at 10. BREC stated it did not consider costs for compliance with NAAQS revisions simply because they would not need to comply immediately. Berry, *loc. cit.* This position of BREC's in the face of Sargent & Lundy's caution that "In order to achieve compliance with potential NAAQS emission reductions, BMC would need to alter their compliance strategy," is not sound utility planning. S&L report at 6-4. BREC implicitly admits it should use a 20-year planning horizon, but fails to consider reasonably foreseeable costs for future environmental controls during that period. Such shortsighted analysis stacks the deck in favor of the proposed Environmental Retrofits because it only looks at subset of costs needed to go down that road. As a result, its 2012 Environmental Plan fails to deliver a least cost solution to meeting customer needs. Failure to consider all options in a cohesive fashion makes it impossible for the Commission to find that retrofits are least cost.

c. Errors

Q Did any of the other errors BREC made in its economic analysis of compliance options materially affect the outcome of its analysis?

A Yes. Among the material errors BREC made were

- Using a natural gas price forecast that is out of date and higher than current forecasts,
- Using a CO_2 emissions price in the determination of market energy prices, but not in unit running costs, and
- Exclusion of ongoing operating and maintenance (O&M) costs at each of the coal units.

Others are listed above and in the prefiled direct testimony of witness Wilson.

I am also concerned about the limited sensitivity analyses. In response to discovery request KIUC 2-5, Big Rivers states that it relied on a single estimate of fuel costs, market prices, allowance prices, etc., as support for its application to the Commission.

> Q. Please explain why Big Rivers used a forward energy price forecast from both Pace Global ("Pace") and APM in the cases studied.
>
> A. Pace's analysis was developed to incorporate a wide range of market uncertainties on key drivers such as fuel prices, electric load growth, carbon compliance costs, and power market prices. This approach provided the context under which Pace developed a reference case hourly price projection for use in further production cost models.

The fact that many variations of input assumptions were used to generate one or more of the reference case input assumptions does not immunize that reference case, itself, from uncertainty. Failure to present sensitivity cases showing whether the proposed Environmental Retrofits are appropriately robust is not good utility practice and should lead to the Commission not to put much weight on it the Application as evidence for the retrofits.

d. Failure to Model Retrofits Against Relevant Alternative Options

Q Did BREC compare the proposed Environmental Retrofits to a full array of alternatives?

A No, it did not. BREC's cost effectiveness evaluation considered three cases: a Build Case (in which it installed all the Environmental Retrofits); a Partial Build Case (in which it installed all but one of those retrofits) and a Buy Case (in which it installed only MATS retrofits). Hite direct at 6. One of those cases considered market purchases, but only as an alternative to some of the controls, not as an alternative to continued operation of one or more of the coal generating units. Other alternatives, such as new natural gas plant, gas conversions, retirements, purchased power agreements for excess capacity, energy efficiency programs and renewable resources were not modeled.

To illustrate the importance of this omission, Synapse compared the Build Case to one of those alternatives—a new natural gas combined cycle (NGCC) unit first using BREC's input assumptions and then using several combinations of more appropriate assumptions. Witness Wilson explains that process and those combinations of assumptions in her prefiled testimony. Those scenarios show that, with reasonable input assumptions and correcting several errors made by BREC in its analyses, replacement of BREC's coal units with natural gas combined-cycle replacement options is more economical on an NPVRR basis than the proposed Environmental Retrofits by between 12 and 20 per cent, depending on the unit, for a fleet-wide savings in excess of one billion dollars NPVRR.

Q Would not reliance on natural gas generation entail some price uncertainty?

A Yes, as with many other options, reliance on natural gas as a fuel entails some price volatile over short and mid-term, perhaps somewhat more so than coal. However, natural gas is not necessarily the only alternative that could be included in a diversified portfolio for BREC that should include increased levels of DSM and renewable resources such as wind. Further, those price fluctuations can be hedged over the short- to mid-term, and the coal retrofit case brings its own suite of risks including excess capacity, cost overruns (discussed below), aging plant considerations, future carbon regulation, and more. Furthermore, a resource portfolio so dominated by one technology and one fuel as BREC's is quite brittle compared to a diverse portfolio of multiple fuels, market purchases, energy efficiency, load management and renewables.

Q You mentioned energy efficiency resources as one alternative not considered by BREC. Please explain further.

A On page 29 of his prefiled direct, witness Berry states that "the magnitude of potential savings from DSM and energy efficiency is insufficient to materially assist Big Rivers in complying with CSAPR and MATS."

Q Are you surprised by that conclusion and do you agree with it?

A I do not agree with that conclusion, but am not surprised that BREC would reach it, as the DSM programs being implemented by BREC are nowhere near what is readily achievable by a utility.

BREC's assertion is merely conclusory and fails to consider the possibility that DSM and energy efficiency could make a difference to the economics of even one of BREC's many coal units. It is also contrary to the experience of national leaders in energy efficiency who have found it possible to achieve savings in excess of 1% of retail sales per year consistently for a decade or more. However, I am not surprised that BREC should reach such a conclusion, based on its approach to DSM evidenced in its 2010 IRP. For example, on page 7-14 of that IRP, BREC states that, Big Rivers and its three distribution member cooperatives currently primarily provide education about energy efficiency, with the exception being distribution of CFL lighting at no cost to members." In my thirty-some years of experience with the design of DSM programs, I have not seen any utility that took such a stance succeed in achieving substantial savings.

Further, In Section 8 of that IRP, BREC presents the projected savings of it future DSM programs, and those savings amount to approximately 0.01% of annual non-smelter sales each year. This is barely a token amount, representing a tiny fraction of the sustained annual savings rate achievable by a vigorous utility DSM program.[1] Such a vigorous program can also be ramped up by committed utility managers within about three years, especially now that effective program designs are well understood.

All in all, it is clear that BREC has not considered DSM and energy efficiency seriously and that, if it had, it would have found that energy efficiency resources would have made a difference in its ability to retire existing units and rely on other resources. It is important to note that sustained savings in energy sales of 1% per year from DSM programs would result in a load reduction in excess of 10% after a decade. This is certainly an amount that can make a difference in the resource needs of BREC and its customers.

e. All or Nothing Alternatives

Q You mentioned that DSM resources might well have made a difference in the economics of at least some of BREC's units. Please explain further the modeling of individual units.

A As witness Wilson explains in her prefiled direct, BREC's Build Case resource scenario analyzed all its coal units as retrofitted. BREC did not analyze the opportunities to retrofit some units and retire others in favor of alternatives. I am concerned that this distorts the outcome, especially in the Smelter sensitivities. If BREC had done its analysis on a unit-by-unit basis, it is likely that DSM could have offset the need to retrofit or replace some units. This is especially problematic given the Smelter sensitivities. In particular, BREC's assertion that

[1] For example, in 2007, states had utility and public benefit programs that saved electric energy at a rate in excess of 0.5% of retail sales (total retail sales, not excluding large industrial sales as in the above Kentucky example) included Vermont, Connecticut, California, Massachusetts, Minnesota, Washington, Oregon, Rhode Island and Iowa. Dan York, Patti Witte, Seth Nowak and Marty Kushler, *Three Decades and Counting: A Historical Review and Current Assessment of Electric Utility Energy Efficiency Activity in the States*, June 27, 2012, ACEEE Research Report U123, available at http://aceee.org/research-report/u123.

the Smelter sensitivity showed no change in the least cost strategy should be given no weight due to this analytical defect.

Q Did BREC consider any coal plant retirements or natural gas conversions (aside from the Reid plant) in its economic analysis? If not, why not?

A Apparently, BREC did not consider any coal plant retirements in its economic analysis. It justified this in the following way in its Response to KIUC 1-26:

> Because of the significant number of generating units involved and the significant unamortized plant balance of the coal units that are being upgraded, retirement of the coal plants or converting them to natural gas would result in the need to recover, through rates, the Unamortized plant balances of the coal plants in addition to any costs of converting the plants to natural gas. Big Rivers believed that this cost could be avoided by pursuing upgrades that would control emissions and comply with EPA regulations for an average cost of about $169 per kW compared to an overnight installed cost of $626 per kW for an advanced combustion turbine and $917 per kW for a new combined cycle unit (Assumptions to the Annual Energy Outlook for 2011, DOE EIA, p. 97; see attached). These differences were so large that Big Rivers did not consider it necessary to evaluate the option of retiring coal plants or converting them to natural gas.

Q Is that justification sound?

A No, it is not. In fact, BREC's excuse is economic nonsense.

I do not necessarily agree that, in the event of a coal unit retirement, the unamortized values would be recoverable in rates under traditional ratemaking. However, from a least cost planning point of view it is irrelevant whether the unamortized costs of those plants are recoverable in rates. That is because, whether or not those costs would be recoverable from BREC's ratepayers, they could not "be avoided by pursuing upgrades that would control emissions and comply with EPA regulations." Rather, those costs are sunk and are completely unaffected by any decision regarding the proposed Environmental Retrofits. This fundamental error is compounded by erroneously comparing capital resources on the basis of their overnight installed cost rather than a full life-cycle revenue requirement.

The following example should clarify this point. Assume for the sake of argument that (1) the unamortized cost of BREC's coal plants at this time including the present value of any carrying charges (TIER, etc.) is $1 Billion, (2) the life cycle cost of retrofitting and operating those plants is $7.4 Billion, (3) the life cycle cost of retiring those plants and replacing them with NGCC plants is $6.2 Billion, and (4) nothing else in BREC's cost of service will change between those two strategies. Then the cost of service difference (NPVRR) will be:

Strategy	Build Case (Install proposed Environmental Retrofits)	Alternative Case (retire existing plants and replace with NGCC)	Difference
Amortization of existing rate base and carrying costs	$1 Billion	$1 Billion	$0
Capital and operating costs of strategy	$7.4 Billion	$6.2 Billion	$1.2 Billion
Total	$8.4 Billion	$7.2 Billion	$1.2 Billion

Clearly, even if we grant BREC the benefit of the doubt on whether the existing rate base would, in fact, be recoverable from customers under the Alternative Case, the amount of that existing rate base cancels out and makes no difference in which strategy is least cost.

5. OTHER CONCERNS WITH THE PROPOSED ENVIRONMENTAL RETROFITS

Q In considering the cost-effectiveness of BREC's plan, can the Commission be confident that the cost estimates presented for the Environmental Retrofits will not increase?

A Not necessarily. First of all, there is the concern already discussed above that the costs presented do not include all of the environmental upgrade costs that BREC would need to enable its plants to continue operating, even with the proposed Environmental Retrofits. Second, as has already been discussed, BREC has not included a specific estimate of owner's costs for the proposed Environmental Retrofits and has not accounted for future capital additions that will be needed to keep the plants running. In addition, there is reason to expect the final costs of such retrofits would exceed the estimates typically offered by utilities at this stage of development. A recent example is the case of AEP's Big Sandy retrofit proposal where there was an increase of about 130% in estimated costs from the base engineering, procurement and construction (EPC) cost to total company cost (from $409 million before escalation and contingency to $940 million after "associated" costs, the cost of landfill modifications required to accept flue gas desulfurization waste, a 20% contingency, American Electric Power owner costs, and allowance for funds used during construction (AFUDC)). I understood that the BREC cost estimate does include contingency and escalation, but describe this recent experience as an illustration of what may happen to initial estimates.

I would also observe that Sargent and Lundy characterizes its capital cost estimates as follows in Sec. 5.1.1 of its report included in the BREC Application:

> The capital costs do not include; sales taxes, property taxes, license fees and royalties, owner costs, or AFUDC (Allowance for Funds Used During Construction). The costs are based on a minimal-contracts lump-sum project approach. The total installed costs are factored from recent projects and quotes obtained by S&L. No specific quotes or engineering was completed for any of the projected upgrades for the BREC units. The costs provided herein reflect an approximate accuracy of +/-20% and are not indicative of costs that may be negotiated in the current marketplace. These costs should not be used for detailed budgeting or solicitation of pollution control bonds.

(I have mentioned owner's costs above.) This suggests some considerable uncertainty. There is some reason to believe that capital costs for such equipment may increase over the next few years due to greater demand. I also note that a 20% margin is greater than the margin by which the proposed Environmental Retrofit life cycle costs exceed NGCC life cycle costs, even in the scenarios that assume BREC's input assumptions. (See Wilson Table 1.). Further, in response to SC 2-4, BREC failed to provide the requested information on cost overruns of prior major capital projects.

6. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize the major conclusions and recommendation from your review of the Company's request.

A My first conclusion is that the Company has not demonstrated that its proposed CPCN for Big Rivers is reasonable and cost-effective for complying with the environmental requirements the Company is facing. That conclusion is based upon the results of our review, which indicates that the Company has not evaluated the full range of resource options available to it, that its projections of revenue requirements for the resource options it did evaluate are not correct, that its evaluation of future scenarios does not include a reasonable projection of carbon prices and that its risk analysis is flawed. My second, related, conclusion is that allowing BREC to recover the costs of installing environmental control equipment on Big Rivers from ratepayers will not result in just and reasonable rates.

Based upon those conclusions my recommendation is that the Commission not approve the Company's request for a CPCN for Big Rivers.

Q. Does this complete your Direct Testimony?

A Yes.

EXHIBIT 6

Power Costs in the Production of Primary Aluminum

by Stuart Burns *on* FEBRUARY 26, 2009
Style: *Category:* Non-Ferrous Metals

Since the aluminum price on the LME dropped below $1500/ton it has been repeatedly stated that some 60-70% of aluminum smelters are losing money. Electricity alone is generally accepted as representing about a third of the cost of aluminum ingot, although at what sales price that metric is judged is open to debate. We thought it would be interesting to explore what the true costs of production are for a ton of primary aluminum and thereby test to what extent the smelters claims that they are losing money are correct. As with the steel industry, many of the industry's woes may have as much to do with low plant capacity utilization as they do with low sales prices.

Although the newest smelters can be closer to 12,500 kWh per ton let's say most smelters are consuming electricity at 14,500-15,000 kWh/ton of ingot produced. With the LME at $1300/metric ton that means electricity should be costing a typical smelter $0.029/kWh. Needless to say smelters are rather coy about their power cost contracts so it's hard to verify how prevalent this number is though many smelters are on variable power cost contracts with their electricity suppliers such that the power generators are paid a fixed percentage of the world ingot price. If we take that as one third then it's not only smelters that are losing money, many power generators must be too. When US national average industrial and commercial electricity consumers are paying $0.0706/kWh and $0.1013/kWh, respectively, according to theEnergy Information Administration, to be selling power to smelters at $0.029/kWh represents a huge subsidy. In reality, power costs to the smaller US smelters are probably higher than this and explains why many have been cut back or idled, but interestingly the same source gives specific power costs for the Pacific NW of only two thirds the national average suggesting that many NW smelters may indeed still be getting power at ingot price related levels.

By comparison, Chinese producers are more open with power costs. The Guangxi smelters typically consume 14,500 kWh/ton and are paying $0.050-0.055/kWh according to China Mining. Power costs of $0.0525/kWh and consumption at 14,500 kWh/ton equates to $760/ton. The domestic ingot price in China as reported on the SHFE is currently $1725/ton, making domestic electricity costs some 44% of the sales price of ingot and may explain why Chinese smelters combined with low capacity utilization due to reduced demand are widely reported to be in the red even at the premium SHFE price for ingot.

Like China, Australia has a comparatively high portion of it's power generation coming from coal, although being a major coal producer local coal costs are lower in Australia than China. Nevertheless an organization calledEarthlife Africa estimates Australian power rates at about the same $0.053/kWh as China, which with ingot selling at LME levels of $1300/metric ton would suggest Australian smelters are incurring an eye watering 59% of finished ingot power cost! We suspect power costs may be tied to ingot prices in Australia as the major smelting groups operating there — Alcoa, Rio, etc — are well-versed in the tactics of leveraging the best deal from local and federal government agencies in return for smelter investments. In addition, Australian smelter costs may benefit from lower bauxite costs than the Chinese as transport costs should be minimal, which could help to mitigate a power cost disadvantage.

Russian smelters on the other hand are built next to massive hydroelectric plants, shares in which many of them own. Electricity costs at Rusal are estimated at $128/ton and the current cost of production at only $1000/ton, so Rusal is still making money even with the LME at $1300/ton. Interestingly the same report says the cost of power is just 12% of the cost of production, suggesting the Alumina, Cryolite, Carbon anodes etc are cumulatively about $880/ton which will be explored in more detail later this week.

Even for those smelters still smart enough or lucky enough to be tied at power costs of one-third of the ingot price with the LME at $1300/ton they will be doing well to break even. Add in the fact many smelters are running at well below optimum capacity and the unit price per ton produced suggests they are indeed losing money " which begs the question why hasn't more capacity been closed down?

EXHIBIT 7

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UPDATE: Big Rivers seeking $74 million annual increase in wholesale electric rates

By Chuck Stinnett

Originally published 01:54 p.m., January 16, 2013
Updated 05:11 p.m., January 16, 2013

HENDERSON, Ky. — Substantial rate increases to rural electric customers, the possible closure or sale of a power plant and increased uncertainty for the future of Rio Tinto Alcan's Sebree aluminum smelter are facing Henderson and Western Kentucky.

Big Rivers Electric Corp. on Tuesday sought permission to raise its wholesale electric rates in Western Kentucky by $74.5 million per year starting in August, primarily to make up for departure of its biggest customer, Century Aluminum's smelter in Hancock County this August.

In an application filed Tuesday with the Kentucky Public Service Commission, Henderson-based Big Rivers estimated that the rate increase, if approved, would boost retail electric bills for a typical residential customer of rural electric co-ops by $21.71 per month or 18.6 percent. That's based on usage of 1,300 kilowatt-hours per month.

However, Greg Starheim, president and CEO of the Kenergy Corp. electric co-op based in Henderson, put the impact even higher: about $24 for a rural home. He said Kenergy will work to educate its customers about ways they can reduce power consumption to save money.

The rate increase wouldn't affect customers of Henderson Municipal Power and Light or Kentucky Utilities Co., which also serve portions of this area.

Rates for Rio Tinto Alcan — which already has complained that existing power costs put it at a competitive disadvantage on the world aluminum market — would rise 15.6 percent under Big Rivers' proposal.

"Obviously, we're disappointed," Alcan plant spokesman Kenny Barkley said Wednesday.

"This kind of increase can cause serious implications" for the 500-employee plant, Barkley said.

Closing the smelter "is an option, but it's not part of the solution we'll be making a decision on" in "the very near future," he said.

"We want to stay in operation in western Kentucky," Barkley said. "Thousands of people depend on us ... A lot is at stake."

"Obviously, this not welcome news to them," Starheim said. "It's causing an extra burden on the already tough environment they're competing in."

Other large industries — from big manufacturing plants to coal mines — could also fill the pinch, with Big Rivers seeking to increase their electric rates 17.9 percent.

Unhappy with Big Rivers' existing rates, Century Aluminum last August filed notice that it would terminate its purchase of power produced by Big Rivers starting this Aug. 20. Century is Big Rivers' largest customer, consuming 482 megawatts of electricity.

That's a substantial amount of power, equaling about four to five times the amount of power typically used in the city of Henderson.

"Cost-cutting alone cannot offset this deficiency," Big Rivers spokesman Marty Littrel said Wednesday.

Losing a customer such as Century could reduce the need for Big Rivers to operate all of its existing generating stations in Western Kentucky, including the Reid-Green-Station Two complex near Sebree; its Coleman power plant in Hancock County; and its Wilson power plant in Ohio County.

Starheim said that "to reduce operational expenses in the future, discussions have included idling or selling a power plant."

In its application with the PSC, Big Rivers declared that idling the Wilson plant next Dec. 1 could result in the cutting of 92 of the company's 627 employees.

But Littrel said that doesn't mean that Wilson would necessarily be the plant that would be mothballed.

"We still don't know if it would be Wilson or not," he said. "We had to put something down for the rate case, and that's what we put down. But that could change ... It doesn't mean that Sebree's (complex of generating stations) are being ignored, either."

In fact, quite a lot isn't known, particularly concerning Century Aluminum's plans. Last August, when Century announced its intention to terminate its power supply contract with Big Rivers, the aluminum company spoke as if it would close its smelter. A month later, Century informed Big Rivers that it intended to buy power on the open market to keep the plant in operation, and Starheim said discussions have taken place concerning such a possibility.

But, he said, "It's not obvious at all what their intent is."

A Century spokeswoman didn't return a phone call Wednesday seeking comment on its plans.

In the meantime, Big Rivers is seeking alternate customers for Century's 482 MW of power, either by trying to recruit new industries that require lots of electricity or selling surplus power to other utilities.

Littrel said Big Rivers submitted an offer to sister companies Louisville Gas & Electric Co. and Kentucky Utilities Co., which last fall sought to buy up to 700 MW of power starting after Jan. 1, 2015. "We are still reviewing the proposals and are on schedule to complete those evaluations by March 15," according to LG&E-KU spokeswoman Chris Whelan.

Big Rivers has also submitted an offer to East Kentucky Power Cooperative and has mentioned other possible buyers of power.

Securing such a buyer or attracting new industries could eventually ease the need for higher rates.

"Certainly this is not intended to be a permanent increase," Kenergy's Starheim said.

"We'll still remain competitive," Littrel said. "Even with this increase, we would not be the highest in Kentucky," which itself is among the lowest-cost states for electric power.

Still, proposing to increase electric rates by 15 to 20 percent puts Big Rivers in an unenviable position.

"This is a pretty abnormal event," Starheim said.