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 K

Basin Electric Power Cooperative
Dry Fork Unit 1 PSD Permit Application
Response to Wyoming Department of Environmental Quality, Air Quality Division
Permit Application No. AP-3546 Completeness Review Dated May 3, 2006

Provided below is a detailed response to questions included in the Wyoming Department of Environmental Quality's (WDEQ) Completeness Review dated May 3, 2006. WDEQ comments are provided below in italics.

WDEQ Comment 1: *BACT for 134 MMBtu/hr Auxiliary Boiler:*

The Division's December 21, 2005 letter requested a top down BACT analysis including an evaluation of a 0.03 lb/MMBtu NO_x emission level for the 134 MMBtu/hr Auxiliary Boiler. In response, Basin Electric evaluated Selective Catalytic Reduction, Low NO_x Burners, and Low NO_x Burners with Flue Gas Recirculation (LNB/FGR). Basin Electric only evaluated LNB/FGR at an emission level of 0.04 lb/MMBtu and proposed this level as BACT. A BACT analysis including emission levels of 0.03 lb/MMBtu and 0.035 lb/MMBtu is required.

Response: Basin Electric Power Cooperative (BEPC) prepared a BACT analysis for NO_x, CO, SO_2, PM_{10} and VOC for the Auxiliary Boiler as part of the response submitted on March 3, 2006. The analysis included a review of low NO_x burners, flue gas recirculation (FGR) and selective catalytic reduction (SCR) as potential control options for limiting NO_x emissions. The BACT analysis was included as Attachment 4, a cost analysis was provided in Attachment 5 and a summary of the RBLC database was in Attachment 6. Based on information from vendors that supply natural gas auxiliary boiler systems in this size category, NO_x emission guarantees less than 0.036 lb/MMBtu were not obtainable without the use of SCR. A cost analysis was presented for SCR versus the use of Low NO_x Burners only and Low NO_x Burners with FGR. The incremental cost difference for the installation of SCR was over $70,000 per ton of additional NO_x removed. BEPC feels that it is also appropriate to have an operating margin above the design guarantee of approximately 10 percent when evaluating a proposed permitted emission rate. This and the review of other recently permitted sources (RBLC database) led to the conclusion that the use of Low NO_x burners and FGR with a permitted emission rate of 0.04 lb/MMBtu was appropriate.

WDEQ Comment 2: *BACT analysis for Mercury:*

A BACT analysis for mercury is required by WAQSR Chapter 6, Section 2(c)(v) including emission levels of 10×10^{-6}, 20×10^{-6}, and 30×10^{-6} lb/MW-hr. The BACT analysis should include control efficiencies associated with proposed emission levels and provide cost effectiveness numbers.

The application currently estimates uncontrolled mercury emissions at approximately 60.4×10^{-6} lb/MW-hr to 90.6×10^{-6} lb/MW-hr and controlled mercury emissions at approximately 30×10^{-6} lb/MW-hr. For reference, the Utah Department of Environmental Quality recently issued a permit to Intermountain Power Generation Station with a mercury emission limit of 20×10^{-6} lb/MW-hr for sub-bituminous coal and EPA estimates that halogenated PAC injection can typically achieve at least 90% mercury control.

Response: In the permit application submitted to WDEQ, BEPC proposed compliance with the Federal Clean Air Mercury Rule (CAMR) with a controlled mercury emission rate of 78×10^{-6} lb/MW-hr based on a 12 month rolling average. As a point of clarification, the application has an estimated uncontrolled mercury emissions range of 60.4 to 96.6 x 10^{-6} lb/MW-hr (not 90.6 as stated above). Also, on June 9, 2006, EPA revised the CAMR limit for new units with dry FGD burning subbituminous coal to 97 x 10^{-6} lb/MWh. BEPC has prepared the following response to the issues addressed in the WDEQ letter of May 3, 2006.

A. Background

Dry Fork Station is a 422-MW (gross) unit located northeast of Gillette, Wyoming, and is scheduled for start-up in January, 2011. The generating unit's boiler will be a pulverized coal design, utilizing sub-bituminous fuel from the Powder River Basin of Wyoming. The design maximum boiler heat input rating is 3,801 MMBtu/hr.

Flue gas from Dry Fork Station will pass through a series of emissions control devices including Low NO_x burners and overfire air for primary NO_x control, Selective Catalytic Reduction (SCR) for additional NO_x removal, a fabric filter dust collector for particulate control, a dry Flue Gas Desulphurization (FGD) system for SO_2 removal, and potential future sorbent injection system for mercury control if required.

Dry Fork Station will be subject to the New Source Performance Standard (NSPS) for Mercury that was promulgated as part of the Clean Air Mercury Rule (CAMR). CAMR was originally published in the Federal Register on March 18, 2005 and became effective on July 18, 2005. In the June 9, 2006 Federal Register (Volume 71, No. 111, pages 33388-33402), EPA revised the NSPS for Mercury based on Best Demonstrated Technology (BDT), type of coal combusted and regional precipitation levels. EPA indicated that dry FGD represents BDT for areas receiving less that 25 inches mean annual precipitation. The revised NSPS for new units burning sub-bituminous coal and utilizing dry FGD systems is 97 x 10^{-6} lb/MW-hr. The emission control technologies utilized for this project, including dry scrubbing for SO_2 control and a fabric filter for control of particulates, represent Best Demonstrated Technology (BDT) for control of mercury for this type of unit according to the CAMR. Basin Electric Power Cooperative will comply with the mercury emissions established under the CAMR.

From a recent report analyzing alternative mercury control strategies, there are two primary approaches to controlling power plant mercury emissions; 1) relying on "co-benefit" Hg reductions from other emission control technologies, and 2) reducing Hg emissions utilizing technologies specifically designed to reduce mercury.[1] This same report also concluded that no coal plants using sub-bituminous or lignite coals are assumed to be able to achieve 90% mercury reduction through co-benefit reductions alone.

B. Review of Recent Permits

As part of the Dry Fork Station mercury emissions analysis, an examination of several recent approved permits was completed. The following units were reviewed:

- Newmont Nevada Mining, Unit 1, Dunphy, Nevada
- MidAmerican Energy, Council Bluffs Energy Center Unit 4, Iowa
- Intermountain Power Agency, Intermountain Unit 3, Delta, Utah
- Xcel Energy, Comanche Unit 3; Pueblo, Colorado

[1] Energy Information Administration, "Analysis of Alternative Mercury Control Strategies", January 2005.

Three of the four projects which were reviewed will burn sub-bituminous coal. Intermountain will burn bituminous with the possibility of blending up to 30% sub-bituminous coal. Intermountain Unit 3 will also utilize a wet limestone FGD system. The following table compares the three permits where only sub-bituminous coal is being burned and a Lime Spray Dryer is being utilized for SO_2 removal.

TABLE 1
Recent Permitted Sub-bituminous Coal Fired Units with Dry FGD Systems

	Newmont Nevada Mining Unit 1	**MidAmerican Energy CBEC Unit 4**	**Xcel Energy Comanche Unit 3**
Location	Dunphy, NV	Council Bluffs, IA	Pueblo, CO
Unit Size	200 MW	790 net MW	750 MW-Supercritical
Permit Date	May 5, 2005	June 17, 2003	July 5, 2005
Coal Type	Sub-bituminous	PRB Sub-bituminous	PRB Sub-bituminous
LNB	Yes	LNB w/OFA	LNB w/OFA
SCR	Yes	Yes	Yes
FGD	Lime Spray Dryer	Lime Spray Dryer	Lime Spray Dryer
Baghouse	Pulse Jet	Yes	Yes
Sorbent Injection	Activated Carbon	Activated Carbon	Yes, Later
Hg Permit Level	0.02 lb/GWhr, or $20X10^{-6}$ lb/MW-hr	$1.7X10^{-6}$ lb/MMBtu; $16.5 X 10^{-6}$ lb/MW-hr (Calculated)	$20X10^{-6}$ lb/MW-hr
Hg Permit Compliance Period	12-month rolling average	Average of 3 tests	12-month rolling average
Hg Emissions Test	Method 29 with three runs	Draft ASTM Z655907	
Hg CEMS	No CEMS Requirement	No CEMS Requirement	CEMS Required
Hg Demo Test Program	No	Yes-Optimization of SO_2, NO_x, Hg	Yes, One year Hg emission reduction test w/ cost ranges

The Hg emissions permit level is 16.5×10^{-6} lb/MWh to 20.0×10^{-6} lb/MWh for the three units burning sub-bituminous coals. Intermountain Unit 3 has permit limits of 6.0×10^{-6} lb/MWh for bituminous coal and 20.0×10^{-6} lb/MWh for sub-bituminous coal. Compliance with the Hg limit on three of the four units is based on a 12-month rolling average.

In addition, the permits for MidAmerican Energy CBEC Unit 4 and Xcel Energy Comanche Unit 3 included provisions for testing and evaluation of a mercury removal system. The MidAmerican permit allows for a nine-month optimization period whereby the affects of increasing activated carbon rates of injection on Hg removal are evaluated. MidAmerican has agreed to a minimum activated carbon injection rate of 10 pounds per million cubic feet of flue gas. The permit can be reopened should results from this study demonstrates a change is necessary.

Within 180 days after start-up, Comanche Unit 3 will 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 shall comply with an emission limit that represents the maximum cost-effective reduction of mercury at Comanche Station achievable with an expenditure of no less than $2 million per year and no more the $5 million per year in the first year's operations and maintenance costs directly associated with mercury controls.

It should also be noted that all of these units (both the bituminous and sub-bituminous boilers) were permitted when a Case-by-Case Mercury MACT determination was required under federal regulation. Subsequently, on March 18, 2005, the Clean Air Mercury Rule was published.

C. BACT Analysis

EPA has developed a process for conducting Best Available Control Technology (BACT) analyses. This method is referred to as the "top-down" method. The steps to conducting a "top-down" analysis are listed in EPA's "New Source Review Workshop Manual," Draft, October 1990. The steps are the following:

- Step 1 – Identify All Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
- Step 3 – Rank Remaining Control Technologies by Control Effectiveness
- Step 4 – Evaluate Most Effective Controls and Document Results
- Step 5 – Select BACT

Basin Electric Power Cooperative conducted a BACT analysis for SO_2, NOx, CO, and PM/PM_{10}, in the original application. While a BACT analysis for mercury is not required on a Federal level, Basin Electric Power Cooperative recognizes the WDEQ authority to request this review. However, for Dry Fork Station a true BACT analysis is not possible for mercury for the following reasons:

- Control technologies for mercury are still in the developmental stage, 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.

D. Discussion and Conclusions

After review of several recent coal fired unit permits and the present status of current Hg removal technologies, there remains a significant level of uncertainty regarding establishing an appropriate permit limit for Hg emissions. The three major areas of concern are:

1. **Unknown effects from numerous unit operating parameters on Hg capture** – Mercury removal pilot and demonstration projects conducted to date have shown that significant questions remain regarding how changing operating conditions can impact Hg emissions.

2. **Uncertainty regarding future coal Hg levels** - Any Hg permit limitation must provide the ability to meet the emissions criteria under the entire range of Hg in the fuel, and at a reasonable cost.

3. **Current status of Continuous Emissions Monitors (CEM)** – Commercially available CEM systems for Hg have just started to come on the market. The accuracy of the current CEMs at very low Hg levels is questionable.

Given the current stage of mercury control technology, the inherent concerns with potential unit operating uncertainties, and the status of CEMs, Basin Electric Power Cooperative proposes the following course of action:

1. The current CAMR emissions limit of 97 X 10^{-6} lb/MWh on an output basis 12 month rolling average ~~should be maintained as a permit limitation (as revised in the June 19, 2006 Federal Register,~~ Volume 71, No. 111, pages 33388-33402).

2. Basin Electric Power Cooperative proposes a Mercury Optimization Study, which would be performed on the Dry Fork Station. This testing program would begin approximately July 2011 (approximately six months after unit start-up), and would continue for one year.

   The testing program will include a review of the following potential mercury technology options:

   a) Sorbent Injection Technologies
   b) Sorbent Enhancement Additives
   c) Coal Pretreatment Processes
   d) Hg^{0} Oxidation Technologies

3. Results from the testing program would be provided to the WDEQ, and implemented on Dry Fork Station as appropriate. Basin Electric Power Cooperative and WDEQ will jointly determine whether permit modifications are necessary.