IN THE MATTER OF A PERMIT APPLICATION (AP-3546) FROM BASIN ELECTRIC POWER COOPERATIVE TO CONSTRUCT A 385 MW PULVERIZED COAL FIRED ELECTRIC GENERATING FACILITY TO BE KNOWN AS DRY FORK STATION

I. INTRODUCTION:

The Air Quality Division received a permit application from Basin Electric Power Cooperative to construct a coal fired electric power generating station adjacent to the Dry Fork Mine on Highway 59, approximately 7 miles north northeast of Gillette, Campbell County, Wyoming. The proposed facility includes one pulverized coal (PC) boiler rated at 422 MW (gross) and 385 MW (net) with associated material handling and auxiliary equipment. The maximum design heat input for the PC boiler is 3,801 MMBtu/hr. The design values used for coal from Dry Fork Mine include a heat value of 8,045 Btu/lb (7,800 Btu/lb minimum to 8,300 Btu/lb maximum) and a sulfur content of 0.33% (0.25% minimum to 0.47% maximum). Material handling will include coal, lime, fly ash, bottom ash, and waste product from the flue gas desulfurization (FGD) system. Auxiliary equipment will include an 8.36 MMBtu/hr Inlet Gas Heater, a 360 hp Fire Pump, and a 2377 hp Emergency Generator.

The Division completed its analysis of the application and 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, Wyoming and the public comment period was extended through the hearing.

The Division received 31 comment letters on the proposed permit during the public comment period: 1) a March 16, 2007 letter from Bertha Ward; 2) a March 19, 2007 letter from Ester Johansson Murray; 3) a March 20, 2007 letter from Jared Schwab; 4) a March 21, 2007 letter from Albert Bitner; 5) a March 21, 2007 letter from Jane Eakin; 6) a March 23, 2007 letter from John Osgood; 7) a March 23, 2007 letter from William Young; 8) a March 24, 2007 letter from David Svendsen; 9) a March 26, 2007 letter from Arlene Bryant; 10) a March 26, 2007 letter from Martha Dubois; 11) a March 26, 2007 letter from Kristin Yannone; 12) a March 22, 2007 letter from EPA Region VIII; 13) a March 28, 2007 letter from Phil Round; 14) a March 28, 2007 letter from the National Park Service; 15) a March 28, 2007 letter with attachments from PRBRC et al. (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); 16) a March 28, 2007 letter from Basin Electric; 17) an April 30, 2007 letter from Albert Bitner; 18) an April 30, 2007 letter from Bertha Ward; 19) a May 4, 2007 letter from Phil Round; 20) a May 11, 2007 letter from Albert Bitner; 21) a May 11, 2007 letter from Ester Johansson Murray; 22) a May 21, 2007 letter from Jared Schwab; 23) a June 4, 2007 letter from Phil Round; 24) a June 5, 2007 letter from Karla Oksanen; 25) a June 28, 2007 letter from the Northern Cheyenne Tribe; 26) a June 28, 2007 letter from the Campbell County Commissioners; 27) a June 28, 2007 letter from the National Park Service; 28) a June 28, 2007 letter from Roy Liedske; 29) a June 28, 2007 letter from Kevin F. Lind; 30) a June 28, 2007 letter from the Powder River Basin Resource Council; 31) a June 28, 2007 letter with attachments from Basin Electric; and 32) written transcript of the testimony of James K. Miller presented at the public hearing on June 28, 2007. Oral testimony was presented at the public hearing by James K. Miller (Basin Electric Power Cooperative), Rich Pullen (Wyoming Municipal Power), Steve Thomas (Wyoming Chapter of Sierra Club), Jill Morrison (Powder River Basin Resource Council), Karla Oksanen (Campbell County Resident), Jim Margudant (South Dakota Chapter of Sierra Club), Wayne Gilbert (South Dakota Chapter of Sierra Club), Kevin Lind (Powder River Basin Resource Council), and Ryan Munz (Wyoming Resident).

Due to the number of public comments with similar concerns, the Division grouped individual comments and developed nine summary comments and responses. The comments from EPA, PRBRC et al., NPS, and Basin Electric were addressed individually. The comments and responses are presented on the following pages. The Division also received positive comments supporting this project. The Division appreciates these comments but they are not included in this document as no response is required. Similarly, a number of general comments not requesting or requiring a response were not included.

II. ANALYSIS OF PUBLIC COMMENTS:

1) **Control of Mercury Emissions** – Comments were received regarding the need to control mercury emissions using the best control methods available.

Response – Mercury emissions are limited by federal New Source Performance Standards (NSPS) to 0.000090 pounds per megawatt-hour. In addition, the permit requires installation and operation of Best Available Control Technology (BACT). Mercury controls for power plants are an emerging technology and the BACT emission level will be determined based on the results of a one year mercury optimization study to be performed at this facility. The permit requires a mercury control system to be installed and a one year mercury optimization study to commence within 90 days of initial startup of the boiler. The target emission level for this study is 20×10^{-6} (0.000020) pounds per megawatt-hour. The final BACT emission limit will be established based on the results of the study. Also see the responses to PRBRC et al. #7c.2, NPS #5e, and Basin Electric #3.

2) **Carbon Dioxide Sequestration** – Comments were received regarding sequestration of carbon dioxide.

Response – Wyo. Stat. § 35-11-213(a) currently prohibits the Department of Environmental Quality (DEQ) or the Environmental Quality Council (EQC) from proposing or promulgating rules or regulations to reduce emissions as called for by the Kyoto Protocol. The Kyoto Protocol addressed Carbon dioxide (CO2), Methane (CH4), Nitrous Oxide (N2O), Hydrofluorocarbons (HFCs), Perfluorocarbons (PFCs), and Sulphur Hexafluoride (SF6) emissions. Since Wyo. Stat. § 35-11-213 prohibits the regulation of CO_2, no CO_2 sequestration requirements have been established under this permit.

3) **Maximum Available Control Technology (MACT) and Best Available Control Technology (BACT)** – Comments were received requesting the use of MACT for all pollutants.

Response – The proposed permit establishes emission limits using the top down Best Available Control Technology (BACT) process. Through the BACT process, all technically feasible control options were evaluated and the most effective controls that are economically reasonable were selected. The emission limits in the proposed permit are among the most stringent limits of any recently permitted PC boiler. BACT and MACT are required under different regulatory programs and the Division's BACT limits are typically more stringent than MACT limits as discussed below.

State and federal regulations require Best Available Control Technology (BACT) for all pollutants regulated under the Prevention of Significant Deterioration (PSD) rules with potential emissions above the PSD significance thresholds. BACT was evaluated for NO_X, SO_2, PM/PM_{10}, CO, VOC, H_2SO_4, fluorides, mercury, and beryllium because the potential emissions for each of these pollutants are above PSD significance thresholds. BACT is also required for other pollutants under WAQSR Chapter 6, Section 2.

Maximum Available Control Technology (MACT) is required for air pollution sources regulated under the National Emission Standards for Hazardous Air Pollutants (NESHAPS). Coal- and Oil-Fired Electric Utility Steam Generating Units are not regulated under NESHAPS and MACT standards do not apply. Several smaller emission units at the proposed facility are subject to MACT standards. The 2377 hp diesel emergency generator is subject to NESHAPS Subpart ZZZZ but does not have to meet any MACT emission limits because it is for emergency use only. The 8.36 MMBtu/hr inlet gas heater is subject to NESHAPS Subpart DDDDD but does not have to meet MACT emission limits due to its small size. The 134 MMBtu/hr auxiliary boiler is subject to NESHAPS Subpart DDDDD and this subpart limits CO emissions to 400 ppm and requires a Continuous Emissions Monitor (CEM) to monitor CO emissions. CO is used as a surrogate to indicate that HAP emissions are controlled adequately.

All of these emission units were subject to a BACT review and the Division's BACT emission limits are typically more stringent than MACT limits. In this permit, the Division's CO BACT limit for the auxiliary boiler is 0.08 lb/MMBtu which corresponds to approximately 100 ppm. This is considerably more stringent than the 400 ppm MACT limit in NESHAPS Subpart DDDDD.

4) **Control of Sulfur Dioxide Emissions** – Comments were received regarding the need to control sulfur dioxide (SO_2) emissions.

Response – A top down BACT analysis was performed for SO_2 and the proposed permit limited emissions to 0.08 lb/MMBtu using a dry lime scrubber. The analysis was based on the use of a lime spray dryer absorber (SDA). Since that time, Basin Electric has proposed to use a different type of dry lime scrubber known as a circulating dry scrubber (CDS). Although this technology is somewhat more effective at controlling SO_2 emissions, there have previously been technical issues that precluded use of this technology. Basin recently informed the Division that the technical issues have been resolved and agreed to use this technology. The Division requested Basin to submit a new BACT analysis for the CDS unit and Basin proposed an emission limit of 0.070 lb/MMBtu, 12 month rolling average. A revised BACT analysis is included as Attachment A to this document. This limit is among the lowest SO_2 emission limits for any PC boiler. Also, see the responses to PRBRC et al. comment #7c.1 and NPS comment #5a.

5) **Alternate Technologies** – Comments were received stating that the Division should evaluate other alternatives such as wind power, solar energy, and conservation.

Response – The Division did not require Basin Electric to evaluate alternate technologies in this permit application. Page B.13 of the draft 1990 *New Source Review Workshop Manual* states, "Historically, EPA has not considered the BACT requirements as a means to redefine the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity)." The July 20, 1992 Order Denying Review for Hawaiian Commercial & Sugar Company (PSD appeal No. 92-1) states, "EPA's PSD permit conditions regulations do not mandate that the permitting authority redefine the source in order to reduce emissions."

6) **Cooling Water** – One comment was received concerning the use of cooling water and notes that the analysis does not address how the plant will be cooled.

Response – The Air Quality Division does not regulate the use of cooling water. The analysis does, however, address BACT for PM_{10} emissions due to drift loss from the auxiliary cooling tower. The primary cooling tower will be an air cooled condenser and will not use water. The auxiliary cooling tower is a wet cooling tower with a flowrate of 17,000 gallons per minute. The drift eliminators used in this tower will have a drift loss of 0.0005% resulting in a loss of 42.5 gallons per minute when the auxiliary tower is in use.

7) **Light Pollution** – One comment was received concerning measures to eliminate night time light pollution.

Response – Light pollution is outside the Air Quality Division's regulatory authority.

8) **Environmental Impact Statement (EIS)** – Comments were received that an air quality permit should not be issued until the Federal EIS is completed.

Response – The DEQ/AQD regulates Wyoming's air resources pursuant to and in accordance with its State Implementation Plan (SIP) (40 CFR § 52.2620 et seq.), Wyoming's Environmental Quality Act (WEQA)(Wyo. Stat. Ann. § 35-11-101 et seq.), and the Wyoming Air Quality Standards and Regulations (WAQSR). The requirements for and preparation of Environmental Impact Statements (EIS) are prescribed by the National Environmental Policy Act of 1969 (42 U.S.C. §§ 4321-47) (NEPA). The NEPA establishes procedures that federal agencies must follow, not the Wyoming DEQ/AQD. The DEQ/AQD has regulatory authority over Wyoming's air quality program. The DEQ/AQD air quality program prescribes permitting requirements. See Wyo. Stat. Ann. § 35-11-801 and WAQSR Ch. 6. The DEQ/AQD's permitting requirements and process are separate and independent from the federal NEPA process and do not require an EIS. The DEQ issues permits "upon proof by the applicant that the procedures of this act [WEQA] and the rules and regulations promulgated hereunder have been complied with." The DEQ/AQD has determined that Basin has complied with the WEQA and DEQ/AQD permitting requirements and is therefore issuing a permit to Basin.

9) **Northern Cheyenne Indian Reservation (NCIR)** – Comment was received requesting that the Department meet face-to-face with the NCIR and Mr. Bill Powers.

Response – The request for the face-to-face meeting was made during the June 28, 2007 public hearing. As outlined by Dave Finley at the outset of the public hearing , the record on the proposed permit closed at the end of the hearing and any comments received prior to and during the hearing were considered in the final decision. While the Division understands the NCIR's concerns, the Division cannot meet the NCIR after the public comment period has closed without giving opportunity for further comments from all interested parties. The Division is willing to meet with the NCIR, but will not consider comments from a meeting in the final decision. Written comments received from the NCIR were considered in the final decision.

III. ANALYSIS OF COMMENTS FROM EPA:

The Division provides the following responses to the comments in EPA's March 26, 2007 letter.

1) **Condition 9 – BACT limits for PSD pollutants** – EPA commented that the draft permit does not set BACT emission limits for sulfuric acid mist (H_2SO_4), fluoride, and VOC.

Response – The final permit includes emission limits of 0.0025 lb/MMBtu H_2SO_4, 2.62 lb/hr fluorides, and 0.0037 lb/MMBtu VOC. The analysis for the proposed permit concluded that these levels represent BACT for fluorides and VOC and that an estimated emission rate of 0.0025 lb/MMBtu represents BACT for H_2SO_4. The proposed permit already contained testing requirements for H_2SO_4 and fluoride and testing requirements were added for VOC in the final permit.

2) **Condition 9 – BACT limit for ammonia** – EPA commented that the draft permit does not set BACT emission limits for ammonia (NH_3).

Response – The final permit includes a 10 ppm (19.6 lb/hr) limit for ammonia. The analysis for the proposed permit concluded that this level represents BACT. The proposed permit already contained testing requirements for ammonia.

3) **Hours limit for Auxiliary Boiler and Inlet Gas Heater** – EPA commented that emissions for the auxiliary boiler and inlet gas heater are calculated based on 2000 hours and 2500 hours, respectively, but the permit does not limit the hours of operation. EPA also noted that the page 16 and 17 of the analysis state that both heaters are limited to 2000 hours each.

Response – The final permit limits operation of the auxiliary boiler to 2000 hours per year and the inlet gas heater to 2500 hours per year. Emissions from the inlet gas heater were calculated using 2500 hours as noted and the reference to 200 hours on page 17 is a typographical error.

4) **BACT limits vs. NSPS** – EPA commented that comparing lb/hr limits for SO_2 and NO_X is not a valid demonstration that the BACT limits are at least as stringent as the NSPS limits because, at low boiler load, the facility could be in compliance with the lb/hr limits but exceed the NSPS lb/MW-hr limits.

Response – The permit, as proposed, includes both the BACT limits and the NSPS limits of 1.0 lb/MW-hr NO_X and 1.4 lb/MW-hr SO_2. The NSPS limits are based on a 30 day rolling average.

5) **BACT limit averaging period for SO_2 and NO_X** – EPA commented that the 12 month rolling averages for the SO_2 and NO_X lb/MMBtu limits are too lengthy an averaging period to represent BACT and to be consistent with EPA's policy on limiting potential to emit.

Response – EPA's June 13, 1989 *Guidance on Limiting Potential to Emit in New Source Permitting* states that, "EPA recognizes that in some rare situations, it is not reasonable to hold a source to a one month limit. In these cases, a limit spanning a longer time is appropriate if it is a rolling limit. However, the limit should not exceed an annual limit rolled on a monthly basis."

The final permit limits SO_2 to 0.070 lb/MMBtu and NO_X to 0.05 lb/MMBtu, both annual limits rolled on a monthly basis. The SO_2 limit is among the lowest and the NO_X limit is the lowest limit we are aware of for a PC boiler. Using a 30 day or shorter averaging time would necessitate an increase in the emission limits in order to account for short term variations and operation at lower loads. The control equipment will experience some variation in short term emission rates due to factors such as load changes, fuel properties, and maintenance activities. It is also not reasonable to expect the control equipment to operate at the same control efficiency at low loads as at maximum load because flow rates and temperatures are both reduced at lower loads. It is the Division's intent that the lower emission limits and longer averaging period will result in lower annual emissions and this is the goal of the BACT process.

EPA's June 13, 1989 *Guidance on Limiting Potential to Emit in New Source Permitting* also states that, "a federally enforceable permit containing short term emission limits (e.g. lbs per hour) would be sufficient to limit potential to emit, provided that such limits reflect the operation of the control equipment, and the permit includes requirements to install, maintain, and operate a continuous emission monitoring (CEM) system." The proposed permit contains lb/hr limits for SO_2 and NO_X, requires CEMs, and determines compliance with CEM data. The lb/hr limits are based on the maximum heat input of 3,801 MMBtu/hr and 0.05 lb/MMBtu for NO_X and 0.075 lb/MMBtu for SO_2.

6) **Averaging periods in tables** – EPA commented that the PM and CO emission limits in condition 9 do not include the averaging times.

Response – The averaging times for the PM/PM_{10} and lb/MMBtu CO limits are specified by the performance test requirements in Condition 12. The lb/MMBtu and lb/hr PM/PM_{10} limits are based on the average of three 120-minute tests per 40 CFR 60.50 Da. The lb/MMBtu CO limit is based on the average of three 1-hour tests as specified in Condition 12. The lb/hr CO limit was revised to a 30 day average using a CEM to demonstrate compliance as discussed in the response to comment #7 below.

7) **Continuous Emission Monitors (CEMs) for PM and CO** – EPA recommended that the Division require a PM CEMs and a CO CEMs.

Response – There are no regulations requiring CEMs for PM and CO and the Division is not electing to require them. However, the permit application states that Basin plans to install a CEM for CO. Upon further discussions, Basin agreed to certify the CEM and use it to demonstrate compliance with the 570.2 lb/hr emission limit on a 30 day rolling average. Condition 9 was revised to indicate that the 570.2 lb/hr limit is on a 30 day rolling average. The 0.15 lb/MMBtu limit is still based on the average of three 1-hour reference method tests. Condition 15 was revised to require a CEM to demonstrate compliance with the lb/hr CO emission limit.

8) **NSPS vs. PSD limits** – EPA commented that the permit includes NSPS limits and states that these limits are not required under PSD. EPA stated that a condition should be added that BACT limits are separate from NSPS requirements and the PSD requirements must be met regardless of compliance with the NSPS.

Response – The proposed permit addresses PSD requirements as well as Wyoming's Chapter 6 Section 2 permitting requirements. There is nothing in the permit that implies that compliance with the NSPS requirements lessens the obligation to comply with PSD BACT limits and the Division does not consider it necessary to add a condition stating this.

9) **NSPS exemptions vs. PSD limits** – EPA commented that conditions 12(A), (C), and (D) include citations of the NSPS which contain exempt periods when determining compliance. EPA stated that PSD does not afford these exemptions and the permit should make this clear.

Response – Conditions 12(A), (C), and (D) specify that the initial performance tests are to be performed in accordance with the NSPS testing requirements. This means that the initial performance tests will be performed during periods of normal operation rather than periods of startup, shutdown, and malfunction. This does not exempt the facility from compliance with the BACT limits during those periods, rather it ensures that the test data is obtained during periods representative of normal operation. There are no regulatory requirements that initial performance testing be performed during periods of startup, shutdown, or malfunction. The Administrator has the ability, however, to require testing at any time compliance is in question per 35-11-110(a)(vii) of the Wyoming Environmental Quality Act.

10) **Performance testing** – EPA commented that Condition 7 requires performance testing, "within 30 days of achieving maximum design rate but not later than 90 days following initial start-up in accordance with Chapter 6, Section 2(j) of the WAQSR. If maximum design production rate is not achieved within 90 days of start-up, the Administrator may require testing at the rate achieved and again when maximum rate is achieved." EPA stated that the word "may" is ambiguous and the permit is unclear whether performance testing is, in fact, required within 90 days.

Response – The first part of Condition 7, which states "Performance tests shall be conducted within 30 days of achieving maximum design rate but not later than 90 days following initial start-up," is clear that an initial performance test has to be conducted within 90 days of startup. The second part of this condition, which states "If maximum design production rate is not achieved within 90 days of start-up, the Administrator may require testing at the rate achieved and again when maximum rate is achieved," allows the Administrator the discretion to require a second test if the initial performance test is not conducted at the maximum design rate.

11) **Equivalent test methods** – EPA commented that conditions 13(B) and 13(E) require testing for fluoride and sulfuric acid mist and specify testing using EPA test methods or equivalent methods. EPA recommended that the conditions be reworded to state, "or equivalent EPA approved test methods."

Response – Condition 13 requires testing to determine emission rates for pollutants for which no limits are established and includes the provision to use equivalent methods. Condition 12 requires testing to verify compliance with emission limits and does not include provisions to use equivalent methods unless they are equivalent EPA approved test methods. Emission limits were not established for fluoride and sulfuric acid mist in the proposed permit but are included in the final permit as discussed in comment #1 above. Because emission limits are now included, the testing requirements for fluoride and sulfuric acid mist were moved to condition 12 and specify testing using EPA approved test methods.

12) **Modeling Analysis for CO** – EPA commented that a CO emission rate of 557 lb/hr was used to model compliance with the NAAQS/WAAQS but the potential emissions are shown as 570.2 lb/hr and that the application should disclose whether startup emissions were considered.

Response – Potential CO emissions during normal operation are 570.2 lb/hr based on 3,801 MMBtu/hr and the 0.15 lb/MMBtu emission limit. The Division ran the model at 570.2 lb/hr and the maximum impacts increased from 22.1 $\mu g/m^3$, 8 hour average and 108.6 $\mu g/m^3$, 1 hour average to 22.6 $\mu g/m^3$, 8 hour average and 111.2 $\mu g/m^3$, 1 hour average. These values are still well below both the NAAQS/WAAQS and PSD Class II Significant Impact Levels (SILs). Basin estimated worst case CO emissions during cold startup to be 1112.1 lb/hr for a one hour period during the 8^{th} hour of cold startup. Basin modeled a 24 hour cold start emissions profile including this value for each of the 365 days of the 2002 meteorological data set. Maximum impacts were still well below both the NAAQS/WAAQS and PSD Class II SILs. Basin subsequently agreed to use a CEM to demonstrate compliance with the 570.2 lb/hr CO limit and agreed to comply with the limit at all times including startup and shutdown. Although there may still be higher hourly emissions during startup and shutdown, the lb/hr CO limit is based on a 30 day rolling average.

Basin Electric's agreement to comply with the emission limits at all times applies not only to CO but to all pollutants. Condition 9 was revised to indicate that emission limits apply at all times including startup and shutdown.

13) **Modeling Analysis for SO_2** – EPA noted that a 3 hour SO_2 emission limit of 380 lb/hr and a 30 day rolling SO_2 emission limit of 304.1 lb/hr is proposed and commented that the application should document how the 3 hour limit was calculated and disclose whether startup conditions were considered.

Response – The 3 hour SO_2 limit of 380 lb/hr is based on maximum heat input to the boiler of 3,801 MMBtu/hr and a worst case short term emission estimate of 0.1 lb/MMBtu. This limit was established to show compliance with Wyoming's 3 hour SO_2 ambient standard and does account for worst case SO_2 emissions during cold startup. Note that the final permit requires Basin Electric to comply with the emission limits at all times including startup and shutdown as discussed in the previous response.

IV. ANALYSIS OF COMMENTS FROM 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:

The Division provides the following responses to the comments in the March 28, 2007 letter from PRBRC et al.

1) **Public Notice Requirements** – PRBRC et al. commented that the Division failed to meet public notice requirements by not including the degree of increment consumption in all locations. PRBRC et al. stated that the Division identified the degree of increment consumption for SO_2 at

the location with the greatest impact, did not identify the degree of increment consumption for NO_X or PM_{10}, and did not identify the degree of increment consumption in Class I areas.

Response – The February 26, 2007 public notice did not include Dry Fork Station's contribution to increment consumption near the plant for NO_X, PM_{10}, 3 hour SO_2 and annual SO_2 because modeled concentrations were below the PSD Class II Significant Impact Levels (SILs). The public notice included the 24-hour SO_2 increment consumption near the plant.

The February 26, 2007 public notice did not include Dry Fork Station's contribution to increment consumption in Class I areas (Wind Cave NP, Badlands NP, and the Northern Cheyenne Indian Reservation) because modeled concentrations were below the proposed EPA Class I SILs for NO_X, PM_{10}, 3 hour SO_2 and annual SO_2 and the proposed facility did not contribute significantly to any of the modeled 24-hour SO_2 exceedances at the Northern Cheyenne Indian Reservation.

A public hearing was scheduled for June 28, 2007 and the public comment period was extended through the hearing. The public notice for the hearing included the anticipated degree of increment consumption for all pollutants and averaging periods near the facility and at Wind Cave National Park, Badlands National Park, and Northern Cheyenne Indian Reservation.

2) **CO_2 and other Greenhouse Gases** – PRBRC et al. commented that the Division failed to address CO_2 and other greenhouse gases and the collateral impacts of competing BACT technologies (i.e. IGCC) including water use, hazardous waste, and endangered species.

Response – BACT (Best Available Control Technology) means "an emission limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under [the WAQSR or the Federal Clean Air Act], which would be emitted from or which results for [sic] 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 through application or production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant." 6 WAQSR § 4(a).

Wyoming follows EPA's "top-down" BACT process. The top-down process ranks all available control technologies in descending order of control effectiveness. The most stringent or "top" alternative is established as BACT unless the applicant demonstrates to the satisfaction of the Division that technical considerations, or energy, environmental, or economic impacts and other costs justify the conclusion that the most stringent technology is not "achievable." If a technology is eliminated, then the next most stringent alternative is considered until BACT is reached. *See New Source Review Workshop Manual*, EPA (Draft Oct. 1990).

The Division considers collateral impacts only when comparing two technically and economically feasible control options designed to control regulated NSR pollutants. "Regulated NSR pollutant" means: (i) any pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the EPA Administrator; (ii) any pollutant that is subject to any standard promulgated under section 111 of the Federal Clean Air Act; (iii) any Class I or II substance subject to a standard promulgated under or established by Title VI of the Federal Clean Air Act; or, (iv) any pollutant that otherwise is subject to regulation under the Federal Clean Air Act, except that any or all hazardous air pollutants either listed in section 112 of the Federal Clean Air Act or added to the list pursuant to section 112(b)(2) of the Federal Clean Air Act, which have not been delisted pursuant to section 112(b)(3) of the Federal Clean Air Act, are not "regulated NSR pollutants" unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Federal Clean Air Act. 6 WAQSR § 4(a). As discussed in the response to public comment #2, CO_2 and other greenhouse gases do not meet the definition of "regulated NSR pollutants" at this time. Basin Electric did consider collateral impacts for the feasible control options evaluated for a PC boiler.

3) **Future CO_2 Regulation** – PRBRC et al. commented that the Division must consider collateral costs of future CO_2 regulation in the BACT analysis.

Response – It is not feasible to consider speculative future costs in the BACT process. The Division notes, however, that IGCC does not inherently include CO_2 capture and PC technology does not preclude it. It is possible to capture CO_2 emissions with add-on control technology from either type of facility should CO_2 become a regulated pollutant in the future. Also see the response to public comment #2.

4) **IGCC** – PRBRC et al. commented that the Division must consider application of production processes and available methods, systems, and techniques to lower airborne contaminants (i.e. IGCC).

Response – The end result of the BACT process is an emission limitation for each regulated NSR pollutant. The BACT process is conducted on a case-by-case, site and source specific manner, evaluating energy, environmental, and economic impacts and other costs of permit conditions to be imposed to ensure the proposed facility uses emission control systems that represent BACT. BACT may involve the application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques to control emissions. *See* 6 WAQSR § 4(a). The permit conditions to be imposed on the facility are not intended to redefine the facility, but are imposed on the facility proposed or defined by the applicant. The Division's BACT review distinguishes elements inherent to the proposed facility for reasons independent from air quality permitting from those elements that may be changed to achieve emission reductions without requiring a redefinition of the proposed facility. Although the Division may request an applicant to consider other types of facilities, the BACT process does not require the Division to redefine the facility.

Basin's Dry Fork Station permit application was for a mine-mouth coal fired electric power generating station, including one PC boiler rated at 385 MW (net). The scope of the BACT analysis and the range of control measures considered is driven by the definition of the proposed facility. The particular inherent design characteristics of the proposed facility are an important part of BACT. The permit conditions evaluated and imposed by the Division are a result of the BACT process for such a facility, not a redefined facility. A PC boiler combusts coal – coal is the fuel. IGCC is a fundamentally different process and technology than a PC boiler, requiring the conversion of coal to a synthetic gas for combustion in a gas turbine – the synthetic gas is the fuel.

Although the Division is not required to consider technologies that would redefine the source and, therefore, did not require Basin Electric to consider IGCC in its BACT analysis, Basin nevertheless evaluated IGCC as discussed in the response to comment #5 below.

5) **IGCC** – PRBRC et al. commented that IGCC is an available technology and must be evaluated as part of BACT.

Response – As discussed above, IGCC is a fundamentally different technology than a PC boiler and the BACT process does not require the Division to redefine the source. Consequently, the Division did not specify that IGCC be included as part of the BACT analysis. Although not required for BACT, Basin Electric did evaluate alternate technologies for generating electricity in a 2005 document entitled, "Coal Power Plant Technology Evaluation for Dry Fork Station," November 1, 2005, prepared for Basin Electric by CH2M HILL. This document is included in Attachment B.

The evaluation in Attachment B concludes that IGCC plants are not proven to meet the availability and capacity requirements necessary for a baseload unit. Basin Electric requires a minimum availability of 90% and a minimum capacity factor of 85% in order to meet projected electrical demand. Of the four coal based IGCC plants in the world, none have achieved these levels of operation. Additionally, of the four IGCC plants in existence, none are greater than 300 MW, none burn sub-bituminous coal, and none are at high altitude. Basin Electric was, therefore, unable to obtain an acceptable performance guarantee for an IGCC plant.

6) **Supercritical Boiler** – PRBRC et al. commented that the Division failed to evaluate a supercritical or ultra-supercritical boiler.

Response – A supercritical boiler requires a completely different boiler and turbine design. As previously discussed, the BACT process does not require the Division to redefine the source. Consequently, the Division did not specify that supercritical or ultra-supercritical boilers be included as part of the BACT analysis.

In the August 30, 2007 Final Statement of Basis for the Deseret Power Electric Cooperative Bonanza Power Plant, EPA Region VIII stated that, "The use of supercritical pressure in a power plant affects the design of all components within the plant cycle, boiler, turbine, pumps, etc. The steam cycle is based on available turbine designs. The boiler and other equipment are designed to meet the steam cycle defined by the turbine." Nevertheless, Region VIII concluded that it is appropriate to consider supercritical technology, as a technology transfer control option under step one of the top-down BACT analysis. While the Division recognizes that a reviewing agency is not precluded from considering a technology that redefines the source, the Division is not required to consider such technologies as discussed in the response to comment #4 above. EPA Region VIII also recognized that the smallest supercritical pressure steam turbines available are for power plants in the range of 500 MW.

Although not required for BACT, Basin Electric evaluated both subcritical and supercritical PC boilers in a 2005 document entitled, "Coal Power Plant Technology Evaluation for Dry Fork Station," November 1, 2005, prepared for Basin Electric by CH2M HILL. This document discusses the efficiency improvements with supercritical boilers and indicates that improvements in the net heat rate (Btu/MW) of 2.0 to 3.0% are typical for PC boilers above 500 MW but less for smaller boilers. Additionally, this unit is designed to operate at higher temperature and pressure than older subcritical units resulting in an improvement in the net heat rate of approximately 2%. As a result, Basin Electric estimates less than 0.5% difference between the net heat rate for this unit and a supercritical boiler. Additionally, a supercritical turbine in this size range would be a one of a kind application requiring significant up front design and engineering costs. Alternatively, a larger than necessary high pressure turbine element could be used but this would further diminish any improvements in efficiency. The document concludes that a supercritical boiler is not appropriate for a boiler of this size.

7a) **Averaging Times** – PRBRC et al. commented that the averaging times for BACT limits must be equal or shorter than the averaging periods for NAAQS and PSD increment.

Response – The averaging periods for both NAAQS and PSD increment are: annual for NO_X; 8-hour and 1-hour for CO; annual, 24-hour, and 3-hour for SO_2; and annual and 24-hour for PM_{10}. There is an annual limit for NO_X, a 3-hour limit for SO_2, and a 6-hour limit for PM_{10} (three 120 minute tests). These are all equal or less than the averaging times for NAAQS and PSD increment. The lb/MMBtu limit for CO is a 3-hour limit which is less than the averaging period for the 8-hour standard but longer than the 1-hour standard. A shorter averaging time is not necessary for CO. The maximum 1-hour concentrations modeled for startup conditions, with an emission rate almost double the 3-hour limit (1112.1 lb/hr vs. 570.2 lb/hr), were still below the PSD Class II Significant Impact Levels (SILs). Additionally, EPA's reference method to determine compliance with the lb/MMBtu CO emission limit is based on the average of three 1-hour tests.

7b) **NO_X Limit** – PRBRC et al. commented that the limits for NO_X don't reflect the maximum reduction that could be achieved. The comment stated that a NO_X emission level of 0.015 lb/MMBtu could be met assuming an emission rate from the boiler of 0.15 lb/MMBtu using low NO_X burners and overfire air and an SCR control efficiency of 90%.

Response – The Division believes that the NO_X limits do reflect the maximum reductions that can be achieved on a continuous basis. The 0.05 lb/MMBtu limit is the lowest BACT limit of which the Division is aware and is equivalent to recent Lowest Achievable Emission Rate (LAER) emission limits set in non-attainment areas. There are technical issues with trying to achieve a lower emission level including additional ammonia slip, deactivation of the catalyst and pluggage of the downstream air heater due to ammonium sulfate and ammonium bisulfate, additional sulfuric acid mist emissions, and increased particulate matter emissions as discussed on page 8 of the analysis. The Division concluded that achieving emission levels below 0.05 lb/MMBtu on a continuous basis is not technically feasible at this time.

7c.1) **SO_2 Limit** – PRBRC et al. commented that the limits for SO_2 don't reflect the maximum reduction that could be achieved because the Newmont Nevada TS power plant permit has a lower SO_2 emission limit. The comment also stated that spray dryer absorbers can generally achieve greater than 90% SO_2 removal and that the Division must set a requirement for removal efficiency due to the variability in coal sulfur content.

Response – The Division believes that the SO_2 limits do reflect the maximum reductions that can be achieved on a continuous basis. As discussed in the response to Public Comment #4 and NPS comment #5a, the final permit limits SO_2 emissions to 0.070 lb/MMBtu, 12 month rolling average, based on a circulating dry scrubber (CDS). With the exception of the 0.065 lb/MMBtu limit for the Newmont Nevada TS power plant, 0.070 lb/MMBtu is the lowest BACT limit of which the Division is aware. The Newmont Nevada TS power plant has not been constructed and Basin Electric evaluated the control efficiencies necessary to meet these permit limits over the range of coal properties expected for the TS power plant. Basin Electric concluded that the spray dryer absorber (SDA) would have to operate at a level equal to or greater than its technical capabilities in order to meet the 0.065 lb/MMBtu limit.

The Division agrees that a spray dryer absorber (SDA) can generally achieve greater than 90% SO_2 removal. In fact, the proposed permit with a 0.08 lb/MMBtu emission limit would require the SDA to achieve an average control efficiency of 92.4% based on an uncontrolled emission rate of 1.055 lb/MMBtu (based on 0.47% sulfur content, 7800 Btu/lb, and the AP-42 emission factor). The final permit limit is 0.070 lb/MMBtu using a circulating dry scrubber (CDS) as previously discussed. This results in an average control efficiency of 93.4%.

There is no requirement to set a removal efficiency in addition to an emissions limitation. The PSD regulations define BACT as an emissions limitation based on the maximum degree of reduction that is achievable and reasonable. The permit contains such an emissions limitation. The actual control efficiency will vary with coal sulfur content. Control efficiencies are higher with higher sulfur content coal. When burning coal with a low sulfur content, the control equipment is not capable of achieving the same removal efficiency even though lb/MMBtu emissions may be less.

7c.2) **Hg Limit** – PRBRC et al. commented that the limits for Hg should be based on a top down BACT analysis and don't reflect the maximum reduction that could be achieved. The comment went on to say that the permit should require at least 90% control efficiency resulting in an emissions limitation between 6.26×10^{-6} and 10.02×10^{-6} lb/MW-hr.

Response – A top down BACT analysis for Mercury is not required under the PSD regulations. However, a BACT analysis was performed under WAQSR Chapter 6, Section 2.

Mercury control is an evolving technology and control efficiencies are site specific depending on coal properties and control devices used for other pollutants. The permit requires Basin Electric to install a mercury control system within 90 days of startup and perform a one year optimization study with a target level of 20×10^{-6} lb/MW-hr. The target level is to ensure that Basin Electric evaluates levels specified in other recent permits. The Division will reopen the permit and establish a final BACT emission limit based on the maximum reductions that can be achieved considering technical feasibility and cost. The final emission limit may be higher or lower than 20×10^{-6} (0.000020) lb/MW-hr. See also the responses to Public Comment #1, NPS comment #5e, and Basin Electric comment #3.

7d) **BACT Limits for VOC, Sulfuric Acid Mist, and Ammonia** – PRBRC et al. commented that the Division must impose BACT limits for these pollutants.

Response – The final permit includes BACT emission limits of 0.0037 lb/MMBtu for VOC, 0.0025 lb/MMBtu for sulfuric acid mist, and 10 ppm (19.6 lb/hr) for ammonia. Also see the responses to EPA comments #1 and #2 above.

7e) **Visible Emission Limit** – PRBRC et al. commented that the Division failed to propose a visible emission limit reflective of BACT and that Continuous Opacity Monitors (COMs) are required to ensure continuous compliance.

Response – WAQSR Chapter 3, Section 2 limits opacity to 20% and this limit is included in the permit. As stated by PRBRC, the definition of BACT contains the phrase "including a visible emission standard." It is the Division's position that this phrase allows but does not require an opacity limit other than the 20% limit. Opacity cannot be directly correlated to particulate emissions. Therefore, it is not feasible to perform a BACT analysis on visible emissions and any limit other than 20% would be arbitrary. Basin Electric is planning to install COMs in order to comply with NSPS Subpart Da. This subpart requires either COMs or PM Continuous Emission Monitors (CEMs).

8) **Condensible PM_{10}** – PRBRC et al. commented that the Division must impose a limit on total PM_{10} (filterable + condensible) or must model at an uncontrolled rate.

Response – There are no methods to control condensible PM_{10}, and therefore it is not feasible to perform a BACT analysis or set emission limits on the total condensibles. Testing will be required for the Dry Fork Project for both filterable and condensible PM_{10}, and the Division will assess the need for additional modeling based on the test results. The Division is imposing a 0.0025 lb/MMBtu limit on H_2SO_4 emissions as discussed in the responses to EPA comment # 1 and Basin Electric comment #1. The Division is also imposing a 2.62 lb/hr limit on fluoride emissions. These two pollutants comprise nearly 65% of the condensible PM_{10} from the Dry Fork boiler, as estimated by Basin Electric. Also see the responses to NPS comments #5c and 7.

9) **$PM_{2.5}$** – PRBRC et al. commented that the Division must address $PM_{2.5}$.

Response – The memo referred to in the comments (Interim Implementation of NSR Requirements for $PM_{2.5}$) states that it is administratively impractical to implement PSD permitting for $PM_{2.5}$ at this time and PM_{10} should be used as a surrogate until appropriate monitoring and modeling tools are available for $PM_{2.5}$. The memo states that, in the interim, the significance level for $PM_{2.5}$ is 15 tpy of PM_{10}. The Division is following the guidance in this memo and PM_{10} emissions are addressed in the analysis. Note that on September 21, 2007, the EPA proposed PSD rules for $PM_{2.5}$ in 72 Fed. Reg. 54112, 54138-39.

10) **Design Parameters** – PRBRC et al. commented that the proposed permit fails to include any conditions regarding the design of the source and states that the permit must identify the type of boiler, maximum heat input, generating capacity, control equipment, and emission limitations that reflect BACT.

Response – Condition 2 of the proposed permit states that the substantive commitments and descriptions set forth in the application are enforceable conditions of the permit. The proposed permit contains emission limitations that reflect BACT.

11a) **<u>24-Hour SO_2 Increment</u>** – PRBRC et al. commented that Basin Electric's Class I area SO_2 modeling analysis predicted violations of the 24-hour SO_2 increment at the Northern Cheyenne Indian Reservation and the Division cannot issue the permit because Dry Fork would contribute to violations of the SO_2 increments at the Northern Cheyenne Indian Reservation Class I area.

<u>Response</u> – Wyoming's PSD regulations require the Division review major source facility applications to ensure that emissions from the proposed facility will not cause or contribute to an exceedance of ambient air quality standards or violation of any PSD air quality increment. 6 WAQSR §§ 2 and 4. An "increment" is the maximum allowable increases in the concentration of a particular pollutant above a baseline. 6 WAQSR § 4(b)(i)(A)(I). Wyoming has increments for PM, SO_2, and NO_X. 6 WAQSR § 4, Table 1. The allowable level of incremental change in ambient air quality is more stringent in Class I than Class II areas.

Analyzing whether a proposed facility will likely 'cause or contribute' to a violation of the PSD allowable increment is conducted by computer modeling and proceeds in stages. See 40 C.F.R. part 51, App. W. Air Quality regulatory agencies may exempt *de minimis* situations "when the burdens of regulation yield a gain of trivial or no value." *See Alabama Power v. Costle,* 636 F.2d 323, 360-61 (D.C.Cir. 1979). In 1996, EPA proposed the use of Significant Impact Levels (SILs) as a screening tool to determine whether a proposed facility would cause or contribute to a violation of a Class I increment. *See* 61 Fed. Reg. 38,249; 38291-92 (July 23, 1996). Although EPA has not finalized these regulations, EPA, Wyoming and other states use the Class I SILs routinely in permitting actions. *See Groce v. Dep't of Envtl. Prot.*, 921 A.2d 567 (PA. Commw. Ct. 2007) (upholding Pennsylvania's use of EPA's proposed Class I SILs), Refinement of Increment Modeling Procedures (Proposed Rule) 72 Fed. Reg. 31372, 31377-78 (June 6, 2007)(describing EPA guidance and recognizing that current modeling practice includes comparing model results to significant impact levels), *PSD rules for $PM_{2.5}$* (Proposed Rule), 72 Fed. Reg. 54112, 54138-39 (Sept. 21, 2007)(setting forth EPA guidance and legal basis for use of SILs).

Since 1996, the Division has relied on the EPA proposed Class I SILs as a screening tool to evaluate the air quality impact of proposed facilities on PSD increment. The Division has found the SILs to be a practical means of defining "significant" and "contribution." Requiring the applicant demonstrate that projected emissions will not cause significant deterioration recognizes that some level of non-zero emission is permissible. The Division recognizes that merely because a computer model can generate an extremely small number does not make it significant – the key is whether the number indicates significant air quality impacts or *de minimis* impacts. If the modeled impacts are *de minimis*, i.e. less than the SIL, the permit applicant is generally not required to conduct a cumulative modeling analysis. However, if the modeled impacts are greater than the SIL, the Division requires a more extensive, time-consuming and costly cumulative modeling analysis to demonstrate that the proposed facility will not cause or contribute to an increment violation. The use of SILs provides the Division with a reasonable method to evaluate the proposed facility's impact on the allowable PSD increment.

Basin Electric's permit application utilized the EPA proposed Class I SILs to demonstrate that its proposed facility would not contribute significantly to any of the modeled SO_2 increment violations at the Northern Cheyenne Indian Reservation (NCIR) at those receptors and time periods which the CALPUFF model predicted would occur.

The Division compared the results of Basin's modeling analysis to the Class I SILs and determined that no additional modeling was necessary. The Division's analysis concluded that the Dry Fork project does not contribute significantly to any of the modeled SO_2 increment violations at the NCIR. Because the Dry Fork facility would not cause or contribute to a violation of the SO_2 increment at the NCIR, the Division may issue the permit.

11b) **Comment** – PRBRC et al. also commented that the Class I SO_2 increment analysis did not include all SO_2 sources and that Basin Electric only modeled the 90th percentile maximum 3-hour and 24-hour SO_2 emission rates from Colstrip Units 3 and 4, rather than the maximum 3-hour and 24-hour average emission rates.

Response – In the initial Class I modeling analyses of Dry Fork SO_2 impacts at Northern Cheyenne Indian Reservation (NCIR), the model predicted SO_2 impact from Dry Fork was greater than the 3-hour and 24-hour Class I SILs for SO_2 at NCIR. As a result, the Division required Basin Electric to conduct cumulative SO_2 Class I 3-hour and 24-hour increment consumption analyses at NCIR.

For the cumulative analysis, the applicant modeled SO_2 emission sources located within a 300 km radius of the NCIR, which is considered as the practical limit for CALPUFF in the current EPA guidance document, Guideline on Air Quality Models. The emissions inventory modeled included sources located in southern Montana, northern Wyoming, and southwest North Dakota. The only source in North Dakota located within 300 km of the NCIR was included in the analysis; the Gascoyne Generating Station, a coal-fired power plant. Sources in Montana include Colstrip Units 3 and 4, Rocky Mountain Power (Hardin), Rocky Mountain Ethanol, Colstrip Energy Limited Partnership, and Roundup Power Project Units 1 and 2. Wyoming sources include WYGEN Units 1, 2, and 3, Neil Simpson Units 1 and 2, Two Elk Unit 1, and the proposed KFx Ft Union plant. One Wyoming source was not included in the cumulative SO_2 increment consumption analysis at the NCIR; the Neil Simpson Unit 1 source, a coal-fired power plant in Wyoming that was constructed in 1969, prior to the major source baseline date for SO_2 of January 6, 1975. Additionally, four small sources of SO_2 were identified in South Dakota. However, because these sources have low SO_2 emissions and the large distance between these sources and the NCIR, these sources of SO_2 were not included in the cumulative Class I area increment consumption analysis.

Initially, Basin Electric modeled all SO_2 sources using allowable short-term SO_2 emission rates, except for Units 3 and 4 at the Colstrip power plant in Montana, which were modeled at the 90th percentile of actual emissions, based on actual emissions data from 2003 and 2004. The Division required Basin Electric to model all sources at the respective short-term SO_2 permitted emission rates, and the revised SO_2 increment analyses submitted have included the two sources at the Colstrip facility modeled at the permitted 3-hour and 24-hour emission rates. Modeling the short-term permitted SO_2 emission rates for Colstrip Units 3 and 4, as submitted in the permit application, and subsequent revisions, does yield predicted SO_2 concentrations that are greater than the 24-hour Class I SO_2 increment of 5 ug/m^3, for both 2002 and 2003.

In their response to this comment, Basin Electric submitted a revised cumulative SO_2 increment consumption analysis for the NCIR using revised SO_2 emission rates for the Colstrip facility - Units 3 and 4, based on the annual average SO_2 emission rates obtained from the USEPA Clean Air Markets web page. Basin Electric states in their response that modeling the revised SO_2 emission rates for Colstrip Units 3 and 4, alone, and in combination with the other SO_2 sources modeled, the highest 24-hour SO_2 concentration at the Northern Cheyenne Indian Reservation did not exceed the Class I SO_2 increment of 5 ug/m^3.

12) **Soils and Vegetation** – PRBRC et al. commented that a complete analysis is required for the impact on soils and vegetation.

Response – A soils and vegetation analysis was prepared by CH2M HILL and discussed in section 7.8.2 of the November 2005 application. As discussed in the analysis, oats and barley were identified by the applicant as sensitive vegetation in the near vicinity of the proposed Dry Fork power plant. A modeling analysis was performed to evaluate 3-hour foliar effects of NO_x and SO_2 on oats. Results of this analysis show the individual NO_x and SO_2 impacts are below 8% of the reference concentration known to cause foliar injury to oats.

A June 20, 2007 document, "Dry Fork Station Air Quality Impacts to Soils and Vegetation" provides additional information and is included as Attachment C. This document discusses that a specific search was made for information regarding soils and vegetation in the area and documents that, for sensitive species, modeled concentrations of pollutants known to be potentially harmful were compared with concentrations at which harm might occur. The analysis concluded that there would be no harm.

This document also discusses endangered species and notes that the only endangered species identified as potentially occurring in the area, the Ute ladies'-tresses orchid, was not found during a site survey. It further states that multiple threats were identified for the species but none related to air quality.

V. ANALYSIS OF COMMENTS FROM THE NATIONAL PARK SERVICE:

The Division provides the following responses to the comments in the March 28, 2007 letter from the National Park Service (NPS).

1) **Notification Requirements** – The NPS commented that 40 CFR52.21(p)(1) requires all information to be submitted to the FLM within 30 days of receipt and at least 60 days prior to hearing. The NPS further commented that the Division did not provide the public notice, analysis, and draft permit conditions until publication of the public notice and that the Federal Land Manager (FLM) should have been provided the opportunity to submit a visibility analysis within 30 days of the Division's preliminary determination and before announcing the public hearing.

Response – The provisions of 40 CFR § 52.21 only apply to major stationary sources proposing to construct on Indian Reservations in Wyoming or that received their DEQ/AQD permit prior to September 6, 1979. 40 CFR § 52.2630(b). The permit review notice requirements for all other major stationary sources proposing to construct in Wyoming are located in Chapter 6 of the Wyoming Air Quality Standards and Regulations (WAQSR). The Basin Dry Fork Station application is for a new major stationary source, so the requirements of Chapter 6 of the WAQSR apply.

Within thirty days of receiving notice of a PSD permit application for a proposed facility which may affect visibility in a Federal Class I area, the Division must notify the FLM. 6 WAQSR § 2(n)(ii). On June 30, 2005, in advance of receiving a formal permit application, the Division began the process of notifying the FLMs of this potential new major source when the Division sent a Class I Modeling Protocol to the NPS, followed by a pre-application meeting on August 4, 2005 attended by the NPS. On September 22, 2005, the Division also sent the NPS a copy of the revised Class I Area modeling protocol outlining the ambient air impact analyses to be conducted for the project.

Within thirty days of receiving a major stationary source permit application subject to PSD requirements, but not later than sixty days before the Division's public notice of its proposed decision, the Division is required to provide written notice to FLMs whose Class I areas may be affected by emissions from the proposed facility. 6 WAQSR § 2(n). This notice includes information relevant to the permit application including "an analysis of the anticipated impacts on air quality and visibility" in the Federal Class I area. The Division received Basin's Dry Fork Permit Application on November 10, 2005 and sent a copy to the NPS on November 14, 2005. Basin's application included an analysis of anticipated impacts on air quality and visibility.

Additionally, no later than sixty days after the Division's completeness determination, the Division must reach and publish its proposed decision approving, conditionally approving, or denying the permit application. 6 WAQSR § 2(g). The rules also require the Division send its proposed decision and analysis to specific persons, including FLMs whose lands may be significantly affected by emissions from the proposed facility, and make the proposed decision and analysis available for a thirty day public comment period and an opportunity for the public to request a hearing. 6 WAQSR § 2(m). On August 18, 2006, the Division notified the NPS that Basin's application was complete and also sent additional information the Division had received from Basin on March 3, June 14, July 12, and July 14, 2006. The Division provided its proposed decision and analysis to the NPS on February 22, 2007. The public comment period started on February 27, 2007 and was originally scheduled to end on March 28, 2007 but was continued until the conclusion of the June 28, 2007 public hearing. The Division concludes that it has provided the NPS with the opportunity to submit a visibility analysis both prior to and during the four month public comment period. The Division notes that the NPS provided to the Division a visibility analysis on March 28, 2007 and a revised visibility analysis on June 28, 2007 and the Division does not need to re-open the comment period.

2) **Impact on Wind Cave NP** – The NPS commented that the proposed Dry Fork project emissions would significantly impact visibility at Wind Cave NP, and the results of the Dry Fork visibility analysis indicate the need for further review. The NPS commented that the visibility analysis should be revised to reflect the higher estimates provided by the National Park Service.

Response – The NPS has developed methods to estimate emission rates for each specie that comprises PM_{10} emissions from coal-fired boilers. The NPS references AP-42 (Table 1.1-5 and Table 1.1-6) as the basis for estimating their total condensable, organic condensable fraction, and inorganic condensable fraction of PM_{10} emissions. The emission factors in AP-42 have ratings, which reflect the quality of the data, as well as the quantity of data that were used to develop the emission factors. The rating scale spans the values of A-E. A rating of A is considered by EPA to be excellent, in that the data used to develop the emission factor were based on high quality source test data from randomly chosen facilities in the industry to minimize variability, whereas a rating of E is considered by EPA to be poor, in that the data used to develop the emission factor were developed from C and D rated test data from very few facilities, and there may be reason to suspect that the selected facilities tested do not represent a random sample of the industry, and the emission factor data may contain variability within the source category population. The emission factor rating for the total PM_{10} condensable emissions calculated by the NPS for pulverized-coal fired boilers has a rating of E, and the emission factor ratings for the organic condensable fraction, and the inorganic condensable fraction of PM_{10} emissions from pulverized-coal fired boilers were listed as ND, which means no data were available.

Basin Electric calculated PM_{10} condensable emission rates based on vendor-specific PM_{10} emission factors, which were derived from coal analyses using actual coal samples. This is consistent with the Division's policy of using vendor guarantees as a primary source of data to calculate emissions and using AP-42 when no higher quality data is available. Large differences exist between the condensable PM_{10} emission rates calculated by the NPS and Basin Electric due to the different emission factors used in those calculations, with the AP-42 emission factors yielding much higher PM_{10} condensable emissions. Testing will be required for the Dry Fork Project for both filterable and condensible PM_{10} and the Division will assess the need for additional modeling based on the test results. Also see the response to NPS comment #8.

Basin Electric conducted revised CALPUFF visibility modeling for the project based on the final emission rates for NO_x (0.05 lb/MMBtu), SO_2 (0.10 lb/MMBtu, 3-hour avg.), and H_2SO_4 (0.0025 lb/MMBtu). At the request of the Division, the modeling was conducted using three methods within the CALPOST program: Method 2, Method 6, and a modified Method 6 that used aerosol background concentrations and relative humidity functions from the Division's BART modeling protocol and a 98th percentile cutoff for the results. The results of the revised modeling, which reflect all three years of meteorological data that were modeled, are presented in the table below:

Class I Area	CALPOST Method 2	CALPOST Method 6	CALPOST Method 6 (modified)
Wind Cave NP (2001-2003)			
Days > 5%	6	1	0
Days > 10%	0	0	0
Maximum %	8.0	5.2	3.5
Badlands NP (2001-2003)			
Days > 5%	0	0	0
Days > 10%	0	0	0
Maximum %	4.9	4.9	2.4
NCIR (2001-2003)			
Days > 5%	5	2	0
Days > 10%	1	1	0
Maximum %	30.0	12.2	2.7

NCIR = Northern Cheyenne Indian Reservation

3) **IGCC** – The NPS commented that the analysis should consider IGCC.

Response – See the responses to PRBRC et al. comments #4 and 5.

4) **Supercritical Boiler** – The NPS commented that the analysis should consider supercritical and ultra-supercritical boilers.

Response – See the response to PRBRC et al. comment #6.

5a) **SO_2 Control** – The NPS commented that SO_2 is controlled better at other facilities using dry FGD such as Newmont Nevada and at several proposed facilities using wet FGD.

Response – The NPS compared the control efficiency of the dry FGD system at Dry Fork Station to three facilities burning low sulfur coal (Newmont Nevada, LS Power-White Pines, and LS Power-High Plains) and three facilities using high sulfur coal (Sithe-Desert Rock, Sierra Pacific-Ely, and FPL-Glades). The comparison to the three units burning high sulfur coal is not relevant because FGD units are more efficient with higher sulfur loading as discussed in the response to PRBRC et al. comment 7c.1. The emission limit in the final permit is 0.070 lb/MMBtu as discussed in the responses to public comment 4 and PRBRC et al. comment 7c.1. This results in an annual average control efficiency of 93.4%, which is equivalent to LS Power-High Plains and higher than that for Newmont Nevada (93.1%) and LS Power-White Pines (93.2%).

The NPS commented that the three facilities using high sulfur coal are controlled with wet FGD and have lower lb/MMBtu emission limits. The Division agrees that wet FGD provides better control for higher sulfur coals. An EPA report, *Controlling SO_2 Emissions: A Review of Technologies*, concludes that control efficiencies for wet and dry FGD are essentially identical for facilities using low sulfur Powder River Basin coal. This is consistent with discussions the Division has had with FGD vendors and other electric utilities. Additionally, the three facilities burning high sulfur coal are all 750 MW units or larger and use a supercritical boiler. This results in a higher efficiency and lower lb/MMBtu emissions. As discussed in the response to PRBRC et al. comment 6, Basin Electric evaluated a supercritical boiler and determined that it is not appropriate for a boiler of this size.

5b) **<u>lb/MW-hr NO_X Emissions</u>** – The NPS commented that lb/MW-hr NO_X emissions are higher than Florida Power and Light's Glades Power Plant due to the higher efficiency of the Glades boilers.

<u>Response</u> – The 0.05 lb/MMBtu NO_X limit for Dry Fork Station is the lowest lb/MMBtu limit the Division is aware of for a PC boiler. The boilers that were proposed for the Glades project are somewhat more efficient as they are much larger (980 MW) supercritical boilers. The Division notes that the Florida Public Service Commission rejected the Glades project on June 5, 2007 because they did not consider it economically feasible.

As discussed in the response to PRBRC et al. comments 4 and 6, a supercritical boiler requires a completely different boiler and turbine design and the BACT process does not require the Division to redefine the source. Although not required for BACT, Basin Electric evaluated a supercritical boiler, as discussed in the response to PRBRC et al. comment 6, and determined that it is not appropriate for a boiler of this size.

5c) **<u>PM_{10} Emission Limits</u>** – The NPS commented that there is no limit proposed for condensible PM_{10} and they are aware of three projects (Sithe's Desert Rock NM, Sithe's Toqoup NV, and North American Power Group's Two Elk expansion) with lower proposed emission limits for filterable PM_{10}.

<u>Response</u> – As discussed in the responses to PRBRC et al. comment 8 and NPS comment 7, there are no methods to control condensible PM_{10}, and therefore it is not feasible to perform a BACT analysis or set emission limits for condensible PM_{10}. Ambient air quality modeling was performed including condensible PM_{10} and testing is required. The Division will assess the need for additional modeling based on the test results.

0.012 lb/MMBtu is the lowest demonstrated filterable PM_{10} limit of which the Division is aware. The proposed permit for Sithe's Desert Rock NM facility does contain a proposed filterable PM_{10} emission limit of 0.010 lb/MMBtu. Likewise, the application for Sithe's Toqoup NV facility proposes a filterable PM_{10} emission limit of 0.010 lb/MMBtu. North American Power Group's Two Elk expansion project originally proposed a filterable PM_{10} emission limit of 0.012 lb/MMBtu and is now requesting a filterable PM_{10} emission limit of 0.015 lb/MMBtu.

The Division required Basin Electric to evaluate filterable PM_{10} emission limits of 0.010 lb/MMBtu and 0.012 lb/MMBtu. The Division considered the incremental cost of $30,771/ton between these two levels to be excessive and determined that 0.012 lb/MMBtu is BACT for this proposed facility. The incremental cost is high because there is only a 34 ton per year difference in potential emissions between these two options and the increase in total annualized cost is $1,050,000 due to the use of specialty filter bags such as P-84 polyimide or teflon in order to meet the lower emission limit.

5d) **H$_2$SO$_4$ limit** – The NPS commented that the H_2SO_4 limit should be lowered to reflect the degree of control achieved by a dry scrubber at Newmont NV.

Response – The H_2SO_4 limit for Newmont, NV is 0.001 lb/MMBtu. As discussed in the response to Basin Electric comment 1, Basin Electric concluded that this level is below the practical analytical detection limit of EPA Reference Method 8 and 8A for a coal fired boiler. The limit in the final permit remains at 0.0025 lb/MMBtu H_2SO_4.

5e) **Hg Limit** – The NPS commented that the Hg limit should be lowered to reflect the degree of control achieved by a dry scrubber at Newmont NV.

Response – The Hg limit for Newmont NV is 20×10^{-6} lb/MW-hr. As discussed in the response to PRBRC et al. comment 7c.2, mercury control is an evolving technology and control efficiencies are site specific depending on coal properties and control devices used for other pollutants. The permit requires Basin Electric to install a mercury control system within 90 days of startup and perform a one year optimization study with a target level of 20×10^{-6} lb/MW-hr. The target level is to ensure that Basin Electric evaluates levels specified in other recent permits. The Division will reopen the permit and establish a final BACT emission limit based on the maximum reductions that can be achieved considering technical feasibility and cost. The final emission limit may be higher or lower than 20×10^{-6} lb/MW-hr.

6) **CEM for PM** – The NPS recommended a Continuous Emissions Monitor (CEM) for PM.

Response – As discussed in the response to EPA comment #7, there are no regulations requiring a CEM for PM and the Division is not electing to require one. NSPS Subpart Da requires either a Continuous Opacity Monitor (COM) or Continuous Emission Monitor (CEM) for PM. Basin Electric is planning to install a COM in order to comply with NSPS Subpart Da.

7) **Total PM$_{10}$ for Modeling** – The NPS commented that Wyoming modeled 63.8 lb/hr total PM_{10} while the application lists 75.7 lb/hr.

Response – The Division modeled a total PM_{10} emission rate of 64.6 lb/hr for the far field analyses (i.e. CALPUFF), which reflects an H_2SO_4 emission rate of 0.0025 lb/MMBtu. The difference between the total PM_{10} emission rate modeled (64.6 lb/hr) and the value reported by NPS (63.8 lb/hr) is due to the molecular weight adjustments the model makes for sulfates. The near-field modeling analyses are based on the higher value of 75.7 lb/hr, which is reflective of a higher H_2SO_4 emission rate of 0.0045 lb/MMBtu.

The total PM_{10} emission rate is the sum of the filterable and condensible components. The filterable portion is discussed in the response to NPS comment 5c and the condensible portion is discussed in the response to PRBRC et al. comment #8. The Division has imposed limits on filterable PM_{10} of 0.012 lb/MMBtu and 45.6 lb/hr. Testing will be required for the Dry Fork Project for both filterable and condensible PM_{10}, and the Division will assess the need for additional modeling based on the test results.

8) **Cumulative Visibility Analysis** – The NPS commented that a cumulative visibility analysis should be performed for Wind Cave and Badlands national parks, based on the results of the CALPUFF visibility analysis.

Response – The Division's regulations for requiring the applicant to conduct a visibility analysis of the proposed project impacts at designated Class I areas adopt those in the PSD Rule by reference, which does not require a cumulative visibility analysis to be performed for the proposed new source or modification. Only the visibility impacts from the proposed new source or modification must be assessed as required under current Federal regulations, and the Wyoming Air Quality Standards and Regulations (WAQSR). Specifically, under WAQSR Chapter 6, Section 4, (b)(i)(B)(I) and 40 CFR Part 51.166 (o)(1), it states that "the owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the facility or modification and general commercial, residential, industrial, and other growth associated with the facility or modification". The applicant has complied with the regulations cited above by assessing visibility impacts from the proposed source. Also see the response to NPS comment #2.

9) **Sulfur Deposition at Wind Cave NP** – The NPS commented that the estimated annual sulfur deposition (0.008 kg/ha/yr) is greater than the Deposition Analysis Threshold (DAT) at Wind Cave National Park and further analysis should be performed.

Response – Chapter 6, Section 4(b)(i)(B)(I) of the WAQSR describes that an applicant for a PSD permit should provide an analysis of the impact to soils and vegetation as a result of the source or modification. Basin Electric (BEP) satisfied this requirement by submitting an analysis of the deposition impacts from the Dry Fork Project alone. The results of the analysis for annual nitrogen deposition at Wind Cave and Badlands national parks were less than 50% of the NPS's Deposition Analysis Threshold (DAT), and the Division did not require any further analysis for nitrogen deposition. The results submitted by BEP for annual sulfur deposition at Wind Cave were obtained with an emission rate reflective of the short-term (3-hour) permit limit for SO_2. Because the deposition DAT was established on the basis of long-term (annual) deposition rates, the Division performed a revised analysis with the long-term (30-day) Dry Fork permit limit of 285.1 lb/hr. The modeled result for annual sulfur deposition with this reduced emission rate was 0.006 kg/ha/yr, which exceeds the established DAT of 0.005 kg/ha/yr, but by a smaller amount than the conservative amount initially reported by BEP.

10) **24-hour Limits for Visibility** – The NPS commented that the permit should include NO_X and PM_{10} limits consistent with the 24-hour emissions modeled in the visibility analysis.

Response – There is no regulatory basis for setting short term emission limits, specific to visibility protection, as there are no established standards for visibility. As discussed in the response to PRBRC et al. comment 7b, the NO_X limit of 0.05 lb/MMBtu, 12-month rolling average, is the lowest BACT limit of which the Division is aware and is equivalent to recent Lowest Achievable Emission Rate (LAER) emission limits set in non-attainment areas. Using a shorter averaging time would necessitate an increase in the emission limit in order to account for short term variations and operation at lower loads as discussed in the response to EPA comment #5. Additionally, setting a short term emission limit would not change actual short term emission rates.

As discussed in the response to EPA comment 6 and PRBRC et al. comment 7a, the lb/MMBtu and lb/hr PM/PM_{10} limits are 6-hour limits based on the average of three 120-minute tests per 40 CFR 60.50 Da. Additionally, the 380.1 lb/hr SO_2 limit is a 3-hour average based on 0.1 lb/MMBtu and this value was used for the visibility analysis. These averaging periods are less than the 24-hour period used in the visibility analysis and shorter averaging periods are not necessary.

11) **<u>Sulfur and Nitrogen Deposition at Devils Tower</u>** – The NPS commented that sulfur and nitrogen deposition should be provided for Devil's Tower.

<u>Response</u> – A deposition analysis at Devils Tower National Monument was not proposed by the applicant in the modeling protocol for the Dry Fork Power Plant submitted by BEP in August, 2005. In the August 4, 2005 meeting in Cheyenne, the NPS provided verbal comments and suggested revisions to the CALPUFF modeling protocol. Appendix A of the revised modeling protocol contained a summary of the NPS suggested revisions to the protocol, in which the applicant agreed to model criteria pollutant impacts and visibility at Devils Tower National Monument. The revised protocol was sent to the National Parks Service on September 22, 2005, and no comments from the NPS were received by the Division regarding any revisions to the protocol. Therefore, deposition impacts were not assessed at Devils Tower National Monument.

12) **<u>Reasonable Progress for Visibility</u>** – The NPS expressed concern about cumulative impacts on visibility from development in the Powder River Basin and around Wind Cave National Park and stated that, under the Regional Haze Rule (RHR), states are to make "reasonable progress" toward the goal of natural visibility by 2064. The NPS commented that they believe it is appropriate for the Division to show how issuance of this permit, in conjunction with other growth in the area, will allow the state to meet the "reasonable progress" obligation.

<u>Response</u> – The State of Wyoming is currently working on a state implementation plan (SIP) to address the requirements of the regional haze rule. Much of the work that has already been completed toward this effort has been accomplished through participation in the Western Regional Air Partnership (WRAP). The WRAP is a collaborative effort of tribal governments, state governments and various Federal agencies, including the National Park Service, to implement the Grand Canyon Visibility Transport Commission's recommendations and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. EPA's regional haze regulations. The WRAP has not ignored the impact of new power generation on visibility in western Class I areas. In 2003, Wyoming and four other western states working through the WRAP, submitted the Nation's first Regional Haze SIPs to meet the requirements of 40 CFR 51.309 which capped SO_2 emissions, including those from new growth, through the first planning period ending in 2018. Therefore, in addition to the NSR BACT review, SO_2 emissions from new EGUs in the State must fit under the multi-state CAP. Controlling SO_2 emissions from major point sources, primarily electric generating units (EGUs), marks a significant achievement toward improving visibility. With respect to NO_X emissions, the contribution to visibility impairment at most western Class I areas on the worst days is relatively small (5-10%). Projected new source growth of EGUs has been included in all visibility modeling efforts. Mobile sources are the largest source of NO_X emissions (2/3) in the West and these emissions will decrease dramatically through 2018 as a result of existing and proposed

Federal fuel and engine standards for on-road and non-road vehicles/equipment (including locomotives and commercial marine). The State and WRAP will continue to assess the NO_X contribution from EGUs, but the focus in this first SIP has been to reduce NO_X from existing EGUs through the application of BART (Best Available Retrofit Technology). WRAP estimates that western states will reduce NO_X levels from coal-fired EGUs by 36% by 2018 from 1998 levels. Another critical part to controlling NO_X from western EGUs is to address two major tribal sources (Navajo and Four Corners), which together emit about 20% of all EGU NO_X in the western power grid. It is EPA's responsibility to address BART from these sources. Addressing the requirements of the Regional Haze Rule is a long-term commitment since the rule directs states to reach natural conditions by 2064. The State will continue to work collaboratively with other states, tribal governments and various Federal agencies to comply with the rule.

VI. ANALYSIS OF COMMENTS FROM BASIN ELECTRIC:

The Division provides the following responses to the comments in the March 28, 2007 letter from Basin Electric Power Cooperative.

1) **H_2SO_4 Limit** – Basin Electric commented that the proposed 0.0025 lb/MMBtu emission limit for H_2SO_4 is equivalent to the practical analytical detection limit of approximately 1 ppm_v @ 3% O_2 for EPA Reference Method 8/8A. Basin stated that vendors are not willing to guarantee H_2SO_4 emissions below approximately 1 to 2 ppm_v @ 3% O_2 due to the limitations of the reference method tests.

   Response – The analysis for the proposed permit concluded that an estimated emission rate of 0.0025 lb/MMBtu represents BACT for H_2SO_4. Basin Electric subsequently proposed a limit of 0.0045 lb/MMBtu due to the limitations of the reference method test discussed above. After further discussions, Basin Electric determined that they should be able to demonstrate compliance with the 0.0025 lb/MMBtu limit by increasing the sample time for Method 8/8A. The final permit limit remains 0.0025 lb/MMBtu.

2) **SO_2 Monitoring** – Basin Electric commented that NSPS Subpart Da only requires SO_2 emissions to be monitored at the outlet of the control device because the Dry Fork boiler will meet the numerical limit provisions of 40 CFR 60.43Da(i). The Division's analysis for the proposed permit states that Subpart Da requires both inlet and outlet monitoring.

   Response – The Division agrees with Basin's comment that only SO_2 outlet monitoring is required in accordance with 40 CFR 60.49Da(b)(2).

3) **Hg Control System** – Basin Electric requested that the Division delete Condition 10(B) requiring a Hg control system within 90 days of startup because it is inconsistent with condition 10(A) which requires a one year mercury optimization study.

   Response – It is the Division's intent for Basin Electric to install and operate a mercury control system within 90 days of startup. It was the Division's expectation that this would be a carbon injection system or another comparable control device. The Division did not specify the type of control system due to the possibility that new or improved controls will be developed in the interim. Basin Electric is now indicating that the circulating dry scrubber (CDS) to be installed for SO_2 control may achieve up to 70 – 80% mercury control. Additionally, Basin Electric indicated that they will install a skid mounted bromine or chlorine injection system and a skid mounted carbon injection system within 90 days of startup.

If Basin Electric can submit documentation to substantiate that the CDS unit is expected to achieve significant mercury control above and beyond what a lime spray dryer absorber (SDA) would achieve, the Division will consider whether or not the CDS unit will fulfill the intent of the requirement to install a mercury control system within 90 days of startup. Skid mounted systems will fulfill the intent of this requirement as long as they are operated to control mercury emissions rather than only used for testing purposes.

Part (A) of this condition requires a protocol for the optimization study to be submitted to the Division for review and approval prior to commencement of the study. Regardless of the control efficiency achieved with the CDS unit, it is the Division's expectation that Basin Electric will evaluate carbon injection as part of the optimization study as a minimum. The Division will reopen the permit and establish a final BACT emission limit based on the maximum reductions that can be achieved considering technical feasibility and cost. The final emission limit may be higher or lower than 20×10^{-6} lb/MW-hr.

VII. DECISION:

On the basis of comments received during the public comment period, an analysis of those comments, and representations made by Basin Electric Power Cooperative in the application, the Department of Environmental Quality has determined that the permit application filed by Basin Electric Power Cooperative complies with all applicable Wyoming Air Quality Standards and Regulations and that a permit will be issued to Basin Electric Power Cooperative allowing construction of Dry Fork Station as described in the application. All of the conditions proposed in the Division's analysis will be included in the permit with the following changes and additions:

1) The 12 month rolling average SO_2 emission limit in condition 9 was changed from 0.08 to 0.070 lb/MMBtu. The 30 day rolling average SO_2 emission limit was changed from 304.1 lb/hr (based on 3,801 MMBtu/hr and 0.08 lb/MMBtu) to 285.1 lb/hr (based on 3,801 MMBtu/hr and 0.075 lb/MMBtu). The tpy emission limit was changed from 1331.8 tpy to 1165.4 tpy (based on 0.070 lb/MMBtu).

2) Emission limits were added to condition 9 for H_2SO_4 (0.0025 lb/MMBtu, 17.1 lb/hr, 74.9 tpy), hydrogen fluoride (2.62 lb/hr, 11.5 tpy), VOC (0.0037 lb/MMBtu, 14.1 lb/hr, 61.6 tpy), and ammonia (10 ppm, 19.6 lb/hr, 85.8 tpy).

3) The lb/hr CO limit in condition 9 was changed to a 30 day rolling average.

4) Requirements for a CO CEM were added to condition 14.

5) Compliance provisions for lb/hr CO emissions using CEM data were added to condition 15.

6) Testing requirements for fluoride and sulfuric acid mist were moved from condition 13 to condition 12 and the provision allowing "equivalent methods" was changed to "equivalent EPA Reference Methods."

7) Condition 9 was revised to indicate that the emission limits apply at all times including startup and shutdown.

Dated this 15th day of October, 2007

David A. Finley
Administrator
Wyoming Air Quality Division

John V. Corra
Director
Wyoming Department of Environmental Quality