BEFORE THE ENVIRONMENTAL QUALITY COUNCIL
STATE OF WYOMING

IN THE MATTER OF:	)	
BASIN ELECTRICAL POWER COOPERATIVE	)	
DRY FORK STATION,	)	Docket No. 07-2801
AIR PERMIT CT-4631	)	

RESPONDENT DEPARTMENT OF ENVIRONMENTAL QUALITY'S MEMORANDUM IN SUPPORT OF MOTION FOR PARTIAL SUMMARY JUDGMENT

Schlichtemeir Affidavit

EXHIBIT R

BASIN ELECTRIC
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June 8, 2007

Chad Schlictemeier
NSR Program Manager
Department of Environmental Quality
Air Quality Division
122 W. 25th Street
Cheyenne, WY 82002

Re: Response to DEQ Questions

Dear Mr. Schlictemeier:

This letter and attachments are in response to the eight items that you, Stewart Griner, and I discussed in April, and your follow-up email regarding the circulating dry scrubber (**CDS**) technology. A discussion of each of the items follows below:

1. **Limit for NH3.** Basin Electric believes that it can meet a 10 ppm limit on ammonia emissions based on a 3-hour test using EPA Conditional Test Method 27. While Basin Electric's goal in operating the SCR system is to maintain ammonia slip at 5 ppm or less, it could not agree to a permit limit that low. Basin Electric also notes that other facilities have not had ammonia limits in their permits, but is willing to work with DEQ in agreeing to a permit limit of 10 ppm, as described above.

2. **Comparison of Basin Electric SO2 Limit with TS Power Plant Limit.** See the attached Sargent & Lundy memorandum regarding the comparison of SO2 emission limits at the two facilities. **Attachment 1**. The memorandum concludes that the Newmont limit is right at the limit of the technology and at some coal sulfur contents lower than the technology limit. The Basin Electric limit of 0.08 lb/MMBtu reflects a margin above the design control rate to allow for consistent compliance with the permit limit.

3. **CEMs for CO.** Basin Electric is planning on installing a CEMs for CO, as set forth in Basin Electric's permit application. The CO permit limit of 0.15 lb/MMBtu is based on a 30-day rolling average.

4. **Information Explaining Why Basin Electric Selected a PC Boiler Rather than an IGCC System.** Basin Electric previously submitted to DEQ a November 1, 2005 report prepared by CH2MHill entitled "Coal Power Plant Technology Evaluation for Dry Fork Station" that described why IGCC was not yet technically feasible and available for use at the Basin Electric Dry Fork station project. We believe this report provides comprehensive information about Basin Electric's technology selection, however, if you have questions or need further information, please let us know.

5. **Supercritical and Ultra-Supercritical Boilers.** Basin Electric's preliminary information on this issue indicates that supercritical and ultra supercritical boilers have only been used for larger size boilers – minimum size of 500 MW for supercritical and over 800 MW for ultra supercritical. Vendor discussions have indicated that smaller size boilers would require custom adaptation to make the technology suitable with little practical experience in such customization. Moreover, the vendors have indicated that the technology loses its efficiency when the boiler is sized less than 500 MW. Basin Electric obtained much of this information in late 2005 as it was planning the design of the Dry Fork Station. Basin Electric is in the process of preparing an additional analysis of this issue.

which it hopes to have completed later this week. As soon as this additional information is ready, we will send it to you.

6. **Mercury Control.** Basin Electric is planning on installing a mercury injection control system up front and using it to perform a full scale mercury optimization study. This additional control technology will augment the expected significant mercury control from the circulating dry scrubber. Because of the uncertainty in mercury emissions, Basin Electric considers the best level of mercury control available and at which it can commit to consistently achieve compliance as 97 x 10^{-6} MW/hr. In the Mercury Optimization Study, Basin Electric will have as its target, a goal of achieving a mercury emission rate of 20×10^{-6} MW/hr.

7. **Soils and Vegetation.** Basin Electric is having additional information prepared to support the soils and vegetation analysis that was performed in connection with the permit application. Basin Electric expects that that additional information will be available later this week. As soon as this additional information is ready, we will send it to you.

8. **Justification of Sulfuric Acid Mist BACT Permit Limit.** See the attached Sargent & Lundy BACT analysis of the sulfuric acid mist emissions limit for the Dry Fork Station plant. **Attachment 2.** This analysis demonstrates that an emission rate of 0.0045 lb/MMBtu is BACT for sulfuric acid mist emissions. In addition, the modeling for Dry Fork Station was performed at 0.0045 lb/MMBtu.

9. **BACT Analysis of a Circulating Dry Scrubber for SO2 Control.** See the attached Sargent & Lundy BACT analysis of CDS. **Attachment 3.** This report concludes that (1) either dry FGD control system (SDA or CDS) could meet the proposed BACT emission limits; (2) the cost effectiveness of either dry FGD control system is essentially identical; and (3) the compliance margin between the performance target and the enforceable permit limit will be minimal with either dry FGD system. However, the report also concludes that the CDS design offers the following advantages: (1) the CDS offers a better chance of complying with stringent SO_2 emission rates given the unique challenges at a mine-mouth plant with respect to variability in the fuel characteristics; (2) potential balance-of-plant impacts associated with operating either system so close to the performance target are potentially less significant with the CDS (i.e., the CDS should not experience wall wetting, scaling, plugging and the associated detrimental impacts on the baghouse); and (3) the CDS will not experience short-term emission spikes associated with routine atomizer changeouts and should be better suited to achieve stringent emission rates based on short-term averaging times. For all of these reasons, Basin Electric has selected CDS as its preferred dry scrubber technology.

If you have any additional questions or would like further information on the above items, please do not hesitate to contact me.

Sincerely,

Jerry Menge

Jerry Menge
Air Quality Program Coordinator

jm/mw
Attachments
cc: Clyde Bush
Jim K. Miller

Sargent & Lundy LLC

Date: June 8, 2007

Project: Dry Fork Unit 1 – Construction Air Permit Application

Subject: Proposed SO_2 Emission Limits
Dry Fork vs. Newmont TS Power

The purpose of this memorandum is to provide additional review and comparison of the proposed Basin Electric Power Cooperative (BEPC) Dry Fork Station SO_2 BACT emission limits to other recently issued/proposed SO_2 BACT limits, specifically the SO_2 emission limits included in the Newmont Nevada Energy Investment, LLC (Newmont) permit to construct issued by the Nevada Bureau of Air Pollution Control.

Background

BEPC's BACT determination, including the original permit application and supplemental information submitted in response to agency comments, included a detailed evaluation of potentially feasible SO_2 control technologies. The BACT analysis included an evaluation of both wet and dry flue gas desulfurization (FGD) systems, and an evaluation of the controlled emission rates achieved in practice at the best controlled similar sources. Based on information included in BEPC's BACT analysis, WDEQ proposed the following SO_2 BACT emission limits:

- 0.08 lb/MMBtu (12-month rolling average)
- 304.1 lb/hr (30-day rolling average)
- 380.1 lb/hr (3-hour block average)

In addition, the facility will be required to meet the applicable NSPS (1.4 lb/MW-hr 30-day rolling average) and an annual SO_2 emission limit of 1,331.8 tpy.

BEPC's BACT analysis included a comparison of Dry Fork's proposed SO_2 limits to other recently issued/proposed BACT limits for coal-fired boilers (see, permit application Appendix E, and information included in BEPC's December 13, 2006 response to questions). Of the recently permitted pulverized coal-fired units proposing to fire subbituminous coal and control SO_2 emissions using dry FGD, the most stringent SO_2 emission rates identified as BACT were imposed on the Newmont Power Plant proposed in Eureka County, Nevada. The Newmont facility received the following SO_2 BACT emission limits:

Newmont Mining TS Power: While combusting coal with a sulfur content ⟨ 0.45% (30-day rolling period) based on daily ASTM sampling;

- 0.09 lb/MMBtu (24-hour rolling average);
- 95% minimum SO_2 removal efficiency (30-day rolling period).

While combusting coal with a sulfur content <0.45% (30-day rolling period), based on daily ASTM sampling:

- 0.065 lb/MMBtu (24-hour rolling average);
- 91% minimum SO_2 removal efficiency (30-day rolling period).

Newmont – Dry Fork Boilers/Fuels/Control Technologies

The Newmont facility is a proposed 200 MW nominal output pulverized coal-fired boiler. The facility is proposing to fire subbituminous coal from the Powder River Basin (PRB) as its primary fuel. Maximum heat input to the boiler will be 2,030 MMBtu/hr.[1] The Dry Fork unit will be 422 MW-gross (385 MW-net) pulverized coal-fired boiler. The Dry Fork unit will fire subbituminous coal from the adjacent Dry Fork mine as its primary fuel. The unit will have a heat input at maximum load of approximately 3,801 MMBtu/hr.

The most significant differences between Newmont and Dry Fork are the size of the boilers and proposed fuel characteristics. The Dry Fork boiler will be approximately twice the size of the Newmont boiler, with a heat input at maximum load of 3,801 MMBtu/hr compared to 2,030 MMBtu/hr for Newmont. The higher heat input results in correspondingly higher flue gas flow rates. A second distinction between the two projects is that Dry Fork will be a mine-mouth plant. Coal from the Dry Fork Mine will be delivered to the power plant via an overland conveyor. Samples from the Dry Fork Mine show considerable variability in the coal characteristics throughout the mine, including variability in the heating value, moisture content, ash, and sulfur content, Based on available analyses, the Dry Fork Station is being designed to fire coal with a heating value between approximately 7,800 and 8,300 MMBtu/lb and a sulfur content in the range of 0.47%.[2]

The Newmont facility proposed firing subbituminous PRB coal as its primary fuel. Coal will be delivered to the facility by rail from various mines throughout the Powder River Basin. Based on a review of fuel characteristics data available from the National Coal Resources (NCR) Data System, PRB coals from Wyoming mines have heating values in the range of approximately 8,200 to 8,800 Btu/lb and sulfur contents in the range of approximately 0.30 to 0.80%. Median heating values and sulfur contents for Wyoming PRB coals in the NCR Data System were 8,550 and 0.61, respectively.

[1] Information regarding the proposed Newmont boiler was obtained from: Newmont Nevada Energy Investment, LLC, Class I Air Quality Operating Permit to Construct, No. AP-4911-1349.

[2] (see, Permit Application Table 2-1)

Evaluation of Newmont's Permit Limits

When firing coal with a sulfur content <0.45% the Newmont facility will be required to achieve a controlled SO_2 emission rate of 0.065 lb/MMBtu (24-hour average) and a minimum removal efficiency of 91% (30-day rolling period). When firing coal with greater than 0.45% sulfur, the Newmont facility will need to achieve a controlled emission rate of 0.09 lb/MMBtu (24-hour average) and 95% removal. For reasons provided below, it is BEPC's position that these permit limits are either equivalent to the design limits of the proposed control technology or beyond the capability of the emission control technology, and are not achievable on an on-going long-term basis.

Dry FGD – Spray Dryer Absorber

The Newmont facility proposed dry FGD designed as a spray dryer absorber (SDA) as BACT for SO_2 control. SDA control systems use a slurry of lime and water injected into the reaction tower to remove SO_2 from the combustion gases. The reaction tower must be designed to provide adequate contact and residence time between the slurry and the exhaust gas, while producing a dry by-product that will be captured in the unit's downstream fabric filter baghouse.

Control efficiencies achievable with an SDA control system are limited by physical and chemical design constraints of the system. Process parameters affecting efficiency of the SDA include the alkalinity-to-SO_2 stoichiometric ratio, temperature drop across the reaction vessel, and how close the SDA is operated to saturation conditions. Alkalinity of the feed slurry can be controlled by adjusting the ratio of fresh lime slurry to recycle slurry. Increasing the ratio of fresh lime will increase the alkalinity-to- SO_2 stoichiometric ratio and incrementally increase SO_2 removal. However, injecting excess slurry, such that the reactant by-product does not completely dry prior to exiting the reaction vessel, will create significant operating problems with the control system.

Increasing the inlet gas temperature to the SDA may provide additional temperature drop across the reaction vessel to allow a small increase in slurry feed. However, increasing the inlet temperature to the vessel will reduce overall boiler efficiency and increase other emissions on a pound-per-net megawatt basis. Operating the system at an outlet temperature approaching saturation may incrementally increase SO_2 removal. However, operating the SDA too close to saturation will create significant operational problems including wall wetting, scaling, and plugging, as well as significant operational problems with the downstream baghouse. Because the slurry feed rate is limited and the SDA must be operated above the saturation temperature in order to produce a dry reactant by-product, control efficiencies with SDA control systems are limited to a range of 94% to 95%.

Based on information obtained from similar recent projects (i.e., subbituminous coal-fired boilers equipped with an SDA control system) and detailed discussions and negotiations with SDA equipment vendors, the most aggressive, sustainable, and commercially acceptable guarantees currently available from SDA vendors are in the range of 94% control <u>or</u> a floor of 0.08 lb/MMBtu, whichever is achieved first. Compliance with guaranteed emission rates are typically demonstrated based on a one-time test defined in the equipment specification and conducted under new and clean conditions. In other words, for coals generating uncontrolled SO_2 emissions above approximately

1.33 lb/MMBtu, vendors will guarantee 94% removal. However, for coals generating uncontrolled SO_2 emissions below 1.33 lb/MMBtu, rather than guaranteeing 94% removal vendors will guarantee a controlled emission rate of 0.08 lb/MMBtu. An emission rate of 0.08 lb/MMBtu is equivalent to an SO_2 concentration in the flue gas of approximately 40 ppmvd @ 3% O_2, a concentration below which vendors have not been willing to guarantee additional SO_2 capture.[3]

It may be possible to obtain more aggressive guarantees with less acceptable commercial terms. For example, vendors may be willing to provide more aggressive guarantees if compliance with the guarantee is to be demonstrated based on a one-time short-term stack test rather then a longer period of time using the unit's SO_2 continuous emissions monitoring system. Similarly, more aggressive guarantees may be available if the vendor's liabilities associated with missing the guarantees are limited.

For this evaluation it will be assumed that an SDA control system could be designed to achieve a removal efficiency of 95% or a controlled emission rate of 0.06 lb/MMBtu, whichever is achieved first. This control efficiency and emission rate represent short-term system performance that may be attainable under optimal operating conditions, but do not necessarily represent enforceable BACT emission limits which should include some reasonable compliance margin to account for normal fluctuations in the controlled SO_2 emission rate. Based on the technical/physical limitations of the SDA control system, and recent experience with SDA control projects, this control efficiency and controlled emission rate represent the technical limits of the SDA control system. However, it should be noted that, to date, vendors have not been willing to guarantee these performance rates over a sustained period of time with acceptable commercial terms.

Margin Between Performance Target and Permit Limit

The U.S.EPA Environmental Appeals Board has repeatedly 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."[4] To establish a reasonable compliance margin for an SDA control system, BEPC reviewed controlled SO_2 emission rates currently achieved in practice at the best-controlled similar source (i.e., an electric utility steam generating boiler firing subbituminous coal and equipped with SDA). Actual

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[3] When reviewing potential vendor guarantees it is important to keep in mind that compliance with a guaranteed emission rate is typically demonstrated based on a one-time test defined in the equipment specification and conducted under strict supervision when the unit and emission control systems are in a new and clean condition. Emission control technology vendors are not required to demonstrate compliance with the guaranteed emission rates on a on-going long-term basis and under all normal boiler operating conditions.

[4] 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.").

emissions data from KCPL Hawthorn Unit 5 were evaluated to identify removal efficiencies achieved in practice and variability in the controlled SO_2 emission rate. Hawthorn Unit 5 is the most recently constructed utility boiler firing subbituminous coal and equipped with an SDA control system. The unit currently achieves the lowest annual average controlled SO_2 emission rate for all units equipped with dry FGD.[5]

Figure 1 (attached at the end of this memo) shows the actual hourly emissions data reported by Hawthorn Unit 5 for 2005.[6] Emission control systems do not operate under steady-state conditions, and controlled emission rates are subject to short-term fluctuations and spikes. Hourly controlled SO_2 emission rates tend to fluctuate around the control system design point. Short-term spikes in controlled emissions might be caused by changes in boiler load, fuel characteristics, flue gas characteristics, and/or routine maintenance procedures. Short-term spikes in the controlled emission rate can be dampened by averaging emissions over a period of time. Figure 2 shows the same data, with the 24-hour and 30-day rolling averages. A summary of the removal efficiencies and the variation in the controlled emission rates achieved during 2005 based on several averaging times is provided in Tables 1 and 2.

Table 1
Average SO_2 Removal Efficiencies
Hawthorn Unit 5 (2005)
Subbituminous Coal / PC Boiler / SDA

		Annual Average	Maximum
Potential Uncontrolled SO_2 Emissions*	lb/MMBtu	0.78	1.09
Average Controlled Emission Rate (annual average)	lb/MMBtu	0.103	0.103
Removal Efficiency	%	86.8%	90.6%

*Potential uncontrolled SO_2 emission rates were estimated based on a fuel shipment data available from FERC Form 423.

[5] A similar evaluation of the hourly emissions data from KCPL Hawthorn Unit 5 for the time period January 1, 2004 through March was provided to WDEQ in BEPC's response to questions dated March 9, 2006 [Response to WDEQ's Completeness Review Dated December 21, 2005]. That analysis concluded that a margin of 21%, or approximately 0.02 lb/MMBtu, was needed between the performance target guarantee and the enforceable 30-day average permit limit to provide a reasonable opportunity for compliance on a consistent basis.

[6] Emission data was obtained from U.S.EPA's Clean Air Market website: http://cfpub.epa.gov/gdm/

Table 2
Average SO_2 Controlled Emission Rates
Hawthorn Unit 5 (2005)
Subbituminous Coal / PC Boiler / SDA

		Averaging Time	
		24-hour	**30-day**
Average Controlled Emission Rate (annual average)	lb/MMBtu	0.103	0.103
Standard Deviation (based on averaging time)	lb/MMBtu	0.071	0.014
Emission Rate at 95% Confidence Level	lb/MMBtu	0.245	0.131
Percent Increase Above Average Emission Rate	%	138%	27%

Based on emissions data submitted to U.S.EPA in 2005, the Hawthorn facility achieved an annual average SO_2 removal efficiency of 86.8% and a controlled SO_2 emission rate of 0.103 lb/MMBtu. During this time period the SDA control system showed significant variability, especially on a short-term basis. Based on standard deviation calculations, the controlled SO_2 emission rate achieved during the year on a 24-hour basis at a 95% confidence level was 0.245 lb/MMBtu, more than twice the annual average emission rate.

Some of the short-term variability associated with the SDA control system may be related to the need to routinely replace the atomizing nozzles in the reactant vessel. Reactant spray nozzle designs are vendor-specific, and both dual-fluid nozzles and rotary atomizers have been used in large coal-fired boiler applications. The atomizing nozzle assembly (either the duel-fluid feed lance assembly or the rotary atomizer assembly) is typically located in the SDA penthouse, and flange mounted to the roof of the absorber vessel. Overhead cranes or hoists located in the penthouse can be used to remove the nozzle assemblies from the absorber vessel for repair and maintenance. Because of the abrasive nature of the reactant slurry, nozzle assemblies must be removed and replaced on a routine basis. Depending on the design of the SDA system, one or more spare nozzle assemblies will be available for use. The nozzle assemblies may be changed without shutting down the SDA system, however, during that time period the SDA may not be able to maintain maximum control efficiencies.

Newmont Permit Limits

Table 3 shows the permit limits and control efficiencies that Newmont will need to achieve to meet its permit limits based on various fuel characteristics. The heating values and sulfur contents used in Table 3 are in the range for typical PRB subbituminous coals. Controlled emissions shown in brackets represent rates or control efficiencies that are beyond the technical capability of the proposed control technology. Control efficiencies or emission rates that are underlined represent values that are within the technical limits of the control technology, but do not include adequate margin for on-going compliance.

Table 3
Newmont – Control Efficiencies Needed to Meet Permit Limits

Fuel characteristics			Permit Limits		Control Efficiency Needed to Meet Emission Rate	Controlled SO_2 Emission Rate based on Removal Efficiency Requirement
Heating Value (Btu/lb)	Sulfur Content	Potential SO_2	Emission Rate	Control Efficiency		
8,800	0.25	0.57	0.065	91%	88.6%	[0.051]
8,000	0.25	0.625	0.065	91%	89.6%	[0.056]
8,800	0.30	0.68	0.065	91%	90.4%	0.061
8,000	0.30	0.75	0.065	91%	91.3%	0.068 (>0.065)
8,800	0.40	0.91	0.065	91%	92.5%	0.082 (>0.065)
8,000	0.40	1.00	0.065	91%	93.5%	0.090 (>0.065)
8,800	0.45	1.023	0.09	95%	91.2%	[0.051]
8,000	0.45	1.125	0.09	95%	92.0%	[0.056]
8,800	0.50	1.136	0.09	95%	92.1%	[0.057]
8,800	0.60	1.364	0.09	95%	93.4%	0.068
8.800	0.70	1.591	0.09	95%	94.3%	0.080
8,800	0.80	1.818	0.09	95%	95.0%	[0.091 (>0.09)]
8,800	0.90	2.045	0.09	95%	[95.6%]	[0.102 (>0.09)]
8,800	1.0	2.272	0.09	95%	[96.0%]	[0.114 (>0.09)]

[ ] = beyond technical capabilities of the proposed control technology
___ = emission may be technically feasible but does not include adequate compliance margin.

Based on an evaluation of control efficiencies achieved in practice and variability in the controlled SO_2 emission rate associated with an SDA control system, it appears that the Newmont facility may experience significant compliance challenges. For example, when firing coals with less than 0.45% sulfur, the Newmont facility will be required to achieve a controlled SO_2 emission rate of 0.065 lb/MMBtu. As discussed above, it is Basin's position that regardless of the inlet SO_2 emission rate, a controlled emission rate of 0.065 lb/MMBtu is essentially equal to the design limits of the control technology, and does not include adequate compliance margin, especially on a 24-hour averaging basis. Moreover, when firing very low sulfur coals (e.g., coals with sulfur contents below approximately 0.25%) the Newmont facility needs to maintain a minimum removal efficiency of 91%. Removal efficiencies of 91% or more on very low sulfur coals results in controlled emission rates below 0.06 lb/MMBtu, which are beyond the technical capabilities of the control technology.

When firing coals with greater than 0.45% sulfur, the Newmont facility will be required to achieve a controlled SO_2 emission rate of 0.09 lb/MMBtu (24-hour average) and a removal efficiency of at least 95% (30-day average). These emission limitations may be achievable over a limited range of fuel characteristics, but provide no margin for normal operating fluctuations. First, a removal efficiency of 95% is essentially equal to the technical limit of the control technology and provides no compliance margin. Second, when firing coals with potential SO_2 emissions greater than approximately 1.9 lb/MMBtu, removal efficiencies greater than 95% will be needed to meet the 0.09 lb/MMBtu emission limit. This control efficiency is above the technical limits of the control technology. Finally, an emission limit 0.09 lb/MMBtu may not provide adequate compliance margin on a 24-hour basis to account for routine control system maintenance and atomizer changeouts.

Conclusions

Based on a review of anticipated vendor guarantees, emission rates achieved in practice, and an evaluation of the variability associated with dry FGD control systems, it is BEPC's conclusion that the SO_2 emission limits included in the Newmont permit are equivalent to, or exceed, the technical limitations of the proposed control equipment. Removal efficiencies and emission rates required in the Newmont permit have not been demonstrated in practice at any existing source.

The proposed permit limits (0.08 lb/MMBtu annual average and 304.1 lb/hr 30-day average) represent controlled emission rates slightly above the design limits for dry FGD control systems. In order to comply with the permit limits, BEPC will have to achieve controlled SO_2 emission rates below 0.08 lb/MMBtu (approximately 40 ppmvd @ 3% O_2) under all normal operating conditions. Compliance with the 0.08 lb/MMBtu emission limit will required BEPC to achieve annual average removal efficiencies in the range of 93.4% (based on an annual average uncontrolled SO_2 emission rate of 1.21 lb/MMBtu). However, control efficiencies in the range of 94%, and controlled emission rates below 0.08 lb/MMBtu, should be achievable with dry FGD control systems while providing some margin for compliance.

Because of the limited margin between the expected design performance target of the SO_2 control system and the proposed permit limits, BEPC has decided to configure the dry FGD control system as a circulating dry scrubber rather than an SDA. A CDS system uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a venturi at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime and circulated reaction by-products where SO_2 is removed. The desulfurized flue gas passes out of the scrubber, along with reaction products, including unreacted hydrated lime, calcium carbonate, and the fly ash to the particulate removal system (fabric filter baghouse).

Based on information available from equipment vendors and engineering judgment, the CDS DFGD system should be capable of achieving SO_2 removal efficiencies equivalent to those achieved with an SDA. Based on a direct project-specific comparison of both DFGD technologies, BEPC concluded the CDS design offered the following advantages over the SDA: (1) the CDS offers a better chance of complying with stringent SO_2 emission rates given the unique challenges at a mine-mouth plant with respect to variability in the fuel characteristics; (2) potential balance-of-plant impacts associated with operating either system so close to the performance target are potentially less significant with the CDS (i.e., the CDS should not experience wall wetting, scaling, plugging and the associated detrimental impacts on the baghouse); and (3) the CDS will not experience short-term emission spikes associated with routine atomizer changeouts and should be better suited to achieve stringent emission rates based on short-term averaging times.

Sargent & Lundy LLC

Figure 1
Hawthorne Unit 5 – Hourly SO_2 Emissions Data (2005)

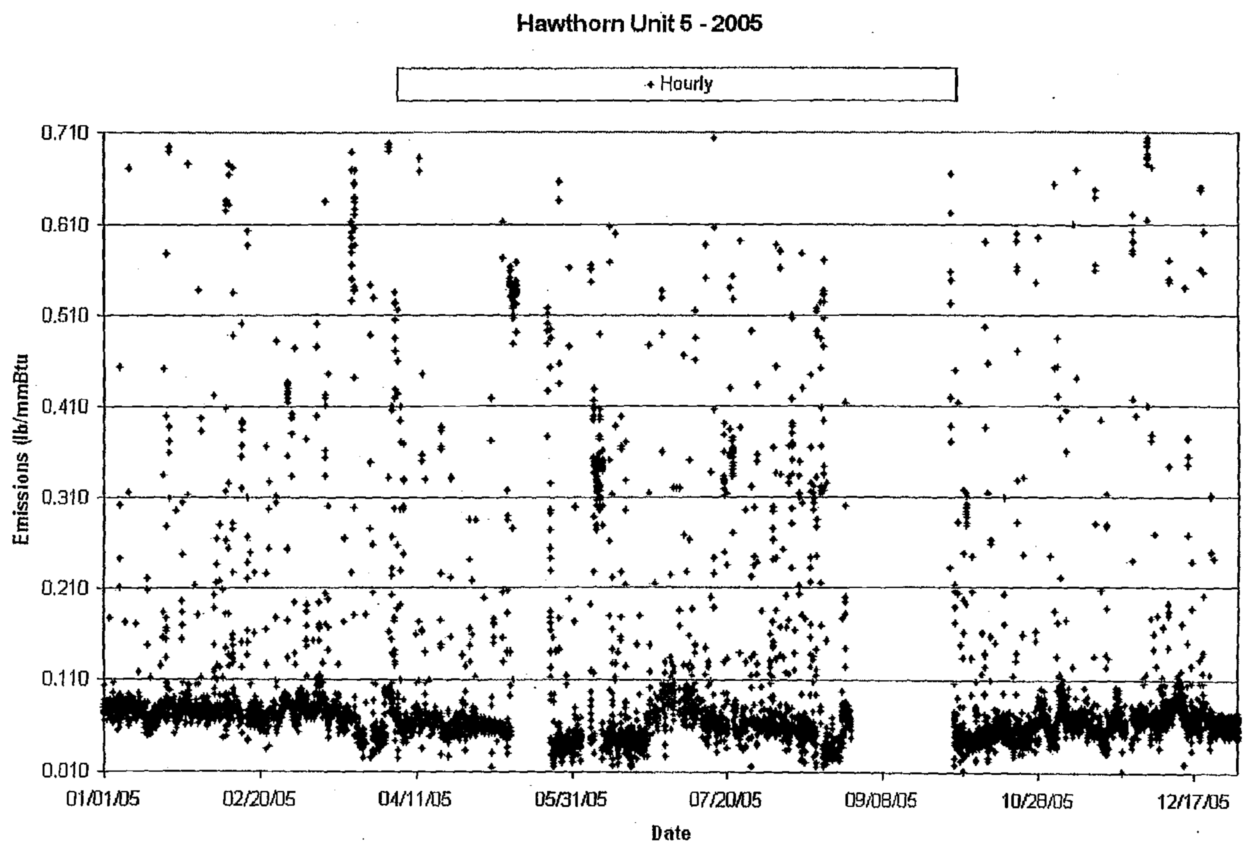

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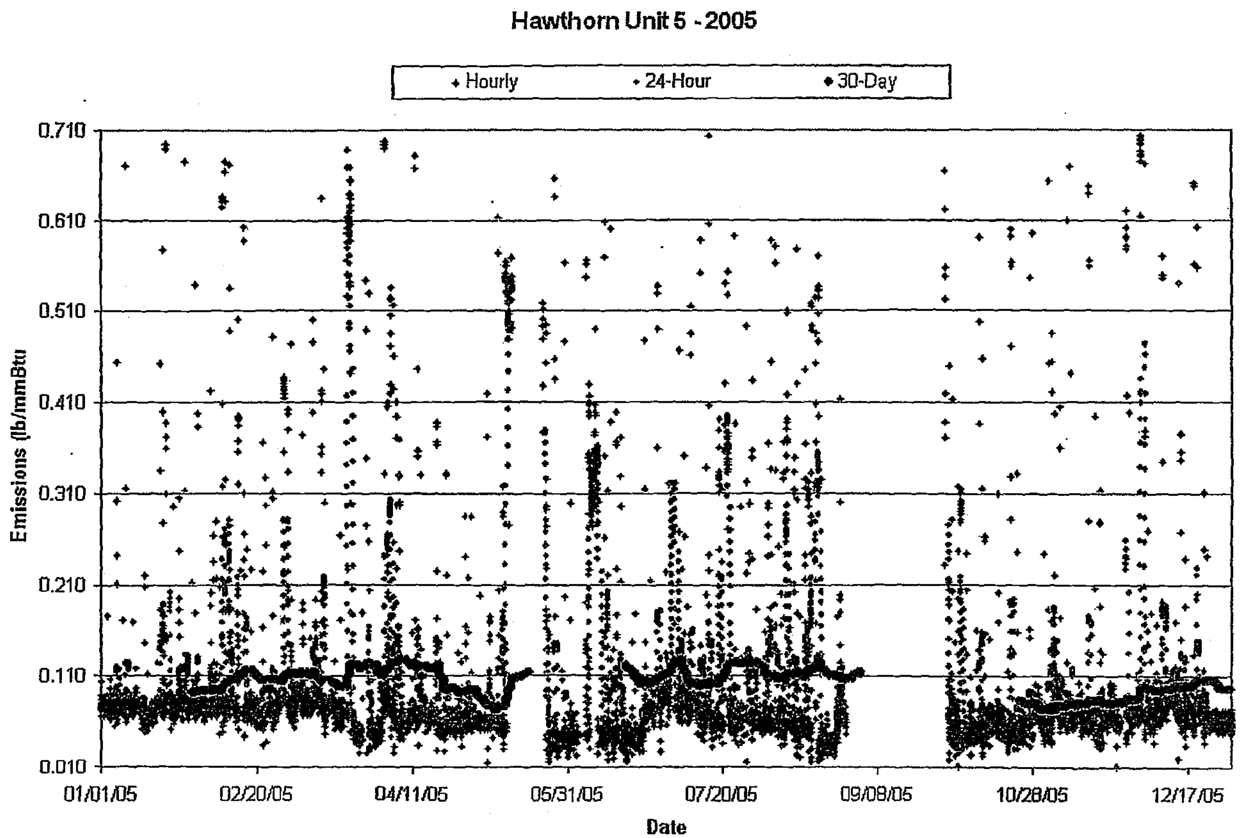
Figure 2
Hawthorne Unit 5 – Hourly SO_2 Emissions Data (2005)



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Sargent & Lundy LLC

Date: June 8, 2007

Project: Dry Fork Unit 1 – Construction Air Permit Application

Subject: Proposed H_2SO_4 Emission Limits

The purpose of this memorandum is to provide additional review of the proposed Basin Electric Power Cooperative (BEPC) Dry Fork Station H_2SO_4 BACT emission limit.

Background

BEPC's permit application, including supplemental information submitted in response to agency questions, included a BACT analysis for the control of sulfuric acid mist (H_2SO_4) emissions from the proposed Dry Fork Boiler (see, Attachment 1 – Revised H_2SO_4 BACT Analysis PC Boiler, June 7, 2006). The BACT analysis included an evaluation of control technologies available to reduce H_2SO_4 emissions from the main boiler (including both wet and dry flue gas desulfurization (FGD) systems). The BACT analysis concluded that the combination of dry FGD and the fabric filter baghouse (DFGD+FF) provided the most effective H_2SO_4 control. BEPC proposed a controlled H_2SO_4 emission rate of 0.0045 lb/MMBtu based on anticipated H_2SO_4 control efficiencies and the ability to demonstrate compliance with the BACT emission limit.

Sulfuric Acid Mist Emission Calculations

Sulfuric acid mist emissions were calculated based on: (1) the sulfur content of the fuel; (2) 2% SO_2 to SO_3 oxidation across the boiler and SCR; (3) 100% conversion of flue gas SO_3 to H_2SO_4; and (4) an H_2SO_4 removal efficiency for each potentially feasible control technology. Potential uncontrolled H_2SO_4 emissions from the Dry Fork boiler were calculated as follows:

$$\frac{1.21 \text{ lb } SO_2}{\text{MMBtu}} \left| \frac{\text{lbmole } SO_2}{64 \text{ lb } SO_2} \right| 2\% \left| \frac{98 \text{ lb } H_2SO_4}{\text{lbmole } H_2SO_4} \right. = 0.037 \text{ lb } H_2SO_4/\text{MMBtu}$$

Control Technology Discussion

A summary of the control technology evaluation included in the Dry Fork permit application and revised H_2SO_4 BACT analysis is provided below:

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Dry FGD/Fabric Filters

As discussed in the permit application, dry FGD control systems, including spray dryer absorbers (SDA) and circulating dry scrubbers (CDS), are technically feasible SO_2/SO_3 control options. Dry FGD systems are designed to use a lime and water slurry injected into the absorber tower to remove SO_2 from the combustion gases. SO_3 will also react with the reactant sprayed into the absorber tower to form calcium sulfate. Dry FGD systems are located upstream of the system's particulate control device and tend to increase the alkalinity of the filter cake, enhancing SO_3 removal in the fabric filter.

A portion of the SO_3 generated in the boiler and SCR will be captured in the unit's fabric filter (BACT for PM_{10} control). Fly ash cake that accumulates on the filter bags acts as an alkaline filter through which the flue gas must pass. SO_3, which is very reactive, readily reacts with alkaline components of the fly ash at temperatures below the H_2SO_4 dewpoint to form sulfate salts. The SO_3 removal efficiency of a fabric filter is dependent upon the alkalinity of the fly ash cake. Fabric filters associated with highly alkaline fly ash will significantly reduce the SO_3 concentration in the flue gas. Coals containing the highest alkalinity are generally low-rank coals such as the subbituminous coals from the Power River Basin and lignites.[1] A dry FGD control system located upstream of the fabric filter will also increase the alkalinity of the filter cake.

The combination of dry scrubbing and fabric filtration has demonstrated the ability to achieve a high SO_3 removal efficiencies from conventional pulverized coal-fired combustion flue gas streams. Based on engineering judgment, it is estimated that a dry scrubber designed as an SDA or CDS, used in conjunction with a fabric filter baghouse, would reduce potential H_2SO_4 emissions by at least 88% under normal operating conditions. A control efficiency of 88% results in an average H_2SO_4 concentration in the flue gas of approximately 1.8 ppmvd @ 3% O_2, which is equivalent to an emission rate of approximately 0.0045 lb/MMBtu.

Wet FGD

Wet FGD was also evaluated as a potential post-combustion SO_2/SO_3 control technology. As discussed in the permit application, the wet scrubbing process uses an alkaline slurry made by adding lime or limestone to water. The alkaline slurry is sprayed into the absorber tower and reacts with SO_2 in the flue gas to form insoluble calcium sulfite and calcium sulfate solids. A wet FGD system must be located downstream of the unit's particulate control device.

SO_3 entering the wet scrubber will react with water and create micron sized sulfuric acid droplets. Micron sized droplets can pass through the spray levels in the absorber tower and the mist eliminator and be emitted as sulfuric acid mist. Although some of the sulfuric acid droplets will react with the alkaline reactant in the wet scrubber, industry experience suggests that many of the micron-sized droplets will not come into contact with limestone.[2] Because of the inherently low SO_3 concentration

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[1] Singer, J.G., editor, Combustion Fossil Power, Combustion Engineering, Inc., 4th ed., 1991 (pp 9-14).

[2] Gooch, J.P., Dismukes, E.B., Formation of Sulfate Aerosol in an SO_2 Scrubbing System, Southern Research Institute, Birmingham, AL.

in the flue gas associated with firing sub-bituminous coal, it is anticipated that a wet FGD system would reduce potential H_2SO_4 emissions by approximately 40% to 60%.

Because the overall control efficiency of a wet FGD system will be lower than the control efficiency of the DFGD/FF control scenario, and because the wet FGD system will result in significant collateral environmental issues, wet scrubbing was not considered a technically viable H_2SO_4 control system for the Dry Fork main boiler.

Wet electrostatic precipitation (WESP) has been proposed on other coal-fired projects as one technology to reduce sulfuric acid emissions from utilities firing high-sulfur eastern bituminous coals controlled with wet FGD.[3] WESP has been demonstrated as an effective control technology to abate SO_3 mist from industrial applications with relatively low flue gas flow rates and high acid mist concentrations, such as sulfuric acid plants. However, until recently, the technology has not been applied to the utility industry because of the high gas flow volumes and low acid mist concentrations associated with utility flue gas. In a utility application, the WESP would be located downstream from the wet FGD to remove micron-sized H_2SO_4 aerosol from the flue gas stream as a condensable particulate.

There is limited commercial operating experience upon which to base a conclusion regarding the effectiveness of WESP on a large utility boiler, and no experience with WESP on a subbituminous fired boiler equipped with dry FGD and fabric filter. In general, WESP systems have been designed to achieved controlled H_2SO_4 emission rates in the range of 5-10 ppmvd. The low sulfur subbituminous fuel proposed for the Dry Fork boiler will generate a maximum H_2SO_4 concentration in the boiler flue gas of approximately 15 ppmvd (uncontrolled), a concentration essentially equivalent to the H_2SO_4 emission rates achieved in practice with WESP in high-sulfur applications. The proposed DFGD/FF control systems are expected to reduce the average H_2SO_4 emission rate to less than 1.8 ppmvd @ 3% O_2. There is no operating history or data available demonstrating that a WESP would be effective on a unit firing subbituminous coal and equipped with DFGD+FF. Because the feasibility and effectiveness of WESP has not been demonstrated on subbituminous-fired boilers, WESP was not considered technically feasible or commercially available for the Dry Fork boiler configuration.

Proposed BACT Emission Limit and Compliance Demonstration

BEPC's BACT concluded that the combination of dry FGD and the fabric filter baghouse provided the most effective H_2SO_4 control. BEPC proposed a controlled H_2SO_4 emission rate of 0.0045 lb/MMBtu. An emission rate of 0.0045 lb/MMBtu is equivalent to an H_2SO_4 concentration in the flue gas of approximately 1.8 ppmvd @ 3% O_2. Assuming an uncontrolled H_2SO_4 emission rate of 0.037 lb/MMBtu (calculated based on 2% SO_2 to SO_3 conversion in the boiler and SCR), the combination of emission

[3] See for example, Thoroughbred Generating Station PSD Permit Application, Submitted to Kentucky Department of Environmental Protection, October 26, 2001.

control technologies will have to achieve an removal efficiencies of at least 88% to ensure compliance with the proposed emission limit.

Compliance Demonstration – Test Method Limits

As discussed in the permit application, the test method used to measure H_2SO_4 emission rates (EPA Test Method 8) has proven to be problematic on coal-fired boilers. For example, interfering agents with Method 8 include fluorides and free ammonia (NH_3). In fact, Method 8 states that if "any of these interfering agents is present… alternative methods, subject to the approval of the Administrator, are required." One alternative test method that has been proposed to measure sulfuric acid emissions from stationary sources is the controlled condensation method (Method 8A), however, certain flue gas characteristics may also result in measurement biases with this method.[4]

Because of the difficulties associated with measuring very low H_2SO_4 emission rates, equipment vendors have not been willing to guarantee H_2SO_4 emissions below approximately 2 ppmvd @ 3% O_2. Based on information from equipment vendors, an emission rate in the range of 1 to 2 ppmvd @ 3% O_2, represents the practical analytical detection limit or the practical limit of quantitation (PQL) limit of Methods 8 and 8A on a coal-fired boiler.

At the 2007 Electric Power Conference (Rosemont, Illinois May 1 – 3, 2007), Mr. Scott Evans of Clean Air Engineering presented a paper discussing the feasibility of using Method 8 to demonstrate compliance with low H_2SO_4 emission limits. Clean Air Engineering provides, among other services, stack testing services for utility boilers.[5] Mr. Evan's presentation, "Demonstrating Compliance with Sub-ppm Acid Mist Limits: Can Method 8 Handle the Challenge" summarized data from an evaluation of the Method 8 biases and detection limits. Among other findings, the study included the following conclusions:

- Practical Limit of Quantitation (PQL) is about 0.5 ppm under tightly controlled conditions;
- PQL is likely higher in the field;
- Many positive bias effects – some correctable;
- Longer runs do not improve detection limits;
- Analysis at sub-ppm levels are very sensitive, i.e., small analytical errors lead to large positive biases; and
- All bets are off with NH_3 is present in the flue gas.

These conclusions are consistent with information submitted in the permit application and information obtained from emission control equipment vendors, that is, that the practical analytical detection limit of Method 8 on a coal-fired boiler is in the range of approximately 1 to 2 ppm.

[4] See, Blythe, G., et al. "Improvements to the Controlled Condensation measurement method for Sulfuric Acid," presented at the EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium: The Mega Symposium. Atlanta, GA, August 16 – 20, 1999. See also, Blythe, G., et al. "Flue Gas sulfuric Acid Measurement Method Improvements."

[5] See, http://www.cleanair.com

Other Recently Permitted/Proposed H_2SO_4 Emission Limits

BEPC's BACT analysis included a list of other recently issued/proposed H_2SO_4 BACT limits for coal-fired boiler. A majority of the recently issued BACT limits were between 0.0037 and 0.0050 lb/MMBtu. The lowest H_2SO_4 emission limits identified in the RBLC Database were:

- City Utilities of Springfield - Southwest Power Station (Missouri)
  - Fuel: subbituminous coal
  - Control Technology: dry FGD
  - Emission Limit: 0.000184 lb/MMBtu
- Newmont Power Station (Nevada)
  - Fuel: subbituminous coal
  - Control Technology: dry FGD
  - Emission Limit: 2.06 lb/hr (0.001 lb/MMBtu)

An emission rate of 0.000184 lb/MMBtu is equivalent to an H_2SO_4 concentration in the flue gas of approximately 0.07 ppmvd @ 3% O_2. Based on information summarized above, this emission rate is significantly below the PQL of Method 8. An emission rate of 0.001 lb/MMBtu is equivalent to an H_2SO_4 concentration in the flue gas of approximately 0.4 ppmvd @ 3% O_2, which is equal to, or slightly below, the PQL of Method 8 under tightly controlled conditions. Based on information from equipment vendors and stack testing companies, both of these facilities will have significant challenges demonstrating compliance with the respective permit limits.

Conclusions

Based on the review of potentially available emission control technologies, BEPC is confident that the proposed control systems (DFGD + FF) will provide the most effective H_2SO_4 control, and that the control systems will consistently achieve H_2SO_4 removal efficiencies of at least 90% and controlled H_2SO_4 emissions below approximately 1.5 ppm @ 3% O_2. However, as discussed in the BACT analysis, BEPC is concerned about the ability of the reference test method to accurately measure H_2SO_4 concentrations in boiler flue gas at low ppm levels, and BEPC does not want to propose a permit limit that is at, or below, the practical analytical detection limit of the test method. Therefore, it is BEPC's position that a controlled emission rate of 0.0045 lb/MMBtu (approximately 1.8 ppmvd @ 3% O_2) represents BACT for H_2SO_4 control for the following reasons:

- The proposed emission rate will require significant H_2SO_4 control in the DFGD and FF.
- Compliance with the emission rate can be demonstrated using EPA Test Method 8A.
- On-going compliance with the H_2SO_4 BACT limit will be based on demonstrating compliance with the SO_2 and filterable PM10 BACT limits. BEPC anticipates stringent SO_2 and filterable PM10 BACT limits that will require proper operation of the DFGD and FF control systems.

- Air quality impact modeling conducted at the proposed H_2SO_4 emission rate demonstrated that emissions from the proposed unit will not contribute to any violations of the applicable NAAQS standards and PSD increments, or cause any adverse impacts on Class I Areas.

Sargent & Lundy LLC

Date: June 8, 2007

Project: Dry Fork Unit 1 – Construction Air Permit Application

Subject: SDA – CDS Comparison

The purpose of this memorandum is to provide additional information comparing dry flue gas desulfurization (DFGD) control systems available for the proposed Basin Electric Power Cooperative (BEPC) Dry Fork Station, and to supplement the SO_2 BACT analysis previously submitted to the Wyoming Department of Environmental Quality (WDEQ).

Background

BEPC prepared a SO_2 BACT analysis for the Unit 1 Boiler as part of the original air construction permit application submitted in November 2005 ("Permit Application", and information and analyses submitted to WDEQ in response to agency requests for additional information (see, Attachment No. 1 to BEPC's Response to WDEQ's Completeness Review Dated December 21, 2005). Information submitted to WDEQ included a detailed analysis of the status of FGD technologies, an evaluation of the technical feasibility of each potentially feasible control technology, emissions information from existing coal-fired units equipped with FGD controls, and a cost effectiveness evaluation of the technically feasible control systems. Based on information submitted in the Permit Application and supplemental submittals (the "BACT Analysis") BEPC proposed dry scrubbing, designed as either a spray dryer absorber (SDA) or circulating dry scrubber (CDS), as BACT for SO_2 control, and BEPC proposed an SO_2 BACT emission limit of 0.10 lb/MMBtu based on a 30-day rolling average.

On February 5, 2007, WDEQ issued a Permit Application Analysis for the Dry Fork facility. The Permit Application Analysis included the agency's BACT analysis for each PSD pollutant. WDEQ concluded that dry FGD designed as an SDA control system with emission limits of 0.08 lb/MMBtu (annual average) and 304.1 lb/hr (30-day average) represented BACT for SO_2 control. The Permit Application Analysis also included a 3-hour block SO_2 emission limit of 380.1 lb/hr. Prior to the issuance of the Permit Application Analysis, BEPC reviewed the proposed emission limits and agreed to accept the more stringent limits.

Subsequently, on March 23, 2007, BEPC submitted comments to WDEQ regarding the Permit Application Analysis and the proposed emission limits. Among other comments, BEPC addressed the more stringent SO_2 emission limits and provided information clarifying its conclusions regarding SO_2 control technologies. Specifically BEPC requested that WDEQ change references to "SDA" to "DFGD" throughout the Permit Application Analysis, and that DFGD refer to either an SDA or CDS control system. ~~BEPC's BACT analysis concluded that both SDA and CDS dry scrubbing systems were~~

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technically feasible and commercially available for the Dry Fork Station. Additional information specifically comparing the dry FGD control options (SDA and CDS) is provided below.

SO_2 BACT Analysis – Supplement

Supplemental information regarding the technical feasibility and cost effectiveness of the spray dryer absorber (SDA) and circulating dry scrubbing (CDS) FGD control systems is provided below. This information is being submitted to supplement information already submitted to WDEQ in BEPC's BACT Analysis.

Step 1 – Identify all Control Technologies

In the BACT Analysis, BEPC identified SO_2 control technologies with potential applicability to Dry Fork Unit 1. Potentially applicable SO_2 control systems identified in the BACT Analysis included various designs of both wet and dry FGD control systems.

Step 2 - Eliminate Technically Infeasible Options

The technical feasibility of each potentially applicable SO_2 control system was evaluated in the BACT Analysis. Supplemental information regarding the technical feasibility of the dry FGD control systems is provided below.

Dry Flue Gas Desulfurization

Dry scrubbing involves the introduction of dry or hydrated lime slurry into a reaction vessel where it reacts with SO_2 in the flue gas to form calcium sulfate and calcium sulfite solids. Dry scrubbing typically includes a separate lime preparation system and reaction vessel. Unlike wet FGD systems that produce a slurry by-product that is collected separately from the fly ash, dry FGD systems produce a dry by-product that is removed with the fly ash in the particulate control equipment. Therefore, dry FGD systems must be located upstream of the particulate control device to remove the fly ash and reaction by-products.

Various dry FGD systems have been designed for use with pulverized coal-fired boilers. Dry scrubbing systems that may be technically feasible for Dry Fork Unit 1 are discussed below.

Spray Dryer Absorber

Spray dryer absorber (SDA) systems have been used in large coal-fired utility applications. SDA systems have demonstrated the ability to effectively reduce uncontrolled SO_2 emissions from pulverized coal units.

The typical SDA uses a slurry of lime and water injected into one or more reaction tower to remove SO_2 from the combustion gases. The reaction towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a dry by-product. The process equipment associated with a spray dryer typically includes an alkaline storage tank, mixing and feed tanks, one or more reactant atomizers, spray chamber, particulate control device, and a recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce sorbent consumption.

Various process parameters affect the efficiency of the SDA process including: the type and quality of the additive used for the reactant, reactant stoichiometric ratio, how close the SDA is operated to saturation conditions, and the amount of solids product recycled to the atomizer. The control efficiency of a SDA system is limited to approximately 94% to 95%, depending on SO_2 loading to the system. SDA control efficiency is a function of numerous operating variables including gas-to-liquid contact and system operating temperatures. In a dry FGD system, the amount of reactant slurry introduced to the spray dryer must be controlled to insure that the reaction products leaving the absorber vessel are dry. Therefore, the outlet temperature from the absorber must be maintained above the saturation temperature. SDA systems are typically designed to operate with an approximate 30 F° approach to the adiabatic saturation temperature. Operating closer to the adiabatic saturation temperature may allow for incrementally higher SO_2 control efficiencies, however, outlet temperatures too close to the saturation temperature will result in severe operating problems including reactant build-up in the absorber modules, blinding of the fabric filter bags, and corrosion in the fabric filter and ductwork.

High SO_2 removal efficiencies in a SDA are also dependent upon good gas-to-liquid contact. Reactant spray nozzle designs are vendor-specific. Both dual-fluid nozzles and rotary atomizers have been used in large coal-fired boiler applications.

Dual-fluid nozzles (slurry and atomizing air) typically consist of a stainless steel head with multiple, ceramic two-fluid nozzle inserts. Slurry enters through the nozzle head and is distributed to the nozzle inserts. Atomizing air enters concentrically into a reservoir in the nozzle head and mixes with the slurry. The atomizing air expands as it passes through the air holes and nozzle exit. This expansion creates the shear necessary to atomize the slurry. Each nozzle is provided with a feed lance assembly consisting of a concentric feed pipe (air around slurry), hose connections, and the nozzle head. The feed lance assembly is inserted down through the SDA roof through a nozzle shroud assembly.

Rotary atomizers are comprised basically of a high-speed rotating atomizer wheel coupled to a drive device and speed-increasing gear box. Because the reactant slurry is abrasive, the atomizing nozzles typically consist of a stainless steel head and multiple abrasion resistant ceramic nozzle inserts. The rotary atomizers are inserted down through the SDA roof. The reactant slurry is atomized as it passes through the rapidly rotating nozzles.

SDA systems have been permitted as BACT on pulverized coal-fired boilers firing low-sulfur subbituminous coals,[1] and are a technically feasible control option for Dry Fork. Based on information obtained from similar recent projects (i.e., subbituminous coal-fired boilers equipped with an SDA control system) and detailed discussions and negotiations with SDA equipment

[1] See, for example, Comanche Unit 3, City Utilities of Springfield – Southwest Power Station, MidAmerican Council Bluffs Unit 4, and Kansas City Power & Light – Hawthorne Facility

vendors, the most aggressive, sustainable, and commercially acceptable guarantees currently available from SDA vendors are in the range of 94% control or a floor of 0.08 lb/MMBtu, whichever is achieved first. Compliance with the guaranteed emissions rates is demonstrated based on a one-time test defined in the equipment specification and conducted under new and clean conditions.[2] In other words, for coals generating uncontrolled SO_2 emissions above approximately 1.33 lb/MMBtu, vendors will guarantee 94% removal based on the applicable reference method test. However, for coals generating uncontrolled SO_2 emissions below 1.33 lb/MMBtu, rather than guaranteeing 94% removal vendors will guarantee a controlled emission rate of 0.08 lb/MMBtu, again based on the applicable reference method test. An emission rate of 0.08 lb/MMBtu is equivalent to an SO_2 concentration in the flue gas of approximately 40 ppmvd @ 3% O_2, a concentration below which vendors have not been willing to guarantee additional SO_2 capture.

It may be possible to obtain more aggressive guarantees with less acceptable commercial terms. For example, vendors may be willing to provide more aggressive guarantees if compliance with the guarantee is to be demonstrated based on a one-time short-term stack test rather then a longer period of time using the unit's SO_2 continuous emissions monitoring system. Similarly, more aggressive guarantees may be available if the vendor's liabilities associated with missing the guarantees are limited.

Based on the design fuel characteristics included in the Permit Application, the highest long-term average SO_2 concentration in the flue gas leaving the Dry Fork boiler is expected to be 1.21 lb/MMBtu, or approximately 620 ppmvd @ 3% O_2. Based on SO_2 emission rates achieved in practice with SDA control systems, vendor information, and engineering judgement, it is expected that the lowest short-term actual SO_2 emissions from Dry Fork Unit 1 will be in the range of 30 to 37 ppmvd @ 3% O_2 (i.e., 94% to 95% reduction from an uncontrolled rate of 620 ppmvd). Concentrations of 30 and 37 ppmvd @ 3% O_2 are equivalent to controlled emission rates of approximately 0.06 to 0.073 lb/MMBtu, respectively. These emission rates represent short-term actual emission rates that may be attainable under optimal operating conditions, but do not necessarily represent enforceable BACT emission limits which should include some reasonable compliance margin to account for normal fluctuations in the controlled SO_2 emission rate.

Circulating Dry Scrubber

A second type of dry scrubbing system is the circulating dry scrubber (CDS). A CDS system uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2 from the flue gas. Flue gas passes through a venturi at the base of a vertical reactor tower. Water is injected into the absorber at the throat of the venturi to humidify the flue gas. The humidified flue gas enters a fluidized bed of powdered hydrated lime and recycled by-produce where SO_2 is removed.

[2] When reviewing potential vendor guarantees it is important to keep in mind that compliance with a guaranteed emission rate is typically demonstrated based on a one-time test defined in the equipment specification and conducted under strict supervision when the unit and emission control systems are in a new and clean condition. Emission control technology vendors are not required to demonstrate compliance with the guaranteed emission rates on a on-going long-term basis and under all normal boiler operating conditions.

Water used to humidify the flue gas evaporates in the absorber, cooling the flue gas from approximately 300 °F at the inlet to approximately 160 °F. Velocity in the absorber is maintained to sustain a fluidized bed of particles. Hydrated lime in the reaction vessel reacts with SO_2 to form calcium sulfite and calcium sulfate solids. Desulfurized flue gas passes out of the absorber, along with fly ash, reaction by-products, and unreacted lime to the unit's particulate control system (fabric filter baghouse).

Based on information available from equipment vendors, the CDS flue gas desulfurization system should be capable of achieving SO_2 removal efficiencies similar to those achieved with an SDA. In fact, vendors advise that the CDS system may be capable of achieving even higher removal efficiencies with increased reactant injection rates and higher Ca/S stoichiometric ratios, and may provide the ability to react more rapidly to short-term changes in the uncontrolled SO_2 emission rate. To date the CDS has had limited application on large pulverized coal-fired boilers. The largest CDS unit, in Austria, is on a 275 MW oil-fired boiler burning oil with a sulfur content in the range of 1.0 to 2.0%. Operating experience on smaller pulverized coal boilers in the U.S., including the 80 MW Neil Simpson Unit 2 in Wyoming, has shown good SO_2 removal capability but relatively high lime consumption rates, and significant fluctuations in lime utilization based on inlet SO_2 loading.[3]

A CDS control system is a technically feasible SO_2 control option for Dry Fork, and based on conversations with equipment vendors, CDS control systems are commercially available in the size range needed for the Dry Fork boiler. However, there is limited operating experience with CDS scrubbers upon which to establish a controlled SO_2 emission rate that could be achieved on an on-going long-term basis. Based on a review of CDS control systems currently in operation, discussions with CDS control system vendors, and engineering judgment, it was concluded that the CDS control system could achieve SO_2 control efficiencies equivalent to control efficiencies achieved with an SDA. In addition, the CDS offers the potential to react more quickly to short-term variations in the uncontrolled SO_2 emissions and should not experience short-term SO_2 emission spikes typically associated with SDA reactant atomizer maintenance.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The technically feasible SO_2 control technologies were ranked by control effectiveness in the Permit Application (Permit Application Table 5-1). Ranges were provided based on emission rates identified in the RBLC Database and recently approved PSD permits. A more detailed evaluation of controlled SO_2 emission rates potentially achievable with dry FGD control systems is provided below.

3 See, Lavely, L.L., Schild, V.S., and Toher, J., "First North American Circulating Dry Scrubber and Precipitator Remove High Levels of SO2 and Particulate",

Dry FGD Technology	Performance Targets* (lb/MMBtu)	Comments
SDA	0.06 to 0.08 lb/MMBtu	Removal efficiencies with an SDA are limited because the outlet temperature from the absorber must be maintained above the saturation temperature to minimize potential for adverse operating problems. Performance targets are equivalent to the most aggressive guarantees currently available from SDA equipment vendors.
CDS	0.06 to 0.08 lb/MMBtu	There is limited operating history available for CDS control systems, and no operating history for a CDS control system on a pulverized coal-fired unit as large as Dry Fork Unit 1. The CDS should achieve controlled emission rates similar to SDA, and offers the potential to achieve higher removal with increased reaction injection rates and higher Ca/S stoichiometric ratios.

* The performance targets listed above represent short-term actual emission rates that may be attainable under optimal operating conditions, but do not necessarily represent enforceable BACT emission limits which should include some reasonable compliance margin to account for normal fluctuations in the controlled SO_2 emission rate.

The performance targets listed above represent short-term emission rates that may be attainable under optimal operating conditions with either dry FGD control system, but do not include any operating margin needed to ensure compliance with an enforceable permit limit. The U.S.EPA Environmental Appeals Board has repeatedly 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."[4] To establish a reasonable margin between the performance targets and permit limits, BEPC reviewed controlled SO_2 emission rates currently achieved in practice at the best-controlled similar sources (i.e., an electric utility steam generating boiler firing subbituminous coal and equipped with dry FGD), and evaluated variability in the controlled emission rate. A statistical analysis of the hourly emissions data from KCPL Hawthorn Unit 5 was provided to WDEQ in BEPC's response to questions dated March 9, 2006 [Response to WDEQ's Completeness Review Dated December 21, 2005]. That analysis concluded that a margin of approximately 0.02 lb/MMBtu or 21% is needed between the SDA performance target and the enforceable 30-day average permit limit to provide a reasonable opportunity for compliance on a consistent basis.

A similar statistical analysis of the hourly emissions data from Neil Simpson Unit 2, a nominal 80 MW pulverized coal-fired unit equipped with a CDS control system, was also provided to WDEQ in BEPC's response to questions dated March 9, 2006. That analysis concluded that, although a CDS system may provide the opportunity for more aggressive control and should achieve removal efficiencies equivalent to those achieved with an SDA, additional margin may be required between the performance target and permit limit because of the limited experience and operating history of this technology. Worldwide,

[4] 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.").

there are no CDS units currently operating at the size required for Dry Fork Unit 1, and there are no operating data available for units achieving current SO_2 BACT limits. However, based on discussions with technology vendors and engineering judgment, the CDS control system is a technically feasible and commercially available option for Dry Fork with the ability to achieve the proposed SO_2 BACT emission limits. In addition, because the CDS control system is designed such that all the boiler flue gas flows through a fluidized bed of reactant, the CDS has the potential to react more quickly to short-term variations in uncontrolled SO_2 emissions, and has some advantages with respect to meeting stringent short-term SO_2 emission limits (discussed below).

Step 4 – Evaluate Most Effective Controls and Document Results

In its response to WDEQ comments dated December 21, 2005, BEPC provided a detailed cost effectiveness evaluation for the following technically feasible and commercially available SO_2 control scenarios:

- Wet FGD @ 0.07 lb/MMBtu
- CDS @ 0.08 lb/MMBtu
- Wet FGD @ 0.08 lb/MMBtu
- SDA @ 0.09 lb/MMBtu
- Wet FGD @ 0.09 lb/MMBtu
- SDA @ 0.10 lb/MMBtu

The emission rates used in the cost effectiveness evaluation represented enforceable permit limits, and were based on expected actual emissions plus operating margin for compliance. The short-term actual emissions attainable under optimal operating conditions that are associated with the enforceable BACT emission limits for each dry FGD system included in the cost-effectiveness evaluation are provided below:

Dry FGD Control Technology Scenario	Enforceable BACT Permit Limit (lb/MMBtu annual average)	Short-Term Actual Emissions Attainable Under Optimal Operating Conditions (lb/MMBtu)
CDS @ 0.08 lb/MMBtu	0.08	0.06
SDA @ 0.09 lb/MMBtu	0.09	0.07
SDA @ 0.10 lb/MMBtu	0.10	0.08

As discussed in more detail below, the cost effectiveness evaluations for SDA control systems at 0.09 and 0.10 lb/MMBtu would also apply to CDS control systems at the same emission rates. The CDS control system was evaluated at 0.08 lb/MMBtu based on the conclusion that the CDS offers the potential to achieve somewhat lower controlled SO_2 emission rates with increased reactant injection rates and increased reactant consumption.

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SDA vs. CDS Costs

The cost effectiveness evaluation included an estimate of both capital costs and operating and maintenance (O&M) costs for each FGD control system. Capital costs include all costs required to purchase equipment needed for the control system, and includes the purchased equipment cost plus direct installation costs (such as foundations and supports, erection, electrical, and piping), and indirect capital costs (such as engineering, contractor fees, performance testing and contingencies). With respect to dry FGD control systems, purchased equipment costs include the reagent preparation system, absorber/reaction system, by-product management system, baghouse costs, and support equipment. Based on information available from control system vendors, the SDA and CDS control systems will have similar capital requirements.

O&M costs include direct O&M costs and indirect operating costs Direct O&M costs are those costs that tend to be proportional to the quantity of exhaust gas processed by the control system. These may include costs for reactant consumption, utilities (steam, electricity, and water), waste treatment and disposal, maintenance materials, replacement parts, and operating and maintenance labor. Of these direct O&M costs, costs for reactants, utilities, waste treatment, and disposal are variable. Labor costs, maintenance materials and replacement parts are semi-variable direct costs as they are only partly dependent upon the exhaust flow rate.

Indirect or "fixed" annual costs are those whose values are totally independent of the exhaust flow rate and, in fact, would be incurred even if the control system were shut down. They include such categories as administrative charges, property taxes, and insurance, and include the capital recovery cost.

With respect to dry FGD control systems, O&M costs include auxiliary power consumption, bag life impacts, reagent costs, by-product handling and disposal, water consumption, operating labor, maintenance materials, and maintenance labor. Based on information from control system vendors and engineering judgement, O&M costs will be similar for SDA and CDS control systems. Auxiliary power requirements needed to fluidize the CDS reaction bed will be similar to the auxiliary power requirements needed for reactant mixing, pumping, and atomization with the SDA. Assuming a similar SO_2 removal requirements, reactant utilization, water consumption, and by-product handling costs should be similar for both dry systems.

Dry FGD Cost Effectiveness Evaluation

Assuming similar SO_2 removal requirements, the SDA and CDS control systems will have similar capital costs, O&M costs, and annual operating costs. Based on cost estimates provided in response to WDEQ's Completeness Review dated December 21, 2005, the average cost effectiveness of either dry FGD control system would be in the range of \$1,189 to \$1,275/ton SO_2 removed (based on controlled emission rates of 0.10 and 0.09 lb/MMBtu, respectively). The cost effectiveness of the CDS control system was also evaluated at a controlled emission rate of 0.08 lb/MMBtu, assuming increase reactant consumption and increased O&M costs. The average cost effectiveness of the CDS control system at 0.08 lb/MMBtu increased to approximately \$1,426/ton SO_2 removed. BEPC ~~concluded, based on average cost effectiveness, that either dry FGD system would be cost~~ effectiveness.

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Step 5 – Select BACT

Based on its original BACT Analysis, BEPC proposed "dry scrubbing (SDA or CDS) with a controlled SO_2 emission rate of 0.10 lb/MMBtu as BACT for Dry Fork Unit 1." (See, Attachment No. 1, Response to WDEQ's Completeness Review Dated December 21, 2005, page 16). The BACT Analysis concluded that a SO_2 emission limit of 0.10 lb/MMBtu (30-day rolling average) should be both technically and economically feasible, requiring BEPC to achieve control efficiencies in the range of 92% (based on an uncontrolled SO_2 emission rate of 1.21 lb/MMBtu). The proposed emission limit and control efficiency requirements should be achievable with either SDA or CDS control systems, including a reasonable operating margin for compliance.

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Subsequently, WDEQ evaluated the control technologies and proposed the following permit limits:

- 0.08 lb/MMBtu (12-month rolling average)
- 304.1 lb/hr (30-day rolling average, based on 0.08 lb/MMBtu x 3,801 MMBtu/hr heat input)
- 380.1 lb/hr (3-hour block average, based on 0.10 lb/MMBtu x 3,801 MMBtu/hr heat input)

In order to achieve the 12-month rolling average emission limit of 0.08 lb/MMBtu, BEPC will need to achieve average control efficiencies in the range of 93.4% (based on an uncontrolled SO_2 emission rate of 1.21 lb/MMBtu). This control efficiency is very close to the technical limits of both the SDA and CDS control systems, and provides limited operating margin for compliance. Similarly, to achieve a 3-hour block average of 380.1 lb/hr, BEPC will need to achieve removal efficiencies in the range of 92% (depending on the fuel sulfur content and boiler load). This short-term control efficiency requirement is also very close to the technical limits of the dry FGD control systems, an may be especially problematic with the SDA system design.

As discussed in the BACT Analysis, both dry FGD control systems will likely experience short-term spikes in the controlled SO_2 emission rate. Several process parameters can contribute to these short-term emission rates, however, with an SDA system one of the contributing factors would be the routine replacement of reactant injection nozzles. The atomizing nozzle assembly (either the duel-fluid feed lance assembly or the rotary atomizer assembly) is typically located in the SDA penthouse, and flange mounted to the roof of the absorber vessel. Overhead cranes or hoists located in the penthouse can be used to remove the nozzle assemblies from the absorber vessel for repair and maintenance. Because of the abrasive nature of the reactant slurry, nozzle assemblies must be removed and replaced on a routine basis. Depending on the design of the SDA system, one or more spare nozzle assemblies will be available for use. The nozzle assemblies may be changed without shutting down the SDA system, however, during that time period, the SDA may not be able to maintain maximum control efficiencies. CDS control systems do not have atomizing nozzles, which should result in less frequent short-term excursions.

A second important factor that can lead to short-term SO_2 excursions is the variability in the inlet SO_2 loading to the control system. As described in the Permit Application, the Dry Fork Station will be a mine-mouth facility and will fire coal from the adjacent Dry Fork Mine. Fuel characteristics, including heating value and sulfur content, are not uniform throughout the mine. As a mine-mouth facility, the Dry Fork station will be required to fire coal delivered from the mine and will have limited time to respond to variability in the fuel characteristics. Based on the design of the CDS control system, including the fact that all of the boiler flue gas is directed through a fluidized bed of reactant, it was concluded that the CDS will respond more effectively to variations in fuel characteristics. In other words, the CDS system offers a better chance of complying with stringent SO_2 emission rates given the unique challenges at a mine-mouth plant.

Finally, potential balance-of-plant impacts were concluded to be potentially less significant with the CDS system compared to the SDA. The more stringent permit limits proposed by WDEQ reduced the compliance/operating margin between the performance target of a dry FGD control system and the enforceable permit limit. Operating an SDA system so close to the design limits increases the potential for detrimental operating impacts such as wall wetting, scaling, plugging and detrimental impacts on the baghouse. Based on engineering judgment, potential operating impacts with the CDS design would potentially be less significant.

Based on a thorough review of the technical, commercial, and economic issues associated with both dry FGD control systems, and given the need to achieve an average emission rate of 0.08 lb/MMBtu and short-term removal efficiencies in the range of 92%, BEPC concluded that: (1) either dry FGD control system (SDA or CDS) could meet the proposed BACT emission limits; (2) the cost effectiveness of either dry FGD control system is essentially identical; and (3) the compliance margin between the performance target and the enforceable permit limit will be minimal with either dry FGD system. However, BEPC also concluded that the CDS design offers the following advantages: (1) the CDS offers a better chance of complying with stringent SO_2 emission rates given the unique challenges at a mine-mouth plant with respect to variability in the fuel characteristics; (2) potential balance-of-plant impacts associated with operating either system so close to the performance target are potentially less significant with the CDS (i.e., the CDS should not experience wall wetting, scaling, plugging and the associated detrimental impacts on the baghouse); and (3) the CDS will not experience short-term emission spikes associated with routine atomizer changeouts and should be better suited to achieve stringent emission rates based on short-term averaging times. Therefore, BEPC is proposing dry FGD, designed as a CDS, as BACT for SO_2 control for Dry Fork Unit 1.

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