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EXPERT REPORT AND ANALYSIS - BASIN ELECTRIC POWER COOPERATIVE'S DRY FORK STATION POWER PLANT:

(1) SUPERCRITICAL BOILER TECHNOLOGY IS NOT A PRACTICAL OPTION FOR THE DRY FORK STATION;

(2) THE DRY FORK PERMITTING PROCESS WAS THOROUGH AND TECHNICALLY SOUND; AND

(3) EMISSION LIMITS INCLUDED IN THE FINAL PERMIT REPRESENT BEST AVAILABLE CONTROL TECHNOLOGY

KENNETH J. SNELL
SARGENT & LUNDY, LLC

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**BEFORE THE ENVIRONMENTAL QUALITY COUNCIL
OF THE STATE OF WYOMING**

IN THE MATTER OF:	)
BASIN ELECTRIC POWER COOPERATIVE	)
DRY FORK STATION,	)
AIR PERMIT CT-4631	)

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(1) SUPERCRITICAL BOILER TECHNOLOGY IS NOT A PRACTICAL OPTION FOR THE DRY FORK STATION; (2) THE DRY FORK PERMITTING PROCESS WAS THOROUGH AND TECHNICALLY SOUND; AND (3) EMISSION LIMITS INCLUDED IN THE FINAL PERMIT REPRESENT BEST AVAILABLE CONTROL TECHNOLOGY

**KENNETH J. SNELL
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I. Main Conclusions of this Expert Report

This report has been prepared by Kenneth J. Snell of Sargent & Lundy LLC (S&L). In preparation of this report, I have conferred with other specialists at S&L, primarily Mr. William Rosenquist as to my opinions on supercritical boiler technologies, and Mr. William DePriest as to my opinions on emission control technologies and achievable emission limits. A summary of my experience and qualifications, and a summary of the experience and qualifications of Mr. Rosenquist and Mr. DePriest are included in Attachment 4 to this report.

This report has been prepared as part of the proceedings before the Environmental Quality Council of the State of Wyoming addressing the Basin Electric Power Cooperative Dry Fork Station Air Permit CT-4631, and will address the following three subjects and provide the basis for my expert opinions as to each subject:

1. <u>Subcritical vs. Supercritical Boiler Technology Use at the Dry Fork Station</u>

The terms "subcritical" and "supercritical" simply refer to the main steam turbine pressure of a power plant boiler. Boilers that generate steam below the critical point of water are termed subcritical units, while boilers that generate steam above the critical point of water are termed supercritical units. Power plants, including the boiler and steam turbine, designed to handle supercritical cycles are generally more efficient than subcritical units at 500 megawatt (MW) or more net energy output. However, the Dry Fork Station, at 385 MW-net, is too small to gain any significant increased efficiency with a supercritical cycle, and supercritical units are significantly more expensive than subcritical units. Therefore, a subcritical boiler was the only practical technology choice that Basin Electric Power Cooperative (BEPC) could make in its consideration of pulverized coal-fired boilers for the Dry Fork Station. In addition, even assuming a marginal efficiency gain of 0.75% to 1.3% in the gross turbine heat rate associated with a supercritical cycle, the cost of such a supercritical boiler would be about $435,880 per ton of additional pollutant reduction. This high cost is an order of magnitude higher than the typical range of $8,000 to $15,000 per ton, above which EPA considers control technologies not cost effective and not Best Available Control Technology (BACT). Supercritical technology would not provide additional efficiency or cost effective emission reduction at the Dry Fork Station.

2. <u>The Wyoming Department of Environmental Quality – Air Quality Division's (WYDEQ-AQD) Role in the Permitting Process</u>

Based on my involvement in the Dry Fork Station permitting processing and my experience with several other similar air permitting projects, the Wyoming Department of Environmental Quality – Air Quality Division (WYDEQ-AQD) conducted a very thorough, complete, and technically sound evaluation of the proposed emission control technologies for the Dry Fork Station. WYDEQ-AQD's review was as thorough, and in many respects more thorough, than other coal-fired power plant permitting projects in which I have been involved over the past eight years in more than seven states. WYDEQ-AQD requested significant amounts of additional technical and economic information from BEPC and did not simply rely on information submitted in BEPC's permit application. WYDEQ-AQD questioned and challenged each emission rate in the permit application and critically reviewed the proposed control technologies. As a result, the final permit issued for the Dry Fork Station contained BACT emission limits that were significantly more stringent than emission limits initially proposed by BEPC. The permitting process resulted in emission limits that will require BEPC to install and properly maintain state-of-the-art emission control technologies to achieve high pollutant removal efficiencies.

3. <u>Emission Limits in the Final Permit Represent Best Available Control Technology (BACT) for the Dry Fork Boiler</u>

The BACT emission limits in the final permit for the Dry Fork Station are among the most stringent emission limits proposed for any coal-fired power plant in the U.S. for NOx, SO_2, PM_{10} and mercury. I have not specifically addressed $PM_{2.5}$ emissions because BEPC and WYDEQ-AQD properly used PM_{10} as a surrogate for $PM_{2.5}$ pursuant to EPA policy. The permit limits imposed by WYDEQ-AQD will require the Dry Fork Station to meet some of the lowest emission rates of any coal-fired electric generating station in the country. After my extensive review of the permit limits for NOx, SO_2, PM_{10}, and mercury, how those permit limits were established, and Dr. Sahu's criticism of those limits, I remain convinced that the limits represent BACT for the Dry Fork Station.

II. Background – Sargent & Lundy's Involvement in the Dry Fork Station Permit

My involvement with the Dry Fork Station (DFS) project commenced in December 2004 at the Northeast Wyoming Generation Project (subsequently renamed the Dry Fork Project) kick-off meeting held at the offices of Basin Electric Power Cooperative (BEPC) in Bismarck, North Dakota. Initial project tasks included reviewing the project's "Phase I Deliverables," and providing technical support for the Dry Fork Station's air construction permit application. Phase I Deliverables included, among other things, an evaluation of alternative locations for the proposed generating facility, an Environmental Licensing Plan, and a Phase I Conceptual Design and Technology Evaluation prepared by CH2MHill.

Following review of the Phase I Deliverables, I was tasked with providing technical input to the facility's air construction permit application. CH2MHill, an environmental and engineering consulting firm, was tasked with preparing the air permit application, with S&L providing technical input and review. BEPC submitted the permit application to the WYDEQ on November 10, 2005 (the "Permit Application"). The Permit Application included, among other things, a description of the proposed facility, emission estimates, a best available control technology (BACT) evaluation, air quality impact modeling results, proposed emission limits, and the permit application forms required by WYDEQ. Prior to submittal of the Permit Application, I reviewed and provided comment on several sections of the application, including Section 3.0 Emissions Summary; Section 5.0 Control Technology Evaluation; Section 6.0 Requested Permit Limits; and Section 9.0 Monitoring Information.

The Permit Application was submitted to WYDEQ-AQD for review. During the review process, my involvement in the permitting project included providing technical support and preparing written responses to WYDEQ-AQD questions and requests for additional information. The review process included several rounds of questions and answers, and the submittal of a significant quantity of detailed information. Information submitted during the permit review process included technical descriptions and evaluations of the PC boiler generating technology, descriptions of the potentially available emission control technologies, information regarding emission rates achieved in practice by the best controlled similar sources, technical information from emission control equipment vendors, anticipated vendor guarantees, and emission rates included in recently issued permits for similar sources.

In preparing this expert report, I have reviewed the original November 10, 2005 Permit Application as well as supplemental information submitted to WYDEQ-AQD during the permit review process. A list of the supplemental technical documents submitted to WYDEQ-AQD that I reviewed in preparation of this report is provided in section IV.B of this report. I have also conferred with other specialists at S&L in the preparation of this report, primarily Mr. William Rosenquist as to my opinions on supercritical boiler technologies, and Mr. William DePriest as to my opinions on emission control technologies and achievable emission limits. I also reviewed the expert report submitted to the Environmental Quality Council on behalf of the Protestants by Dr. Ranajit Sahu dated May 1, 2008.

III. Overview of the Dry Fork Station Permit and its BACT Emission Limits

The Dry Fork Station will consist of a pulverized coal (PC) boiler, air pollution control systems, steam turbine/generator, and auxiliary support equipment including material handling systems, an auxiliary boiler, fire suppression systems, and an air cooled condenser. The facility will be located adjacent to the Dry Fork Mine, approximately 7 miles north of Gillette, Wyoming.

The main boiler at the Dry Fork Station will be an indoor-type PC boiler designed for baseload operation. The unit will have a maximum heat input of approximately 3,801 million British thermal units per hour (MMBtu/hr), a maximum gross generation output of approximately 422 megawatts (MW), and a net generation output of approximately 385 MW at annual average conditions. The boiler is being designed to be capable of developing main steam turbine throttle pressures and temperatures in the range of 2,520 pounds per square inch gauge (psig) and 1,050 ^{o}F, respectively, and a reheat steam temperature at the inlet of the intermediate pressure (IP) turbine of approximately 1,050 ^{o}F. Because the main steam turbine throttle pressure is below the critical point of water, the boiler is classified as a subcritical PC boiler.

Prior to proposing a subcritical PC boiler for the Dry Fork Station, BEPC thoroughly evaluated several candidate technologies including both subcritical and supercritical PC units as well as circulating fluidized bed (CFB) boilers and integrated gasification and combined cycle (IGCC) technologies. Results of the conceptual design review were included in a report titled "Coal Power Plant Technology Evaluation for Dry Fork Station" prepared by CH2MHill, November 1, 2005 (included as Attachment 1 to this report). That report, which was completed prior to BEPC's submittal of the Permit Application, provided a conceptual level technology evaluation to address the advantages and limitations of PC boilers, CFB boilers, and IGCC power generating technologies. The various generating technologies were evaluated with respect to BEPC's defined needs for baseload capacity, environmental compliance, reliability and availability, commercial availability, and economic criteria. Based on site-specific considerations, the evaluation concluded that subcritical PC technology was the only practical generating technology choice for the proposed project.

BEPC submitted an application for a permit to construct the Dry Fork Station to the WYDEQ-AQD on November 10, 2005. The Permit Application included all of the information required by WAQSR Chapter 6, Sections 2 and 4, including a description of the proposed facility, drawings showing the general arrangement of the facility, detailed emission calculations for each proposed source (including the main boiler), an emissions control technology evaluation, proposed BACT emission limits, and ambient air quality impact modeling.

Over the next 14 months WYDEQ-AQD conducted an exhaustive evaluation of BEPC's Permit Application. In addition to reviewing information submitted with the Permit Application, WYDEQ-AQD required BEPC to provide additional supporting information and data. WYDEQ-AQD challenged each emission control technology and each BACT emission limit proposed by BEPC, and required BEPC to submit additional information and data on the following emissions related topics:

- Technical capabilities of potentially available sulfur dioxide (SO_2) emission control technologies, including wet flue gas desulfurization (WFGD) and dry flue gas desulfurization (DFGD) control technologies;
- Technical capabilities of potentially available nitrogen oxide (NOx) emission control technologies, including combustion control systems and post-combustion NOx control system.
- Information evaluating the technical capabilities of PM and PM_{10} emission control technologies;
- Information regarding condensable PM_{10} emissions from the main boiler;

- Additional ambient air quality impact modeling analyses;
- BACT analysis for mercury emissions from the main boiler;
- Technical capabilities of potentially available sulfuric acid mist (SAM) emission control technologies;
- Emissions data from the best controlled similar sources using emission control technologies that could be applicable to the Dry Fork boiler, including units equipped with wet- and dry- flue gas desulfurization systems, and units equipped with post-combustion selective catalytic reduction NOx controls;
- Information regarding potential unit efficiency gains with supercritical cycle design;
- Information regarding anticipated emission control technology vendor guarantees; and
- Emission limits included in other recently issued PSD permits for coal-fired boilers.

On February 5, 2007, WYDEQ-AQD issued its Permit Application Analysis NSR-AP-3546 for the Dry Fork Station. The Permit Application Analysis included a description of the proposed facility, emissions summary, regulatory applicability review, BACT analysis, and impact modeling analysis. The analysis concluded that the facility will comply with all applicable Wyoming Air Quality Standards and Regulations, and included WYDEQ-AQD's intent to issue a construction permit. A draft permit, including proposed BACT emission limits was included as part of the Permit Application Analysis.

WYDEQ-AQD advertised its proposed decision to issue a permit in the Gillette News-Record on February 26, 2007 giving opportunity for public comment and a public hearing on the matter. A public hearing was held on June 28, 2007 at the Campbell County Library in Gillette. Following the close of the public comment period, WYDEQ-AQD requested from BEPC more information regarding the subcritical design of the boiler, as well as information regarding NOx and SO_2 emission rates achievable with the proposed BACT control technologies.

On October 15, 2007, WYDEQ-AQD issued the Permit No. CT-4631 (the "Final Permit") for the Dry Fork Station. In addition to the Final Permit, WYDEQ-AQD issued a detailed evaluation and response to comments received during the public comment period. The Final Permit included the following BACT emissions limits:

PC Boiler (ES1-01) Allowable Emissions

Pollutant	lb/MMBtu	lb/MW-hr	lb/hr	tpy
NO_X	0.05 (12 month rolling)	1.0 (30-day rolling)[1]	190.1 (30-day rolling)	832.4
SO_2	0.070 (12 month rolling)	1.4 (30-day rolling)[1]	380.1 (3-hr block) 285.1 (30-day rolling)	1165.4
PM/PM_{10}	0.012[2]	–	45.6	199.8
CO	0.15	–	570.2 (30-day rolling)	2497
Hg	–	97×10^{-6} (12 month rolling)[1]	–	0.16
H_2SO_4	0.0025	–	9.5	41.6
HF	–	–	2.62	11.5
VOC	0.0037	–	14.1	61.6
NH_3	–	–	10 ppm_v[3], 19.6 lb/hr	85.8

1 NSPS Subpart Da Limit
2 Filterable PM/PM_{10}
3 Dry Basis, 3% O_2

The BACT emission limits in the Final Permit were developed by WYDEQ-AQD based on a comprehensive review of information submitted by BEPC during the permitting process, as well as independent review and verification by AQD staff. The BACT emission limits were based on a review of available emission control technologies, information available from control technology vendors, anticipated vendor guarantees, a review of emission rates proposed as BACT in other recently issued PSD permits, an evaluation of actual emissions achieved in practice at the best controlled similar sources, an assessment of the potential balance-of-plant impacts associated with each control technology, and an assessment of the economic impacts and collateral environmental impacts associated with potentially feasible controls. In order to achieve the BACT emission limits listed above, BEPC will have to install and continuously maintain and operate the following emission control technologies:

- Combustion controls to minimize boiler emissions of carbon monoxide (CO) and volatile organic compounds (VOC);
- Combustion controls including low NOx burners (LNB) and overfire air (OFA) systems to reduce boiler NOx emissions;
- Selective Catalytic Reduction (SCR) to reduce NOx emissions;
- Dry Flue Gas Desulfurization (DFGD) designed as a Circulating Dry Scrubber (CDS) to minimize SO_2 and SAM emissions;
- A fabric filter baghouse to minimize PM and PM_{10}.

Based on my review of the permitting process, the emission control technology requirements, and the BACT emission limits, it is my opinion that:

1. BEPC thoroughly evaluated alternative power generating technologies prior to making its decision to proceed with a subcritical PC boiler and submitting the application for the new facility. Potentially feasible generating technologies (including subcritical and supercritical PC, CFB, and IGCC) were evaluated with respect to BEPC's defined needs for baseload electricity generating capacity, environmental compliance, reliability and availability, commercial availability, and economic criteria. Based on the foregoing evaluation, BEPC determined that PC boiler technology was the only technically feasible and available generating technology for the Dry Fork project. Subcritical and supercritical PC designs were further evaluated based on site-specific considerations, including the specific generation needs, Dry Fork fuel characteristics, boiler size, steam turbine size, site altitude, site ambient conditions, emission control technologies, and air cooled condensing system. Based on that evaluation, BEPC concluded that subcritical PC technology was the only practical generating technology choice for the proposed project.

2. The permitting process conducted by WYDEQ-AQD was very thorough and complete, and included a technically sound evaluation of the proposed emission control technologies. WYDEQ-AQD did not simply rely on information submitted in BEPC's initial Permit Application, but requested significant amounts of additional technical and economic information. WYDEQ challenged each and every emission rate proposed in the Permit Application, critically reviewed the proposed control technologies, and required BEPC to provide additional technical information, emissions information, and cost data to support the Permit Application.

3. Emission limits included in the Final Permit represent BACT for a subbituminous coal-fired boiler. The BACT emission limits will require BEPC to install state-of-the-art emission control technologies, and will require BEPC to properly maintain and continuously operate the control technologies to achieve high pollutant removal efficiencies. The BACT emission limits included in the Final Permit are among the most stringent BACT emission limits proposed for any coal-fired boiler in the country, and will require the Dry Fork Station to achieve some of the lowest emission rates of any coal-fired electric utility steam generating unit.

IV. Why Dr. Sahu's Criticisms of the Dry Fork Permit are Incorrect

This section provides a detailed response to the issues raised in Dr. Sahu's Expert Report (the "Sahu Report"). Dr. Sahu's report criticized the permitting process used by WDEQ-AQD to develop emission limits for the Dry Fork boiler, focusing on: (1) the choice of subcritical technology for the power plant; (2) the permitting process; and (3) the determination of the BACT emission limits for NOx, SO_2, and mercury. (Sahu Report, paragraph 9).

A. Subcritical Boiler Technology was the Only Practical Generating Technology Choice for the Dry Fork Station

The main boiler at the Dry Fork Station will be an indoor-type pulverized coal (PC) boiler designed for baseload operation. The unit will have a maximum heat input of approximately 3,801 MMBtu/hr, a maximum gross generation output of approximately 422 MW, and a net generation output of approximately 385 MW at annual average conditions. The proposed boiler is being designed to be capable of developing main steam turbine throttle pressures and temperatures in the range of 2,520 psig and 1,050 °F, respectively, and a reheat steam temperature at the inlet of the intermediate pressure (IP) turbine of approximately 1,050 °F. Because the main steam turbine throttle pressure is below the critical point of water; the boiler is classified as a subcritical PC boiler.

Prior to proposing a subcritical PC boiler for the Dry Fork Station, BEPC thoroughly evaluated several candidate technologies including both subcritical and supercritical PC units, CFB boilers, and IGCC technologies. Results of the conceptual design review were included in a report titled "Coal Power Plant Technology Evaluation for Dry Fork Station" prepared by CH2MHill, November 1, 2005 (included as Attachment 1 to this report). That report, which was completed prior to BEPC's submittal of the Permit Application, provided a conceptual level technology evaluation to address the advantages and limitations of PC boilers, CFB boilers, and IGCC power generating technologies. The various generating technologies were evaluated with respect to BEPC's defined needs for baseload capacity, environmental compliance, reliability and availability, commercial availability, and economic criteria. Based on site-specific considerations, the evaluation concluded that subcritical PC technology was the only practical generating technology choice for the proposed project.

In paragraphs 10 through 17 of his Expert Report, Dr. Sahu reviews subcritical and supercritical pulverized coal-fired boiler designs, and concludes that: "It is my opinion that the BEPC and WDEQ-DAQ have not critically examined this issue and have erred in refusing to consider the use of super-critical technology for the DFS." (Sahu Report, paragraph 11). As described above, BEPC critically reviewed various generating technologies prior to submitted the permit application. Furthermore, the decision to build a subcritical unit was revisited several times as the project matured: prior to permit application, prior to developing the turbine generator specification for procurement, and upon receipt of comments from third parties during the public review/comment period (including comments from the National Parks Services and environmental groups). In response to these comments, WYDEQ-AQD requested BEPC to provide additional technical information addressing the selection of subcritical technology.

In response to WYDEQ's request, S&L prepared a site-specific evaluation of the potential efficiency improvements that would result if the Dry Fork boiler were designed for a supercritical cycle, and compared the results to the 385 MW (net) subcritical unit. (Memorandum from Sargent & Lundy LLC re: Subcritical-Supercritical Boiler Comparison, dated June 11, 2007, the "June 11th Tech Memo" included as Attachment 2 to this report). The primary author of the June 11th Tech Memo was S&L's Mr. Bill Rosenquist. That evaluation addressed the specific Dry Fork fuel characteristics, steam turbine size, steam conditions, boiler size, site altitude, site ambient conditions, emissions control technologies, air cooled condensing system and other site specific factors that are often overlooked in more general comparisons between supercritical and subcritical units.

1. Subcritical and Supercritical PC Unit Classification

Coal-fired units can be classified by their main steam turbine operating pressure and temperature. Units operating at a main steam pressures and temperatures above the critical point of water (approximately 3,208 psi and 705 ^{o}F) are termed "supercritical" units. Units operating below the critical point of water are termed "subcritical" units. Although the main difference between sub- and supercritical units is related to the main steam pressures and temperatures, there are significant differences in the design of units designed to handle subcritical cycles and those designed to handle supercritical cycles.

In a subcritical boiler, water circulating through tubes that form the furnace wall lining absorbs heat generated in the combustion process. As the water absorbs heat, a portion of the circulating water is evaporated into steam. Steam produced in the boiler will be superheated prior to being conveyed through the main steam line to the steam turbine. Saturated steam produced in the boiler must be separated from the water before it enters the superheater. Subcritical units utilize a steam drum and internal separators to separate the steam from the water circulating in the boiler tubes. The temperature of the boiler steam is increased in the superheater above the saturated temperature level. The superheated steam is conveyed to the high pressure (HP) section of the turbine. The reheater receives superheated steam which has partially expanded through the HP section of the turbine. The role of the reheater is to re-superheat the steam to a desired temperature ahead of the intermediate pressure (IP) section of the steam turbine.

Modern subcritical units have a maximum turbine throttle pressure of approximately 2,520 psig. Turbines for 2,400 psig operation are usually designed for steam pressures of 2,520 psig at the turbine throttle – a condition of 5% overpressure. A boiler-drum operating pressure of between 2,750 and 2,850 psig is required to allow for pressure drop through the superheater and the main steam line. Main steam pressures, main steam temperatures, and reheat steam temperatures of new subcritical units will be in the range of 2,520 psig, 1050 °F, and 1,050 °F, respectively, which are significantly higher than pressures and temperatures achievable with older units (which are typically in the range of 2,400 psig / 1,000 °F / 1,000 °F). This increase in pressures and temperatures has improved the efficiency of modern subcritical units.

Supercritical boilers operate at a main steam pressure above the critical point of water. When water is heated at a pressure above 3,208 psi it does not boil; therefore, it does not have a saturation temperature nor does it produce a two-phase mixture of water and steam. Instead, the water undergoes a transition in its physical properties (including density, compressibility and viscosity) changing continuously from those of a liquid (water) to that of a vapor (steam), and the temperature rises steadily. Supercritical steam boilers are "once-through" boilers and do not require the use of a boiler drum to separate steam from water as subcritical boilers do. Unlike subcritical boilers that evaporate circulating water into steam, in a supercritical boiler all of the boiler feedwater is turned into steam. Supercritical PC units are typically designed to develop a main steam turbine throttle pressures and temperatures in the range of 3,500 psig and 1,050 °F, and a reheat steam temperature of 1,050 °F. Changing a pulverized coal-fired boiler to handle supercritical cycles is not as simple as increasing the main steam turbine throttle pressure, and would require a complete redesign of the boiler.

2. Supercritical Boiler Efficiency Gains are Not Applicable to the Dry Fork Station

Dr. Sahu states that "[f]rom an engineering standpoint, super-critical and ultra super-critical steam cycle design plants have greater efficiencies – i.e., that they can generate the same amount of electrical power from less quantity of coal burned in the boiler – than sub-critical designs." (Sahu Report, paragraph 10). To support this statement, Dr. Sahu cites to a technical article titled "Review of Potential Efficiency Improvements at Coal-Fired Power Plants" prepared by Perrin Quarles Associates, Inc., at the request of the U.S.EPA's Clean Air Markets Division. (attached as Exhibit 4 to the Sahu Report). The article states that supercritical systems can achieve higher thermal efficiencies than subcritical systems; however, it also states that the review is "a general discussion of this issue in the context of several different types of coal-fired plants." (Sahu Report, Exhibit 4, page 1).

In general, without considering site-specific conditions, I would agree that supercritical cycles are more efficient than subcritical cycles, especially for units designed at greater than 500 MW (net) energy output. However, generalized comparisons often ignore the fact that plant performance, regardless of technology, is highly site specific. Site specific design issues include fuel characteristics, boiler size, steam turbine size, site altitude, site ambient conditions, emissions control technologies, and cooling system design. General comparisons also tend to ignore the fact that many improvements in performance attributed to supercritical technology can be implemented in subcritical technologies as well. For example, increasing main steam and hot reheat steam temperatures will improve efficiency of either technology. Generalized comparisons often compare a supercritical design with older subcritical units having lower main and reheat steam temperatures.

The efficiency of the thermodynamic process of a coal-fired unit depends upon how much of the heat energy that is fed into the cycle is converted into electrical energy. The throttle pressure and temperature of a subcritical cycle is limited by the properties of water, which limits the amount of heat energy that can be converted into working steam. The throttle pressure and temperature of a supercritical cycle is not limited by the properties of water, but by the capabilities of the materials used in the boiler, piping, and turbine to handle high pressures and temperatures. Therefore, more heat energy can be utilized in a supercritical cycle. If the energy input to the cycle remains constant, output can be increased with elevated pressures and temperatures for the water-steam cycle.

Efficiency improvements associated with supercritical cycles are associated with the increased steam flow (at high pressures) through the steam turbine. For a single reheat supercritical unit with a power output in the range of 600 – 1,000 MW, a typical turbine design would consist of three separate turbine modules operating at different pressure and temperature levels.[1] These three modules are the high pressure (HP) turbine, the intermediate pressure (IP) turbine, and the low pressure (LP) turbine section. The generator is directly coupled to the last LP turbine.

In the HP turbine steam is expanded from the main steam turbine throttle pressure to the pressure of the reheat system. Because of the high pressures associated with supercritical cycles, the inlet volumetric flow to the HP turbine is significantly lower than the inlet volumetric flow to the HP turbine on a subcritical unit. Turbine manufactures have designed HP turbine blades specifically for use with supercritical cycles to account for this reduced volumetric flow. The steamflow is further expanded in the IP turbine section. In both subcritical and supercritical cycles there is a trend to increase the temperature of the reheat steam that enters the IP turbine section in order to raise the cycle efficiency. In the LP turbine section the steam is expanded down to the condenser pressure.

Low inlet volumetric flow to the HP turbine (associated with supercritical pressures) is one of the main reasons supercritical units have not been typically considered for sizes less than approximately 500 MW-net. As size decreases below 500 MW, efficiency improvements associated with the higher inlet pressures to the HP turbine are reduced. Some of the decrease in efficiency is due to the necessary application of very short turbine blading in the early HP stages due to the reduced volumetric flow. The shorter blades used with high pressure cycles will still be mounted on relatively high base diameters so that acceptable rotor dynamics can be achieved. On smaller units this results in a high ratio of

[1] Rosenkranz, J., Wichtmann, A., "Balancing Economics and Environmental Friendliness – The Challenge for Supercritical Coal-Fired Power Plants with Highest Steam Parameters in the Future," Siemens-Westinghouse, Study supported by funds provided by the German Federal State of North Rhine-Westphalia (European Regional Development Fund – ERDF), [registration number 85.65.69-T-138].

seal clearance area to nozzle flow area as compared to higher MW rated units with taller HP stage blades. The increased pressure and reduced volumetric flow results in increased nozzle edge friction losses and seal losses, reducing efficiency improvements in the HP turbine.

3. Supercritical and Subcritical Performance Calculations Demonstrate that a Subcritical Cycle Design was the Only Practical Generating Technology Choice for the Dry Fork Station

S&L's June 11th Tech Memo compared performance calculations for both subcritical and supercritical units using Dry Fork specific design criteria (e.g., fuel specifications, ambient conditions, air cooled condensing system, feed pump drivers, etc.). Heat balances and performance calculations were prepared taking into consideration potential HP turbine efficiency gains and auxiliary power requirements. In his Expert Report, Dr. Sahu states that "[t]he efficiency comparison made by Sargent & Lundy is flawed because it was assuming the DFS unit was going to be 250 MW (DFS was initially planned to be only 250 MW, but was later increased to 422 MW)." (Sahu Report, paragraph 17). This statement is incorrect.

To clarify, the Dry Fork Station was originally planned for 250 MW-net output and was later increased to 385 MW-net. Nevertheless, the June 11th comparison was made based on the Dry Fork boiler design at 385 MW (net), and relied on Dry Fork specific design criteria, including site specific ambient conditions and the fact that the Dry Fork Station will be designed with an air cooled condenser. The June 11th comparison calculations were based on a theoretical gross turbine heat rate efficiency gain of 2.3% with a supercritical cycle. Gross turbine heat rate is a measurement of the efficiency of the steam turbine, and is measured by dividing heat input to the cycle (Btu) by the gross turbine energy output (kW-gross). Therefore, gross turbine heat rate uses the unit's Btu/kW-gross. More efficient turbines have a lower gross turbine heat rate.

A 2.3% efficiency gain in gross turbine heat rate represents a theoretical efficiency gain based on thermodynamic properties of steam that would be expected on a larger unit (i.e., 500 MW-net or larger) with the HP section of the turbine specifically designed for a supercritical cycle. In my opinion, a supercritical cycle on the Dry Fork Station would not achieve a 2.3% efficiency gain in the gross turbine heat rate for the following reasons. First, based on information received from turbine vendors, for a 500+ MW unit, the cycle improvement in efficiency would not reach 2.3%, and would actually be in the range of 1.5% to 1.8%. (See, Sahu Report, Exhibit 10, page 2 of 4). Second, as described above, on a smaller unit, such as the 385 MW-net Dry Fork unit, the low inlet volumetric flow to the HP turbine, the short turbine blading in the early HP stages, and the higher friction losses in the HP section of the turbine, will reduce potential efficiency gains. Based on information available from turbine vendors, the 1.5 to 1.8% efficiency gain you would get from supercritical pressure on a 500+ MW cycle would be reduced by half as you move down toward 250 MW. Third, based on information received from turbine suppliers (included in the record), suppliers would not design and build a supercritical turbine specifically for the Dry Fork Station. Rather, turbine vendors would adapt an "off-the-shelf" supercritical turbine intended for 500 MW or larger capacity for the smaller capacity at Dry Fork, further reducing potential efficiency gains.

Based on the Dry Fork boiler size (385 MW-net) and information from turbine vendors, it is my opinion that the actual improvement in gross turbine heat rate with a supercritical cycle on the Dry Fork boiler would be in the range of 0.75% to 1.3%. Using these gains in gross turbine heat rate, and taking into consideration site-specific auxiliary power requirements, a comparison of the performance differences achievable with subcritical and supercritical cycles is summarized below:

Parameter	**Units**	**Subcritical**	**Supercritical @1.3% improvement in gross turbine heat rate**	**Supercritical @0.75% improvement in gross turbine heat rate**
Auxiliary Power Requirements	% of gross	8.41%	9.30%	9.30%
Boiler Efficiency	%	86%	86%	86%
Gross Turbine Heat Rate	**Btu/kW-gross (% improvement)**	**7,436 (base)**	**7,339 (1.3%)**	**7,380 (0.75%)**
Net Plant Heat Rate	Btu/kWh-net	9,440	9,409	9,461
Plant Efficiency	%	36.14%	36.26%	36.06%
Full Load Heat Input*	MMBtu/hr	3,762	3,748	3,769
Full Load Fuel Feed Rate	lb/hr	467,633	465,893	468,503

*Performance calculations summarized in this table were generated for the Dry Fork Station using annual average ambient conditions.

In general, without considering site-specific conditions, supercritical cycles are more efficient than subcritical cycles, especially for units designed at greater than 500 MW (net) energy output. However, supercritical cycle efficiency gains are not available for the Dry Fork Boiler. On smaller units, such as the 385

MW-net Dry Fork unit, the low inlet volumetric flow to the HP turbine, the short turbine blading in the early HP stages, and the higher friction losses in the HP section of the turbine, will reduce potential efficiency gains. Furthermore, turbine vendors would adapt an "off-the-shelf" supercritical turbine intended for 500 MW or larger capacity for the smaller capacity at Dry Fork, further reducing potential efficiency gains.

Using an efficiency gain in gross turbine heat rate of 1.3%, and taking into consideration site-specific auxiliary power requirements, the overall efficiency of the Dry Fork boiler will change from 36.14% (subcritical) to 36.26% (supercritical), representing a 0.33% gain in overall plant efficiency [i.e., (36.26 - 36.14)/34.16 x 100]. Using an efficiency gain in gross turbine heat rate of 0.75%, and taking into consideration site-specific auxiliary power requirements, the overall efficiency of the Dry Fork boiler will actually drop from 36.14% to 36.06%. This is because efficiency gains in the gross turbine heat rate are more than off-set by the increased auxiliary power requirements. Thus, the best case improvement in overall plant efficiency is 0.33% (based on a 1.3% increase in gross turbine heat rate), and an equally likely increase in the gross turbine heat rate of 0.75% would actually result in a decrease in overall plant efficiency.

4. Supercritical Cycle Design Would Not Represent BACT for the Dry Fork Station

The generating technology for the Dry Fork Station was determined based on a comprehensive evaluation of potentially feasible generating technologies (i.e., subcritical PC, supercritical PC, CFB, or IGCC) completed prior to submittal of the Permit Application. Because subcritical PC boiler design was determined to be the only practical generating technology choice for the project, the BACT analysis focused on emission control technologies capable of reducing emissions from a PC boiler. Generating technology choice is not revisited in the BACT analysis. Redesigning the Dry Fork boiler for a supercritical cycle design would not represent BACT for two reasons. First, a comparison of subcritical and supercritical boiler designs is not included as part of the BACT analysis because supercritical technology would require BEPC to redesign the boiler and would constitute redefining of the emissions source. The BACT determination process is intended to evaluate emission control technologies with a practical application to the emissions source as defined by the applicant. Second, even if a comparison of subcritical and supercritical boilers was required by the BACT process, supercritical design would not be a cost effective option to reduce emissions from the Dry Fork boiler.

Dr. Sahu argues that subcritical and supercritical technologies are similar, and that redesigning the cycle for supercritical conditions would not constitute a fundamental redesign of the source. To support this opinion, Dr. Sahu cites to two sentences in S&L's June 11th Tech Memo. The first reads: "Turbines designed for use in supercritical applications are fundamentally similar to turbine designs used in subcritical power plants." The second reads: "There are no significant differences between the IP and LP turbine sections of a supercritical and subcritical plant." (Sahu Report, paragraph 12, citing S&L's June 11th Tech Memo, at page 3). However, focusing on the similarities of the turbine design ignores the significant differences in boilers designed for supercritical cycles and boilers designed for subcritical cycles. As described in section IV.A.1, there are several significant differences in the design of a subcritical and supercritical unit. These differences are primarily related to the different boiler designs needed to achieve different steam pressures and temperatures.

In addition, the high temperature components of the supercritical HP turbine, such as the inlet nozzle, rotor, and inner casing must be made with advanced metallurgy. Similarly, other components of a supercritical system subject to high pressures and temperature must be designed with more expensive materials of construction. The supercritical design requires an additional feedwater heater, as well as additional systems designed to protect the boiler and turbine equipment during start-up and shutdown. Higher pressure feedwater pumps, thicker piping, and higher pressure rated valves are required to address the increased steam pressures. Startup piping and valve systems, and turbine and superheater bypass systems are required for equipment protection. In order to utilize supercritical cycles, the Dry Fork boiler would have to be redesigned.

Even if a comparison of subcritical and supercritical PC boilers was required by the BACT process, supercritical unit design would not represent BACT for the Dry Fork Station because it would not be a cost effective way to reduce emissions. All of the design changes described above tend to increase the cost of a supercritical unit compared to the cost of a subcritical unit. Published cost comparisons for supercritical units typically range anywhere from 2% to almost 8% higher than similarly sized subcritical units, depending on unit size. U.S.EPA published a comprehensive review of the environmental footprints and costs of various coal-based generating technologies, including subcritical and supercritical PC boilers. (U.S. EPA, "Final Report – Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies", EPA-430/R-06/006, July 2006). Cost estimates, presented in Appendix A of the EPA report, provide a comparison of both total capital requirements and annual operating costs for a 500 MW (net) sub- and supercritical PC boiler. Cost data presented in the final report for sub- and supercritical PC boilers designed to fire a western subbituminous coal are summarized below:

Parameter	Unit	Subcritical	Supercritical
Net Plant Output	MW-net	500	500
Annual Output	MWh-net	4,161,000	4,161,000
Total Capital Requirement	$/kW	$1,387	$1,473
Annual Operating Costs	$1,000/yr	$28,300	$29,600
Annual Operating Costs	$/MWh-net	$6.80	$7.11

Note: Information in this table was taken from U.S.EPA's Final Report, Appendix A, Exhibits A-3, A-4, and A-8. Annual output was calculated based on a net plant output of 500 MW and assuming a 95% capacity factor.

Based on cost estimates developed by EPA, total capital requirements (including the PC boiler and accessories, flue gas cleanup, ducting and stack, steam turbine and generator plant, engineering, and contingencies) for a 500 MW-net supercritical PC unit will be approximately 6.2% greater than the total capital requirements for a similarly sized subcritical boiler. Annual operating costs, including operating labor, maintenance, administrative & support labor, and consumables (but excluding fuel costs) were estimated to be approximately 4.56% higher for the supercritical unit. Higher annual operating costs for the supercritical unit are typically related to increased maintenance associated with the high pressure and temperature components of the system. Because supercritical boilers are generally more efficient than subcritical boilers, fuel costs for the supercritical unit will be somewhat lower than fuel costs for the subcritical unit.

Applying these costs to the Dry Fork Station project, the total annual cost (including capital recovery cost, annual operating costs, and fuel costs) of each design are summarized below:

Parameter	Unit	Subcritical	Supercritical
Annual Output (1)	MWh-net	3,316,000	3,315,000
Total Capital Requirement (2)	x $1,000	$1,350,000	$1,433,700
Capital Recovery Factor (3)	--	0.0743	0.0743
Annual Capital Recovery	$/year	$100,305,000	$106,524,000
Annual Operating Cost	$/MWh-net	$6.80	$7.11
Annual Operating Cost (4)	$/year	$22,549,000	$23,570,000
Annual Fuel Consumption (5)	MMBtu/yr	34,881,000	34,751,000
Fuel Cost	$/MMBtu	$0.37	$0.37
Annual Fuel Cost	$/year	$12,906,000	$12,858,000
Total Annual Cost (6)	**$/year**	**$135,760,000**	**$142,952,000**
Annual Increase	$/year	base	**$7,192,000**

(1) Annual output was calculated based on the net plant output calculated at average annual ambient conditions and assuming a 95% capacity factor.

(2) Total capital requirement was calculated based on the actual total capital requirement cost estimate for the Dry Fork Station (subcritical) and using U.S.EPA's 6.2% difference in total capital requirements for a similarly sized supercritical design.

(3) The capital recovery factor (CRF) was calculated using the methodology described in U.S.EPA OAQPS Control Cost Manual. CRF is calculated using the following equation:

$$CRF = \frac{i * (1+i)^n}{(1+i)^n - 1}$$

Where:

i = interest rate; and

n = economic life of the emission control system

An economic life of 42 years and an interest rate of 7% was used in this calculation.

(4) Annual Operating Costs were calculated based on U.S.EPA's cost comparison ($/MWh-net) and assuming a 95% capacity factor.

(5) Annual fuel consumption was calculated based on full load heat input to the boiler at annual average ambient conditions and assuming a 95% capacity factor.

(6) Total annual cost is the sum of the Annual Capital Recovery, Annual Operating Cost, and Annual Fuel Cost.

Controlled emission rates (i.e., lb/MMBtu) will be the same for sub- and supercritical units, assuming similar sizes, fuels, and emission control technologies. Therefore, potential emission reductions (tpy) associated with supercritical unit designs relate to improved efficiencies. In other words, more efficient units require less fuel to produce the same net power generation. Based on the Dry Fork permit limits and site-specific performance calculations prepared for the Dry Fork Station, included in subsection IV.A.4 above, potential annual emissions from the Dry Fork boiler are summarized below:

Parameter		**Subcritical**	**Supercritical**	**Difference (tpy)**
Full Load Heat Input (MMBtu/hr)		3,762	3,748	
Controlled Emission Rates	MMBtu/hr	tpy*	tpy*	
NOx	0.05	782.7	779.8	2.9
SO_2	0.07	1,095.6	1,091.8	3.8
CO	0.15	2,348.1	2,339.3	8.8
VOC	0.0037	57.9	57.7	0.2
PM/ PM_{10}	0.012	187.8	187.2	0.6
H_2SO_4	0.0025	39.2	39.0	0.2
Total				16.5

*Annual emissions were calculated based on the full load heat input at annual average ambient conditions and a 95% annual capacity factor.

Cost effectiveness of the supercritical unit can be evaluated by comparing the increase in total annual costs to the annual reduction in NSR regulated pollutants. Because a comparison of competing generating technologies is outside the scope of the BACT process, there is little guidance available describing how to calculate the cost effectiveness of an emission control strategy that results in the reduction of more than one NSR regulated pollutant. Based on a review of guidance provided in EPA memoranda, cost effectiveness could be evaluated in one of two ways. The first, compares the annualized cost of the technology to the sum of NSR pollutants reduced. The second, apportions the annualized costs between each pollutant based on the weight percentage of each pollutant in the emissions stream being controlled (See, Memorandum from Brian L. Beals, EPA Region 4, to Edward Cutrer, Georgia Department of Natural Resources, March 24, 1997).[2]

Total annual costs associated with the supercritical unit, including capital recovery, annual operating costs, and fuel costs, are estimated to be approximately $7,192,000 higher than total annual costs associated with a subcritical boiler. A majority of this cost increase is associated with capital recovery and annual maintenance costs. The combined reduction in NSR regulated pollutants would be approximately 16.5 tpy, using a 1.3% efficiency increase in the gross turbine

[2] When comparing subcritical and supercritical boilers, either methodology will result in the same cost effectiveness value. Because emission decreases with the supercritical design are related to unit efficiency, annual emissions of all of the pollutants will be reduced proportionate to the overall change in efficiency. In other words, an overall efficiency gain 36.14% (subcritical) to 36.26 (supercritical) will reduce fuel consumption at full load by 0.37% (3,762 lb/MMBtu compared to 3,748 lb/MMBtu), and reduce annual emissions of each pollutant by 0.37%. Therefore, apportioning the increase in total annual costs to each NSR regulated pollutant based on its weight percentage in the emissions stream will not change the cost effectiveness result.

heat rate. The cost effectiveness of the supercritical option would be \$435,880/ton (\$7,192,000 / 16.5 tons).

Although EPA has not published a bright-line \$/ton cost effectiveness threshold for BACT evaluations, based on my experience on other PSD permitting projects, control technologies with cost effectiveness values above \$8,000 to \$15,000 per ton are generally not considered cost effective. Supercritical technology does not provide a cost effective means of reducing emissions at the Dry Fork Station

5. Subcritical vs. Supercritical – Conclusions as to Why a Subcritical Cycle Design Was the Only Practical Choice for the Dry Fork Station

Prior to submitting the Permit Application for the Dry Fork Station, BEPC thoroughly evaluated potentially feasible generating technologies for the Dry Fork Station. Various generating technologies, including subcritical PC, supercritical PC, CFB, and IGCC, were evaluated with respect to BEPC's defined needs for baseload capacity. Based on site-specific considerations, the evaluation concluded that subcritical PC technology was the only practical technology choice for the proposed project.

The decision to build a subcritical unit was revisited throughout the permitting process. In response to comments received during the public review/comment period, WYDEQ required BEPC to provide additional information addressing the selection of subcritical technology. In response to WYDEQ's request, S&L prepared the June 11th Tech Memo, a site-specific evaluation of the potential efficiency improvements that would result if the Dry Fork boiler were designed for a supercritical cycle, and compared the results to the 385 MW (net) subcritical unit. That evaluation concluded, that the supercritical unit design would provide little if any efficiency improvement at the Dry Fork Station.

For purposes of this report, overall plant efficiency of the Dry Fork boiler was calculated using a 1.3% gain in the gross turbine heat rate (with a supercritical cycle), and taking into consideration site-specific auxiliary power requirements. Based on these performance calculations, the overall efficiency difference between subcritical and supercritical unit technology was only 0.33% (36.14% compared to 36.26%).

Changing the Dry Fork boiler to a supercritical cycle design constitutes a redefinition of the emissions source. Competing generating technologies are outside the scope of the BACT review, which focuses on emission control technologies with a practical application to the source as defined by the applicant. However, even if a comparison of subcritical and supercritical PC boilers was required by the BACT process, supercritical unit design would not represent BACT for the Dry Fork Station.

Supercritical boilers require more expensive construction materials and require additional systems designed to protect the boiler and turbine equipment during start-up and shutdown. These differences increase the cost of a supercritical unit. Based on published U.S.EPA cost comparisons, the total capital requirement for supercritical boiler will be approximately 6.2% higher than the total capital requirement for a similarly sized subcritical boiler. Annual operating costs, excluding fuel costs, are also higher for supercritical boilers, due to increased maintenance on the high pressure and high temperature components of the system.

Based on a comparison of total annual costs (including capital recovery costs, annual operating costs, and annual fuel costs), and summing all potential reductions in NSR regulated pollutants, the cost effectiveness of the supercritical unit at the Dry Fork station was estimated to be greater than $435,880/ton. This cost is clearly in excess of cost effectiveness values generally determined to represent BACT. Based on my experience on other PSD permitting projects, control technologies with cost effectiveness values above $8,000 to $15,000 per ton are generally not considered cost effective. Supercritical technology does not provide a cost effective means of reducing emissions at the Dry Fork Station.

B. The DFS Permitting Process Was Thorough and Complete

As described above, I have been involved in the DFS permitting process since December 2004. My involvement included providing technical input and review of the Permit Application prepared by CH2MHill, and assisting in the preparation of technical responses to requests from WYDEQ-AQD for additional information.

WYDEQ-AQD did not simply rely on information submitted in BEPC's initial Permit Application, but requested significant amounts of additional technical and economic information from BEPC throughout the permitting process. WYDEQ-

AQD required BEPC to provide additional technical information, emissions information, and cost data to support the permit application. Provided below is a brief chronology of the permit review process. Documents listed below are documents that were developed during the permitting process, and include information used by WYDEQ-AQD to establish the BACT emission limits.

a. BEPC submitted its air construction Permit Application to WYDEQ-AQD on November 10, 2005.

b. On December 21, 2005 WYDEQ-AQD issued its first Completeness Review for Permit Application No. AP-3546 (Completeness Review No. 1). Among other issues, Completeness Review No. 1 requested:

   1. An analysis of the technical feasibility and cost effectiveness of achieving more stringent SO_2 emission limits with both wet and dry flue gas desulfurization control technologies;
   2. An analysis of the technical feasibility and cost effectiveness of achieving more stringent NOx emission limits;
   3. An analysis of the technical feasibility and cost effectiveness of achieving more stringent PM_{10} emission limits; and
   4. Additional information regarding PSD Class II modeling issues.

c. In response to Completeness Review No. 1, BEPC submitted additional technical information to support its Permit Application. BEPC's response, dated March 7, 2006 (Response to Completeness Review No. 1), included information responding to each request from WYDEQ-AQD for additional information, including a detailed analysis of the technical feasibility and cost effectiveness of achieving more stringent SO_2, NOx, and PM10 emission limits.

d. On March 28, 2006, WYDEQ-AQD issued its second Completeness Review (Completeness Review No. 2). Completeness Review No. 2 focused on impact modeling issues and requested BEPC to quantify, if possible, condensable PM_{10} emissions from the main boiler.

e. WYDEQ-AQD issued its third Completeness Review on May 3, 2006 (Completeness Review No. 3). In Completeness Review No. 3 WYDEQ requested additional technical information regarding BEPC's BACT analysis for the proposed auxiliary boiler, and WYDEQ-AQD requested BEPC to prepare a BACT analysis for mercury emissions from the proposed boiler.

f. On May 30, 2006 WYDEQ issued its forth Completeness Review (Completeness Review No. 4). Completeness Review No. 4 again focused on the technical feasibility and cost effectiveness of achieving even lower SO_2 and NOx emission limits.

g. On June 7, 2006, BEPC submitted its response to Completeness Review No. 2. BEPC's Response to Completeness Review No. 2 provided information responding to WYDEQ-AQD's request for additional impact modeling analyses, and provided a detailed discussion of potential condensable PM_{10} emissions from the main boiler. BEPC quantified condensable PM_{10} emissions from the boiler, and attached a revised SAM BACT analysis.

h. On July 11, 2006, BEPC submitted its response to Completeness Review No. 3. The response included a BACT analysis for the control of mercury emissions from the main boiler.

i. On July 14, 2006, BEPC submitted its response to Completeness Review No. 4. The response provided additional evaluation and analysis of the technical feasibility and cost effectiveness of achieving even more stringent NOx and SO_2 emission limits.

j. On December 13, 2006, in response to another request for additional information from WYDEQ-AQD, BEPC submitted more information regarding the technical feasibility of achieving lower NOx and SO_2 emission limits. Supplemental information provided by BEPC included a description of the methodology used to by BEPC to determine achievable emission limits, information regarding anticipated vendor guarantees, and a detailed comparison of the proposed Dry Fork NOx and SO_2 emission limits to BACT limits included in other recently issued PSD permits for coal-fired boilers.

k. On February 5, 2007, WYDEQ-AQD issued its Permit Application Analysis NSR-AP-3546 for the Dry Fork Station. The Permit Application Analysis included a description of the proposed facility, emissions summary, regulatory applicability review, BACT analysis, and impact modeling analysis. The analysis concluded that the facility will comply with all applicable Wyoming Air Quality Standards and Regulations, and included AQD's intent to issue a construction permit. A draft permit, including proposed BACT emission limits was included as part of the Permit Application Analysis.

l. WYDEQ-AQD advertised its proposed decision to issue a permit in the Gillette News-Record on February 26, 2007. A public hearing was held on June 28, 2007 at the Campbell County Library in Gillette, Wyoming, and the public comment period was extended through the hearing.

m. WYDEQ-AQD received 31 comment letters on the proposed permit, including comments from EPA Region VIII, National Park Service, and a coalition of environmental groups (including the Powder River Basin

Resource Council, Wyoming Chapter of Sierra Club, Wyoming Wilderness Association, Wyoming Outdoor Council, Biodiversity Conservation Alliance, Western Resource Advocates, and Natural Resources Defense Council).

n. On June 25, 2007, BEPC submitted to WYDEQ-AQD extensive comments in response to comments submitted by EPA, NPS, and the environmental groups. BEPC provided responses to comments submitted by the various groups, and included copies of important technical information and analysis previously submitted as part of the permitting process.

o. On September 4, 2007, WYDEQ-AQD issued a request for additional information from BEPC, including information regarding the SAM BACT emission limit, and emissions achievable during startup and shutdown of the boiler.

p. September 7, 2007, BEPC submitted a response to WYDEQ-AQD's September 4, 2007 request for additional information. Information submitted included a discussion of emission rates achievable during boiler startup and shutdown.

q. Finally, on October 15, 2007, WYDEQ-AQD issued the Final Permit for the Dry Fork Station. In addition to the Final Permit, WYDEQ-AQD issued a detailed evaluation and response to comments received during the public comment period.

Based on my involvement in the DFS permitting process, and my experience on other similar PSD permitting projects, it is my opinion that WYDEQ conducted a very thorough, complete, and technically sound evaluation of the proposed facility. WYDEQ did not simply rely on information submitted in BEPC's initial Permit Application, but requested significant amounts of additional technical and economic information. WYDEQ challenged each and every emission rate proposed in the Permit Application, critically reviewed the proposed control technologies, and required BEPC to provide additional technical information, emissions information, and cost data to support the Permit Application. The permitting process was thorough and complete and resulted in BACT emission limits that will require BEPC to install state-of-the-art emission control technologies and properly maintain and continuously operate the control technologies to achieve high pollutant removal efficiencies.

C. Emission Limits in the Final Permit Represent BACT for the Dry Fork Station

1. The Overall BACT Process and How the Dry Fork Station Permit Compares to Other Power Plants

BEPC's Permit Application included a comprehensive BACT analysis of emission control technologies capable of reducing NOx and SO_2 emissions from the proposed Dry Fork boiler (Permit Application Section 5.2.4). In addition to the BACT analysis in the Permit Application, BEPC provided WDEQ additional technical evaluation of the NOx and SO_2 control technologies and achievable emission rates in its response to Completeness Reviews No. 1 and No. 4, dated March 7, 2006 and July 14, 2006, respectively. In addition, in its December 13, 2006 submittal to WDEQ, BEPC provided updated information regarding NOx and SO_2 control efficiencies, performance targets, and BACT emission limits.

Information submitted to WDEQ as part of the BACT analysis and permitting process included detailed technical descriptions of the available control technologies, anticipated vendor guarantees, a review of emission rates proposed as BACT in other recently issued PSD permits, an evaluation of hourly emissions achieved in practice at the best controlled similar sources, an evaluation of the variability in controlled NOx and SO_2 emissions associated with various emission control technologies, an assessment of potential balance-of-plant impacts, and an assessment of the economic impacts and collateral environmental impacts associated with potential control technologies.

BACT is defined in Chapter 6 §4(a) of the Wyoming Air Quality Standards and Regulations as:

> ...an emission limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under these Standards and Regulations or regulation under the Federal Clean Air Act, which would be emitted from or which results for any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification....

As the definition of BACT indicates, there are several considerations, including technical as well as economic and environmental impacts, that form a part of the BACT determination. In order to provide a framework for BACT determinations being made by various air permitting authorities such as WYDEQ-AQD, EPA issued the following guidance document that is widely used in PSD reviews: U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990 (the "NSR Manual"). The NSR Manual describes a "top-down" BACT determination process. In general, the top-down BACT process involves the following steps for each pollutant:

1. Identify all potential control technologies;
2. Eliminate technically infeasible control options;
3. Rank the remaining control technologies by control effectiveness;
4. Evaluate the control technologies, starting with the most effective for:
   - economic impacts,
   - energy impacts, and
   - environmental impacts;
5. Select BACT

A brief description of the top-down BACT process, taken from the NSR Manual, is provided below:

> Step 1 - Identify All Control Options
>
> The first step in the top-down BACT process is to identify, for the emission unit in question, all available control options. Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation.
>
> Step 2 - Eliminate Technically Infeasible Control Options
>
> The second step in the top-down BACT process is to review the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. Whether or not a control technology is technically feasible depends on whether it has been installed and operated on the type of source under review, or, if not, whether it is both available and applicable for that source. Alternatively, a control option may be technically infeasible if it is shown that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/ infeasibility. Options that are not technically feasible for the intended application are eliminated from further review.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

All technically feasible options are ranked in order of overall control effectiveness. Control effectiveness is generally expressed as the rate that a pollutant is emitted after the control system. The most effective control option is the system that achieves the lowest emissions level.

Step 4 - Evaluate Most Effective Controls

After identifying the technically feasible control options, each option, beginning with the most effective, is evaluated for associated economic, energy and environmental impacts. Both beneficial and adverse impacts should be assessed and, where possible, quantified. In the event that the most effective control alternative is shown to be inappropriate due to energy, environmental or economic impacts, the basis for this finding is documented and the next most stringent alternative evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy or economic impacts.

Economic Analysis

The economic analysis performed as part of the BACT determination examines the cost-effectiveness of each control technology, on a dollar per ton of pollutant removed basis. Annual emissions using a particular control device are subtracted from base case emissions to calculate tons of pollutant controlled per year. Annual costs are calculated by adding annual operation and maintenance costs to the annualized capital cost of an option. Cost effectiveness ($/ton) of an option is simply the annual cost ($/yr) divided by the annual pollution controlled (ton/yr).

Energy Impact Analysis

The energy requirements of a control technology should be examined to determine whether the use of that technology results in any significant or unusual energy penalties or benefits.

Environmental Impact Analysis

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal. The environmental impact analysis should be made on a consideration of site-specific circumstances.

Step 5 - Select BACT

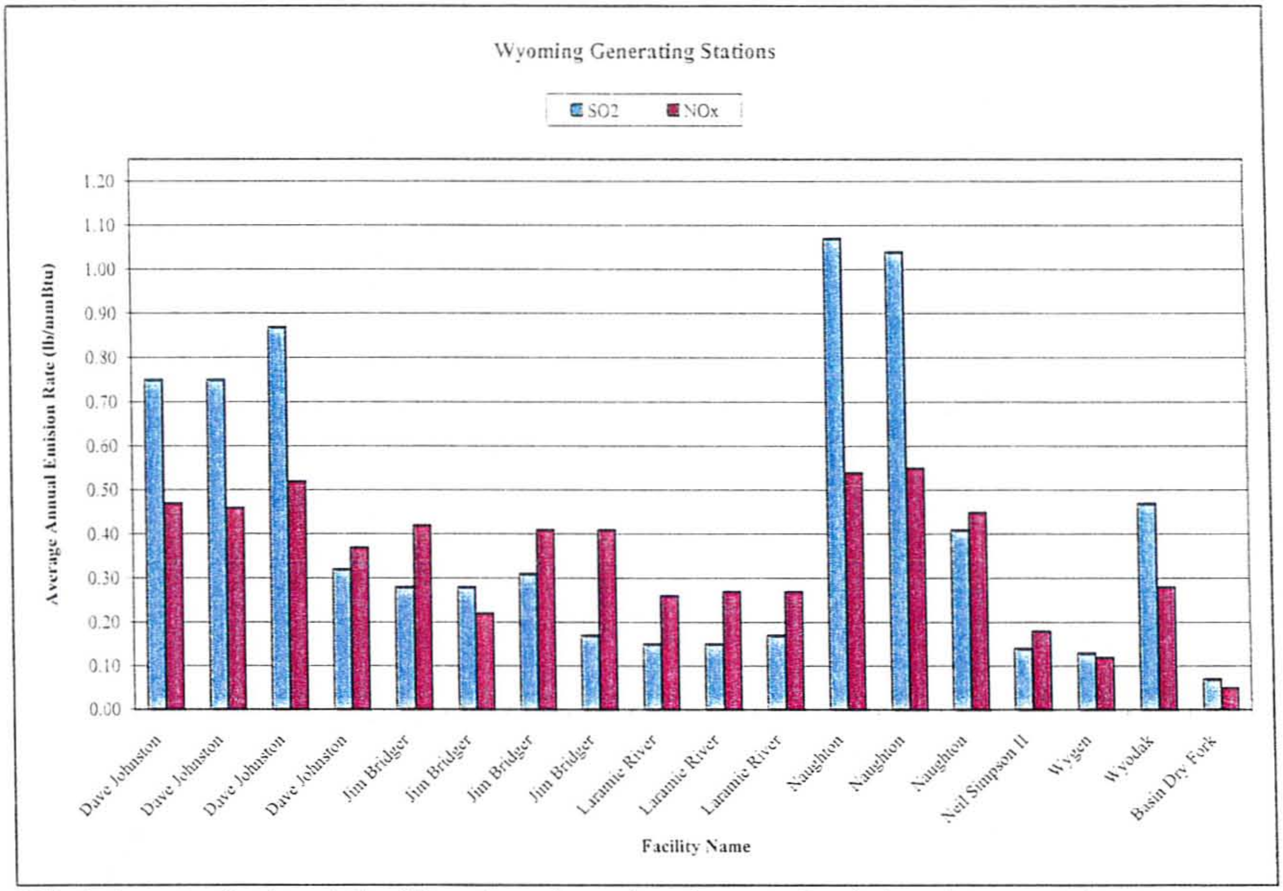
The combined result of these considerations is the selection of a BACT emission limit and control technology.

WYDEQ-AQD used the top-down BACT process described in the NSR Manual to identify emission control technologies capable of reducing emissions from the Dry Fork boiler. BACT control technologies and BACT emission limits included in the Final Permit were based on a comprehensive review of available control technologies, information available from equipment vendors, emission limits included in other recently issued PSD permits, and emission rates achieved in practice by the best controlled similar sources. WYDEQ-AQD did not rely on any single source of information to establish the BACT limits, but based its determination on the consideration of several sources of information.

Based on my experience on other similar PSD permitting projects, including PSD permitting projects for coal-fired electric utility steam generating units in the States of Illinois, Oklahoma, Missouri, North Dakota, Montana, and Utah, the review process conducted by WYDEQ was as thorough, or more thorough, than any NSR/PSD permitting process that I have been involved with, and it is my opinion that the control technologies and emission limits included in the Final Permit represent BACT for the Dry Fork Station.

The emission limits imposed by WYDEQ as BACT for the Dry Fork boiler will require the Dry Fork boiler to achieve emission rates that are significantly lower than emission rates achieved in practice by existing electric utility steam generating units in Wyoming, and are among the most stringent BACT emission limits proposed in the country. The following figure (Figure 1) compares the Dry Fork BACT emission limits to actual NOx and SO_2 emission rates achieved by existing units in Wyoming.

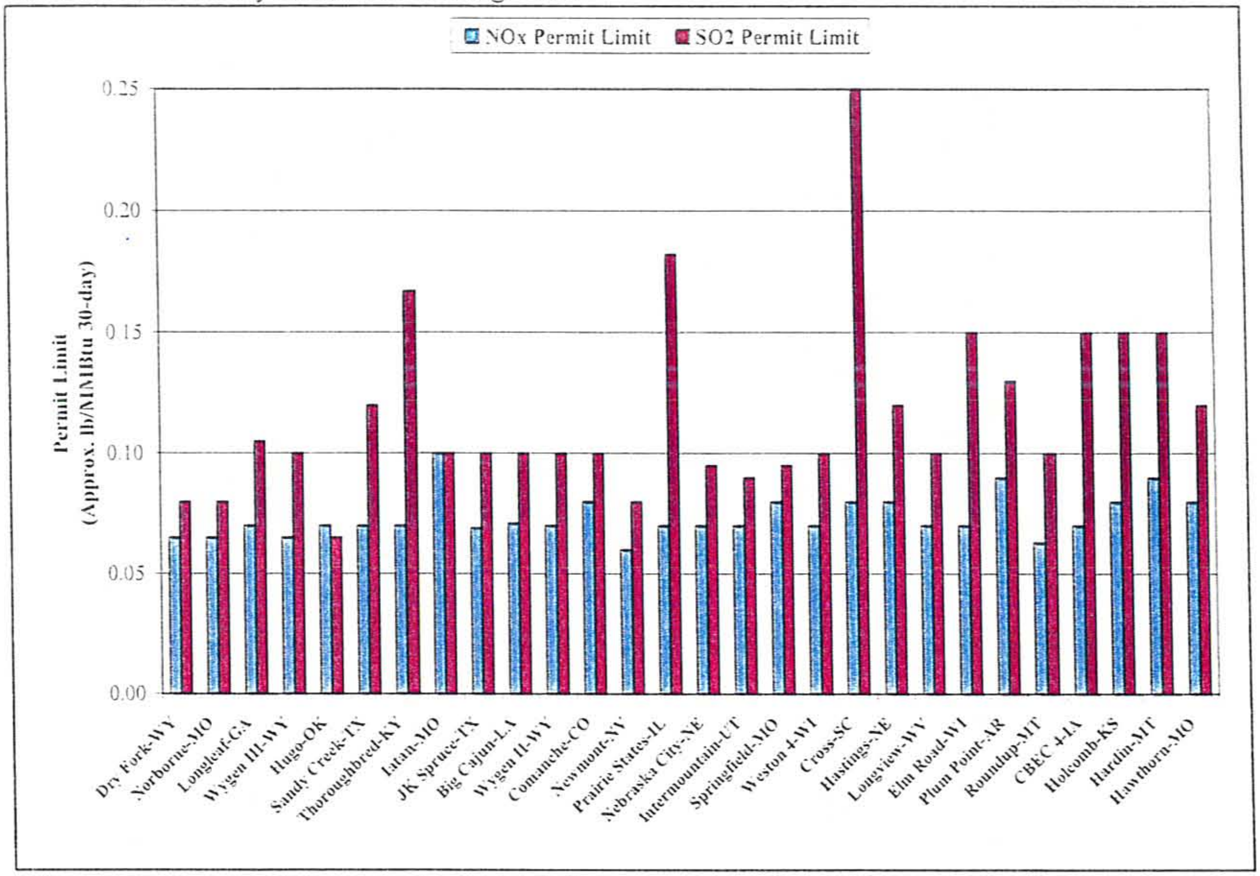
Figure 1: Existing NOx and SO_2 Actual Emissions from Coal-Fired Boilers in Wyoming Compared to the Dry Fork BACT Emission Limits*



* Emission rates for the existing Wyoming units are based on actual emissions data reported to U.S.EPA pursuant to the Acid Rain Program (http://www.camdataandmaps.epa.gov/gdm), and represent actual annual average emissions.

The next figure (Figure 2) compares the Dry Fork BACT emission limits to BACT limits included in recently issued PSD permits for coal-fired electric utility steam generating power plants. Because different permitting agencies can take a different approach to setting BACT limits (e.g., BACT limits can be based on various emission units (lb/hr, lb/MMBtu, lb/MWh) and various averaging times (3-hr, 24-hr, 30-day, annual), the emission rates shown in Figure 2 are intended to represent the lb/MMBtu emission rates that, in my opinion, each unit will need to achieve on a 30-day rolling average to ensure compliance with all of the emission limits included in their respective permits. Although emission limits shown in Figure 2 could vary slightly from those shown, it is clear that the BACT emission limits in the Final Permit are consistent with emission limits included in other recently issued PSD permits, and that the Dry Fork Station will have to install, maintain, and operate the emission control technologies to continuously achieve high levels of pollutant reduction.

Figure 2: Comparison of Recently Issued NOx and SO_2 BACT Permit Limits for Coal-Fired Electric Utility Steam Generating Units*



* Emission rates shown in Figure 2 are intended to represent the lb/MMBtu emission rates that, in my opinion, each unit will need to achieve on a 30-day rolling average to ensure compliance with all of the emission limits included in their respective permits.

In paragraphs 25 through 48 of his Expert Report, Dr. Sahu comments on the NOx, SO_2, and Hg BACT emission limits included in the Dry Fork Station's Final Permit. In general, Dr. Sahu concludes that "[t]he approved NOx, SO_2, and mercury BACT permit limits do not represent the maximum degree of reduction that can be achieved while generating electricity from coal." (Sahu Report, paragraph 25). More specifically, Dr. Sahu asserts that: (1) the averaging times in the final permit do not ensure that emission control technologies will be operating at their maximum level at all times; (2) lower NOx emission levels are possible with the selected control technologies; (3) the BACT limits for SO_2 are flawed because they are too high and wet scrubber technology was improperly rejected during the BACT analysis process; and (4) the Hg target emission level for the optimization study of 20×10^{-6} lb/MW-hr is unexplained. I will address each of these specific issues individually.

2. BACT Emission Limit Averaging Times Included in the Final Permit Will Require BEPC to Install, Maintain, and Properly Operate State-of-the-Art Emission Control Technologies

Dr. Sahu's first BACT-related argument focuses on the averaging times established in the Dry Fork Station's Final Permit for NOx and SO_2. The Final Permit included the following BACT emission limits for NOx and SO_2:

NOx 0.05 lb/mmBtu (12 month rolling average)
1.0 lb/MW-hr (30-day average)
190.1 lb/hr (30-day rolling average)
832.4 tpy

SO_2 0.070 lb/MMBtu (12 month rolling average)
1.4 lb/MW-hr (30-day rolling average)
380.1 lb/hr (3-hour block average)
285.1 lb/hr (30-day rolling average)
1,165.4 tpy

Dr. Sahu asserts that the BACT control technologies must continuously limit emissions of air pollutants, and that "[t]he proposed BACT limits for NOx of 0.05 lb/MMBtu (12 month rolling) and for SO_2 of 0.070 lb/MMBtu (12 month rolling) do not meet this standard." (Sahu Report, paragraph 26).

It is my opinion that the NOx and SO_2 BACT emission limits included in the Final Permit for the Dry Fork Station are consistent with BACT emission limits included in other recently issued PSD permits for coal-fired boilers, and that the BACT limits, including the shorter-term lb/hr limits and the longer-term lb/MMBtu emission rates, will ensure that emission control technologies are operated at a high level of efficiency on a continuous basis. When all of the emission limits in the Final Permit are considered as a whole, the Dry Fork Station BACT emission limits are among the most stringent in the country.

A comparison of the NOx and SO_2 BACT limits included in recently issued PSD permits for coal-fired boilers is provided in Attachment 3 to this report. Making an "apples-to-apples" comparison of BACT permit limits can be difficult because different permitting agencies often take a slightly different approach to establishing permit limits. For example, BACT limits can be based on various emission units (lb/hr, lb/MMBtu, lb/MWh) and various averaging times (3-hr, 24-hr, 30-day, annual). However, based on my review of BACT permit limits included in recently issued PSD permits for coal-fired power plants, and taking into consideration the emission rates and averaging times, it is my opinion that the Dry Fork BACT limits are among the most stringent in the country.

Dr. Sahu argues that meeting a 30-day lb/hr emission limit does not necessarily ensure that emission control technologies will be operating at their maximum levels at all times, and that "BACT requires that the boiler be controlled to the maximum extent at all times." (Sahu Report, paragraph 27). To illustrate this, Dr. Sahu provides an example calculation to demonstrate that NOx emission rates can be greater than the 0.05 lb/MMBtu 12-month average for those periods of time when actual heat input to the boiler is below the design maximum heat input rate. (Sahu Report, paragraph 28). I disagree with Dr. Sahu's characterization of "BACT," and I think that the example provided by Dr. Sahu in paragraph 28 of his report is based on a boiler operating scenario that has no practical application to the Dry Fork boiler.

BACT is defined in Chapter 6 §4(a) of the Wyoming Air Quality Standards and Regulations as "...an emission limitation...based on the maximum degree of reduction of each pollutant subject to regulation...which would be emitted from or which results for any proposed major stationary source...which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, <u>determines is achievable</u> for such source or modification..." (WAQSR Chapter 6 §4(a), emphasis added). While BACT is based on the maximum degree of reduction, the determination of an appropriate BACT emission limit also takes into account several technical, as well as economic, energy, and environmental considerations.

As Dr. Sahu illustrates, when heat input to the Dry Fork boiler is below the design maximum heat input of 3,801 MMBtu/hr, the boiler's lb/MMBtu emission rates could exceed for some period of time 0.05 lb/MMBtu (NOx) and 0.07 lb/MMBtu (SO_2), which are the 12-month rolling average emission limits, while remaining in compliance with the 30-day average lb/hr limits of 190.1 lb/hr (NOx) and 285.1 lb/hr (SO_2). However, Dr. Sahu ignores the fact that BEPC must operate the boiler and emission control technologies in a manner that ensures compliance with all of the permit limits. BEPC could not meet the 12-month average permit limits if the boiler was operated for any significant period of time at low loads and high lb/MMBtu emission rates.

Other than short-term periods, such as boiler startup and shutdown, there are no operating scenarios under which BEPC could operate at low loads and high emission rates. Operating the boiler for any extended period of time at low loads and high lb/MMBtu emission rates would result in the facility exceeding its 12-month lb/MMBtu emission limits.

The Dry Fork boiler is being designed to provide baseload power. This means that the boiler is being designed to achieve high capacity factors (calculated as the unit's actual energy produced divided by the unit's capacity). Annual capacity factors for baseload generation can be in the range of 90% and greater. To illustrate baseload power plant operation, I reviewed the 2006 heat input data (available from U.S.EPA Clean Air Markets Website, http://camddataandmaps.epa.gov/gdm/) for Basin Electric's Laramie River Station. The Laramie River Station, located near Wheatland, Wyoming, operates three baseload coal-fired units. The data show that in 2006, all three generating units at the Laramie River Station achieved annual capacity factors greater than 90%. Furthermore, when the units were operating, heat input to the boilers average approximately 95% of maximum.

Because the Dry Fork Station is being designed as a baseload facility, similar heat inputs (as a function of the design maximum) and annual capacity factors would be expected. Therefore, even in the short-term the Dry Fork boiler will have to achieve controlled NOx and SO_2 emission rates very close to the 12-month lb/MMBtu permit limits to ensure compliance with the 30-day lb/hr permit limits.

Even under the unlikely scenario that the boiler is operated at a low load for an extended period of time, BEPC would still have to continuously control NOx and SO_2 emissions to ensure compliance with the 12-month average emission limits. The annual lb/MMBtu emission limits are even more limiting given the methodology required by WYDEQ-AQD to calculate 12-month rolling averages. The Final Permit requires BEPC to use the following equation to calculate 12-month rolling average emission rates (permit condition 15.A):

$$E_{avg} = \frac{\sum_{h=1}^{n} (C)_h}{n}$$

Where:

C	=	1-hour average emission rate (lb/MMBtu) for hour "h" calculated using valid data from the CEM equipment.
E_{avg}	=	Weighted 12 month rolling average emission rate (lb/MMBtu).
n	=	The number of unit operating hours in the 12 month period with valid emissions data.

This equation applies the same "weight" to each hourly emission rate (lb/MMBtu) regardless of boiler load. In other words, the equation counts each hourly emission rate (lb/MMBtu) equally without taking into account heat input or boiler load. WYDEQ-AQD required this methodology to ensure that BEPC could not operate the boiler at low loads and high emission rates for any significant period of time without exceeding its 12-month permit limit.

For example, assume the boiler was operated for a 30-day period (720 hours) at 50% load and in a manner that simply complies with the 190.1 lb/hr 30-day average NOx permit limit. During the 30-day period, heat input to the boiler would be 1,901 MMBtu/hr and the NOx emission rate would be 190.1 lb/hr ÷ 1,901 MMBtu/hr = 0.10 lb/MMBtu. For the remainder of the year (7,602 hours assuming the boiler operates 95% of the time) BEPC would have to continuously "over-control" NOx emissions to an emission rate below 0.045 lb/MMBtu to ensure compliance with the 0.05 lb/MMBtu 12-month average permit limit. An emission rate of 0.045 lb/MMBtu is very close to the design limit of the SCR control system, and provides essentially no margin to account for normal operating fluctuations. Therefore, BEPC could not operate the boiler/SCR control systems at a low enough NOx emission rate to make-up for short-term NOx emissions greater than 0.05 lb/MmBtu.

A similar example can be provided for SO_2. Assuming the boiler was operated for a 30-day period (720 hours) at 50% load and in a manner that simply complies with the 285.1 lb/hr 30-day average SO_2 permit limit, heat input to the boiler would be 1,901 MMBtu/hr and the SO_2 emission rate would be 285.1 lb/hr ÷ 1,901 MMBtu/hr = 0.15 lb/MMBtu. For the remainder of the year (7,602 hours assuming the boiler operates 95% of the time) BEPC would have to continuously achieve a controlled SO_2 emission rate below 0.062 lb/MMBtu to ensure compliance with the 0.07 lb/MMBtu 12-month permit average. An emission rate of 0.062 lb/MMBtu is very close to the design limit of the flue gas desulfurization control system, and provides essentially no margin to account for normal operating fluctuations. Therefore, BEPC could not operate the FGD control system to achieve low enough SO_2 emission rates to make-up for short-term SO_2 emissions greater than 0.07 lb/MmBtu.

Dr. Sahu concludes that: "To ensure that controls will be operating at their maximum level at all times, the permit must include control efficiency values for the control equipment such as the SCR or scrubbers or by lb/MMBtu values on a short term basis." (Sahu Report, paragraph 27). As discussed above, it is my opinion that the combination of the lb/hr (30-day limits) and the lb/MMBtu (12-month limits) included in Dry Fork's Final Permit will require BEPC to install, maintain, and operate state-of-the-art emission controls to continuously achieve high pollutant removal efficiencies. Emission limits in the Dry Fork permit are already very close to the design limits of the proposed control technologies, thus requiring control efficiency values for the control equipment would provide no further emission reductions. Similarly, including an additional lb/MMBtu 30-day limit would be redundant and would provide no further emission reductions.

The Dry Fork boiler and emission control systems must be operated in a manner that ensures compliance with all permit limits. As a baseload unit, hourly heat input to the boiler will average close to the unit's design maximum heat input. There are no practical operating scenarios, other than short-term unit startup and shutdown, where BEPC could operate in compliance with the 30-day lb/hr emission limits while exceeding the lb/MMBtu 12-month limits. Given the methodology mandated by WYDEQ-AQD to calculate the 12-month averages, BEPC could not operate the boiler at low loads and high lb/MMBtu emission rates for any extended period of time without exceeding its 12-month average lb/MMBtu permit limits.

3. NOx BACT Limits in the Final Permit Represent BACT for the Dry Fork Boiler

In paragraphs 31 through 34 of his Expert Report, Dr. Sahu asserts that the proposed NOx emission limit of 0.05 lb/MMBtu (12 month rolling) is not BACT for the Dry Fork Station, and that "[l]ower levels of NOx BACT are possible with the selected control technologies." (Sahu Report, paragraph 31). Control technologies selected as BACT for NOx include a combination of combustion controls to reduce boiler NOx emissions (low NOx burners (LNB) and overfire air (OFA)) and post-combustion selective catalytic reduction (SCR).

a. The NOx BACT Emission Limits Included in the Final Permit for the Dry Fork Station Were Based on a Comprehensive Evaluation of Potentially Available NOx Control Technologies and Potentially Achievable Controlled Emission Rates.

BEPC's permit application included a NOx BACT analysis for the proposed Dry Fork main boiler (Permit Application Section 5.2.4). In addition to the BACT analysis in the Permit Application, BEPC provided WDEQ additional technical evaluation of the NOx control technologies and achievable emission rates in its response to Completeness Reviews No. 1 and No. 4, dated March 7, 2006 and July 14, 2006, respectively. In addition, in its December 13, 2006 submittal to WDEQ, BEPC provided updated information regarding NOx control efficiencies, performance targets, and BACT emission limits.

Information submitted to WDEQ as part of the BACT analysis and permitting process included detailed technical descriptions of the available NOx control technologies, anticipated vendor guarantees, a review of NOx emission rates proposed as BACT in other recently issued PSD permits, an evaluation of hourly NOx emissions achieved in practice at the best controlled similar sources, an evaluation of the variability in the controlled NOx rate associated with SCR, and an assessment of the potential balance-of-plant impacts associated with NOx control. The BACT analysis concluded that a combination of combustion controls (LNB/OFA) and SCR represented BACT for main boiler NOx control.

It is my understanding from my work on other PSD permitting projects that the BACT determination of an achievable emission rate can include a reasonable margin between the design limits of the control technology and the enforceable BACT limit. The U.S.EPA Environmental Appeals Board has recognized that "permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather will allow permittees to achieve compliance on a consistent basis." See, Three Mountain Power, PSD Appeal No. 01-05 at 21 (May 30, 2001), citing: In re Masonite Corp., 5 E.A.D. 560-61 (EAB 1994) ("There is nothing inherently wrong with setting an emission limitation that takes into account a reasonable safety factor."); and In re Knauf Fiber Glass, GmbH, PSD Appeal Nos. 99-8 to –72, slip op. at 21 (EAB, Mar. 14, 2000) ("The inclusion of a reasonable safety factor in the emission limitation is a legitimate method of deriving a specific emission limitation that may not be exceeded.").

From an engineering perspective, it is also necessary to include a reasonable margin between the control technology design target and the enforceable BACT permit limit. Emission control systems do not operate under steady-state conditions, and controlled emissions will tend to fluctuate around the system's design target Operating variables that can affect controlled NOx emissions include, but are not necessarily limited to, boiler load and load changes, burner temperature, excess oxygen, flue gas temperatures, reactant (ammonia) mixing, and catalyst activity.

Furthermore, operating air pollution control systems in such a way as to achieve the design target regardless of operating conditions can increase the risk of adverse impacts to other parts of the power plant. For example, one option available to reduce NOx emissions toward the end of the SCR catalyst life is to increase the ammonia injection rate. However, increasing ammonia injection will also increase the quantity of unreacted ammonia in the flue gas (termed "ammonia slip") which can lead to downstream plugging of ductwork and emission controls, and result in excess ammonia in the fly ash. Excess ammonia in the fly ash can lead to ammonia off-gassing and worker exposure to ammonia during fly ash handling and disposal. In my opinion it would be irresponsible to propose an enforceable BACT emission limit that does not include a reasonable operating margin to allow for normal operation of the emission control system.

To establish a reasonable margin between the design target and permit limits, S&L, in conjunction with BEPC, reviewed controlled NOx emission rates currently achieved in practice at the best-controlled similar sources. S&L chose three representative units to evaluate SCR control effectiveness, and to quantify variability in the controlled NOx emission rate: KCPL Hawthorn Unit 5 in Missouri and W.A. Parish Generating Station Units 5 and 6 in Texas. Actual hourly NOx emissions data from the three representative units were provided to WDEQ during the permit review process, including the Response to Completeness Letter No. 1 (Attachment 2 to the response dated March 7, 2006); and Response to Completeness Letter No. 4 dated December 13, 2006.

Emissions data from the representative units clearly showed that SCR control systems are not steady-state operations, and that the controlled NOx emission rate will vary around a design point. Hourly emissions data from each of the existing sources were evaluated using standard deviation calculations in order to quantify short-term variability in the controlled NOx emission rate. Based on this evaluation, S&L quantified the margin needed between the design target of the SCR control system and the enforceable BACT limit to provide BEPC the ability to achieve compliance on a consistent basis.

Dr. Sahu dismisses WDEQ's evaluation of emissions data from the best controlled similar sources in footnote 46 of his report by stating that "for the Texas plants, WYDEQ-DAQ did not establish whether these plants were running under conditions that minimize NOx formation to the lowest achievable level before being chosen for comparison. At a minimum, without such analysis, further comparisons to this data are meaningless for the purpose of establishing BACT." In the same footnote, Dr. Sahu states "[c]onsideration of this type of [emissions] data is important in a BACT determination, but WYDEQ should have also gathered and considered other available data on pollution reduction from control technology vendors, consultants, and technical journals and reports."

It is my opinion, based on a review of the permitting record, that WDEQ-AQD did exactly what Dr. Sahu suggests. First, the three existing units identified above were chosen for review because the units were determined to be representative of the proposed Dry Fork boiler. All three of the existing units are pulverized coal-fired units firing subbituminous coal and equipped with combustion controls and SCR that operates on a year round basis. In addition, based on emissions data submitted to U.S.EPA pursuant to the Acid Rain Program (available at http://camdataandmaps.epa. gov/gdm/), all three units currently achieve among the lowest annual NOx emissions rates of all electric utility generating units. Second, the statistical evaluation of the emissions data was only used to quantify the margin needed between the design target and the enforceable permit limit. The control technology design target took into consideration emissions achieved in practice at the best controlled existing sources, as well as information available from control technology vendors, anticipated vendor guarantees, and BACT emission limits included in other PSD permits.

b. The Boiler NOx Emission Rate of 0.25 lb/MMBtu Used to Evaluate Potentially Feasible Post-Combustion NOx Control Systems is Representative of Boiler NOx Emissions Achievable Under All Normal Boiler Operating Conditions

With respect to boiler NOx emissions, Dr. Sahu contends that the boiler outlet rate of 0.25 lb/MMBtu, used by BEPC to assess post-combustion NOx control systems, is too high, and that "lower NOx emission rates can be achieved with current state-of-the-art low NOx burners and overfire air." (Sahu Report, paragraph 32). To support this conclusion, Dr. Sahu cites to three technical articles authored, or jointly authored, by two burner vendors (Sahu Report, Exhibits 20 and 21 published by Babcock & Wilcox Company, and Exhibit 22 published by Riley Power, Inc.). The three articles describe combustion control retrofit projects, including the installation of low NOx burners and overfire air systems, that achieved controlled NOx levels below 0.25 lb/MMBtu.

Although articles published by control equipment vendors are informative and should be used as input to the BACT process, there is an important distinction between emission rates reported in technical articles and the boiler NOx emission rate used by S&L and BEPC to assess the effectiveness of post-combustion controls and establish the BACT emission limits. Most importantly, emission rates reported in the technical articles represent short-term NOx emissions achieved during optimization and performance testing. On the other hand, the emission rate used to evaluate post-combustion control systems should be representative of NOx emissions that are achievable under all normal boiler operating conditions. Technical articles typically describe NOx emission rates achieved during short-term performance tests, and these emission rates may not be representative of emission rates achievable under all normal operating conditions.

Combustion control systems proposed for the Dry Fork boiler include LNB and OFA. LNB control systems limit NOx formation by controlling both the stoichiometric and temperature profiles of the combustion flame. Reduced oxygen in the primary combustion zone and reduced flame temperature are combustion techniques that will minimize boiler NOx formation. OFA control systems are a combustion control technology in which a fraction of the total combustion air is diverted from the burners and injected through ports located above the burner level. However, it is important to understand that combustion strategies designed to limit NOx formation (e.g., reduced oxygen in the primary combustion zone and reduced flame temperatures) also tend to increase the formation of CO and VOC emissions. The Final Permit includes not only a NOx BACT emission limit, but a BACT limit for CO and VOC emissions as well.

BEPC will be required to continuously meet all three BACT emission limits (NOx, CO and VOC) under all boiler operating conditions. Boiler NOx, CO, and VOC emissions are a function of several operating variables, including boiler temperatures, excess oxygen, boiler turbulence, and boiler load and load changes, and while there are post-combustion control systems available for NOx control (e.g., SCR), combustion control is the only method available for controlling CO and VOC emissions. BEPC must achieve its CO and VOC BACT emission limits by controlling combustion processes within the boiler, even though combustion controls designed to minimize CO and VOC formation tend to increase boiler NOx emissions. The NOx emission rate of 0.25 lb/MMBtu used during the permitting process to evaluate the feasibility and effectiveness of post-combustion NOx controls represents a boiler emission rate that should be achievable (using LNB/OFA controls) under all normal operating conditions, including load changes, while minimizing CO and VOC emissions to maintain compliance with the CO and VOC BACT emission limits.

c. The NOx BACT Emission Limit of 0.05 lb/MMBtu (12-month average) Will Require BEPC to Install and Operate State-of-the-Art SCR Controls to Continuously Achieve High NOx Removal Efficiencies

With respect to the SCR control system, Dr. Sahu argues that WDEQ-DAQ "did not evaluate the maximum degree of NOx reduction that can be achieved with the control system (i.e., SCR) after the burner" and that in his opinion, "[e]very major SCR vendor...will guarantee SCR at a minimum 90% reduction efficiency…." (Sahu Report, paragraph 33).

Emission rates achievable with SCR controls were thoroughly evaluated in the Dry Fork Station BACT analysis. The evaluation included a review of emission rates achieved in practice by the best controlled similar sources, anticipated vendor guarantees, a review of the technical literature, and a review of BACT limits in other recently issued PSD permits. See, BEPC's Response to Completeness Review No. 1 (Attachment 2 to the response dated March 7, 2007); BEPC's Response to Completeness Review No. 4 dated July 14, 2006; and BEPC's Additional Information Submittal dated December 13, 2006.

As described in the Permit Application, SCR involves injecting ammonia (NH_3) into boiler flue gas in the presence of a catalyst to reduce NOx to nitrogen (N_2) and water. The performance of an SCR system is influenced by several factors, including flue gas temperature, inlet NOx level, available catalyst surface area, volume and age of the catalyst, and the quantity of unreacted excess ammonia acceptable in the flue gas (ammonia slip). In order to effectively reduce NOx, NH_3 injected into the flue gas must come into contact with the NOx molecules within the required temperature window and in the presence of active catalyst. Effective NOx control requires adequate flue gas temperatures, thorough NH_3 mixing, and available active catalyst surface area. These variables will fluctuate during normal boiler operations, including boiler load changes, low load operation, and toward the end of the catalyst life.

Potentially available vendor guarantees were taken into consideration to establish the Dry Fork Station's NOx BACT limit. As described in the Permit Application, "[t]he most aggressive SCR vendors are reluctant to guarantee emissions less than 0.05 lb/mmBtu without an NH_3 slip requirement that will cause operational problems elsewhere in the plant." (BEPC Additional Information Submittal dated December 13, 2006, page 2 of 14). Vendor guarantees do not focus exclusively on a NOx removal efficiency, but include a combination of controlled NOx emission rates and NH_3 slip, as well as a description of the stack testing that will be done to demonstrate compliance with the guarantee (e.g., stack test methods, duration of the stack tests, and the timeframe in which the testing will be completed). Ammonia slip guarantees that are too high can lead to unacceptable adverse impacts to other parts of the power plants, including catalyst blinding, plugging of downstream ductwork, and excess ammonia in fly ash captured in the fabric filter. Finally, vendor guarantees are demonstrated under new and clean conditions using one-time short-term emissions stack tests, and are not demonstrated using continuous emissions monitoring systems that BEPC must use to demonstrate continuous compliance with its NOx emission limits.

For these reasons, vendor guarantees are only a part of the information upon which the BACT emission limit should be established. Vendor guarantees do not take into account long-term operation of the emissions control system. Vendors do not guarantee performance beyond the initial operation of the control system, and do not provide guarantees over the life of the control system under all operating conditions. BEPC, on the other hand, will have to comply with the enforceable BACT emission limit continuously, over the life of the plant and under all operating conditions.

Several design variables will influence the long-term performance of the SCR system, including the available catalyst surface area and catalyst activity. Catalyst that has been in service for a period of time will have decreased performance because of normal deactivation and deterioration. Catalyst that is no longer effective due to plugging, blinding, or deactivation must be replaced. Thus, it is reasonable to assume that the effectiveness of an SCR system will diminish as the catalyst ages, until some or all of the catalyst is replaced to restore NH_3-NOx mixing, flue gas flow through the SCR, and catalyst activity. In addition to short-term fluctuations in the controlled NOx emission rate (discussed above), the enforceable BACT permit limit should take into account long-term operation of the control system.

NOx removal efficiency of an SCR control system is a function of several operating variables, including inlet NOx loading, ammonia slip, and catalyst activity. A removal efficiency of 90%, as suggested by Dr. Sahu, would represent the performance target for a unit with boiler NOx emissions significantly higher than 0.25 lb/MMBtu, and compliance with the 90% performance target would be demonstrated based on limited short-term performance testing. Based on my experience on the Dry Fork project, as well as other new coal-fired boiler permitting projects, I am not aware of any SCR vendors that would provide a commercially viable guarantee for 90% NOx removal at an inlet loading rate of 0.15 lb/MMBtu, with acceptable NH_3 slip and adequate compliance testing.

d. NOx BACT Conclusions

The Dry Fork BACT analysis evaluated the effectiveness of each technically feasible NOx control technology. The project-specific NOx BACT emission limits were based on a review of emission rates achieved in practice by the best controlled similar sources, an evaluation of the variability associated with an SCR control system, a review of NOx BACT emission limits included in recently issued PSD permits, consideration of potential vendor guarantees, and an evaluation of potential balance-of-plant impacts. Based on all this information WDEQ-AQD imposed a project-specific BACT emission limit which is among the most stringent proposed for any large pulverized coal-fired boiler.

4. SO_2 Limits in the Final Permit Represent BACT for the Dry Fork Station

In paragraphs 35 through 46 of his Expert Report, Dr. Sahu asserts that the "BACT limits for SO_2 [in the Final Permit] are flawed because they are too high and wet scrubber technology was improperly rejected during the BACT analysis." (Sahu Report, paragraph 35).

a. The SO_2 BACT Emission Limits Included in the Final Permit for the Dry Fork Station Were Based on a Comprehensive Evaluation of Potentially Available SO_2 Control Technologies and Potentially Achievable Controlled Emission Rates.

Basin's permit application included a SO_2 BACT analysis for the proposed Dry Fork main boiler (Permit Application Section 5.2.3). In addition to the BACT analysis in the Permit Application, BEPC provided WDEQ-AQD additional technical evaluation of the SO_2 control technologies and achievable emission rates in its response to Completeness Reviews No. 1 and No. 4, dated March 7, 2006 and July 14, 2006, respectively. In its December 13, 2006 submittal to WDEQ-AQD, BEPC provided updated information regarding SO_2 control efficiencies, performance targets, and BACT emission limits. BEPC also provided additional technical information and evaluation of SO_2 controls in its response to comments submitted by EPA Region 8, the National Park Service, and the environmental groups regarding the WDEQ's Permit Application for the Dry Fork Station, submitted to WDEQ on June 25, 2007.

Information submitted to WDEQ-AQD as part of the BACT analysis and permitting process included detailed technical descriptions of the available SO_2 control technologies, anticipated vendor guarantees, an evaluation of hourly SO_2 emissions achieved in practice at the best controlled similar sources (using various SO_2 control technologies), an evaluation of the variability in the controlled SO_2 rates associated with various flue gas desulfurization (FGD) control systems, an assessment of the potential collateral environmental impacts associated with each SO_2 control technology, as well as a detailed comparison of SO_2 emission rates proposed as BACT in other recently issued PSD permits. The BACT analysis concluded that a dry FGD control system designed as a circulating dry scrubber (CDS) followed by a fabric filter baghouse represented BACT for main boiler SO_2 control.

b. BEPC Used an Appropriate Coal Sulfur Content in its BACT Analysis to Establish Baseline SO_2 Emissions and Evaluate Economic Impacts.

Dr. Sahu argues that "cost-effectiveness calculations should have been conducted assuming coal sulfur at this value [0.47%] as opposed to the lower average or design value of 0.33%.... By likely relying on the lower value of 0.33% as in the original permit application, the analysis underestimates the potential tons of SO_2 emissions reductions and makes the cost-effectiveness value seem larger than it is." (Sahu Report, paragraph 37).

An evaluation of economic impacts is one of the steps in a top-down BACT analysis. An economic analysis is performed as part of the BACT determination process, and examines the cost-effectiveness of each control technology, on a dollar per ton of pollutant removed basis. Annual emissions using a particular control device are subtracted from uncontrolled emissions to calculate tons of pollutant controlled per year. Annual costs are calculated by adding annual operation and maintenance costs to the annualized capital cost of a control option. Average cost effectiveness ($/ton) of an option is simply the annual cost ($/yr) divided by the annual reduction in emissions (ton/yr).

In addition to the average cost effectiveness, relative to uncontrolled emissions, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the cost effectiveness of the more stringent control. Incremental cost effectiveness is calculated by dividing the difference in total annual costs between two competing control technologies by the difference in annual emission reductions.

BEPC's Permit Application included a BACT analysis for SO_2. The BACT analysis concluded that both wet- and dry- FGD control systems were technically feasible control options for the Dry Fork boiler, and that wet scrubbing systems demonstrated the ability to achieve the lowest controlled SO_2 emissions rate. (Permit Application, page 5-6). The BACT analysis proceeded, as required, to review the economic impact associated with each technically feasible SO_2 control option. Average BACT cost effectiveness for the dry and wet FGD control systems were calculated at $1,248/ton and $1,450/ton, respectively, and the incremental cost effectiveness of the wet scrubbing system was estimated to be $13,157/ton. (Permit Application, page 5-10).

Baseline SO_2 emissions used in the BACT economic impact evaluation were based on the design annual average coal sulfur content of 0.33% (or 0.82 lb/MMBtu). Because the BACT cost effectiveness evaluation is calculated on an annual basis (e.g., annual costs divided by annual emission reductions), it is reasonable and appropriate to use an annual average design coal sulfur content to calculate baseline emissions.

Of course, the BACT economic impact analysis could also be done using a higher baseline SO_2 emissions rate as suggested by Dr. Sahu. Using a baseline coal sulfur content of 0.47% (or 1.21 lb/MMBtu, which represents the maximum expected short-term sulfur content of coal from the Dry Fork Mine) rather than 0.33% (or 0.82 lb/MMBtu, which represents the annual average sulfur content of fuel from the Dry Fork Mine) would: (1) increase the baseline SO_2 emissions; (2) increase the tons of SO_2 removed by each control option; and (3) reduce the average cost effectiveness of each control technology. However, using a higher baseline SO_2 emission rate has no effect on the incremental cost effectiveness calculation because that calculation depends on the relative difference between the quantity of SO_2 removed by each control option, and that relationship is not affected by a higher baseline SO_2 emission rate. Accordingly, the results of the economic impact assessment do not change.

Wet FGD was not rejected as BACT based on average cost effectiveness. In fact, the BACT analysis in BEPC's permit application states: "[b]ased on average cost effectiveness calculations, both wet and dry FGD systems appear to be cost effective." (Permit Application page 5-9). Rather, wet FGD was rejected as BACT based on a combination of incremental cost effectiveness, which is not a function of the baseline SO_2 emission rate, and collateral environmental impacts (discussed in more detail below).

c. Control Efficiencies and Controlled SO_2 Emission Rates Used in the BACT Economic Impact Analysis for Both Wet- and Dry-FGD Control Systems Were

Representative of the Capabilities of Each Control System on a Subbituminous Coal-Fired Unit

In paragraphs 38 through 44 Dr. Sahu argues that "WYDEQ-DAQ also relies on a flawed assumption that wet FGD SO_2 reduction efficiency is limited to 89%." Dr. Sahu cites to several technical articles that describe wet FGD control technologies capable of achieving greater than 89% SO_2 reduction, and concludes that "all major vendors of wet FGD are presently able to guarantee control efficiencies of 99% SO_2 reduction." (Sahu Report, paragraph 38).

My review of the permitting record shows that: (1) WYDEQ-DAQ did not rely on the assumption that wet FGD SO_2 reduction efficiency was limited to 89%; and (2) the control efficiencies and controlled SO_2 emission rates used in the BACT cost evaluation for wet FGD control technologies were appropriate.

Although the original BACT analysis (submitted with the permit application) evaluated the cost effectiveness of wet FGD at a permit level of 0.09 lb/MMBtu (which represents an 89% reduction from the baseline emission rate of 0.82 lb/MMBtu), WDEQ did not rely on this initial evaluation to reject wet FGD from consideration as BACT. In its Completeness Review No. 1 (dated December 21, 2005), WDEQ requested an analysis of the technical feasibility and cost effectiveness of wet scrubbers at 0.07 and 0.08 lb/MMBtu. In its Completeness Review No. 4 (dated May 30, 2006), WDEQ requested additional review and consideration of the technical feasibility of achieving even lower SO_2 emission limits using wet FGD.

In response to WDEQ's requests, BEPC provided a detailed comparison of both wet- and dry-FGD scrubbing systems, and updated the BACT cost estimates and economic impact evaluations. BEPC also provided information regarding potential vendor guarantees, a detailed evaluation of the controlled SO_2 emission rates achievable with each control technology, and a comparison of the proposed Dry Fork emission limits to emission limits included in other recently issued PSD permits.

In order to establish the most aggressive permit limits available for each control technology, BEPC coupled information from equipment vendors, emission rates proposed in recently permitted similar sources, engineering judgment, and emissions data from similar sources using each control technology. Emissions data from the similar sources were used to identify SO_2 emission rates currently achieved in practice and to evaluate the variability in the controlled emission rate associated with each control technology.

Based on this analysis, S&L concluded that the most aggressive design target for a wet FGD ("WFGD") control system on the Dry Fork boiler would be in the range of approximately 0.054 lb/MMBtu. The design target represents the actual average emission rate that the control technology should achieve under ideal operating conditions. Based on an analysis of the variability seen in the controlled SO_2 emission rates at existing units equipped with WFGD control systems, it was determined that a design target of 0.054 lb/MMBtu corresponds to a permit limit of 0.07 lb/MMBtu. The permit limit takes into account fluctuations in the controlled SO_2 emission rate associated with normal operations of the control system. In order to provide uniformity in the BACT cost effectiveness evaluation, the same methodology was used to determine the expected BACT emission limit associated with the dry FGD control systems.

To achieve a design target of 0.054 lb/MMBtu, the WFGD control system would have to achieve a removal efficiency of at least 95.5% (based on an uncontrolled SO_2 emission rate of 1.21 lb/MMBtu). Therefore, WDEQ did not rely on a WFGD control efficiency of 89% as Dr. Sahu suggests, and to state that WDEQ relied on a flawed assumption that WFGD SO_2 reduction efficiency is limited to 89% is incorrect.

In my opinion, the controlled SO_2 emission rates used in the BACT economic impact assessment for both dry- and wet-FGD control systems were representative of the most aggressive technically feasible emission rates achievable on a consistent basis with each control technology. Even at these more aggressive control efficiencies, BEPC's March 10, 2006 BACT economic impact analysis showed that the incremental cost effectiveness of WFGD was $12,610 (at 0.07 lb/MMBtu) to $24,052 (at 0.09 lb/MMBtu) per ton SO_2 removed compared to the dry scrubbing option at 0.10 lb/MMBtu.[3]

[3] As described, cost effectiveness evaluations included in the Permit Application comparing the cost effectiveness of the wet- and dry-FGD control systems were updated at WYDEQ's request in order to evaluate the cost effectiveness of achieving lower SO_2 emission limits. At that time, the control technology costs were also reviewed and updated. Therefore, cost effectiveness values in BEPC's

Although there is no bright-line $/ton cost effectiveness threshold for BACT evaluations, based on my experience on other PSD permitting projects, control technologies with cost effectiveness values above $8,000 to $15,000 per ton are generally not considered cost effective. Therefore, WYDEQ-AQD appropriately eliminated WFGD from consideration as BACT based on incremental economic impacts. Even if the incremental cost effectiveness of WFGD is not considered excessive, the WFGD control option would be eliminated from consideration as BACT on the Dry Fork unit based on collateral environmental impacts alone (discussed below).

Dr. Sahu argues higher WFGD control efficiencies, in the range of 98% to 99%, should have been used in the BACT cost effectiveness evaluation, and had a higher WFGD control efficiency been used, the overall and incremental cost effectiveness values for WFGD would be much lower and WFGD would be not be eliminated from considered as BACT based on economic impacts. In order to support this argument for higher WFGD control efficiencies, Dr. Sahu referenced the following technical articles:

a. Data from a magnesium-enhanced lime (MEL) WFGD retrofit project at Mitchell Power Station Unit 33 that demonstrated greater than 99% SO_2 removal during four months in 1983 and 1984 (Sahu Report, paragraph 39);

b. A 2003 paper published by the Chiyoda Corporation and Black & Veatch Corporation discussing the actual operating performance of the Chiyoda JBR WFGD technology, and reporting that the CT-121 WFGD can achieve an SO_2 removal efficiency of over 99% on an instantaneous basis. (Sahu Report, paragraph 40);

c. A technical article written by Mitsubishi Heavy Industries (MHI) describing MHI's Double Contact Flow Scrubber (DCFS), and reporting that the scrubber had achieved SO_2 removal efficiencies greater than 99% (Sahu Report, paragraph 41);

d. A technical article written by Alstom, describing its FLOWPAC™ WFGD scrubber technology, and reporting SO_2 removal efficiencies greater than 99% (Sahu Report, paragraph 42);

March 10, 2006 BACT economic impact varied somewhat from cost effectiveness values in the Permit Application.

e. A second technical article written by Alstom and Public Power Corporation S.A.S describing Alstom's WFGD control system on a coal-fired unit in Greece, and reporting SO_2 removal efficiencies of 99%+ (Sahu Report, paragraph 43); and

f. An article from the Coal Utilization Research Council, concluding in its 2006 Roadmap that "up to 99% removal for FGD was commercially available in 2005 (Sahu Report, paragraph 44).

There are several commercially available wet scrubbing systems, including MHI's Dual Contact Flow Scrubber (DCFS), Alstom's FLOWPAC™ WFGD, and Chiyoda's CT-121 WFGD. Although the WFGD system designs will vary, all wet scrubbing systems use an alkaline slurry (typically limestone ($CaCO_3$)) that reacts with SO_2 in the flue gas to form insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts. In a spray tower WFGD design the limestone slurry reactant is sprayed countercurrent to the flow of the flue gas. Design variations may include changes to increase the alkalinity of the scrubber slurry (such as the MEL-WFGD systems), increase slurry-to-SO_2 contact, and minimize scaling in the reactor vessel. Equations 1 through 5 summarize the chemical reactions that take place within the wet scrubbing systems to remove SO_2 from flue gas.

$$SO_2 + CaO + \tfrac{1}{2}H_2O \rightarrow CaSO_3 \cdot \tfrac{1}{2}H_2O \qquad (1)$$
$$SO_2 + CaO + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O \qquad (2)$$
$$SO_2 + CaCO_3 + H_2O \rightarrow CaSO_3 \cdot H_2O + CO_2 \qquad (3)$$
$$CaSO_3 + \tfrac{1}{2}O_2 + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O \qquad (4)$$
$$SO_2 + 2H_2O + \tfrac{1}{2}O_2 + CaCO_3 \rightarrow CaSO_4 \cdot 2H_2O + CO_2 \qquad (5)$$

Wet scrubbing systems account for a large majority of the flue gas desulfurization systems on utility boilers firing high-sulfur coals. As described in the technical articles cited by Dr. Sahu, WFGD systems have demonstrated the ability to achieve control efficiencies as high as 99% on boilers firing high-sulfur fuels under optimal conditions; however, the actual control efficiency of a WFGD system will depend on several operating variables, including the SO_2 concentration in the flue gas entering the system.

The chemistry of wet scrubbing consists of a complex series of kinetic and equilibrium-controlled reactions occurring in the gas, liquid, and solid phases. In general, the amount of SO_2 absorbed from the flue gas is governed by the vapor-liquid equilibrium between SO_2 in the flue gas and the absorbent liquid. If no soluble alkaline species are present in the liquid, the liquid quickly becomes saturated with SO_2 and absorption is limited.[4] Likewise, as the flue gas SO_2 concentration goes down, absorption will be limited by the SO_2 equilibrium vapor pressure. Therefore, higher removal efficiencies can be achieved on flue gases with high concentrations of SO_2. High removal efficiencies become increasingly difficult to achieve as the SO_2 concentration in the flue gas decreases. This is the case with subbituminous PRB coals which have an inherently low sulfur content and lower SO_2 concentrations in the flue gas entering the FGD control system.

As discussed in my response to the NOx BACT issues, emission rates presented in technical articles often describe the results of short-term performance tests conducted under optimum operating conditions. These short-term test results are informative, and can help establish the design limitations of the control technologies, but emission rates based on short-term performance tests are not necessarily representative of the controlled emission rates that are achievable over a longer period of time and under all normal operating conditions.

For example, the technical articles describing control efficiencies achieved by Chiyoida's CT-121 WFGD, MHI's DCFS WFGD, and Alstom's FLOWPAC™ WFGD all describe control efficiencies achieved during short-term performance tests. The MHI article (Sahu Report, Exhibit 28) states that "[d]uring guarantee testing, this unit [KOA Oil Co., Ltd] recorded an SO_2 removal efficiency of 99.9% or 2 ppm SO_2 in the outlet duct." (Sahu Report, Exhibit 28, page 8). It is clear that the high removal efficiencies included in the MHI article were short-term instantaneous removal efficiencies observed during performance tests. Also, the high removal efficiency was observed on a boiler firing high sulfur oil, with an inlet SO_2 concentration of 2,219 ppm, an inlet concentration that is more than four-times the inlet concentration expected to the FGD control system on the Dry Fork boiler.

Similarly, Alstom's article provided a detailed description of the FLOWPAC WFGD installed at the Karlshamn Power Station in Sweden (Sahu Report, Exhibit 30). However, the article includes only one emission data point, reporting an outlet SO_2 emission rate of 10 ppm and an control efficiency of 99%. The article does not describe the test method used or the

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4 Combustion Fossil Power – A Reference Book on Fuel Burning and Steam Generation, edited by Joseph P. Singer, Combustion Engineering, Inc., 4th ed., 1991 (pp. 15-41).

duration of the performance testing; however, it is likely the data point provided in the article was measured during a short-term performance test under optimal conditions.

Dr. Sahu also provides emissions data from a four-month period in 1983 and 1984 showing that the MEL WFGD system at the Mitchell Power Station in Pennsylvania achieved a daily average SO_2 removal efficiency of greater than 99%. (Sahu Report, paragraph 39). Although emissions from the station were measured over four 1-month periods, the emissions data provided does not take into consideration long-term operation of the control system, normal operating variables, potential balance-of-plant impacts (such as scaling and plugging), or potential collateral environmental impacts. Based on a review of actual emissions data reported by the Mitchell Station to U.S.EPA pursuant to the Acid Rain Program (available at http://camddataandmaps.epa.gov/gdm), Mitchell Station Unit 33 has not maintained such high removal efficiencies (or such low emission rates). Since 1995 Mitchell Unit 33 has achieved the following actual controlled SO_2 emission rates (annual average):

Year	Annual Average SO_2 Emission Rate (lb/MMBtu)
1995	0.119
1996	0.156
1997	0.130
1998	0.131
1999	0.129
2000	0.138
2001	0.128
2002	0.184
2003	0.177
2004	0.171
2005	0.176
2006	0.109

The annual average emission rates achieved in practice at Mitchell Unit 33 are significantly higher than the short-term emission rates reported during the 1983/84 performance tests, which were in the range of 0.011 lb/MMBtu.

Exhibit 31 to the Sahu Report, includes a description of the Alstom WFGD control system installed on a high-sulfur coal-fired power plant in Greece. The report states that "the WFGD system has achieved SO_2 removal efficiencies of 99%+ without the use of organic additives." (Sahu Report,

Exhibit 31, page 12). However, it is interesting to note that the report provides flue gas measurements and SO_2 emissions data from 8 stack tests performed over a three-day period. The stack test data in the report shows instantaneous removal efficiencies ranging from 94.9% to 99.2%. Removal efficiency during the 8 tests averaged 97.4%, and the outlet SO_2 emission rate averaged 167 mg/Nm^3 (or approximately 0.13 lb/MMBtu, well above the Dry Fork SO_2 BACT limit). These test results support the conclusions that WFGD control systems are not steady-state systems, that the controlled SO_2 emission rate will fluctuate, and that individual performance tests may not be representative of long-term operation.

Emission rates and removal efficiencies described in technical articles published (or co-published) by equipment vendors are interesting and informative and should be taken into consideration during the BACT determination process. However, these emission rates and control efficiencies typically describe short-term instantaneous emissions achieved under optimal conditions. Emission rates used in the BACT analysis, including the BACT economic impact analysis, should represent emission rates that are achievable over a long period of time and under all normal operating conditions.

Emission rates used in the Dry Fork BACT analysis were based on a review of information available from equipment vendors, anticipated vendor guarantees, emission rates included in recently issued PSD permits for similar sources, engineering judgment, and emissions data from similar sources using each control technology. These emission rates were representative of BACT emission limits for both the dry- and wet-FGD control technologies, thus the BACT cost effectiveness analysis included in the Permit Application was an accurate comparison of the competing SO_2 control technologies.

d. Collateral Environmental Impacts Associated With Wet FGD Control Systems Would Exclude Wet FGD as BACT for SO_2 Control on the Dry Fork Boiler

BACT is not based on cost-effectiveness alone. The BACT analysis includes an analysis of economic, environmental and energy impacts. Although Dr. Sahu did not address potential collateral environmental impacts associated with wet scrubbing systems in his report, WFGD was rejected as BACT for the Dry Fork station based on economic impacts <u>and</u> collateral environmental impacts.

Collateral environmental impacts associated with each technically feasible FGD control system were evaluated in the Permit Application. There are several collateral environmental impacts associated with WFGD control systems. WFGD systems generate a calcium sulfate waste by-product that must be properly managed. Historically, solid wastes generated from WFGD systems have been dewatered and disposed of in landfills. Most new WFGD systems utilize a forced oxidation system that results in a gypsum by-product that can sometimes be sold into the local gypsum market. If an adequate local gypsum market is not available, the gypsum by-product will require proper disposal.

WFGD systems also result in increased project emissions from the following sources:

1. WFGD systems use more reactant (e.g., limestone) than do dry systems, therefore the limestone handling system and storage piles will generate more fugitive dust emissions.

2. WFGD systems must be located downstream of the unit's particulate control device; therefore, dissolved solids from the WFGD system will be emitted with the WFGD plume. WFGD control systems also generate lower stack temperatures that can reduce plume rise and result in a visible plume.

3. SO_3 remaining in the flue gas will react with moisture in the WFGD to generate sulfuric acid mist. Sulfuric acid mist (SAM) is classified as a condensible particulate. Therefore, compared to dry FGD control systems (located upstream of the particulate control system) WFGD control systems will have higher SAM and condensable PM_{10} emissions.

In addition, the WFGD control system will increase overall emissions of NOx, CO, VOC and PM_{10} associated with the project. Auxiliary power requirements for the WFGD system are greater then the auxiliary power requirements of the dry FGD systems, and will reduce the unit's net plant heat rate. Consequently, heat input to the boiler would need to increase by approximately 1.5% with the WFGD to achieve the same net plant output. The calculated maximum heat input to the boiler with the dry FGD configuration was calculated to be 3,801 MMBtu/hr. To achieve the same net output with a WFGD the maximum heat input to the boiler would need to increase to approximately 3,858 MMBtu/hr, increasing NOx, CO, PM_{10}, and VOC emissions on a per MW-generated basis.

Alternatively, BEPC could design the Dry Fork boiler with WFGD controls and reduce the net plant output from 385 MW to approximately 380 MW without an increase in collateral emissions. However, the lost output (approximately 43,800 MWh annually) would need to be replaced with power from existing power stations. Existing power stations emit significantly more pollutants per MW output than the proposed Dry Fork Station.

Finally, and probably most importantly for the Dry Fork Station, WFGD systems also require significantly more water than the dry systems, and generate a wastewater stream that must be treated and discharged. Based on preliminary engineering calculations, it was estimated that a WFGD system would require at least 30% more water than a dry system, or approximately 200 million gallons per year. The importance of an adequate water supply in the determination of FGD control technology design was recognized by U.S.EPA in its Clean Air Mercury Rule. In that rule, EPA concluded that:

> new units located in some areas will have access to an adequate supply of water while units in other areas will not have such access. Where adequate water is available, we believe…that wet FGD represents best demonstrated technology (BDT). We also believe; however, that where adequate water is not available, dry FGD represents BDT. (70 FR 62216)

EPA determined that areas receiving greater than 25 inches per year precipitation, based on U.S. Department of Agriculture 30-year data, would generally have an adequate supply of water to support operation of a wet FGD control system. Campbell County Wyoming does not receive 25-inches per year of precipitation, and water consumption is an important factor in the design of the Dry Fork Station. In fact, because water availability is so important, the station is being designed with an air cooled condensing system to minimize water consumption.

e. SO_2 BACT Conclusions

Dr. Sahu's assessment of the SO_2 BACT analysis focused on the WFGD control efficiencies used in the BACT cost effectiveness evaluation. In paragraph 45 of his Expert Report, Dr. Sahu states:

> It is my opinion that the BACT analysis for wet FGD should be redone as follows: (a) obtain cost and vendor guarantees and base the analysis on these guarantees; (b) include as permit conditions, key assumptions (such as coal sulfur content) of such analysis. I believe that this will show wet FGD to be a top control technology. And, doing so, assuming that 98% control is possible, the BACT limit should be far lower than the currently (sic) permit limit of 0.07 lb/MMBtu.

First, WDEQ did not rely on a WFGD control efficiency of 89% in its SO_2 BACT analysis, and WDEQ required BEPC to evaluate the cost effectiveness of WFGD control systems capable of achieving greater than 95.5% removal. Second, the baseline SO_2 emission rate in the BACT cost effectiveness analysis has no impact on the incremental cost effectiveness of the WFGD control system, and increasing the baseline SO_2 emission rate would not affect the cost effectiveness conclusion. Finally, and most importantly, the BACT determination is not based on economic impacts alone. BACT requires the applicant to evaluate potential collateral environmental impacts associated with the control technologies. Based on site-specific collateral impacts alone, including increased water consumption, increased sulfuric acid mist and condensable PM_{10} emissions, and increased auxiliary power requirements, WDEQ could reasonably reject WFGD from consideration as BACT.

5. Mercury Control Requirements in the Final Permit Represent BACT for Mercury Emissions from the Dry Fork Boiler.

The Final Permit included the following emission limits with respect to mercury emissions from the main boiler:

Permit Condition 9:

Mercury (Hg): 97 x 10-6 lb/MW-hr (12-month rolling average), and 0.16 tpy

Permit Condition 10:

> A. A one year mercury optimization study shall be performed at this facility with a target emission rate of no more than 20 x 10-6 lb/MW-hr, 12 month rolling average. A protocol for the study shall be submitted to the Division for review and approval prior to commencement of the study. The protocol shall include a description of control techniques(s) to be employed including type of sorbent, if applicable, and proposed operational parameters (e.g., carbon injection rate), test methods, and procedures. The optimization study shall commence no later than 90 days after initial startup. The results of the study shall be submitted to the Division within 30 days of completion of the study.
>
> B. A mercury control system shall be installed and operated at this facility within 90 days of initial startup. This permit shall be reopened to revise the mercury limit in condition 9 and/or add operational parameters to this condition based on the results of the mercury optimization study.

In paragraphs 47 and 48 of his Expert Report, Dr. Sahu challenges the mercury emission limits in the Final Permit, stating that "I could not find a BACT analysis for mercury in the record." (Sahu Report, paragraph 47), and that "[a]side from being unenforceable, the choice of even the 'target emission level' for the optimization study of 20 x 10-6 lb/MW-hr is unexplained." (Sahu Repot, paragraph 48).

Although mercury emissions from coal-fired power plants are not subject to the federal BACT requirements, in its Completeness Review No. 3 (dated May 3, 2006), WYDEQ-AQD requested BEPC to provide a BACT analysis for mercury pursuant to WAQSR Chapter 6, Section 2(c)(v). In response, BEPC submitted its Response to Completeness Review No. 3 (dated July 11, 2006), including an evaluation of potentially available mercury controls, a review of mercury emission limits included in other recently issued permits, and a mercury BACT analysis. The BACT analysis concluded:

- Control technologies for mercury are still in the developmental state, resulting in only limited information regarding possible alternatives and potential control efficiencies.
- A top-down analysis with cost estimates is not possible with current incomplete technology alternatives and cost information.

- Commercially available mercury control systems and associated vendor guarantees are very limited to date. Activated Carbon sorbent injection systems have been proposed and designed by a few vendors but other control technologies are at the planning and demonstration stages.

Based on its assessment of the state of mercury control technology development contemporaneous with the permitting process, including unknown effects from numerous unit operating parameters on mercury capture, and the fact that mercury removal and pilot demonstration projects conducted to date had shown that significant questions remained regarding how changing operating conditions can impact Hg emissions, BEPC concluded that it could not establish a meaningful and appropriate BACT limit for mercury emissions.

Although Dr. Sahu states that he could not find a BACT analysis for mercury in the record, BEPC's Response to Completeness Review No. 3 included a mercury BACT analysis. The mercury BACT analysis stopped at Step 1 of the top-down process, concluding that the state of mercury control technology development could not support a conclusion as to the technical feasibility and commercial availability of mercury controls for the Dry Fork Station. This is an acceptable result of the top-down BACT process.

Nevertheless, BEPC proposed meeting the applicable federal mercury New Source Performance Standard (NSPS), and based on a review of several recently issued permit for coal-fired electric utility steam generating units, BEPC proposed to implement a mercury optimization control study to evaluate the feasibility and effectiveness of potentially available mercury controls. The testing program would commence within 90 days of initial startup of the unit and would include an evaluation of the following potential mercury technology options:

- Sorbent Injection Technologies
- Sorbent Enhancement Additives
- Coal Pretreatment Processes
- Hg Oxidation Technologies

WYDEQ adopted these requirements into the Final Permit, and, in addition, required BEPC to install and operate a mercury control system within 90 days of initial startup (Final Permit, Condition 10.B). Permit provisions that require the permittee to conduct an emissions control optimization study certainly represent enforceable permit conditions, and are used in PSD permits to provide the permitting agency the opportunity to evaluate the applicability and effectiveness of new control technologies and establish appropriate project-specific permit limits. BEPC will be required to commence the optimization study within a specified time frame, BEPC will be required to prepare a test protocol for WYDEQ's review and approval prior to commencing the study, and BEPC will be required to conduct the study in accordance with the WYDEQ-approved protocol. All of these requirements represent enforceable permit conditions.

Furthermore, as described in BEPC's mercury BACT determination, other recently issued PSD permits for coal-fired steam electric generating facilities included provisions for a mercury control optimization study. For example, the permits for MidAmerican Energy CBEC Unit 4 (Iowa) and Xcel Energy Comanche Unit 3 (Colorado) included provisions for testing and evaluation of a mercury removal system. The MidAmerican permit required the facility to install an activated carbon injection control system, but allowed for a nine-month optimization period whereby the affects of increasing activated carbon injection rates on Hg removal were to be evaluated. Similarly, within 180 days after start-up, Comanche Unit 3 was required to enter into a one-year test program of various mercury removal technologies on Comanche Units 1 & 2. Within two years from the start-up of Unit 3, Xcel Energy would be required to comply with an emission limit that represents the maximum cost-effective reduction of mercury at Comanche Station. Clearly, permit conditions that require the permittee to conduct optimization studies are not unique to the Dry Fork permit and are enforceable.

Mercury control technologies continue to be studied and developed for commercial deployment. Potential mercury control strategies include co-benefit mercury capture with emission control technologies designed for NOx, SO_2 and PM_{10} control, as well as mercury-specific control strategies. Based on published test data, the effectiveness of any mercury control system will be a function of the mercury speciation in the boiler flue gas. Mercury speciation is a function of the coal being fired. During combustion, mercury readily volatilizes from the fuel and is found in the flue gas predominantly in the vapor phase as elemental mercury (Hg^o). As the flue gas cools, a series of complex reactions begin to convert Hg^o to ionic mercury (Hg^{2+}) compounds and Hg compounds that are in a solid-phase at flue gas temperatures (Hg_p).[5] The effectiveness of any mercury control strategy will depend on the species of mercury in the flue gas.

Mercury speciation testing indicates that the distribution of Hg^0, Hg_p, and Hg^{2+} (most likely $HgCl_2$) varies with coal type, and is dependant upon the chloride concentration in the coal. Specifically, test results indicate that flue gas from subbituminous coals (such as the Dry Fork coal) will contain significantly more Hg^0 than flue gas from bituminous coals, while higher concentrations of Hg^{2+} are associated with bituminous coals, especially those with high chloride concentrations.[6] In general, Hg^0 is the most difficult form of mercury to capture.

On January 30, 2004 EPA published its proposed Maximum Achievable Control Technology (MACT) rule for mercury control from coal-fired boilers (the "Proposed MACT Rule").[7] Although the Proposed MACT Rule was never finalized, the proposed rule included a "MACT floor" finding for subbituminous coal-fired utility units. The MACT floor developed by EPA for new units was based on the emission control achieved in practice by the best-performing similar source. In order to develop an emission limitation for new units, EPA ranked the existing subbituminous coal-fired units from lowest emitting to highest based on Hg emission rates from the existing stack test data. EPA then selected the numerical performance value from the best-performing unit, and applied a factor to account for potential uncertainty and variability in the emission test reports. EPA quantified the test and analytical method variability by statistical analysis of the test results in order to establish the corresponding MACT floor. Based on this evaluation, EPA proposed an emissions standard of 20×10^{-6} lb/MWh (annual average based on gross output) as MACT for subbituminous-fired units.

The target emission limit in BEPC's Final Permit was based on EPA's proposed MACT emission limit of 20×10^{-6} lb/MWh for new subbituminous-fired units. Dr. Sahu states that this target limit is not the lowest mercury limit required for a new subbituminous coal-fired unit, citing the mercury emission limit included in the permit for the Walter Scott Jr. Energy Center ("WSEC" previously known as Council Bluffs Energy Center). (Sahu Report, paragraph 48). The WSEC permit included a mercury emission limit of 1.7×10^{-6} lb/MMBtu, which

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[5] See, e.g., "Control of Mercury Emissions From Coal-Fired Electric Utility Boilers," U.S. Environmental Protection Agency, Office of Research and Development, Air Pollution Prevention and Control Division, Research Triangle Park, NC.

[6] Utility RTC, page 13-38.

[7] 60 FR 4652 (January 30, 2004)

is equivalent to an emission rate of approximately 15 x 10^{-6} lb/MWh. (Sahu Report, Exhibit 34, page 5 of 27). However, Condition 14.M.6 of the WSEC permit states: "This permit shall be reopened and the permit limits adjusted if the information in the [optimization study] report shows an amendment is necessary." Thus, the WSEC mercury limit also represents an emissions target, and can change depending on the results of the optimization study. Furthermore, WSEC is required to conduct stack tests to demonstrate compliance with the mercury emission limit, which is a less stringent requirement than the continuous emissions monitoring required by Condition 10.b of the Dry Fork Final Permit.

Subsequent to EPA's publication of the Proposed MACT Rule, mercury control technologies have continued to be studied and have continued toward commercial deployment. Control technologies being studied for mercury capture are at various stages of commercial development. The most widely tested approach to mercury control on coal-fired boilers involves injection of a sorbent into the boiler flue gas. The most widely tested sorbent for mercury control at utility boilers is powdered activated carbon (PAC). PAC has been evaluated for mercury control in several pilot- and full-scale tests, including boilers firing bituminous, subbituminous, and lignite coals, and a PAC control system has been required to be installed on one new coal-fired electric generating unit (the Walter Scott Jr. Energy Center (formerly known as CBEC) Unit 4 in Iowa.

Test data from full-scale studies demonstrate that PAC injection systems offer the opportunity for significant mercury control on coal-fired units. However, the test data also indicate that several factors may limit the effectiveness of PAC injection on subbituminous-fired units. One of the more important limiting factors may be the absence of available halogens (or chlorine) in the fuel, and the resulting high concentration of Hg^0 and low concentration of Hg^{2+} in the flue gas. Parametric testing suggests that adequate chlorine in the gas stream is necessary for capture of Hg^0 by PAC.

Although PAC injection systems are the most widely tested approach to mercury control, mercury capture with PAC injection on a boiler firing a low sulfur, low chlorine subbituminous coal (such as the Dry Fork coal) may be significantly limited. Furthermore, PAC injection has not been tested or demonstrated on a subbituminous coal fired unit equipped with a circulating dry scrubber (such as that required as BACT for SO_2 control on the Dry Fork boiler). Finally, there are several other potentially feasible mercury control options that might be available, and more effective, for the Dry Fork Station, including:

- Co-benefit Hg capture in the emission control technologies designed for NOx, SO_2, and PM_{10} control;
- Fuel additives to promote Hg oxidation across the SCR;
- SCR catalyst formulations that promote Hg oxidation;
- Sorbent Injection Systems:
  - Activated carbon injection;
  - Halogenated activated carbon injection;
  - Non-carbon based sorbent injection;
- Fuel Additives
  - Chemical addition to the coal to promote Hg oxidation
  - Chemical addition to the boiler to promote Hg oxidation

Dry Fork Unit 1 will fire a low sulfur, low chlorine subbituminous coal and will be equipped with a circulating dry scrubber for SO_2 and sulfuric acid mist removal. Based on full-scale test data from existing subbituminous coal-fired units, mercury capture with a PAC injection system may be significantly limited on the Dry Fork boiler. Given the fact that other developing mercury control technologies may provide more effective mercury capture, it was reasonable for WYDEQ-AQD to establish a mercury emission limit in the Final Permit based on the then applicable federal NSPS and require BEPC to install and operate mercury-specific controls within 90-days of initial startup, while requiring BEPC to implement a comprehensive mercury control study. In my opinion, given the Dry Fork specific fuel characteristics and emission control configuration (e.g., SCR, CDS and baghouse) the mercury control optimization study will result in a more efficient and effective mercury control system for the Dry Fork boiler.

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Date

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