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

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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 Coleman Unit 2 Coleman Unit 3	Dry Bottom Conversion - Remote SSC & Fly Ash Conversion to Dry Pneumatic	38
Green Unit 1 Green Unit 2	Dry Bottom Conversion - Remote SSC	28
HMP&L Unit 1 HMP&L Unit 2	Dry Bottom Conversion - Remote SSC	28

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><th>316(b)</th><th>S&L Recommended Tech</th><th>Capital Cost ($M)</th><th>Annual O&M ($M)</th></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.

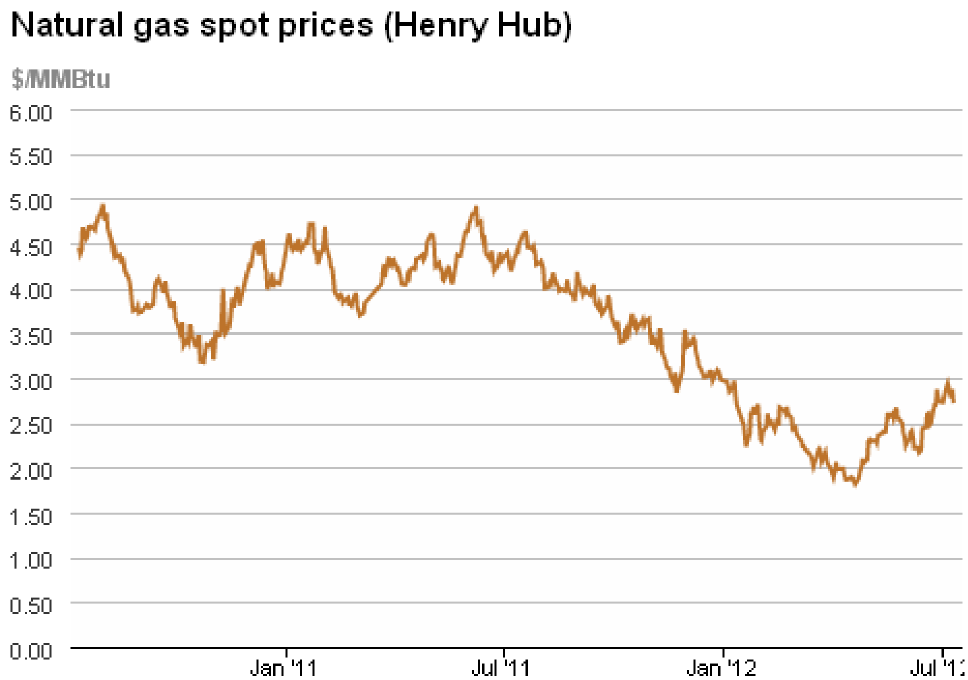

Figure 3. Natural gas spot prices at Henry Hub ($/mmBtu).[5]

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

[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.