BEFORE THE ENVIRONMENTAL QUALITY COUNCIL
STATE OF WYOMING

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| 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 T

# 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 $20\times10^{-6}$ (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) <u>**Control of Sulfur Dioxide Emissions**</u> – Comments were received regarding the need to control sulfur dioxide ($SO_2$) emissions.

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

<u>**Response**</u> – 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 8th 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 $6.26\times10^{-6}$ and $10.02\times10^{-6}$ 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 $20\times10^{-6}$ 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 $20\times10^{-6}$ (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) **24-Hour $SO_2$ Increment** – 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.

**Response** – 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 90$^{th}$ 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 90$^{th}$ 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 98$^{th}$ 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) <u>IGCC</u> – The NPS commented that the analysis should consider IGCC.

<u>**Response**</u> – See the responses to PRBRC et al. comments #4 and 5.

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

<u>**Response**</u> – See the response to PRBRC et al. comment #6.

5a) <u>**$SO_2$ Control**</u> – 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.

<u>**Response**</u> – 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) **lb/MW-hr $NO_X$ Emissions** – 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.

**Response** – 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) **$PM_{10}$ Emission Limits** – 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 $PM_{10}$.

**Response** – 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) **$H_2SO_4$ 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 $20\times10^{-6}$ 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 $20\times10^{-6}$ 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 $20\times10^{-6}$ 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 $20\times10^{-6}$ 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

# Attachment A – Revised $SO_2$ BACT analysis

## Attachment A
## Revised $SO_2$ BACT Analysis

Basin Electric evaluated the following emission control technologies:

1. Wet Flue Gas Desulfurization (FGD) – For wet FGD, $SO_2$ is reacted with a limestone or lime slurry to produce calcium sulfite or calcium sulfate (gypsum). Forced oxidation is commonly used to assure that only calcium sulfate is produced. Wet FGD can provide a better control efficiency but uses more water than dry FGD and has a visible moisture plume. Wet FGD results in higher emissions of particulate matter compared to dry FGD because the particulate removal device must be upstream of the wet FGD. Wet FGD also has lower removal efficiencies for acid gases and may result in higher mercury emissions.

2. Spray Dryer/Absorber (Dry FGD) – In a spray dryer/absorber, $SO_2$ is reacted with a $Ca(OH)_2$ slurry to produce calcium sulfate (gypsum). The calcium sulfate is captured downstream in the fabric filter. Significantly less water is used compared to wet FGD and there is typically no visible moisture plume.

3. Circulating Dry Scrubber (CDS) – In a CDS unit, $SO_2$ is reacted with dry $Ca(OH)_2$ to produce calcium sulfite or calcium sulfate (gypsum). CDS units are expected to achieve a slightly higher $SO_2$ removal efficiency than spray dryer/absorbers. The Division originally did not consider a CDS unit because there are only two units operating in the United States and both have experienced problems with severe corrosion, high lime consumption (approximately twice that for a spray dryer/absorber), and high energy costs (approximately 1/3 higher than a spray dryer/absorber). Basin has since informed the Division that the technical issues have been resolved and agreed to consider this technology.

Basin Electric evaluated dry FGD and wet FGD at several emission levels and originally proposed dry FGD with an emission limit of 0.10 lb/MMBtu, 30 day rolling average, and 380.1 lb/hr, 3 hour block (based on 0.10 lb/MMBtu). As with $NO_X$, Basin Electric evaluated the variability in actual 30 day rolling average emission levels at two facilities and added two standard deviations. This equated to a 23% margin of safety added to the 0.073 lb/MMBtu actual emissions for an emission level of 0.09 lb/MMBtu. Basin Electric then proposed 0.10 lb/MMBtu.

A review of recently issued PSD permits indicates that Newmont Nevada Energy Investment's TS Power Plant uses SDA and has the lowest $SO_2$ emission limit for a PC boiler burning sub-bituminous coal. The TS Power Plant has different emission limits depending on the sulfur content of the coal combusted. When combusting coal with a sulfur content less than 0.45%, the boiler is limited to 0.065 lb/MMBtu (24-hour rolling average) and 91% removal efficiency. When combusting coal with a sulfur content greater than or equal to 0.45%, the boiler is limited to 0.09 lb/MMBtu (24-hour rolling average) and 95% removal efficiency. The design coal for Basin Electric's proposed facility contains 0.33% sulfur with sulfur contents ranging from 0.25% to 0.47%. At the upper end of sulfur content for Basin Electric's proposed facility (0.47%), a 95% removal efficiency results in 0.06 lb/MMBtu. Therefore, the TS Power plant would be limited to no more than 0.065 lb/MMBtu (24-hour rolling average) when combusting coal with sulfur contents equivalent to those for Basin Electric's proposed facility. As a result of this finding, the Division requested Basin Electric to evaluate lower emission levels.

Basin Electric provided an analysis of cost effectiveness for wet FGD with emission limits of 0.07, 0.08, and 0.09 lb/MMBtu and for SDA with emission limits of 0.09 and 0.10 lb/MMBtu. As previously discussed, Basin Electric added a 23% margin to the 0.073 lb/MMBtu design target emission level for SDA to derive an emission limit of 0.09 lb/MMBtu. Similarly, they added a 29.6% margin to the 0.054

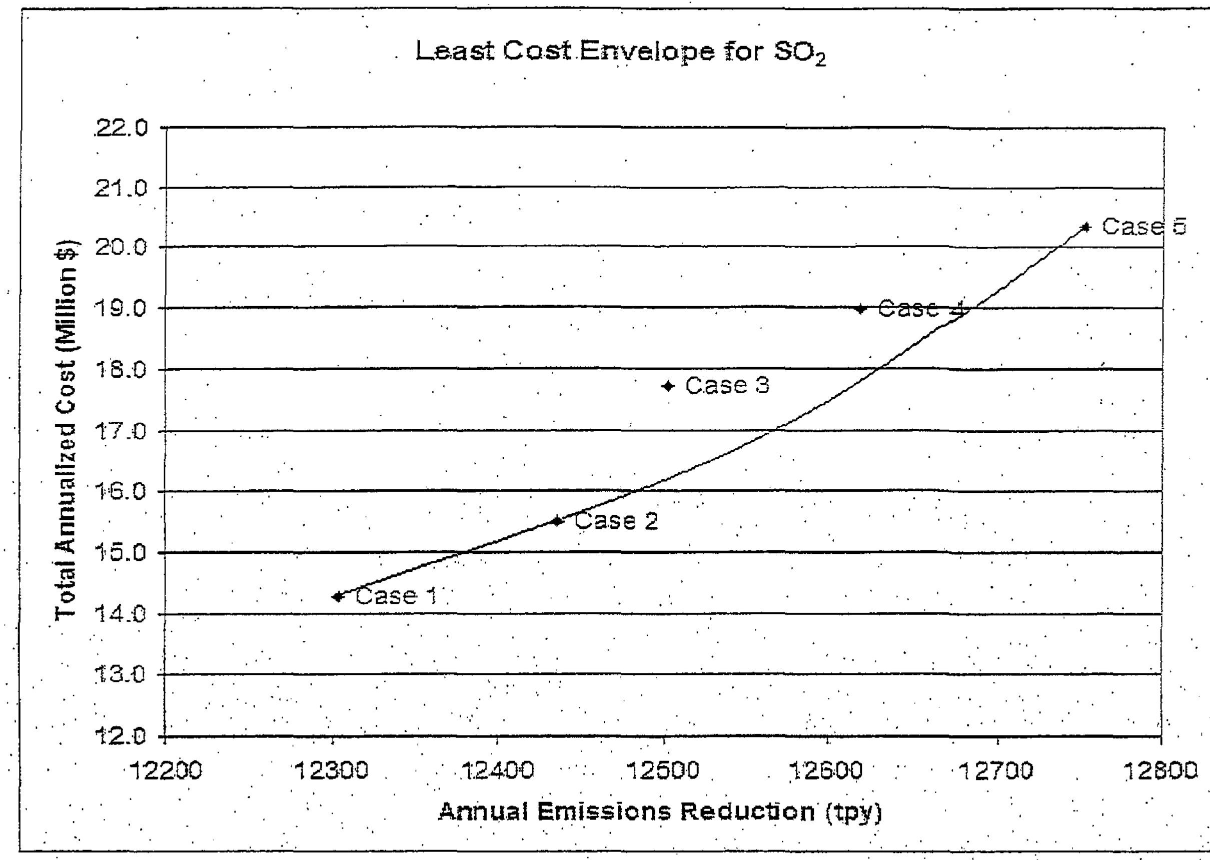
lb/MMBtu design target for wet FGD to derive an emission limit of 0.07 lb/MMBtu. Therefore, the Division used the economic information provided but divided the proposed emission limits by 123% for SDA and 129.6% for wet FGD so that the analysis is based on design target levels as with $NO_X$. The results are shown in the following table. The emissions reduction is the difference between an uncontrolled baseline emission rate of 0.82 lb/MMBtu and the design target level emission rate using wet FGD or SDA. The average cost effectiveness is the total annualized cost for the option, including capital cost and annual operating and maintenance costs, divided by the emissions reduction. The Division considers the average cost effectiveness to be reasonable for all options.

**Average Cost Effectiveness for $SO_2$**

| Case | Design Target Emission Level | Emissions Reduction (tpy) | Total Annualized Cost (Million $) | Average Cost Effectiveness ($/tons removed) |
|---|---|---|---|---|
| 1 | SDA @ 0.081 lb/MMBtu | 12303 | 14.3 | 1,159 |
| 2 | SDA @ 0.073 lb/MMBtu | 12436 | 15.5 | 1,246 |
| 3 | Wet FGD @ 0.069 lb/MMBtu | 12503 | 17.7 | 1,417 |
| 4 | Wet FGD @ 0.062 lb/MMBtu | 12619 | 19.0 | 1,504 |
| 5 | Wet FGD @ 0.054 lb/MMBtu | 12753 | 20.3 | 1,595 |

[1] Emission rates derived by dividing proposed emission limits by 123% for SDA and 129.6% for wet FGD.

In addition to average cost effectiveness, the draft 1990 New Source Review Workshop Manual provides a method to evaluate incremental cost effectiveness between dominant options known as the least cost envelope. For this method, a plot of annual emissions reduction vs. total annualized cost is produced and the dominant control options are indicated by fitting a curve or line through the lower and right most points as shown below. Points above and to the left of the line are considered inferior controls because points on the line provide more emissions reduction for less money.




The dominant options are Cases 1 (SDA @ 0.081 lb/MMBtu), 2 (SDA @ 0.073 lb/MMBtu), and 5 (Wet FGD @ 0.054 lb/MMBtu). The incremental cost effectiveness for the dominant options is calculated in the following table. The incremental emissions reduction and incremental increase in total annualized cost is the difference in these values for each option from the previous table. The incremental cost effectiveness is the incremental increase in total annualized cost divided by the incremental emissions reduction.

**Incremental Cost Effectiveness between Dominant Options for $SO_2$**

| Options Compared | Incremental Emissions Reduction (tpy) | Incremental Increase in Total Annualized Cost (Million $) | Incremental Cost Effectiveness ($/ton) |
|---|---|---|---|
| Cases 1 and 2 | 133 | 1.2 | 9,296 |
| Cases 2 and 5 | 316 | 4.8 | 15,299 |

The average cost effectiveness values for all three dominant options are reasonable but the Division considers an incremental cost effectiveness of $15,299/ton excessive when combined with the negative environmental impacts of wet FGD discussed previously (higher water usage, visible moisture plume, higher PM emissions, lower removal efficiency for acid gases, and possibly higher mercury emissions). Therefore, the incremental cost effectiveness is considered reasonable for SDA with a design target emission level of 0.073 lb/MMBtu.

As with $NO_X$, it was necessary to determine a reasonable margin between the design target emission level and an emission limit at this point in the review. Further discussions with Basin Electric indicated that are several issues that necessitate a margin of safety as discussed below:

1) Basin Electric stated that the lowest emission guarantee available for SDA is 94% removal with a floor of 0.08 lb/MMBtu (regardless of $SO_2$ loading). With an $SO_2$ loading of 1.33 lb/MMBtu, 94% removal results in an emission level of 0.08 lb/MMBtu. Basin stated that vendors will guarantee 94% removal with $SO_2$ loadings above 1.33 lb/MMBtu but will not guarantee less than 0.08 lb/MMBtu (equivalent to an $SO_2$ concentration of approximately 40 $ppm_v$ @ 3% O2) with lower $SO_2$ loadings. Basin Electric originally established a performance target (i.e. design target) of 0.073 lb/MMBtu based on an $SO_2$ loading of 1.21 lb/MMBtu and 94% removal but subsequently learned that 0.073 lb/MMBtu is below the floor of 0.08 lb/MMBtu for an emission guarantee.

2) Injecting additional lime slurry and/or operating the system at an outlet temperature approaching saturation may increase $SO_2$ removal but the slurry feed rate is limited by the requirement to operate the SDA above saturation temperature and produce a dry by-product. Operating the SDA at or below the design limit increases the potential for operating issues including wall wetting, scaling, plugging, and operational problems with the downstream fabric filter.

As a result of these discussions, Basin Electric agreed to an annual average emission limit of 0.08 lb/MMBtu with a 30 day rolling average limit of 304.1 lb/hr (based on 3,801 MMBtu/hr and 0.08 lb/MMBtu). As with $NO_X$, a lb/hr limit for the 30 day averaging period provides more flexibility and allows the facility to come back into compliance quickly by lowering power output. Emissions in lb/MMBtu do not necessarily decrease with power output.

Subsequent to the public comment period, Basin Electric indicated that the technical issues with Circulating Dry Scrubbers (CDS) have been resolved and agreed to consider this technology as previously discussed. Basin provided a revised BACT analysis for CDS indicating that CDS should be able to achieve a higher control efficiency than SDA because higher reactant injection rates and Ca/S ratios can be used without the operational problems discussed above for SDA. Additionally, a smaller margin of safety is necessary with CDS because there is less of an issue with short term emission spikes. Periodic maintenance must performed on the reactant atomizer nozzles for SDA and short term emissions increase during this time because individual nozzles are taken out of service. There are no atomizer nozzles for CDS. The expected gains in efficiency are partially offset by the limited experience and operating history of this technology. Basin's revised BACT analysis stated that the costs for CDS are similar to those for SDA. Based on these considerations, Basin proposed CDS with an emission limit of 0.070 lb/MMBtu, 12 month rolling average as BACT. This is among the lowest $SO_2$ emission limits for any PC boiler and the Division concludes that CDS with emission limits of 0.070 lb/MMBtu, 12 month rolling average, and 285.1 lb/hr, 30 day average, represents BACT for $SO_2$.

# Attachment B – "Coal Power Plant Technology Evaluation for Dry Fork Station," November 1, 2005

*Report*

# Coal Power Plant Technology Evaluation for Dry Fork Station

Prepared for

**Basin Electric Power Cooperative**

Bismarck, ND

November 1, 2005

CH2MHILL
9193 South Jamaica Street
Englewood, CO 80112

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## Appendices

# Executive Summary

## Background

In December 2004, Basin Electric announced plans to build a 250 MW (net) coal-based generation resource in Northeast Wyoming. Basin Electric's goal for this new generation resource is to build a high quality, environmentally sound, cost-effective generation facility.

Basin Electric and its consulting engineers conducted extensive reviews of the current progress being made in alternative coal-based technologies, including the proven pulverized coal (PC) and circulating fluidized bed (CFB) boilers, and the demonstration integrated gasification combined cycle (IGCC) power plants. As a result of this review, Basin Electric and consultants have determined that the project can meet or exceed all of the project goals by utilizing the latest generation of air pollution control (APC) technology with a PC boiler. A PC unit with state of the art emission control equipment offers performance that exceeds the proven capabilities of CFB or IGCC systems.

In May 2005, based on a revised load forecast for Basin Electric's member cooperatives, the annual average net plant output for the proposed coal unit was increased to 350 MW (net). The technology comparison at this rating is virtually identical to the 250 MW design case. The plant was named the Dry Fork Station in August 2005.

This conceptual level technology evaluation was conducted to address the advantages and limitations of PC, CFB and IGCC coal-based power generation technologies for the new Dry Fork Station. The evaluation addresses the capability of each technology to fulfill the need of the project based on technical, environmental, reliability, commercial, and economic evaluation criteria.

The basis of this evaluation is a coal-fueled power plant that will be mine mouth using PC, CFB or IGCC technology. The facility would be base loaded with a minimum 85 percent capacity factor and 90 percent availability. While not part of the current proposal, the possibility does exist for the future expansion of the site with a second unit. The current online operational date for the facility is January 2011.

Basin Electric desires to identify the most prudent power generation technology for this new coal-fired power plant. That identification process is guided by these desired characteristics for the proposed generation:

- Baseload Capacity
- Environmental Compliance
- High Reliability and Availability
- Commercially Available and Proven Technology
- Cost Effective

Coal-based power generation technology selected for this project must be capable of meeting the desired characteristics listed above.

## Technical Evaluation

The main incentive for IGCC development has been that units may be able to achieve higher thermal efficiencies than PC plants, be able to match the environmental performance of gas-fired plants, and potentially provide a more cost-effective means of removing $CO_2$ should that become a future regulatory requirement. However, the thermal efficiencies of new PC plants using superheated steam have also increased as has their environmental performance. The coal plant technology configurations selected for evaluation are shown in Table ES-1.

The PC configuration selected uses a conventional high dust/high temperature SCR system for $NO_x$ control, and a Circulating Dry Scrubber (CDS) FGD system for $SO_2$ control.

The CFB configuration selected uses a Selective Non-Catalytic Reduction (SNCR) system for $NO_x$ control, and limestone addition in the boiler with a downstream CDS FGD system for $SO_2$ control.

The two IGCC configurations selected for evaluation represent a conventional IGCC unit and an ultra-low emissions IGCC unit. The conventional IGCC unit uses an amine gas treatment system to reduce $H_2S$ to approximately 25 ppmv in the syngas sent to the combustion turbine generators (CTGs) for $SO_2$ control, and water injection or nitrogen dilution with low-$NO_x$ burners in the CTGs for $NO_x$ control.

The ultra-low emissions IGCC unit uses a Selexol gas treatment system to reduce $H_2S$ to approximately 10 ppmv in the syngas sent to the CTGs for $SO_2$ control, water injection with low-$NO_x$ burners in the CTGs and an SCR system for $NO_x$ control, and a catalytic oxidation catalyst (Cat-Ox) system for CO control.

**TABLE ES-1**
Coal Plant Technology Evaluation Criteria
*Basin Electric Dry Fork Station Technology Evaluation*

| Criteria | PC | CFB | Conventional IGCC | Ultra-Low Emission IGCC |
|---|---|---|---|---|
| Net Plant Output (MW) | 250 MW | 250 MW | 250 MW | 250 MW |
| Net Plant Heat Rate (Btu/kW-Hr) | 10,512 | 10,872 | 11,450 | 11,132 |
| Annual Plant Capacity Factor (%) | 85% Coal | 85% Coal | 15% Natural Gas, 70% Coal | 15% Natural Gas, 70% Coal |
| $SO_2$ Control System | CDS FGD | $CaCO_3$ in Boiler and CDS FGD | Amine Syngas Treatment for $H_2S$ Removal | Selexol Syngas Treatment for $H_2S$ Removal |
| $NO_x$ Control System | LNB and SCR | SNCR | LNB and Water Injection | LNB, Water Injection and SCR |
| CO Control System | Combustion Controls | Combustion Controls | Combustion Controls | Cat-Ox |

Notes: CDS FGD – Circulating Dry Scrubber Flue Gas Desulfurization System; LNB – Low NOx Burners; SCR – Selective Catalytic Reduction; SNCR – Selective Non-Catalytic Reduction; Cat-Ox – Catalytic Oxidation



DEQ/AQD 004187

## Environmental Evaluation

A PC boiler combined with appropriate APC technology offers similar emission rates to a CFB boiler for $SO_2$, $NO_x$, particulate matter, mercury and other hazardous air pollutants (HAPs). A PC boiler based plant with the latest generation of proven APC technology offers lower $SO_2$ and $NO_x$ emission rates as compared to the two U.S. demonstration IGCC plants at the Public Service of Indiana (PSI) Wabash River and Tampa Electric Company (TECO) Polk stations.

Future IGCC plants have the potential of offering lower $SO_2$ and $NO_x$ emission rates, but at a significantly higher total plant capital cost and project risk compared to a PC unit along with the uncertainties associated with the use of this developing integration of technologies (including costly poor plant availability for a number of years). Table ES-2 compares the proposed Dry Fork Station PC emission rates with the current annual emission rates from existing CFB commercial plants and from existing U.S. IGCC demonstration plants.

**TABLE ES-2**
Comparison of Coal Combustion Technology Emission Rates
*Basin Electric Dry Fork Station Technology Evaluation*

| | Emission Rates for Coal Combustion Technologies (Lb/MMBtu) | | |
|---|---|---|---|
| Pollutant | PC (Potential BACT) | CFB (Existing U.S. Commercial Plants) | IGCC (Existing U.S. Demonstration Plants)* |
| $SO_2$ | 0.10 | 0.10 | 0.17 |
| $NO_x$ | 0.07 | 0.09 | 0.09 |
| $PM_{10}$** | 0.019 | 0.019 | 0.011 |
| CO | 0.15 | 0.15 | 0.045 |
| VOC | 0.0037 | 0.0037 | 0.0021 |

Notes:

* PSI Energy Wabash River Station and TECO Polk Power Station Existing IGCC Demonstration Plants.

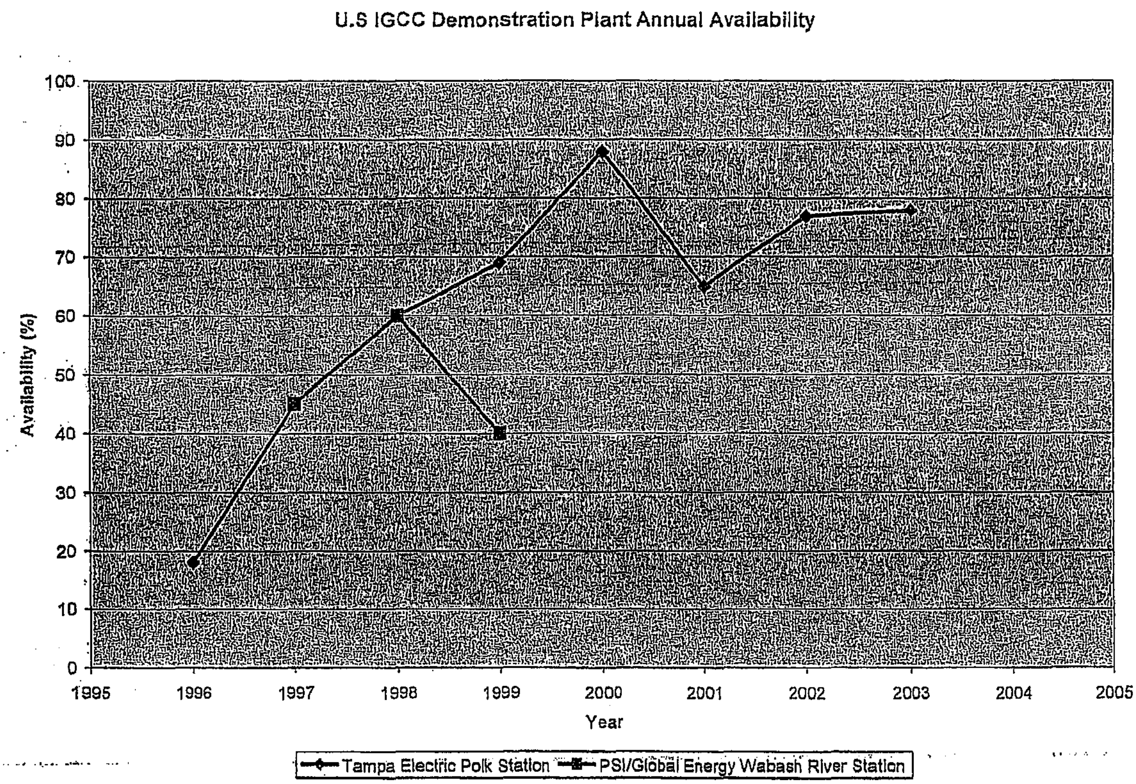
** $PM_{10}$ includes filterable and condensable portions.

## Reliability Evaluation

Both PC and CFB technologies have demonstrated high reliability. IGCC technology has demonstrated very low reliability in the early years of plant operation. Higher reliability has been recently demonstrated after design and operation changes were made to the facilities, however, the availability of IGCC units is still much lower than PC and CFB units.

The PC and CFB technologies are capable of achieving a 90 percent annual availability, an 85 percent annual capacity factor, and are suitable for baseload capacity. The IGCC technology has only demonstrated a 70 percent annual availability and 70 percent capacity factor. Using an IGCC for a baseload unit would require natural gas as a backup fuel for the combustion turbine combined cycle section of the plant or duplicate spare equipment. The gasification islands in the four IGCC demonstration plants have generally only been able to achieve up to 70 percent capacity factors, even after 10 years of operation. The annual availability and capacity factor data for the two U.S. IGCC Demonstration Plants are compared against the expected annual availability and capacity factor for a new PC unit in Figures ES-1 and ES-2. The availability for the last three years of data reported for the Polk IGCC unit (2001 to 2003) is calculated to be 73 percent. The availability for the three years of data reported for the Wabash River IGCC unit (1997 to 1999) is calculated to be 48 percent. The capacity factor for the last three years of data reported for the Polk and Wabash River IGCC units (1999 to 2001) is calculated to be 70 percent and 38 percent, respectively.

Figure ES-1

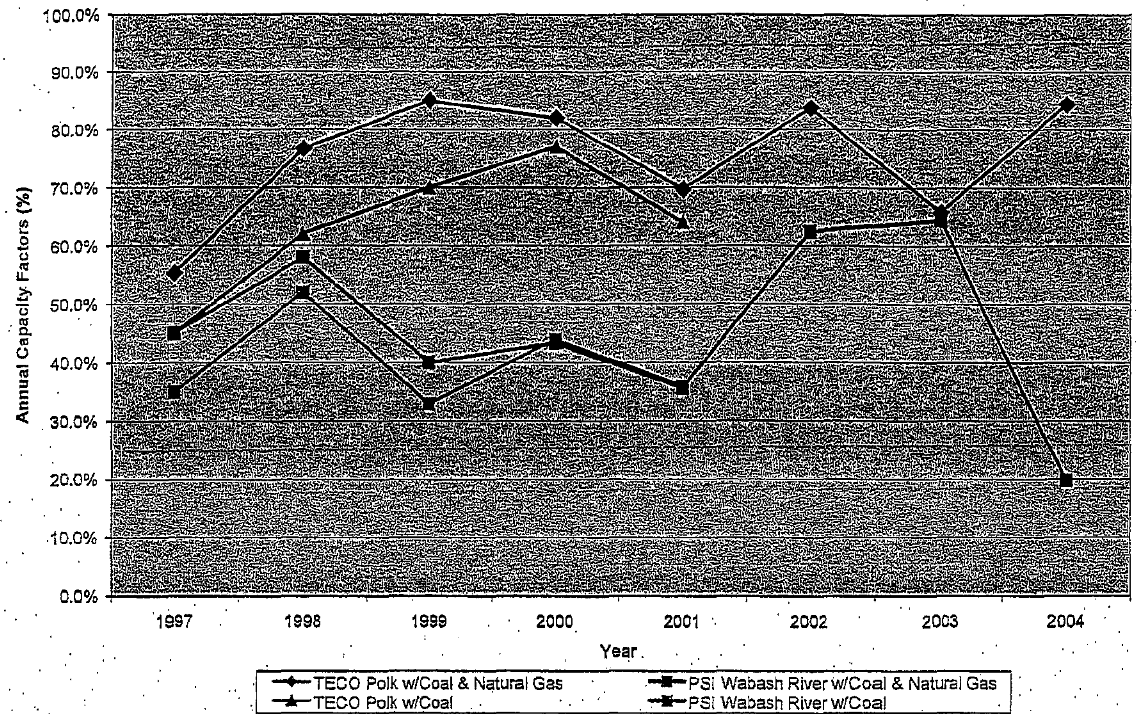




DEQ/AQD 004189

Figure ES-2

U.S. IGCC Demo Units - Annual Capacity Factors




## Commercial Evaluation

Basin Electric received proposals from only three of the six IGCC technology leaders in response to an IGCC Feasibility Study Request for Proposal (RFP) in February 2005. All three of the proposals received were deemed unresponsive; they did not specify the terms and conditions which would be proposed for this type of commercial offering and did not describe the financial backing which could be offered for such guarantees and warranties, as specified in the RFP. All parties required further studies, additional money, and more time to get to a point where some of the performance and commercial information requested would be available.

There is a lack of acceptable performance warranties/guarantees for commercial IGCC offerings. The reliability of the technology is an important factor given that this plant is intended for baseload generation and represents approximately 10 percent of the Basin Electric generation portfolio. In the business of building large scale generation resources, it is standard practice for suppliers to offer plant performance guarantees that are specific and precise in nature and are a direct reflection of their confidence that the plants will perform as desired. The providers of IGCC technology were unwilling to provide such assurances, greatly increasing the risk and potential future costs should this option be chosen and fail to perform to expectations. This is a clear indication of how much more development this technology requires before it can be considered to fill the role of reliable, large-scale generation.

While IGCC technology holds much future promise, it is still an emerging technology, especially for the lower ranked sub-bituminous coal typical of the Powder River Basin of Wyoming. For future development of this new and promising technology in Wyoming, Basin Electric would be open to considering a partnership with state or federal agencies to help mitigate the risk for their membership.

## Economic Evaluation

A PC boiler is expected to have a slightly lower cost compared to a CFB boiler. However, no CFB boilers have been built and operated at the 350 MW net size required for the Basin Electric project. For a CFB based design, the project would have to use a boiler size that is not yet proven, or use two CFB boilers at 50 percent size which would result in an approximate plant cost increase of 20 percent.

IGCC plants are most competitive in capital and busbar cost with conventional PC plants based on high heating value/high sulfur content eastern bituminous coal or petroleum coke fuels, plant elevations near sea level and a plant size of at least 500 to 600 MW. The Basin Electric Dry Fork Station project will be a nominal 350 MW (net) plant at an elevation of 4,250 feet with low heating value/low sulfur Powder River Basin (PRB) coal fuel. An IGCC plant for this project would incur a significant capital and operating cost penalty due to the small plant size and lower rank high moisture fuel, and a significant power output derating for the plant gas turbines due to the high plant elevation. Based upon available data, an IGCC unit for the NE Wyoming project would be approximately 50 percent higher in capital cost and approximately twice the busbar cost of electricity (COE) generated compared to a PC unit.

The first year busbar COE for the four evaluated technology cases are compared in Figure ES-3.

## Conclusions and Recommendations

PC technology is capable of fulfilling Basin Electric's need for new generation, and is recommended for the NE Wyoming Power Project.

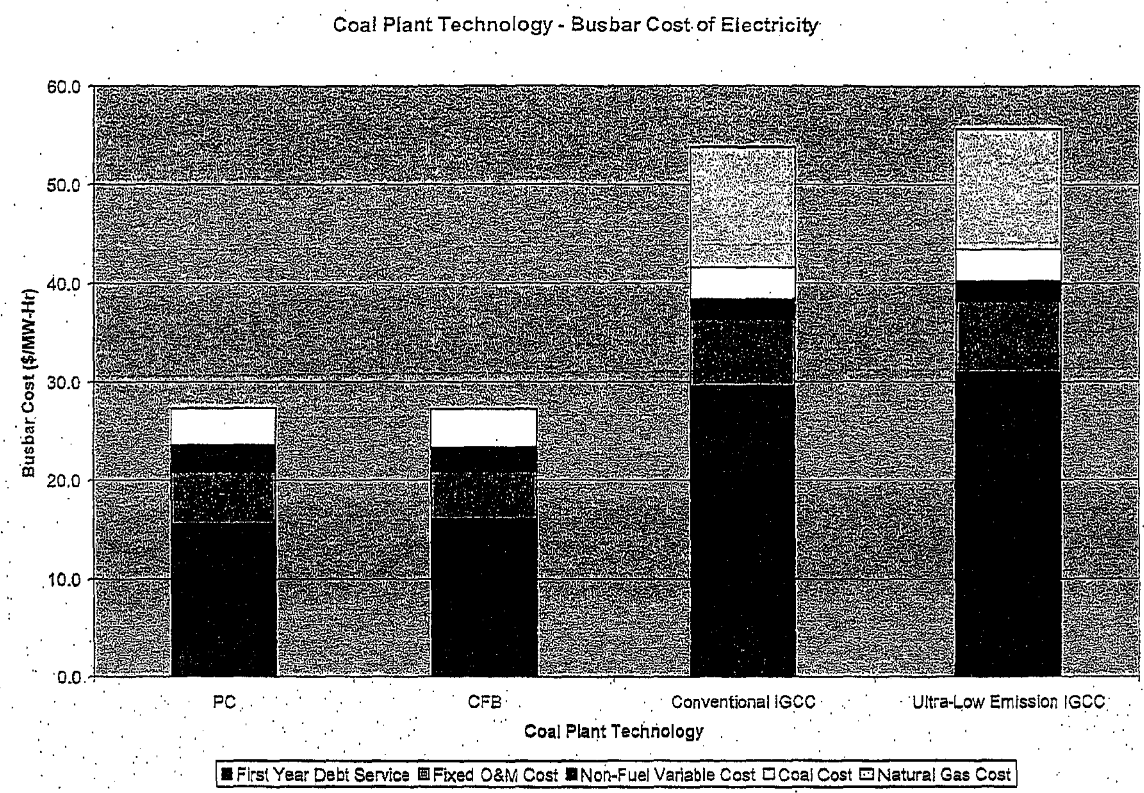
CFB technology meets Basin Electric's need; however, it lacks demonstrated long-term operating experience on PRB coal.

IGCC technology is judged not capable of fulfilling the need for new generation. IGCC does not meet the requirement for a high level of reliability and long-term, cost-effective, and competitive generation of power. In addition to higher capital costs, there are problem areas, discussed in this report, that have not demonstrated acceptable reliability. Current approaches to improving reliability in these areas result in less efficient and/or higher capital cost facilities, negatively impacting the cost-effectiveness.

DOE has a Clean Coal Technology program with the goal of providing clean coal power-generation alternatives which includes improving the cost-competitiveness of IGCC. However, the current DOE time frame (by 2015) does not support Basin Electric's 2011 needs.

IGCC offers the potential for a more cost effective means of $CO_2$ removal as compared to PC and CFB technologies should such removal become a requirement in the future. However, at this time, it is only speculative as to if such requirements will be enacted, when they will be enacted, and what they will consist of and apply to if enacted. The risk of installing a more costly technology, that has not been proven to be reliable and for which strong commercial performance guarantees are not available, is far too great for Basin Electric to take on for such speculative purposes.

Figure ES-3



SECTION 1.0

# Introduction

In December 2004, Basin Electric Power Cooperative (BEPC) announced plans to build a 250 MW (net) coal-based generation resource in Northeast Wyoming. Basin Electric's goal for this new generation resource is to build a high quality, environmentally sound, cost-effective generation facility.

CH2M HILL was requested by Basin Electric to evaluate coal combustion technologies for the NE Wyoming Power Project. This investigation was initiated in July 2004 as part of the Technology Assessment Study, and continues today as an ongoing investigation.

The facility, now named the Dry Fork Station, would be base loaded with a minimum 85 percent capacity factor and 90 percent availability. The currently targeted online operational date for the unit is January, 2011. This evaluation compares the Pulverized Coal (PC), Circulating Fluid-Bed (CFB), and Integrated Gasification Combined Cycle (IGCC) technologies based on the capability of each technology to fulfill the need of the project based on technical, environmental, reliability, commercial and economic evaluation criteria.

The evaluation was guided by these desired characteristics for the proposed generation:

- Baseload Capacity
- Environmental Compliance
- High Reliability and Availability
- Commercially Available and Proven Technology
- Cost Effective

This report compares the technical applicability, environmental capability, plant reliability and availability, commercial availability, and cost of PC, CFB and IGCC coal-based power generation technologies for a new Basin Electric 250 MW Powder River Basin (PRB) coal-based power plant project in northeast Wyoming. This study evaluates four technology options based on the selected plant site; one PC case, one CFB case, and two IGCC cases (conventional IGCC and ultra-low emissions IGCC). Basin Electric does not consider the BACT requirement as a process that should be used to define an emission source. However, an equivalent "Top-Down" BACT Analysis was performed based on the four evaluated cases.

## 1.1 Preliminary Technology Assessment

A preliminary conceptual level technology assessment was conducted to address the advantages and limitations of PC, CFB and IGCC coal-based power generation technologies for a new BEPC 250 MW PRB coal-based power plant project in northeast Wyoming. The technology assessment did not address the specifics at each of the candidate plant sites, but instead focused on the general characteristics of the three technologies under assessment.

The assessment addressed the capability of each technology to fulfill the need of the project based on technical, environmental, commercial, economic, and regulatory and political evaluation criteria.

The assessment concluded that the PC technology was capable of fulfilling Basin Electric's need for new generation, and was recommended for the NE Wyoming Power Project. It was determined that the CFB technology met Basin Electric's need, however, it lacked demonstrated long-term operating experience on PRB coal.

The IGCC technology was judged not capable of fulfilling the need for new generation. IGCC did not meet the requirement for a high level of reliability and long-term, cost-effective, and competitive generation of power.

## 1.2 Technology Evaluation

In May 2005, based on a revised load forecast for Basin Electric's member cooperatives, the average annual net plant output for the new coal unit was increased to 350 MW net. This evaluation has been conducted based on the 250 MW net plant output to maintain consistency with previous PC and CFB plant designs and cost estimates developed for this plant size. Section 10 of this report discusses the impact on plant design, heat rate and cost due to the plant size increase from 250 MW to 350 MW net plant output.

SECTION 2.0

# Design Basis

The design basis in this study for the proposed Dry Fork Station is described in the following sections.

## 2.1 GENERAL AND SITE CRITERIA

| | |
|---|---|
| Plant Location: | Near Gillette, Wyoming |
| Elevation: | 4,250 ft. above mean sea level |
| Annual Average Ambient Temperature: | 44°F |
| Ambient Air Design Temperature: | |
| Summer Design: | 100°F DB, 62°F WB |
| Condenser Cooling Water System: | Dry Air Cooled Condenser |
| Auxiliary Cooling Water System: | Cooling Tower w/Plate & Frame HX |
| Water Supply: | Well Water |
| Housing: | Indoor Steam Turbine Generator |
| | Allowance for Future Expansion |
| Design Life: | 40 years |

## 2.2 PLANT PERFORMANCE CRITERIA

| | |
|---|---|
| Net Electrical Output, Design: | 250 MWe (100°F @ design condenser pressure) |
| Net Electrical Output, Max: | 275 MWe (44°F and below) |
| Schedule Milestones: | |
| Start Construction Date: | March 2007 |
| COD Date: | January 2011 |
| Plant Loading Profile: | Base loaded |
| Capacity Factor | 85% |
| Availability Factor | 90% |
| Primary Fuel: | Powder River Basin (PRB) Coal (see Table 2-1) |
| Backup Fuel for Start-up: | Natural Gas |

TABLE 2-1
Dry Fork Mine Estimated Coal Quality
*Basin Electric Dry Fork Station Technology Evaluation*

| Parameters | Estimated Coal Quality | | |
|---|---|---|---|
| | Target | Minimum | Maximum |
| **As Received Proximate Analysis** | | | |
| Heating Value (BTU/Lb) | 8,045 | 7,800 | 8,300 |
| Moisture (%) | 32.06 | 30.5 | 33.8 |
| Ash (%) | 4.77 | 4.2 | 6.5 |
| SO2 (Lb/MMBtu) | 0.82 | 0.60 | 1.21 |
| Volatile Matter (%) | 30.12 | 28.05 | 32.01 |
| Fixed Carbon (%) | 33.05 | 31.64 | 34.14 |
| **As Received Ultimate Analysis** | | | |
| Carbon (%) | 47.22 | 46.55 | 48.14 |
| Hydrogen (%) | 3.23 | 2.98 | 3.37 |
| Nitrogen (%) | 0.72 | 0.65 | 0.69 |
| Chlorine (%) | < 0.1 | < 0.1 | < 0.1 |
| Sulfur (%) | 0.33 | 0.25 | 0.47 |
| Oxygen (%) | 11.67 | 10.68 | 13.68 |

# Combustion Technology Description

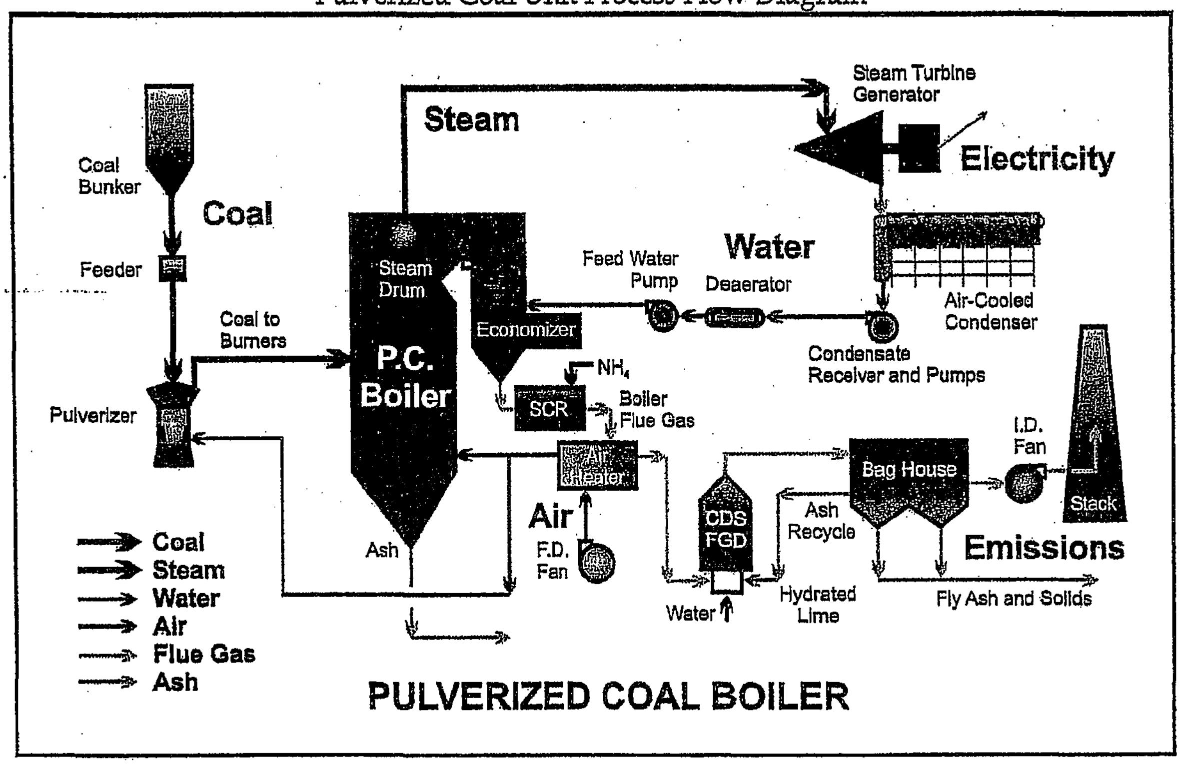
This study evaluates four technology options based on the selected plant site:

- Pulverized Coal (PC)
- Circulating Fluid Bed (CFB)
- Conventional Integrated Gasification Combined Cycle (IGCC)
- Ultra-Low Emissions Integrated Gasification Combined Cycle (IGCC)

## 3.1 Pulverized Coal Process Description

PC plants represent the most mature of coal-based power generation technologies considered in this assessment. Modern PC plants generally range in size from 80 MW to 1,300 MW and can use coal from various sources. Units operate at close to atmospheric pressure, simplifying the passage of materials through the plant, reducing vessel construction cost, and allowing onsite fabrication of boilers. A typical process flow diagram for a PC unit is shown in Figure 3-1.

Figure 3-1
Pulverized Coal Unit Process Flow Diagram




The concept of burning coal that has been pulverized into a fine powder stems from the fact that if the coal is made fine enough, it will burn almost as easily and efficiently as a gas.

Crushed coal from the silos is fed into the pulverizers along with air preheated to about 580°F. The hot air dries the fine coal powder and conveys it to the burners in the boiler. The burners mix the powdered coal in the air suspension with additional pre-heated combustion air and forces it out of nozzles similar in action to fuel being atomized by fuel injectors.

Combustion takes place at temperatures from 2400-3100°F, depending largely on coal rank. Steam is generated, driving a steam turbine-generator. Particle residence time in the boiler is typically 2-5 seconds, and the particles must be small enough for complete burnout to have taken place during this time. Steam generated in the boiler is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity.

The boiler produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash, $NO_x$, and $SO_2$. The pollution control equipment includes either a fabric filter or ESP for particulate control (fly ash), Selective Catalytic Reduction (SCR) for removal of $NO_x$, and a Flue Gas Desulfurization (FGD) system for removal of $SO_2$. Limestone is required as the reagent for the most common wet FGD process, limestone forced oxidation desulfurization. A spray dryer FGD process, which is more commonly used on lower sulfur western coal, uses lime as the reagent and provides significant savings in water consumption over wet FGD systems. A lime or limestone storage and handling system is a required design consideration with this system.

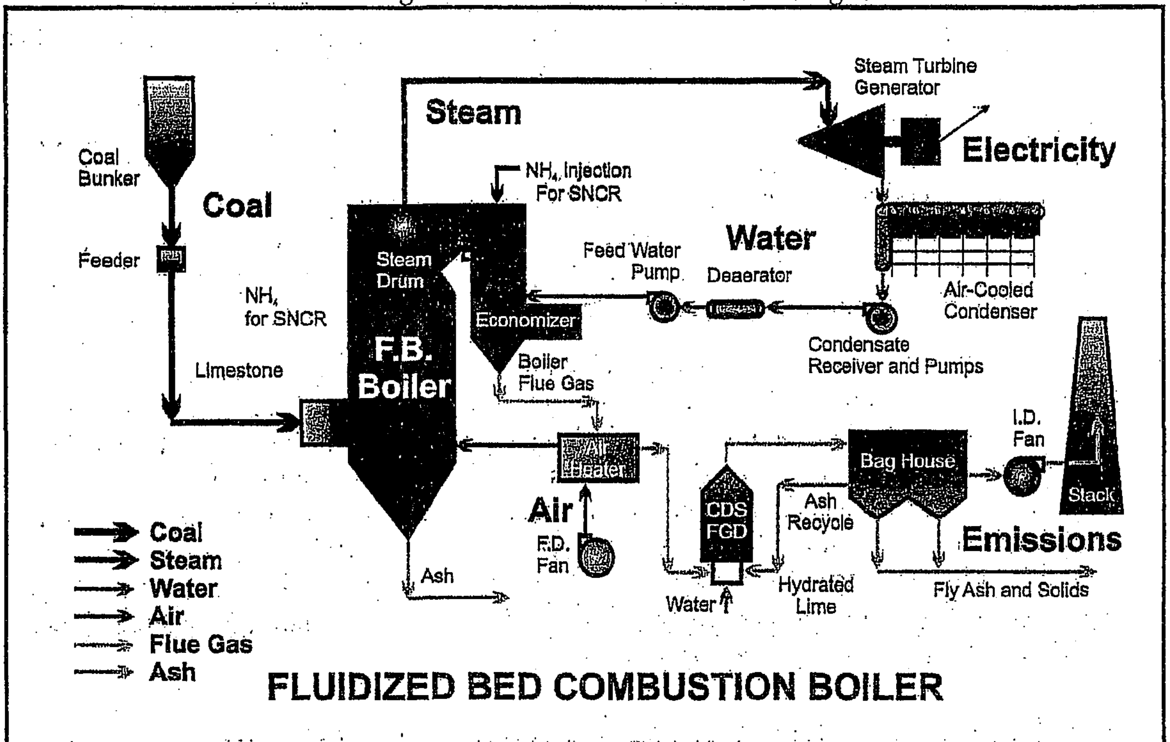
## 3.2 Circulating Fluidized Bed Process Description

The CFB fuel delivery system is similar to that of a PC unit, but somewhat simplified to produce a coarser material. The plant fuel handling system unloads the fuel, stacks out the fuel, crushes or otherwise prepares the fuel for combustion, and reclaims the fuel as required. The fuel is usually fed to the CFB by gravimetric feeders. The bed material is composed of fuel, ash, sand, and the sulfur removal reagent (typically limestone), also referred to as sorbent. In the CFB the fuel is combusted to produce steam. Steam is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity. A typical process flow diagram for a CFB unit is shown in Figure 3-2.

CFB combustion temperatures of 1,500 to 1,600°F are significantly lower than a conventional PC boiler of up to 3,000°F which results in lower $NO_x$ emissions and reduction of slagging and fouling concerns characteristic of PC units. In contrast to a PC plant, sulfur dioxide can be partially removed during the combustion process by adding limestone to the fluidized bed.

Circulating beds use a high fluidizing velocity, so the particles are constantly held in the flue gases, and pass through the main combustion chamber and into a particle separation device such as a cyclone, from which the larger particles are extracted and returned to the combustion chamber. Individual particles may recycle anywhere from 10 to 50 times, depending on their size, and how quickly the char burns away. Combustion conditions are relatively uniform through the combustor, although the bed is somewhat denser near the bottom of the combustion chamber. There is a great deal of mixing, and residence time during one pass is very short.

Figure 3-2
Circulating Fluid Bed Unit Process Flow Diagram




CFBs are designed for the particular coal to be used. The method is principally of value for low grade, high ash coals which are difficult to pulverize, and which may have variable combustion characteristics. It is also suitable for co-firing coal with low grade fuels, including some waste materials. The advantage of fuel flexibility often mentioned in connection with CFB units can be misleading; the combustion portion of the process is inherently more flexible than PC, but material handling systems must be designed to handle larger quantities associated with lower quality fuels. Once the unit is built, it will operate most efficiently with whatever design fuel is specified.

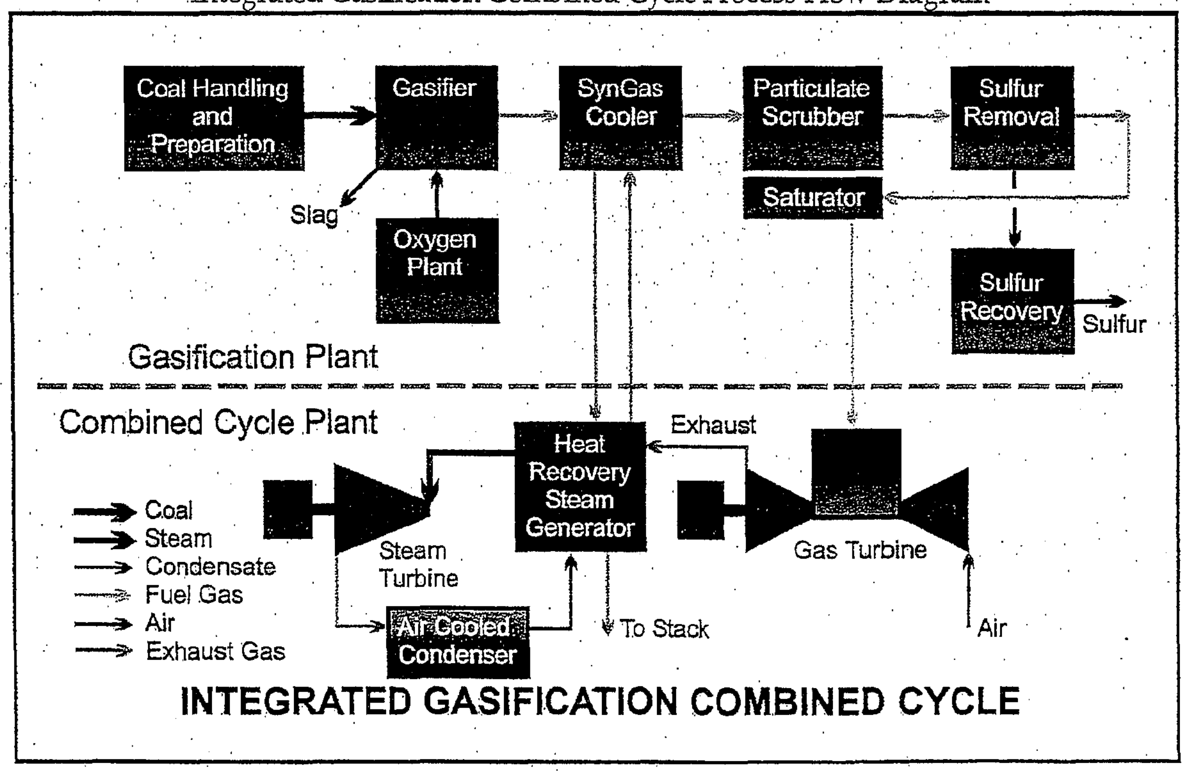
The design must take into account ash quantities, and ash properties. While combustion temperatures are low enough to allow much of the mineral matter to retain its original properties, particle surface temperatures can be as much as 350°F above the nominal bed temperature. If any softening takes place on the surface of either the mineral matter or the sorbent, then there is a risk of agglomeration or of fouling.

The CFB produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash and sulfur dioxides. $NO_x$ emissions can be mitigated through use of selective non-catalytic reduction (SNCR) using ammonia injection, usually in the upper area of the combustor. The pollution control equipment external to the CFB includes either a fabric filter (baghouse) or electrostatic precipitator for particulate control (fly ash). A polishing FGD system may be required for additional removal of sulfur dioxides to achieve similar emission levels to PC units with FGD systems. Limestone is required as the reagent for the most common wet FGD process, limestone forced oxidation desulfurization, and also as sorbent for the fluidized bed. A spray dryer FGD process, another option for low SO2 concentration flue gas streams, uses lime as the reagent. A limestone storage and handling system is a required design consideration for CFB units. A lime storage and handling system would also be required if a lime spray dryer is used for the polishing FGD system.

## 3.3 IGCC Process Description

IGCC for use in coal-based power generation reacts coal with steam and oxygen or air at high temperature to produce a gaseous mixture consisting primarily of hydrogen and carbon monoxide. The gaseous mixture requires cooling and cleanup to remove contaminants and pollutants to produce a synthesis gas suitable for use in the combustion turbine portion of a combined cycle unit. The combined cycle portion of the plant is similar to a conventional combined cycle. The most significant differences in the combined cycle are modifications to the combustion turbine to allow use of a 200 to 400 Btu/SCF gas and use of steam produced via heat recovery from the raw gas in addition to that from the combustion turbine exhaust (HRSG). Specifics of a plant design are influenced by the gasification process and matching coal supply, degree of heat recovery, and methods to clean up the gas. A typical process flow diagram for an IGCC unit is shown in Figure 3-3.

Figure 3-3
Integrated Gasification Combined Cycle Process Flow Diagram




Coal gasification takes place in the presence of a controlled 'shortage' of air/oxygen, thus maintaining reducing conditions. The process is carried out in an enclosed pressurized reactor, and the product is a mixture of CO, $H_2$ and $CO_2$ (called synthesis gas, syngas or fuel gas). The sulfur present in the fuel mainly forms $H_2S$ but there is also a small amount of carbonyl sulfide (COS). The $H_2S$ can be more readily removed than COS in gas cleanup processes; therefore, a hydrolysis process is typically used to convert COS to $H_2S$. Although no $NO_x$ is formed during gasification, some is formed when the fuel gas or syngas is subsequently burned in the combustion turbines. The product gas is cleaned and then burned with air, generating combustion products at high temperature and pressure.

Three basic gasifier designs are possible, with fixed beds (not normally used for power generation), fluidized beds and entrained flow. Fixed bed units typically use lump coal, fluidized bed units use a feed of 3-6 mm size, and entrained flow gasifiers typically use a pulverized coal slurry feed.

The IGCC demonstration plants that have been built use different process designs, and are testing the practicalities and economics of different degrees of integration. In all IGCC plants, there is a requirement for a series of large heat exchangers to cool the syngas to temperatures at which it can be cleaned. In such exchangers, solids deposition, fouling and corrosion may take place. Currently, cooling the syngas is required for conventional cleaning, and it is subsequently reheated before combustion. At Puertollano, quenching is used to cool the syngas. This is a simple, but relatively inefficient procedure, however, it avoids deposition problems, as the ash present is rapidly cooled to a solid non-sticky form. The cold gas cleaning processes used are variants of well proven natural gas sweetening processes to remove acid impurities and any sulfur present.

The syngas is produced at temperatures up to 2900°F (in entrained flow gasifiers), while the gas clean up systems which are being assessed, operate at a maximum temperature of 900-1100°F. Large heat exchangers are required, and there is the possibility of solids deposition in these exchangers which reduces heat transfer. It seems that unless it is possible to develop hot gas cleaning as a reliable procedure, the comparative economics of IGCC will remain unattractive.

### 3.3.1 Conventional IGCC

A Conventional IGCC unit uses chemical absorption with an amine process such as an MDEA (methyldiethanolamine) gas treatment system to remove H2S from the syngas and a sulfur plant to convert the H2S to elemental sulfur for sale or disposal. The syngas combustion turbines use water injection and low-NOx burners to control NOx emissions.

### 3.3.2 Ultra-Low Emissions IGCC

An Ultra-Low IGCC unit uses physical absorption with a process such as a Selexol or Rectisol (methanol sölvent) gas treatment system to remove H2S from the syngas and a sulfur plant to convert the H2S to elemental sulfur for sale or disposal. The syngas combustion turbines use water injection or nitrogen dilution, low-NOx burners and downstream SCR to control NOx emissions and a downstream catalytic oxidation catalyst (Cat-Ox) to control CO emissions.

SECTION 4.0

# Technical Evaluation

This section contains an evaluation of the technical capability of the PC, CFB and IGCC technologies.

## 4.1 Pulverized Coal

Pulverized coal has been used for large utility units for over 50 years. The technology has evolved in areas such as distributed control systems and emissions control to improve its performance.

### 4.1.1 Development History / Current Status

Presently, pulverized coal power is still based on the same methods started over 100 years ago, but improvements in all areas have brought coal power to be an inexpensive power source used widely today. There are thousands of units around the world, accounting for well over 90 percent of the coal-fired generation capacity. PC units can be used to fire a wide variety of coals, although it is not always appropriate for those with a high ash content.

#### Subcritical PC

The typical coal units of 250 MW and above that have been built in the U.S. since 1960 are subcritical PC designs using a 2400 psig/1000°F/ 1000°F single reheat steam power cycle providing a net plant efficiency (HHV)[1] of approximately 36 percent based on a bituminous coal fuel. Occasionally a 2400 psig/1050°F/ 1050°F steam cycle has been employed.

#### Supercritical PC

A typical commercial supercritical PC design uses a 3500 psig/1050°F/1050°F single reheat steam power cycle providing a net plant efficiency (HHV) of approximately 39 percent.

In Continental Europe, once-through boilers have been traditional, which do not require differentials between water and steam phases to operate. Due to high fuel prices in Europe, it was therefore logical for steam pressures to continue to be increased above 2400 psig in the quest for greater unit efficiency. In Japan, the Ministry of Trade and Industry encouraged a relatively early and universal change to supercritical steam conditions, and virtually all steam boiler/turbine units above 350 MW operating in Japan use supercritical steam conditions.

While the majority of coal-fired units in the U.S. have used subcritical drum boilers, a significant number of supercritical units have also been built. Early supercritical units experienced various reliability problems. Between the first commercial demonstration of the

[1] Net Plant Efficiency (HHV) is defined as the net electrical output of the plant divided by the higher heating value fuel consumption of the plant.

supercritical technology by AEP in 1956, and the mid-1970s, substantial experience was accumulated. Some of that experience was disappointing. However, most of the supercritical units built in that period continue to operate today, and many now have good availability records. Ameren, an electric utility provider in Missouri and Illinois continues to operate 1000 MW supercritical units built in 1966 and 1968. American Electric Power (AEP), an electrical utility provider to 11 states based in Columbus, Ohio, has units of 600, 800 and 1300 MW that entered service between 1968 and 1990.

### 4.1.2 Efficiency

A Basin Electric 250 MW PC unit would use a subcritical steam cycle design. The additional capital cost for a supercritical steam cycle is typically only justified by the efficiency improvement for PC units of 350 MW and larger. There is also a minimum 350 MW size limitation due to the first stage design of the steam turbine.

### 4.1.3 Operating History w/PRB Coal

Most of the PRB coal used for electricity generation is burned in PC plants. PC units experienced many problems during the initial use of PRB coals, but experience has resulted in development of PC boiler designs to successfully burn PRB coals. PC designs for PRB coal are based on the specific characteristics of the fuel such as moisture content, ash composition and softening temperature, and sulfur content.

### 4.1.4 PC Configuration Selected for Evaluation

The PC configuration selected for evaluation uses a conventional high dust/high temperature SCR system for NOx control and a Circulating Dry Scrubber (CDS) FGD system for SO2 control.

## 4.2 Circulating Fluid Bed

CFB power plants have demonstrated technical feasibility in commercial utility applications for about 20 years. The technology has evolved during that time to improve its technical performance.

### 4.2.1 Development History / Current Status

Study of the fluidized bed coal combustion concept began in the early 1960s. The original goal was to develop a compact "package" coal boiler that could be pre-assembled at the factory and shipped to a plant site (a lower cost alternative to the costly onsite assembly of conventional boilers). In the mid-1960s, it was realized that a fluidized bed boiler not only represented a potentially lower cost, more efficient way to burn coal, but also a much cleaner technology. The same turbulent, or "fluidizing," mixing of the coal to improve combustion also provided a way to inject sulfur-absorbing limestone to clean the coal while it burned. A 500-kilowatt fluidized bed coal combustor test plant was built in Alexandria, Virginia, in 1965. It provided much of the design data for a 30-megawatt prototype unit at the Monongahela Power Company's Rivesville, West Virginia, plant built in the mid-1970s.

The first commercially successful fluidized bed was an industrial-size atmospheric unit (equivalent to a 10-megawatt combustor) built with federal funds on the campus of Georgetown University in 1979. The Georgetown unit still operates today.

The technology progressed into larger scale utility applications due, in large part, to Federal partnership programs with industry. The Colorado-Ute Electric Association project in Nucla, CO (now operated by Tri-State Generation and Transmission Association, Inc., of Denver) was one of the early demonstrations in the Clean Coal Technology Program. From this project came significant design improvements in utility-scale atmospheric fluidized bed technology, and as a result, commercial confidence in this advanced, low-polluting combustion system picked up considerably.

In 1996, Jacksonville Electric Authority (JEA) chose to replace two older oil and gas fired units at their Northside Station with atmospheric fluidized bed combustion technology. DOE contributed more than $74 million to the project as one of the original projects under its Clean Coal Technology Program. The federal funding went to install one of the two combustors. JEA repowered the second steam turbine using the new technology with its own funding. On October 14, 2002, the utility declared the new technology to be fully operational. The two 300 MW fluidized bed systems at the Northside Station became fully operational in October, 2002. At the time they went into operation, they were the largest fluidized bed combustors ever installed in a power plant.

### 4.2.2 Efficiency

In the 100-200 MWe range, the thermal efficiency of CFB units may be lower than that for equivalent size PC units by a few percentage points, depending on coal quality. In CFB, the heat losses from the cyclone(s) are considerable. This results in reduced thermal efficiency, and even with ash heat recovery systems, there tend to be high heat losses associated with the removal of both ash and spent sorbent from the system. The use of a low grade coal with variable characteristics tends to result in lower efficiency, and the addition of sorbent and subsequent removal with the ash results in heat losses. It is projected that a 250 MW CFB unit for the BEPC Dry Fork project would have an efficiency similar to a PC unit.

### 4.2.3 Operating History w/PRB Coal

The majority of existing utility CFB units burn bituminous coal, anthracite coal waste or lignite coal. The operating history of utility CFB boilers burning PRB or other types of subbituminous coal is limited. CFB technology typically has an economic advantage only when used with high ash and/or high sulfur fuels. Therefore, bituminous coal, petroleum coke, coal waste, lignite and biomass fuels are the typical applications for CFB technology.

The two JEA 300 MW CFB demonstration units are designed to burn both bituminous coal and petroleum coke. There is a minimum coal ash content versus coal sulfur content specification for these units. The lowest specified coal sulfur content of 0.50 wt. percent corresponds to a minimum coal ash content of 12 wt. percent. Most of the PRB coals proposed for the Basin Electric Dry Fork project contain between 0.30 to 0.50 wt. percent sulfur and between 4.0 to 8.0 wt. percent ash. The Dry Fork Mine coal averages approximately 0.33 wt. percent sulfur and 4.77 wt. percent ash. Therefore, none of these PRB

coals would be an acceptable fuel for the JEA CFB units based on sulfur and ash content unless they were blended with a higher sulfur and/or ash fuel.

PRB coals may also have a tendency to produce small particle size (fine) fly ash that makes it more difficult to maintain the required bed volume in a CFB unit. Therefore, additional quantities of inerts such as sand and limestone may be required for a CFB unit burning low sulfur/low ash PRB coals.

A joint Colorado Springs Utilities / Foster Wheeler 150 MW Advanced CFB demonstration project at the Ray D. Nixon Power Plant south of Colorado Springs was proposed and accepted by DOE NETL in 2002 as part of the federal Clean Coal Power Initiative (CCPI). DOE agreed to a $30 million cost share of the $301.5 million project. The next generation CFB unit would be designed to burn PRB coal and PRB blended with coal waste, biomass and petroleum coke. However, Colorado Springs Utilities and Foster Wheeler cancelled and withdrew from the CCPI project in 2003.

### 4.2.4 CFB Configuration Selected for Evaluation

The CFB configuration selected for evaluation uses a Selective Non-Catalytic Reduction (SNCR) system for NOx control and a CDS FGD system for SO2 control.

## 4.3 Integrated Gasification Combined Cycle

IGCC has been demonstrated in a few commercial-scale facilities. A variety of coals have been gasified, the resulting gases have been cleaned up to allow use in combustion turbines, and electricity has been generated. However, the capital cost and performance in a number of areas have not been as attractive as planned. The troublesome areas for IGCC have included high-temperature heat recovery and hot gas cleanup.

An important part of achieving an attractive heat rate is generation of high pressure and temperature steam from the high-temperature raw gas generated by gasifying coal. The temperature of the raw gas is dependent on the gasification process and the coal. Slagging gasifiers, such as the Texaco process, typically generate gases in the 2500 to 2800°F range. These high-temperature gases containing corrosive compounds, such as $H_2S$, create a very demanding environment for the generation of high pressure and temperature steam. The alternative of not recovering the heat in the raw gas, such as direct quenching of the gas, results in lower efficiencies.

It is also attractive from an efficiency perspective to provide clean gas to the combustion turbine at an elevated temperature without cooling and reheating, hence the desire to use hot gas cleanup. Again, this demanding service has not been reliably demonstrated in a commercial application, resulting in less efficient approaches being used for current plants.

The main incentive for IGCC development has been that units may be able to achieve higher thermal efficiencies than PC plants, and be able to match the environmental performance of gas-fired plants. However, the thermal efficiencies of new PC plants using superheated steam have also increased as has their environmental performance.

## 4.3.1 Development History / Current Status

IGCC has been under development since the 1980s. A number of demonstration units, around 250 MWe size are being operated in the USA and Europe. Table 4-1 at the end of this section lists the commercial scale IGCC plants that have been built and their current status. Most of the IGCC units have used entrained flow gasifiers and are oxygen blown, but one unsuccessful demonstration unit (Pinion Pine IGCC) was based on an air-blown fluidized bed gasifier. The two plants currently operating in the U.S. are the 262 MW PSI/Global Energy Wabash River IGCC in Indiana and the 250 MW Tampa Electric Polk IGCC in Florida. The 253 MWe unit at Buggenum in The Netherlands, started up in 1993. The largest unit is located at Puertollano in Spain with a capacity of 318 MW.

All of the current coal-fueled IGCC demonstration plants are subsidized. The U.S. plants are part of the DOE Clean Coal Program, and the European plants are part of the Thermie Programme. The DOE has partially funded the design and construction of the U.S. plants, as well as the operating costs for the first few years. The Wabash River plant was a repowering project, but from the point of view of demonstrating the viability of various systems, it is effectively a new plant, even though tied to an existing steam turbine. The Cool Water and Louisiana Gasification Technology Inc (LGTI) projects were the first commercial-scale IGCC projects constructed in the United States, and were constructed with guaranteed price support from the U.S. Synthetic Fuels Corporation; both projects were shut down once the duration of the price guarantee period expired.

## 4.3.2 Operating History w/PRB Coal

The only commercial size IGCC demonstration plant that has operated with PRB coal fuel was the 160 MWe Dow Chemical Louisiana Gasification Technology, Inc. (LGTI) plant in Plaquemine, LA. This plant used an oxygen blown E-Gas entrained flow gasifier and is reported to have operated successfully from 1987 to 1995. The plant is now shutdown.

The Power Systems Development Facility (PSDF), located near Wilsonville, Alabama, is a large advanced coal-fired power system pilot plant. It is a joint project of DOE NETL, Southern Company and other industrial participants. The Haliburton KBR Transport Reactor was modified from a combustor to coal gasifier operation in 1999. The initial gasification tests have concentrated on PRB coals because their high reactivity and volatiles were found to enhance gasification. The highest syngas heating values were achieved with PRB coal, since PRB coal is more reactive than bituminous coals.

Southern Company, Orlando Utilities Commission, and Kellogg Brown and Root, were recently selected by DOE NETL for co-funding in the Round 2 Clean Coal Power Initiative (CCPI) solicitation. They propose to construct and demonstrate operation of a 285 MW coal-based transport gasifier plant in Orange County, Florida. The proposed facility would gasify sub-bituminous coal in an air-blown integrated gasification combined cycle power plant based on the KBR Transport Gasifier. Southern Company estimated the total cost for the project at $557 million ($1954/MW) and requested $235 million of DOE funds to support the project.

### 4.3.3 Efficiency

The driving force behind the development of IGCC is to achieve high thermal efficiencies together with low levels of emissions. It is hoped to reach efficiencies of over 40 percent, and possibly as high as 45 percent with IGCC. Higher efficiencies are possible when high gas inlet temperatures to the gas turbine can be achieved. At the moment, the gas cleaning stages for particulates and sulfur removal can only be carried out at relatively low temperatures, which restricts the overall efficiency obtainable.

### 4.3.4 IGCC Configurations Selected for Evaluation

The two IGCC configurations selected for evaluation represent a conventional IGCC unit and an ultra-low emissions IGCC unit.

The conventional IGCC unit uses an MDEA gas treatment system to reduce H2S to approximately 25 ppmv in the syngas sent to the combustion turbine generators (CTGs) for SO2 control, and water injection with low-NOx burners in the CTGs for NOx control.

The ultra-low emissions IGCC unit uses a Selexol gas treatment system to reduce H2S to approximately 10 ppmv in the syngas sent to the CTGs for SO2 control, water injection with low-NOx burners in the CTGs and an SCR system for NOx control, and a catalytic oxidation catalyst (Cat-Ox) system for CO control.

**TABLE 4-1**
Commercial Scale IGCC Power Plants
*Basin Electric Dry Fork Station Technology Evaluation*

| Plant Name | Plant Location | Net Output (MWe) | Feedstock | Gasifier Design | Gas Cleanup | Power Island | Net Plant Heat Rate (Btu/kWh) | Operation Status |
|---|---|---|---|---|---|---|---|---|
| Texaco Cool Water | Daggett, CA | 96 | Low S & High S Bituminous Coal | O2 Blown Texaco Entrained Flow (2500°F, 600 Psig) | Cold H2S and Ash Removal | GE 7FE CTG / STG | 11,300 (HHV Basis) | 1984-1988 (shutdown) |
| Dow Chemical / Destec LGTI | Plaquemine, LA | 160 | Subbituminous PRB Coal | O2 Blown E-Gas Entrained Flow (2700°F, 400 Psig) | Cold H2S and Ash Removal | West. 501 CTG / STG | 10,500 (HHV Basis) | 1987-1995 (shutdown) |
| Sierra Pacific Pinon Pine | Tracy Station, Reno, NV | 107 | Low S Western Bituminous Coal | Air Blown Pressurized KRW fluid bed (1800°F, 325 Psig) | Hot H2S and Ash Removal | GE 6FA CTG / STG | 8,390 (HHV Basis) | 1998-2000 (never successfully started-up) |
| Tampa Electric Polk Plant | Polk County, FL | 250 | High S Bit. Coal & Petroleum Coke | O2 Blown Chevron-Texaco Entrained Flow (2500°F, 375 Psig) | Cold H2S and Ash Removal | GE 7FA CTG / STG | 9,650 (HHV Basis) | 1996-Present |
| PSI / Global Energy Wabash River | West Terre Haute, IN | 262 | High S Bit. Coal & Petroleum Coke | O2 Blown E-Gas Entrained Flow (2600°F, 400 Psig) | Cold H2S and Ash Removal | GE 7FA CTG / STG | 8,900 (HHV Basis) | 1995-Present |
| NUON/Demcolec / Willem-Alexander | Buggenum, The Netherlands | 253 | Bituminous Coal | O2 Blown Shell Entrained Flow (2600°F, 400 Psig) | Cold H2S and Ash Removal | Siemens V94.2 CTG / STG | 8,240 (HHV Basis) | 1994-Present |
| ELCOGAS / Puertollano | Puertollano, Spain | 318 | 50%/50% Coal & Petroleum Coke Mix | O2 Blown Prenflo Entrained Flow (2900°F, 400 Psig) | Cold H2S and Ash Removal. | Siemens V94.3 CTG / STG | 8,230 (HHV Basis) | 1998-Present |

SECTION 5.0

# Environmental Evaluation

Environmental impacts associated with PC units include air emissions, water/wastewater discharge issues, and solid waste disposal. Impacts are minimized by utilizing air pollution control equipment, wastewater pretreatment controls, and the potential reuse of ash.

Environmental impacts associated with a CFB coal unit include air emissions, water/wastewater discharge issues, and solid waste disposal. Impacts are minimized by utilizing air pollution control equipment, wastewater pretreatment controls, and the potential reuse of ash. A CFB design does have the advantage of burning a wider range of fuels including waste materials such as petroleum coke or renewable biomass.

The overall environmental impacts from an IGCC unit would be between those of a natural gas-fired combustion turbine combined cycle unit and a PC unit. Environmental impacts would include air emissions, water/wastewater discharge, and solid waste disposal.

## 5.1 Air Emissions

### Pulverized Coal

A PC unit for the Dry Fork Station will use low-$NO_x$ burners and SCR for $NO_x$ control, CDS FGD for $SO_2$ control, and a fabric filter for particulate control. There would be $PM_{10}$ emissions from coal, ash, and lime material handling operations. There would also be other sources of air emissions from miscellaneous support equipment such as diesel or natural gas-fired emergency generators, fire pumps, and the installation of a natural gas-fired auxiliary boiler. A case-by-case, maximum achievable control technology (MACT) analysis would be required for trace metals in the coal, organics, and acid gases.

### Circulating Fluid Bed

Combustion takes place at temperatures from 1500-1600°F, resulting in reduced $NO_x$ formation compared with a PC unit. While the air emissions exiting a CFB boiler (especially $NO_x$, $SO_2$, and CO) are lower than a conventional PC boiler, the final stack emissions would be similar based on the use of add-on control equipment. Current BACT would require SNCR for $NO_x$ control, limestone injection in the furnace for $SO_2$ control, and a fabric filter for particulate control. A polishing CDS FGD system would also be required for additional $SO_2$ control.

There would be $PM_{10}$ emissions from coal, ash, lime and limestone material handling operations. There would also be other sources of air emissions from miscellaneous support equipment, such as diesel or natural gas-fired emergency generators, fire pumps, and the installation of a natural gas-fired auxiliary boiler. A case-by-case MACT analysis would be required for trace metals in the coal, organics, and acid gases.

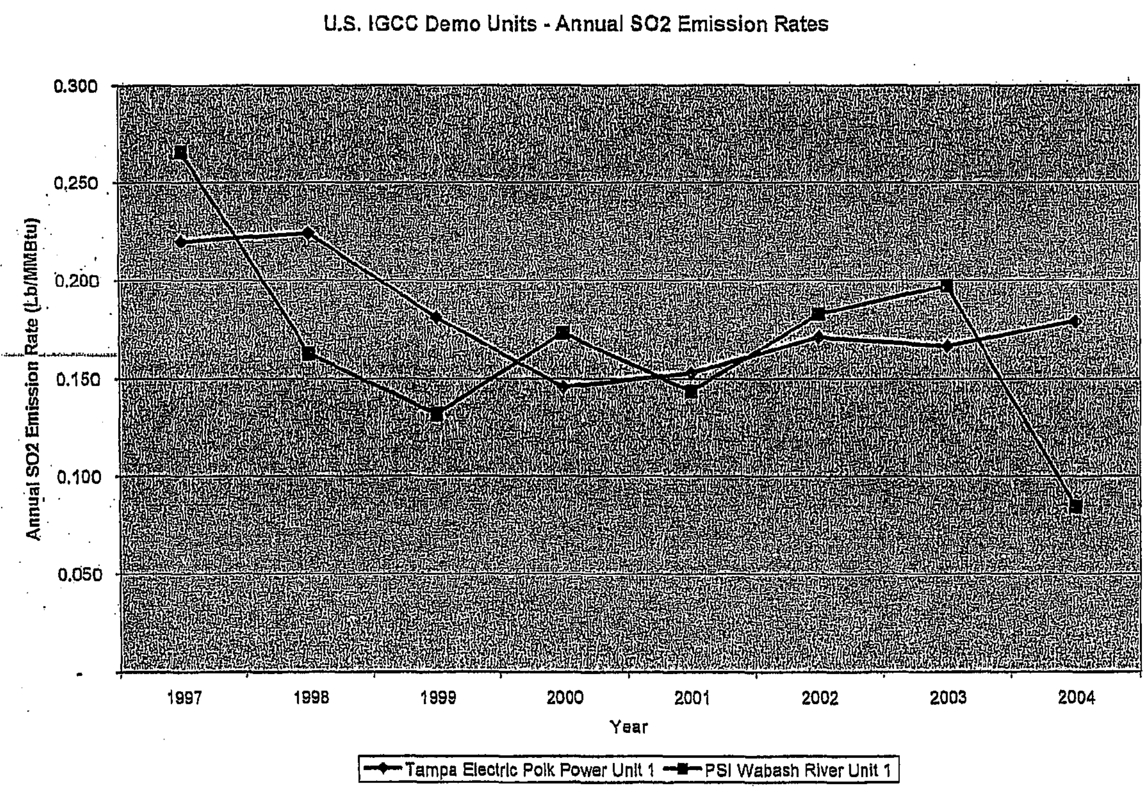
## Integrated Gasification Combined Cycle

An IGCC plant has the potential for reduced emissions of $SO_2$, $NO_x$, Hg and particulates compared to levels produced by conventional PC and CFB units. $SO_2$ removal up to 98 to 99 percent and Hg removal of approximately 90 percent is possible in the gas treatment system downstream of the gasifier. Particulates will be removed to levels approaching natural gas fired combustion turbines. $NO_x$ emissions from the gas turbines should be similar to emissions from natural gas fired combustion turbines. Based on a BACT analysis, additional controls may be required including SCR for $NO_x$ reduction and catalytic oxidation for CO reduction.

There would be $PM_{10}$ emissions from coal and ash material handling operations. There would also be other sources of air emissions from the IGCC process from the syngas/natural gas-fired auxiliary boiler used to dry the PRB coal, flaring of treated or untreated syngas during plant startups, shutdown and upsets, and from miscellaneous support equipment such as diesel or natural gas emergency generators and fire pumps.

The reported annual SO2 and NOx emission rates for the two U.S. IGCC demonstration plants are shown in Figures 5-1 and 5-2.

Figure 5-1





DEQ/AQD 004211

Figure 5-2

U.S. IGCC Demo Units - Annual NOx Emission Rates

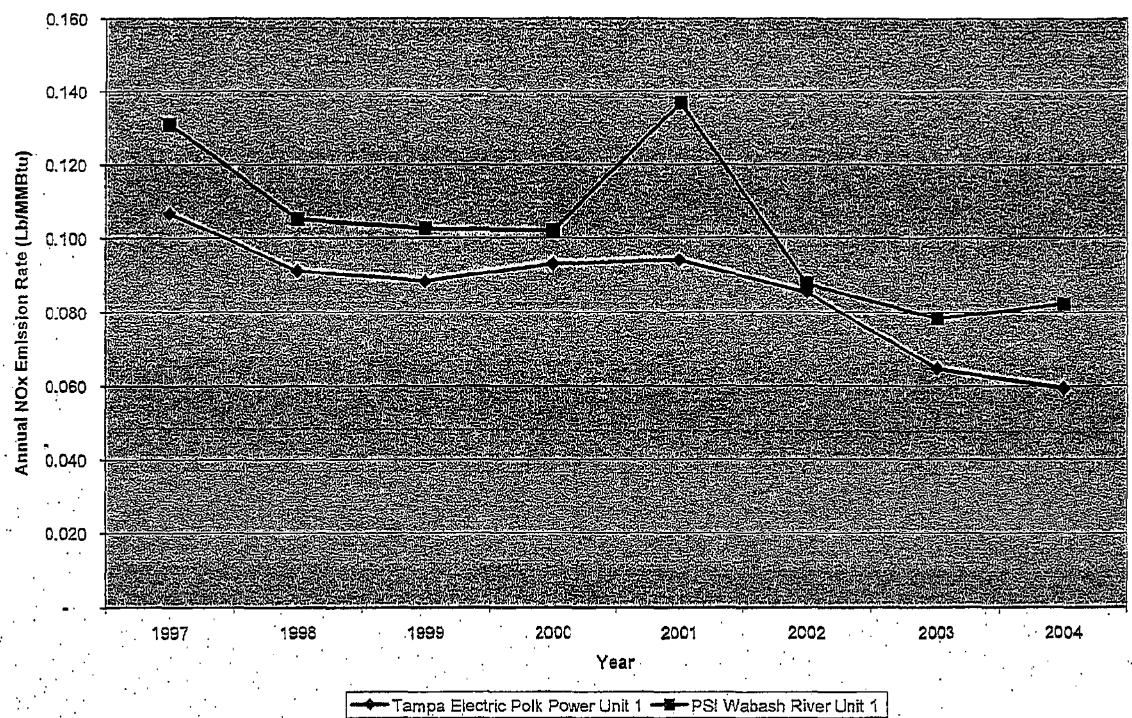



Table 5-1 compares the proposed Dry Fork Station PC emission rates with the current annual emission rates from existing CFB commercial plants and from existing U.S. IGCC demonstration plants.

TABLE 5-1
Comparison of Coal Combustion Technology Emission Rates
*Basin Electric Dry Fork Station Technology Evaluation*

| | Emission Rates for Coal Combustion Technologies (Lb/MMBtu) | | |
|---|---|---|---|
| Pollutant | PC (Potential BACT) | CFB (Existing U.S. Commercial Plants) | IGCC (Existing U.S. Demonstration Plants)* |
| $SO_2$ | 0.10 | 0.10 | 0.17 |
| $NO_x$ | 0.07 | 0.09 | 0.09 |
| $PM_{10}$** | 0.019 | 0.019 | 0.011 |
| CO | 0.15 | 0.15 | 0.045 |
| VOC | 0.0037 | 0.0037 | 0.0021 |

Notes:
* PSI Energy Wabash River Station and TECO Polk Power Station Existing IGCC Demonstration Plants.
**$PM_{10}$ includes filterable and condensable portions.

## 5.2 Water/Wastewater

### Pulverized Coal

Liquid wastes would include boiler feed water (BFW) blowdown, auxiliary cooling tower blowdown, and chemicals associated with water treatment. Dry cooling and zero liquid discharge systems will be used to reduce overall water consumption and discharge. A groundwater protection permit will be required if evaporation ponds are included in the plant design. Stormwater discharge permits and stormwater pollution prevention plans (SWPPP) would be required. Spill Prevention, Control, and Countermeasures (SPCC) plans may also be required.

### Circulating Fluid Bed

Similar to a PC plant, CFB plant liquid wastes would include BFW blowdown, auxiliary cooling tower blowdown, and chemicals associated with water treatment. Dry cooling and zero liquid discharge systems will be used to reduce overall water consumption and discharge. A groundwater protection permit will be required if evaporation ponds are included in the plant design. Stormwater discharge permits and stormwater pollution prevention plans (SWPPP) would be required. Spill Prevention, Control, and Countermeasures (SPCC) plans may also be required.

### Integrated Gasification Combined Cycle

An IGCC unit for the Dry Fork project would have two primary liquid effluents. The first is blowdown from the BFW purification system, although the blowdown will be less compared to a PC or CFB unit since the steam cycle in an IGCC plant typically produces less than 40 percent of the plant's power. However, BFW makeup may be the same as, or even larger, than a PC or CFB based plant of comparable output, even if it is well designed, operated and maintained. A coal gasification process may consume significant quantities of BFW in tap purges, pump seals, intermittent equipment flushes, syngas saturation for $NO_x$ control, and ~~direct steam injection into the gasifier as a reactant and/or temperature moderator.~~

The second liquid effluent from an IGCC plant is process water blowdown. This process water blowdown is typically high in dissolved solids and gases along with the various ionic species washed from the syngas such as sulfide, chloride, ammonium and cyanide. The Wabash River IGCC plant installed an add-on mechanical vapor recompression (MVR) system in 2001 to better control arsenic, cyanide and selenium in the wastewater stream.

As with the PC and CFB power units, dry cooling and zero liquid discharge systems will be used to reduce overall water consumption and discharge. The Tampa Electric Polk IGCC plant treats process water blowdown with ammonia stripping, vapor compression concentration, and crystallization to completely eliminate process water discharge.

Liquid wastes would also include auxiliary cooling tower blowdown and chemicals associated with water treatment. A groundwater protection permit will be required if evaporation ponds are included in the plant design. Stormwater discharge permits and stormwater pollution prevention plans (SWPPP) would be required. Spill Prevention, Control, and Countermeasures (SPCC) plans may also be required.

## 5.3 Solid Waste

### Pulverized Coal

Solid wastes include bottom ash from the boiler, and combined dry FGD and fly ash solid waste from the fabric filter. Disposal of these wastes is a major factor in plant design and cost considerations.

### Circulating Fluid Bed

Solid wastes include boiler bed ash, and combined dry FGD and fly ash solid waste from the fabric filter. Since limestone is injected into the CFB boiler for SO2 removal, there will be additional CaO, $CaSO_4$ and $CaCO_3$ present in the bed and fly ash. There may be a high free lime content, and leachates will be strongly alkaline. Carbon-in-ash levels are higher in CFB residues that in those from PC units. As with PC fired units, disposal of these wastes is a major factor in plant design and cost considerations.

### Integrated Gasification Combined Cycle

IGCC power generation has demonstrated reduced environmental impact compared to PC and CFB plants in terms of solid waste quantities and the potential for leaching of toxic substances into the soil and groundwater. The largest solid waste stream produced by an IGCC using an entrained bed gasifier is slag. This type of gasifier operates above the fusion temperature of the coal ash, producing a black, glassy, sand-like slag material that is a potentially marketable byproduct. Leachability data obtained from different entrained-bed gasifiers has shown that this gasifier slag is highly non-leachable. The slag may be suitable for the cement industry, asphalt production, construction backfill and landfill cover operations.

Most gasification processes also produce a smaller amount of char (unreacted fuel) and/or fly ash that is entrained in the syngas. This material is typically captured and recycled to the gasifier to maintain high carbon conversion efficiency and to convert the fly ash into slag to eliminate fly ash disposal.

The other large volume byproduct produced by IGCC plants is elemental sulfur or sulfuric acid, both of which can be sold to help offset plant operating costs. This contrasts with a PC or CFB unit with a dry or semi-dry lime FGD System, which recovers sulfur as dry spent sorbent mixed with the fly ash. Spent sorbent and fly ash must typically be disposed of as waste materials in an appropriate landfill.

# Reliability Evaluation

## 6.1 Annual Availability and Capacity Factors

Both PC and CFB technologies are considered to be mature and are used for baseload power plants. The overall plant availability of well maintained baseload PC and CFB units is approximately 90 percent. All four of the demonstration IGCC plants experienced very low availability during their early years of operation. The availability improved after design and operation changes were made to each facility, however, their current annual availability is still lower than what can be achieved with PC and CFB units.

Capacity factor measures the amount of electricity actually produced compared with the maximum output achievable. The overall plant capacity factor for well maintained baseload PC and CFB units is approximately 85 percent. All four of the demonstration IGCC plants continue to experience low capacity factors compared to baseload PC and CFB units. The reported annual availability and capacity factors for the two U.S. IGCC demonstration plants are shown in Figures 6-1 and 6-2. Data for some years was not available.

Figure 6-1

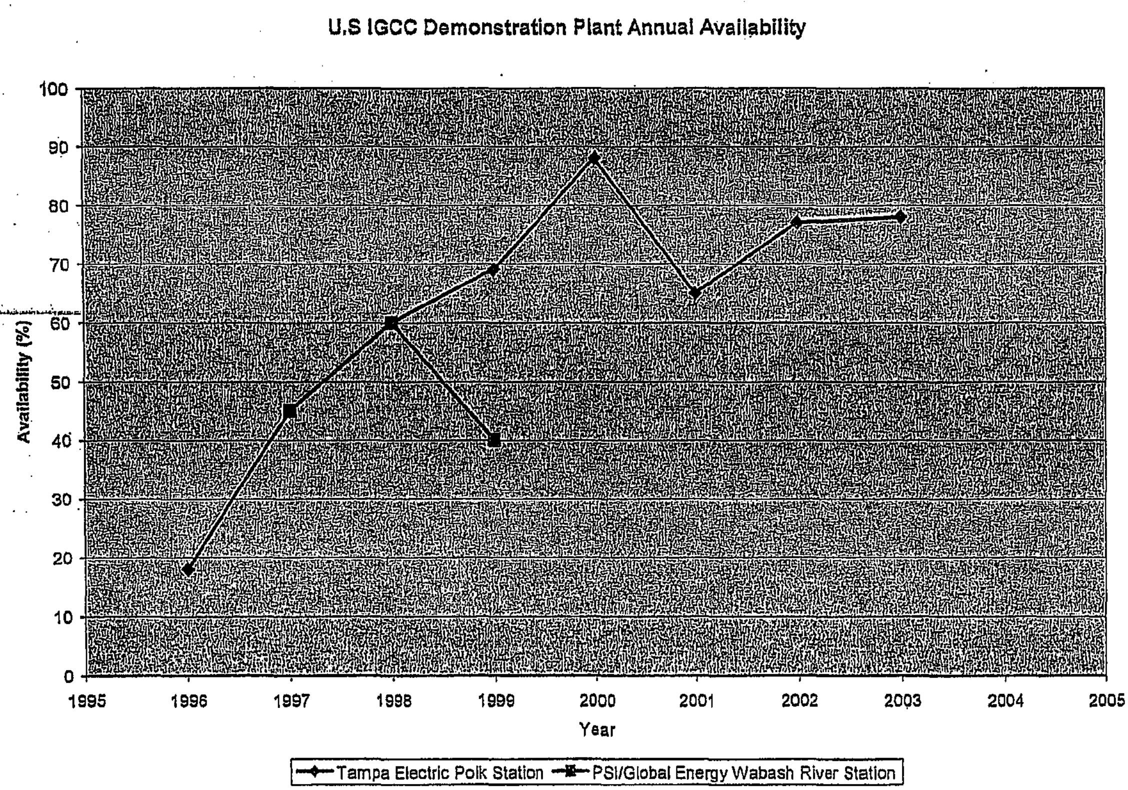
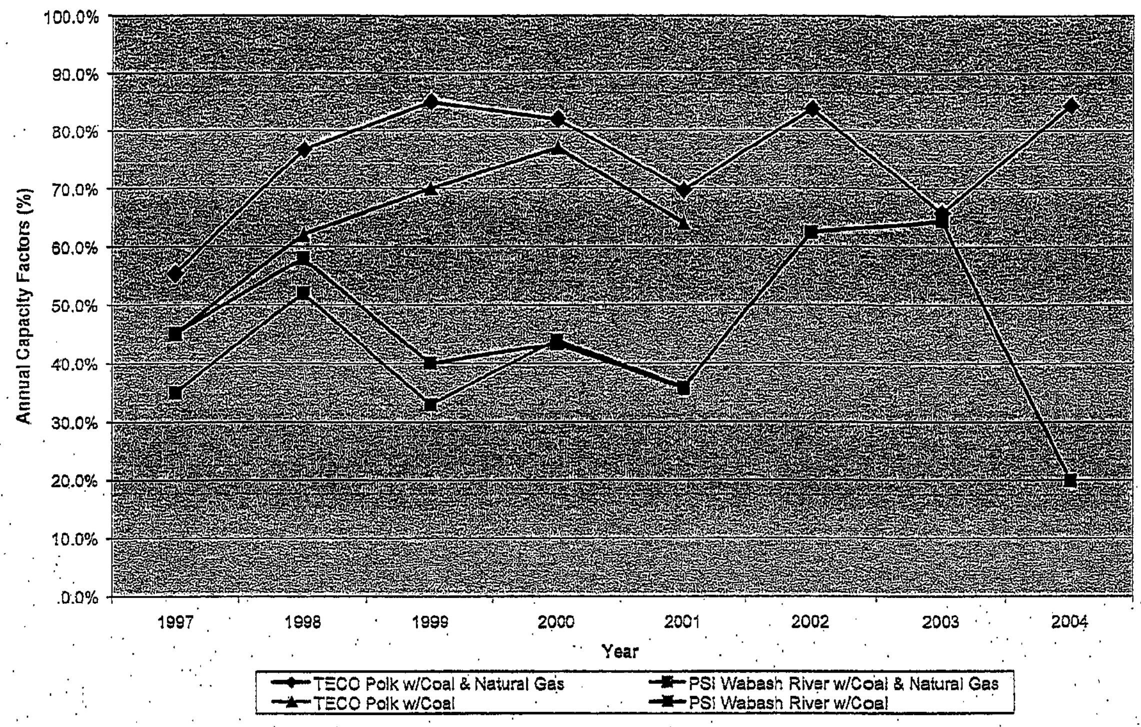


Figure 6-2

U.S. IGCC Demo Units - Annual Capacity Factors




## 6.2 TECO Polk Power Station IGCC

The Polk IGCC Power Plant began commercial operation in September 1996. Key availability factors reported by Tampa Electric are summarized in Table 6-1. Availability is defined by Tampa Electric in their published papers and reports as the percent of time during each period that the unit was in service or in reserve shutdown.

TABLE 6-1
TECO Polk Power Station IGCC Availability

| Year | Air Separation Unit (ASU) | Gasification Island | Combined Cycle Power Block | Total Plant |
|---|---|---|---|---|
| 1996 | N/A* | N/A | N/A | 18% |
| 1997 | N/A | N/A | 55% | 45% |
| 1998 | N/A | N/A | 87% | 60% |
| 1999 | N/A | N/A | 92% | 69% |
| 2000 | N/A | N/A | 87% | 88% |
| 2001 | N/A | N/A | 91% | 65% |
| 2002 | 96% | 77% | 94% | 77% |
| 2003 | 95% | 78% | 80% | 78% |

* N/A – Not Available
Source: Presentation at the 2003 Gasification Technologies Conference entitled "Polk Power Station – 7th Commercial Year of Operation" by John McDaniel and Mark Hornick.

## 6.3 PSI Wabash River Power Station IGCC

The Wabash River 262 MW IGCC Power Plant began commercial operation in late 1995. Key IGCC plant availability and gasification island forced outage rates reported by PSI are summarized in Table 6-2.

TABLE 6-2
PSI Wabash River IGCC Availability and Gasification Island Forced Outage Rate
*Basin Electric Dry Fork Station Technology Evaluation*

| Year | Availability | | Forced Outage Rate |
|---|---|---|---|
| | Gasification Island | Total Plant | Gasification Island |
| 1997 | N/A* | 45 | N/A |
| 1998 | N/A | 60 | N/A |
| 1999 | N/A | 40 | N/A |
| 2000 | 73.3 | N/A | 18 |
| 2001 | 72.5 | N/A | 22 |
| 2002 | 78.7 | N/A | 11** |
| 2003 | 74 | N/A | 17.5 |

* N/A – Not Available
** Estimated on partial year data
Source: Presentation at the 2002 and 2003 Gasification Technologies Conferences entitled "Operating Experience at the Wabash River Repowering Project" by Clifton Keeler.

## 6.4 NUON Buggenum Power Station IGCC

The Buggenum IGCC Power Plant started operation in 1994. It is a 250 MW plant located in the Netherlands. Key availability factors reported by NUON are summarized in Tables 6-3. In addition to burning coal, other types of fuel are being explored including wood, sewage sludge, coffee, rice and chicken litter, with varying degrees of success.

TABLE 6-3
NUON Buggenum Power Station IGCC Availability
*Basin Electric Dry Fork Station Technology Evaluation*

| Year | Gasification Island | Combined Cycle Power Block |
|---|---|---|
| 1999 | 45 | N/A |
| 2000 | 50 | N/A |
| 2001 | N/A* | N/A |
| 2002 | 67.3 | 89.3 |
| 2003 | 64.6 | 94.8 |

* N/A – Not Available
Source: Presentation at the 2000 and 2003 Gasification Technologies Conference entitled "Operating Experience at the William Alexander Centrale" by J.Th.G.M. Eurlings and Carlo Wolters, respectively.

## 6.5 Elcogas Puertollano Power Station IGCC

The Puertollano 335 MW IGCC Power Plant had its first 100 hours of continuous operation in August 1999. Key availability and forced outage rates reported by Elcogas are summarized in Tables 6-4 and 6-5.

TABLE 6-4
Elcogas Puertollano Power Station IGCC Availability
*Basin Electric Dry Fork Station Technology Evaluation*

| Year | Air Separation Unit (ASU) | Gasification Island | Combined Cycle Power Block | Total Plant | Comments |
|---|---|---|---|---|---|
| 2000 | 87.5 | 65.9 | 70.6 | N/A | |
| 2001 | N/A* | 71.5** | 83.9 | 59.6 | |
| 2002 | 91.4 | 74.9 | 85.5 | 63.7 | |
| 2003 | 86.7 | 85.7 | 64.3 | 51.9 | |

* N/A – Not Available

** Includes ASU and ASR

Source: Presentations at the 2001 and 2003 Gasification Technologies Conference by Ignacio Mendez-Vigo.

TABLE 6-5
Elcogas Puertollano Power Station IGCC Forced Outage Rate
*Basin Electric Dry Fork Station Technology Evaluation*

| Year | Air Separation Unit (ASU) | Gasification Island | Combined Cycle Power Block | Total Plant | Comments |
|---|---|---|---|---|---|
| 2000 | 11.4 | 33.8 | 3.1 | N/A | |
| 2001 | N/A* | 26.7 | 13.4 | 36.9 | |
| 2002 | 2.3 | 14.7 | 3.3 | 25 | |
| 2003 | 5.4 | 7.9 | 5.1 | 22.6 | |

* N/A – Not Available

Source: Presentations at the 2001 and 2003 Gasification Technologies Conference by Ignacio Mendez-Vigo.

SECTION 7.0

# Commercial Availability

PC technology is available commercially, with a long history of being the technology of choice for large base-load utility units. The CFB technology is also available commercially, but the largest CFB units in operation are approximately 300 MW in size. The CFB boiler suppliers indicate a willingness to provide larger units with full commercial guarantees.

Current and near-term IGCC plants must be viewed as still under development, and not yet delivering the cost and performance to be economically attractive. Current IGCC plants are providing good information about the technology, but not demonstrating the necessary cost of electricity to expect the technology to be available commercially in time frame to support Basin Electric's needs.

## 7.1 Number/Quality of Suppliers

Both PC and CFB based coal-fired power plant technologies are offered commercially on a turnkey basis by some of the larger suppliers such as Bechtel and Mitsubishi. In addition, engineering/boiler vendor/contractor consortiums will also offer these types of plants on a turnkey basis. In contrast, IGCC plants are still considered to be high risk ventures and are not currently offered on a turnkey basis. A General Electric and Bechtel partnership is developing a 600 MW standard design based on the ChevronTexaco entrained bed gasifier with an eastern bituminous coal fuel. A ConocoPhillips and Fluor partnership is also developing a 600 MW standard design based the E-Gas entrained bed gasifier with an eastern bituminous coal fuel. Both consortiums plan to offer turnkey systems in the future based on the standard plant designs. There are no turnkey IGCC systems available for a 250 MW IGCC plant based on PRB coal fuel.

## 7.2 Availability of Process, Performance and Emission Guarantees

PC and CFB units are available commercially with strong, financially backed process, performance and emission guarantees on a turnkey basis, or from the individual equipment suppliers. These types of project guarantees are not currently available for IGCC plants on a turnkey basis due to their early development status and limited commercial experience.

## 7.3 Availability of Financing Alternatives

Project financing is available for both PC and CFB based power plants. The lack of adequate developmental and project financing has been a major challenge to the deployment of IGCC power plants. The significant underlying causes include the following items:

- Perceived low rate of availability at IGCC projects in early years of operation resulting in substantially lower NPVs for that period.

- Uncertain capital funding needs of IGCC projects.
- Lack of guarantees for overall performance of the IGCC power units by plant designers, equipment suppliers and construction companies.
- Perceived need to finance IGCC power plants with government subsidies.
- Technical and business risk related to IGCC plant development. (Note that members of the John F. Kennedy School of Government of Harvard University, acknowledging that risk is a barrier to IGCC plant development, have recently proposed a "3Party Covenant" whereby the Federal Government provides loan guarantees which allow lower cost financing, state public utility commissions provide guarantees that output can be sold even if it is not the lowest-cost resource, and equity investors provide project financing based on the federal and state guarantees).

SECTION 8.0

# Economic Evaluation

## 8.1 Economic Criteria

The major economic criteria used for the cost evaluation of the PC, CFB, Conventional IGCC and Ultra-Low Emission IGCC cases are listed in Table 8-1.

TABLE 8-1
Coal Plant Economic Evaluation Criteria
*Basin Electric Dry Fork Station Technology Evaluation*

| Criteria | PC | CFB | Conventional IGCC | Ultra-Low Emission IGCC | Comments |
|---|---|---|---|---|---|
| Net Plant Output (MW) | 273 MW | 273 MW | 273 MW | 273 MW | Annual Average |
| Net Plant Heat Rate (Btu/kW-Hr) | 10,500 | 10,800 | 10,500 | 10,500 | Annual Average |
| Annual Plant Capacity Factor (%) | 85% Coal | 85% Coal | 15% Natural Gas, 70% Coal | 15% Natural Gas, 70% Coal | |
| Interest Rate (%) | 6.0% | 6.0% | 8.0% | 8.0% | Higher rate for IGCC due to risk |
| Discount Rate (%) | 6.0% | 6.0% | 6.0% | 6.0% | |
| Capital Cost Recovery Period (Years) | 42 years | 42 years | 42 years | 42 years | |
| Plant Economic Life (Years) | 42 years | 42 years | 42 years | 42 years | |
| Fixed O&M Cost ($/kW-Yr) | 38.33 | 34.50 | 50.00 | 52.50 | |
| Non-Fuel Variable O&M Costs ($/kW-Hr) | 0.0027 | 0.0025 | 0.0020 | 0.0021 | |
| Coal Cost ($/MMBtu) | 0.35 | 0.35 | 0.35 | 0.35 | |
| Natural Gas Cost ($/MMBtu) | 7.50 | 7.50 | 7.50 | 7.50 | |

## 8.2 Economic Analysis Summary

The overnight capital costs and life cycle economic analysis for the PC, CFB, Conventional IGCC and Ultra-Low Emission IGCC cases is shown in Table 8-2. The net present value (NPV) for the PC, CFB, Conventional IGCC and Ultra-Low Emission IGCC cases was calculated based on the 6.0 percent discount rate and annual cash flows for a plant economic life of 42 years.

**TABLE 8-2**
Economic Analysis Summary for Combustion Technology Options
*Basin Electric Dry Fork Station Technology Evaluation*

| Costs | Cost ($ Million) | | | |
|---|---|---|---|---|
| | PC | CFB | Conventional IGCC | Ultra-Low Emission IGCC |
| CAPITAL COST | 482 | 497 | 720 | 756 |
| FIRST YEAR O&M COST | | | | |
| Fixed O&M Cost | 10.7 | 9.6 | 13.9 | 14.6 |
| Non-Fuel Variable Cost | 5.6 | 5.2 | 4.1 | 4.4 |
| Coal Cost | 7.6 | 7.8 | 6.5 | 6.5 |
| Natural Gas Cost | 0.0 | 0.0 | 24.7 | 24.7 |
| **TOTAL FIRST YEAR OPERATING COST** | **23.9** | **22.6** | **49.3** | **50.2** |
| **FIRST YEAR DEBT SERVICE** | **31.7** | **32.6** | **60.0** | **63.0** |
| **TOTAL FIRST YEAR COST** | **55.6** | **55.3** | **109.2** | **113.1** |
| **Net Present Value (NPV)** | **961** | **950** | **1,982** | **2,046** |
| | Incremental Control Cost | | | |
| Total Pollutant Emissions (Tons/Yr) | 3,657 | 3,981 | 1,491 | 804 |
| Incremental Pollutants Removed (Tons) | Base | -324 | 2,166 | 2,853 |
| Incremental First Year Control Cost ($/Ton Pollutants Removed) | Base | 987 | 24,767 | 20,173 |

* Based on SO2, NOx, CO, VOC and PM pollutants removed.

The total first year cost for the PC case is $55.6 Million versus $55.3 Million for the CFB case. The higher CFB Unit annual debt service is offset to a greater degree by the lower annual fixed O&M and non-fuel variable cost compared to a PC Unit. The total first year cost for the Conventional IGCC and Ultra-Low Emission IGCC cases are $109.2 Million and $113.1 Million, respectively.

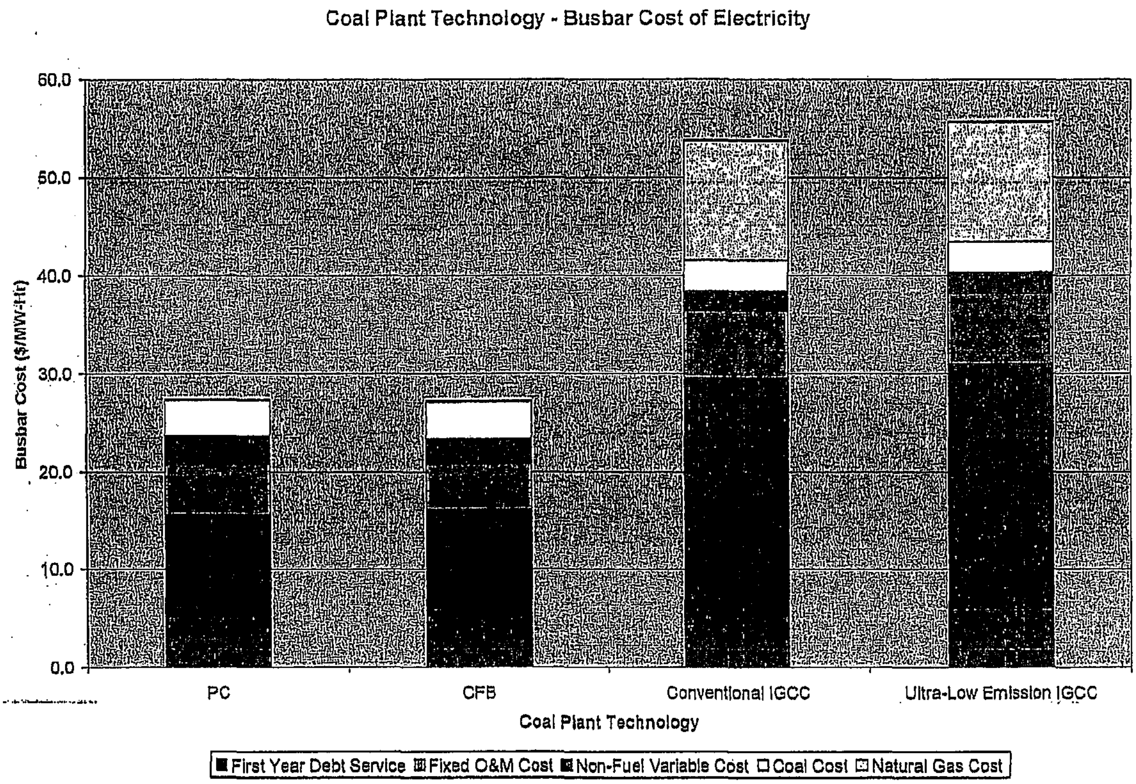
The NPV for the PC case is $961 Million versus $950 Million for the CFB case over the 42 year plant economic life. The NPV for the Conventional IGCC and Ultra-Low Emission IGCC cases is $1.98 Billion and $2.05 Billion, respectively.

The largest life cycle cost driver for all of the four cases is the debt service for the capital cost of the plant. The annual debt service cost was calculated based on financing 100 percent of the plant capital cost for 42 years at an annual interest rate of 6.0 percent for the PC and CFB cases and 8.0 percent for the IGCC cases. The interest rate for the IGCC cases is higher due to the greater project risk for an IGCC plant.

Besides capital cost and annual debt service, the other large cost differential between the PC/CFB cases and the two IGCC cases is the natural gas usage. Both PC and CFB are mature technologies that can meet the 85 percent annual capacity factor for the project. IGCC technology has not demonstrated over 70 percent annual capacity factor, and must use natural gas as a secondary fuel for the gas turbines to make up the 15 percent annual capacity factor difference (to meet the 85 percent annual capacity factor for the project).

A comparison of the first year busbar cost of electricity for the four technology cases is shown in Figure 8-1.

Figure 8-1



SECTION 9.0

# Equivalent BACT Analysis

Basin Electric does not consider the Best Available Control Technology (BACT) requirement as a process that should be used to define or re-define a proposed emission source. Rather, the BACT process should be used to identify the emission control technologies available to reduce emissions from the source as defined by the proponent. The BACT process, coupled with PSD increment and ambient air quality modeling, will ensure that emissions from the proposed facility will be minimized and the proposed facility will not cause or contribute to any violation of an ambient air quality standard.

Notwithstanding Basin's objection to using the BACT process to define the proposed emission source, an equivalent "Top-Down" BACT Analysis was performed based on the three competing electricity generating technologies. Basin Electric will follow, to the extent possible, the 5-step top-down BACT evaluation process described in the NSR manual to evaluate the environmental, energy and economic impacts associated with PC, CFB and IGCC generating technologies. The BACT analyses for sulfur dioxide ($SO_2$), nitrogen oxides ($NO_x$), particulate matter (PM), carbon monoxide (CO), and volatile organic compounds (VOC) air pollutants will be based on BACT air pollution control equipment utilized for each type of combustion technology.

## 9.1 Pollution Controls

The proposed new unit will be equipped with controls to limit the emissions of $SO_2$, $NO_x$, PM, CO, and VOC.

### 9.1.1 Sulfur Dioxide and Related Compounds

Emissions of sulfur dioxide and other sulfur compounds will be controlled on the new unit with the use of pulverized-coal (PC) boiler and a circulating dry scrubber (CDS) flue gas desulfurization (FGD) system. The FGD system will have a design $SO_2$ emission rate of 0.10 lb/MMBtu, which corresponds to an $SO_2$ removal efficiency of 91.3 percent at the design maximum coal sulfur content of 0.47 wt. percent.

In a CDS FGD system, water is injected into the flue gas prior to the inlet venturi of the absorber vessel to reduce the flue gas temperature to approximately 35°F above the adiabatic approach to the saturation point. Pebble sized lime (calcium oxide) reagent is hydrated with water to form hydrated lime (calcium hydroxide) powder. The hydrated lime is mixed with recycle solids captured in the downstream fabric filter and injected into the absorber vessel to remove SO2.

The solids are recycled between the CDS absorber and fabric filter to provide a long residence time for reagent particles to react with SO2 in the flue gas. The solids bleed stream consists of a dry calcium sulfite, calcium sulfate and fly ash byproduct. The collected dry solids will be conveyed pneumatically to a storage silo and trucked to a landfill disposal site or potentially reused.

### 9.1.2 Nitrogen Oxides

$NO_x$ is formed in the PC boiler in the combustion process, particularly when the peak combustion temperatures in the flame exceed 2,500° F. The emissions of $NO_x$ from the new unit will be limited through the use of Low $NO_x$ Burners (LNB) with Overfire Air (OFA) and Selective Catalytic Reduction (SCR). LNB with OFA control the formation of $NO_x$ by staging the combustion of the coal to keep the peak flame temperature below the threshold for $NO_x$ formation. The burner initially introduces the coal into the boiler with less air than is needed for complete combustion. The flame is then directed toward an area where additional combustion air is introduced from over-fire air ports allowing final combustion of the fuel.

A selective catalytic reduction unit will also be installed on The new unit to further reduce the $NO_x$ emissions. The proposed SCR is designed for high dust loading applications and will be located external from the boiler. The SCR system uses a catalyst and a reductant (ammonia gas, $NH_3$) to dissociate $NO_x$ into nitrogen gas and water vapor. The catalytic process reactions for this $NO_x$ removal are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O, \text{ and}$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O.$$

The optimum temperature window for this catalytic reaction is between approximately 575 and 750 °F. Therefore, the SCR reaction chamber will be located between the boiler economizer outlet and air heater flue-gas inlet. The system will be designed to use ammonia as the reducing agent. The anhydrous ammonia will be transported to and stored onsite. Gaseous ammonia will be released from the aqueous ammonia and injected into Unit 3 through injection pipes, nozzles, and a mixing grid that will be located upstream of the SCR reaction chamber. A diluted mixture of ammonia gas in air will be dispersed through injection nozzles into the flue-gas stream. The ammonia/flue-gas mixture then enters the reactor where the catalytic reaction occurs.

The SCR system will be designed to achieve a controlled $NO_x$ emission rate of 0.07 lb/MMBtu (30-day average).

### 9.1.3 Particulate Matter and $PM_{10}$

PM and $PM_{10}$ will be controlled at the new unit by a fabric filter. The fabric filters operates by passing the particle-laden flue gas through a series of fabric bags. The bags accumulate a filter cake that removes the particles from the flue gas, and the cleaned flue gas passes out of the fabric filter. The fabric filters will have a particulate removal efficiency of greater than 99 percent.

The fabric filter system will consist of a number of parallel banks of filter compartments located downstream of the air preheaters and the flue gas desulfurization system and upstream of the induced draft fans. Individual filter compartments consist of a bottom collection hopper, a collector housing, and an upper plenum. A group of cylindrical filter bags, each covering a cylindrical wire cage retainer, hang from a tubesheet, which separates the upper plenum from the collector housing.

Particle-laden flue gas from the boiler enters the collector housing, just above the bottom collection hopper. The flue gas stream travels up through the collector housing where particles collect on the outside of the cylindrical filter bags. The filtered flue gas then travels up through the inside of the cylindrical filter bags, through the tubesheet, and out through the upper plenum. Particulate matter captured on the filter bags will form a filter cake. The filter cake increases both the filtration efficiency of the cloth and its resistance to gas flow.

Fabric filtration is a constant-emission device. Pressure drop across the filters, inlet particulate loading, or changes in gas volumes may change the rate of filter cake buildup, but will not change the final emission rate. Actual performance of a fabric filter depends on specific items, such as air/cloth ratio, permeability of the filter cake, the loading and nature of the particulate (e.g., irregular-shaped or spherical), and particle size distribution.

The filter bags must be cleaned routinely to remove accumulated filter cake. The cleaning frequency of the individual compartments will depend, in part, on the inlet grain loading and the flow resistance of the filter cake formed. It is anticipated that the fabric filter system will be designed as a pulse jet-type system. In a pulse jet-type system, gas flow through an isolated compartment is stopped and pulses of compressed air are blown down into the inside of each bag causing the filter bag to puff and fracturing the filter cake. The filter cake falls into the collection hopper for transport to the flyash-handling system.

Fabric filter system design involves inlet loading rates, flyash characteristics, the selection of the cleaning mechanism, and selection of a suitable filter fabric and finish.

### 9.1.4 Carbon Monoxide and Volatile Organic Compounds

CO and non-methane VOCs are formed from the incomplete combustion of the coal in the boiler. The formation of CO and VOCs is limited by controlling the combustion of the fuel and providing adequate oxygen for complete combustion. Thus, good combustion control is the technique to be used to limit CO and VOC emissions.

## 9.2 Combustion Technologies

### 9.2.1 Pulverized Coal Technology

Pulverized coal (PC) plants represent the most mature of coal-based power generation technologies considered in this assessment. Modern PC plants generally range in size from 80 MW to 1,300 MW and can use coal from various sources. Units operate at close to atmospheric pressure, simplifying the passage of materials through the plant, reducing vessel construction cost, and allowing onsite fabrication of boilers.

The concept of burning coal that has been pulverized into a fine powder stems from the fact that if the coal is made fine enough, it will burn almost as easily and efficiently as a gas. Crushed coal from the silos is fed into the pulverizers along with air preheated to about 580°F. The hot air dries the fine coal powder and conveys it to the burners in the boiler. The burners mix the powdered coal in the air suspension with additional pre-heated combustion air and force it out of nozzles similar in action to fuel being atomized by fuel injectors.

Combustion takes place at temperatures from 2400-3100°F, depending largely on coal rank. Steam is generated, driving a steam turbine-generator. Particle residence time in the boiler is typically 2-5 seconds, and the particles must be small enough for complete burnout to have taken place during this time. Steam generated in the boiler is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity.

Most PC boilers operate with what is called a dry bottom. Combustion temperatures with subbituminous coal are held at 2400-2900°F. Most of the ash passes out with the flue gases as fine solid particles to be collected in a Fabric Filter (baghouse) before the stack.

The boiler produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash, $NO_x$, and $SO_2$. The pollution control equipment includes a fabric filter for particulate control (fly ash), LNB with OFA and SCR for removal of $NO_x$, and a circulating dry FGD system for removal of $SO_2$.

## 9.3 Circulating Fluidized Bed Technology

In a circulating fluidized bed (CFB) boiler, the coal is burned in a bed of hot combustible particles suspended by an upward flow of combustion air. The CFB fuel delivery system is similar to that of a PC unit, but somewhat simplified to produce a coarser material. The plant fuel handling system unloads the fuel, stacks out the fuel, crushes or otherwise prepares the fuel for combustion, and reclaims the fuel as required. The fuel is usually fed to the CFB by gravimetric feeders. The CFB units use a refractory-lined combustor bottom section with fluidized nozzles on the floor above the wind box, an upper combustor section, and a convective boiler section.

The bed material is composed of fuel, ash, sand, and the sulfur removal reagent (typically limestone), also referred to as sorbent. In the CFB the fuel is combusted to produce steam. Steam is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity.

CFB combustion temperatures of 1,500 to 1,600°F are significantly lower than a conventional PC boiler of up to 3,000°F which results in lower $NO_x$ emissions and reduction of slagging and fouling concerns characteristic of PC units. In contrast to a PC plant, sulfur dioxide can be partially removed during the combustion process by adding limestone to the fluidized bed.

CFBs are designed for the particular coal to be used. The method is principally of value for low grade, high ash coals which are difficult to pulverize, and which may have variable combustion characteristics. It is also suitable for co-firing coal with low grade fuels, including some waste materials. The advantage of fuel flexibility often mentioned in connection with CFB units can be misleading; the combustion portion of the process is inherently more flexible than PC, but material handling systems must be designed to handle larger quantities associated with lower quality fuels. Once the unit is built, it will operate most efficiently with whatever design fuel is specified.

The design must take into account ash quantities, and ash properties. While combustion temperatures are low enough to allow much of the mineral matter to retain its original properties, particle surface temperatures can be as much as 350°F above the nominal bed temperature. If any softening takes place on the surface of either the mineral matter or the sorbent, then there is a risk of agglomeration or of fouling.

The CFB produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash and sulfur dioxides. $NO_x$ emissions can be mitigated through use of selective non-catalytic reduction (SNCR) using ammonia injection, usually in the upper area of the combustor. The pollution control equipment external to the CFB includes a fabric filter (baghouse) for particulate control (fly ash). A polishing FGD system may be required for additional removal of sulfur dioxides to achieve similar emission levels to PC units with FGD systems. Limestone is required as sorbent for the fluidized bed. A limestone storage and handling system is a required design consideration for CFB units.

CFB units have been built and operated up to 300 MW in size. Therefore, the NE Wyoming project would require one new boiler larger than previously demonstrated CFB boilers, or two 50 percent size CFB boilers to achieve 350 MW net output.

## 9.4 Integrated Gasification Combined Cycle (IGCC) Technology

Integrated gasification combined cycle (IGCC) is a developing technology that has potential application for electric generation in the United States. When fully developed, it may allow electricity production from coal at greater efficiencies and lower environmental impacts than traditional coal-fired power plants, and with the potential to co-produce other products, such as hydrogen for fueling of vehicles, carbon dioxide for tertiary oil production or chemicals production, and sulfuric acid or elemental sulfur. Continued research of IGCC should be a top priority of the United States, with specific research areas including the reliability and availability of the integrated gasification/generation systems, improvements to emission controls including mercury removal, and efficiency improvements, such as hot gas cleaning techniques.

IGCC systems combine elements common to chemical plants and power plants. Because chemical process engineering training and experience are required to develop and operate an IGCC plant, it requires expertise typically not found in utility companies. Major components of a typical IGCC plant include coal handling and processing, cryogenic oxygen plant(s), pressurized gasification systems, "syngas" quench and cooling systems, syngas scrubbers with carbonyl sulfide hydrolysis systems and equipment to flash or otherwise separate $H_2S$ off the scrubbing liquid, either a sulfuric acid plant or a Claus sulfur plant, combustion turbines, heat recovery steam generators (HRSG), and steam turbine(s).

At least five types of gasification technologies currently exist.[2] These include dry-ash moving bed, slagging moving bed, dry ash fluidized bed, agglomerating fluidized bed, and slagging entrained-flow gasifiers. Oxygen for the partial oxidation of the coal can be supplied through either oxygen from an air separation unit (cryogenic oxygen plant) or through compressed air. The compressed air for either the oxygen plant or for direct feed to the gasifiers can be supplied either through dedicated air compressors or by bleeding a portion of the air from the compression section of the gas turbine. Many choices of gas cleanup systems are available. Fuel utilization efficiency improvements can be achieved by feeding steam produced by cooling the raw syngas into the HRSG or steam turbine, although this complicates the startup, shutdown, and operation of the facility and creates major challenges

2 "Major Environmental Aspects of Gasification-Based Power Generation Technologies - Final Report", Unites States Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, December 2002.

in the ability of the facility to adjust total electrical output to follow demand load. There are no clear "best" choices among these many technology selections.

At this time, IGCC technology is not fully developed, and it is not technically feasible in the context of a BACT analysis. According to George Rudins, United States Department of Energy (DOE) deputy assistant secretary for coal, "Right now, there is not a single company producing a turnkey IGCC power plant, so you have components sold by different companies, and that increases the challenge."[3] Therefore, at this time, the burden is on the owner and engineer of the facility to integrate the gasification, oxygen, gas cleaning, and gas combustion systems, which substantially increases the complexity and risk of IGCC plant development. Representatives of DOE, the utility industry, and environmental groups generally agree that tax credits or other economic incentives will be required to offset the technological and financial risks associated with development of commercial IGCC plants.

Because the burden for technological development rests on the project developer, the technology cannot truly be considered commercially available. The EPA states that, "A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales state of development. "[4] While various types of gasifiers, gas cleaning unit processes, and combustion turbines are commercially available, there are no vendors offering commercial sales of complete IGCC package systems. Furthermore, EPA states that, "Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility."[5] Basin Electric is not aware of any vendors offering guarantees on the air emissions from either the combustion turbine or tail gas incinerator components of an IGCC system consuming sub-bituminous coal; this problem is a function of the fact that developers must integrate systems offered by different vendors.

Basin Electric is aware that General Electric (GE) has recently purchased Chevron/Texaco's IGCC technology, and is in the process of developing a standard plant design for an IGCC system with Bechtel. This has not yet been accomplished, and the level of uncertainty regarding specifics of the plant design remains high. Firm pricing for such a system is not yet available.

A case in point regarding the technological and commercial terms challenges is the recent Pinon Pine project in Storey County, Nevada. Innovative concepts incorporated in the design of this plant included use of Kellogg KRW air-blown gasifiers as an alternative to oxygen-blown gasifiers, and use of hot gas cleanup technology. The project was funded 50 percent by the DOE, and benefited from the technological expertise of the DOE. Despite the expertise available to the project, the plant never achieved steady state operation, and as such, environmental and economic performance of the project could not be evaluated. Eighteen unsuccessful attempts were made to start up the gasification system; each subsequent startup attempt was not begun until the cause of the previous malfunction was

3 "Coal - Can it ever be clean", *Chemical & Engineering News*, February 23, 2004.

4 EPA, *New Source Review Workshop Manual*, October 1990, Page B.18.

5 *New Source Review Workshop Manual*, Page B.20.

resolved.[6] Technical problems with the system included failure of HRSG components, unacceptable temperature ramps in the gasifiers, which caused failures in gasifier refractory, a fire in the particulate removal system, and multiple other problems with the particulate removal system. While many lessons were learned from development of the plant, and these lessons may lead to improved plant design in the future, the plant certainly could not be considered a technological success.

Only two commercial IGCC plants are currently in operation in the United States. These are the Wabash River project in central Indiana and Tampa Electric Company's Polk Power Project in Florida. Both projects were co-funded by the DOE as demonstration projects. As these projects involved development of technology, substantial modifications were made to both projects after initial construction. There has never been a commercial IGCC plant in the United States that was not either co-funded by DOE or otherwise provided financial incentives for the purpose of technology demonstration.

Furthermore, little operating experience exists regarding IGCC plants consuming sub-bituminous coal. None of the four commercial-scale IGCC plants currently operating in the world consume sub-bituminous coal; all four consume either bituminous coal or petroleum coke.[7] One commercial-scale IGCC plant, the Dow Chemical/Destec LGTI project, was previously operated on sub-bituminous coal; however this project was supported with guaranteed product price support offered by Dow Chemical and the U.S. Synthetic Fuels Corporation, and was promptly shut down when the price support expired.[8] National Energy Technology Laboratory (NETL) also notes that, "The following developments will be key to the long term commercialization of gasification technologies and integration of this environmentally superior solid fuels technology into the existing mix of power plants...[fifth of eight bullets] Additional optimization work for the lower rank, sub-bituminous and lignite coals."[9] It is clear that the majority of operating experience for coal-based IGCC plants is with bituminous coals and that further study is required to prove the technical and economic feasibility of IGCC operation with sub-bituminous coals, and in the context of published cost data, it would be irresponsible to assume that an IGCC plant consuming sub-bituminous coal could match the performance of an IGCC plant consuming bituminous coal.

A February 2004 paper by members of the John F. Kennedy School of Government at Harvard University proposes innovative financing mechanisms for IGCC projects. This proposal is driven in part by the fact that, due to the increased risks presented by IGCC projects, the cost of capital hinders IGCC plant development. The study notes that, "The overnight capital cost of IGCC is currently 20 to 25 percent higher than [pulverized coal] systems and commercial reliability has not been proven." [10] The paper further acknowledges that due to risk, private investors are unlikely to develop IGCC projects and state public utility commissions (PUCs) are unlikely or unable to shift the burden for these costs to the

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[6] Project Fact Sheet - Pinon Pine IGCC Power Project, United States Department of Energy - Office of Fossil Energy, http://www.netl.doe.gov/cctc/factsheets/pinon/pinondemo.html, July 2004.

[7] "Major Environmental Aspects...", Page 1-25.

[8] "Major Environmental Aspects...", Page 1-19.

[9] "Gasification Plant Cost and Performance Optimization", U.S. Department of Energy National Energy Technology Laboratory, Revised August 2003, Page ES-3.

[10] Rosenberg, William G., Dwight C. Alpern, and Michael R. Walker, "Financing IGCC – 3Party Covenant," BSCIA Working Paper 2004-01, Energy Technology Innovation Project, Belfer Center for Science and International Affairs, Page 1.

ratepayer. Therefore, a "3 Party Covenant" between the federal government, state PUCs, and equity investors is proposed to ensure a revenue stream for an IGCC project (i.e., to ensure that facility offtake can be sold even if it is not the lowest cost generation resource) and to develop financing at lower interest costs than for typical generation projects, thus mitigating business risk and higher cost of capital. If such innovative measures are required to spur successful development of IGCC projects, for a utility that is required by law to develop new projects to meet customer demand yet satisfy PUC requirements for financial responsibility, it seems imprudent to consider "forcing" the utility to select IGCC via the BACT process.

In fact, the Public Service Commission of Wisconsin (PSCW) recently came to a very similar conclusion. Wisconsin Energy Corporation (WE Energy) proposed construction of two new PC generating units and one IGCC unit at its Elm Road project south of Milwaukee. PSCW reviewed the project within the context of its statutory mandate to consider concerns regarding engineering, economics, safety, reliability, environmental impacts, interference with local land use plans, and impact on wholesale competition. PSCW concluded that the IGCC project was not an acceptable risk or financial burden for its ratepayers and denied WE Energy's request to develop it.

In its November 10, 2003, decision, the PSCW made the following finding:

> "5. The two SCPC [supercritical pulverized coal] units are reasonable and in the public interest after considering alternative sources of supply, individual hardships, engineering, economic, safety, reliability, and environmental factors. The IGCC unit does not meet this standard."

The proposed new unit is a PC unit similar to those approved by the PSCW.

None of the commercial systems constructed to date have operated at the almost 5,000-foot altitude of the proposed new unit. This altitude will result in de-rating of the combustion turbines, and would thus require a larger combined cycle component of the IGCC system to produce the same output as a system constructed at lower elevation. This would further degrade IGCC economics at the NE Wyoming Project.

The longer time required for startup/shutdown, and inflexibility of system output for load-following, of an IGCC system versus a PC system creates additional challenges for utilities. Startups have reportedly required up to 70 hours, and flaring of treated and untreated syngas during these startups can create substantial additional air emissions, which are not typically included in IGCC emission estimates.

IGCC systems also have relatively low availability, due in large part to frequent maintenance required for gasifier refractory repair. This creates the need for redundant gasifier systems, or burning pipeline natural gas as a backup fuel which further increases the system capital and operating costs and operating complexity.

IGCC is thus a generation method, which is fundamentally different from that of the proposed project in terms of technology, costs, and business risk. BACT has not historically been used as a means of redefining the emission source. EPA regulations and policy guidance make it clear that BACT determinations are intended to consider alternative emission control technologies, not to redefine the entire source.

## 9.5 BACT Determination

This section presents the BACT analysis.

### 9.5.1 Applicability

The requirement to conduct a BACT analysis and determination is set forth in section 164(a)(4) of the Clean Air Act and in federal regulations 40 CFR 52.21(j).

### 9.5.2 Top-Down BACT Process

EPA has developed a process for conducting 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

Each of these steps has been conducted for the $SO_2$, $NO_x$, PM, CO and VOC pollutants and is described below.

### 9.5.3 $SO_2$, $NO_x$, $PM_{10}$, CO and VOC Analysis

The BACT analysis for Sulfur Dioxide, Nitrogen Oxides, Particulate Matter, Carbon Monoxide and Volatile Organic Compounds is presented below.

#### 9.5.3.1 Step 1 – Identify All Control (Combustion) Technologies

The first step is to identify all available combustion technologies. Most recent PSD permit applications submitted to the applicable permitting agencies proposing to construct a coal combustion steam electric generating unit have defined the source as a pulverized coal-fired (PC) unit. In a majority of the PSD permit reviews, the permitting agency applied the top-down BACT for emission controls based on the source as defined by the applicant (i.e. PC unit). State permitting agencies in Wisconsin, West Virginia and Wyoming have not required CFB and/or IGCC technologies to be considered in recent BACT determinations.

Combustion technology information related to this type of BACT Analysis is not available from the EPA RACT/BACT/LAER Clearinghouse (RBLC) database accessible on the Internet. However, recent similar BACT determinations have evaluated the following potential combustion technology emission reduction options:

- Pulverized Coal (PC);
- Circulating Fluidized Bed (CFB);
- Integrated Gasification Combined Cycle (IGCC).

### 9.5.3.2 Step 2 – Eliminate Technically Infeasible Options

#### 9.5.3.2.1 PC Option

The PC with FGD option is technically feasible for use in reducing emissions from The new unit. Most of the PRB coal used for electricity generation is burned in PC plants. PC units experienced many problems during the initial use of PRB coals, but experience has resulted in development of PC boiler designs to successfully burn PRB coals. PC designs for PRB coal are based on the specific characteristics of the fuel such as moisture content, ash composition and softening temperature, and sulfur content.

#### 9.5.3.2.2 CFB Option

The majority of existing utility CFB units burn bituminous coal, anthracite coal waste or lignite coal. The operating history of utility CFB boilers burning PRB or other types of subbituminous coal is limited. CFB technology typically has an economic advantage only when used with high ash and/or high sulfur fuels. Therefore, high sulfur bituminous, high sulfur petroleum coke, high ash coal waste, high ash lignite and other high ash biomass fuels are the typical applications for CFB technology.

PRB coals may have a tendency to produce small particle size (fine) fly ash that makes it more difficult to maintain the required bed volume in a CFB unit. Therefore, additional quantities of inerts such as sand and limestone may be required for a CFB unit burning low sulfur/low ash PRB coals.

A joint Colorado Springs Utilities / Foster Wheeler 150 MW Advanced CFB demonstration project at the Ray D. Nixon Power Plant south of Colorado Springs was proposed and accepted by DOE NETL in 2002 as part of the federal Clean Coal Power Initiative (CCPI). DOE agreed to a $30 million cost share of the $301.5 million project. The next generation CFB unit would be designed to burn PRB coal and PRB blended with coal waste, biomass and petroleum coke. However, Colorado Springs Utilities and Foster Wheeler cancelled and withdrew from the CCPI project in 2003.

The CFB option is probably technically feasible for use in reducing $SO_2$ emissions from the new unit, but it is not considered the best application for PRB coal.

#### 9.5.3.2.3 IGCC Option

The only commercial size IGCC demonstration plant that has operated with PRB coal fuel was the Dow Chemical Louisiana Gasification Technology, Inc. (LGTI) plant in Plaquemine, LA. This plant used an oxygen blown E-Gas entrained flow gasifier and is reported to have operated successfully from 1987 to 1995. The plant is now shutdown.

The Power Systems Development Facility (PSDF), located near Wilsonville, Alabama, is a large advanced coal-fired power system pilot plant[11]. It is a joint project of DOE NETL, Southern Company and other industrial participants. The Haliburton KBR Transport Reactor was modified from a combuster to coal gasifier operation in 1999. The initial gasification tests have concentrated on PRB coals because their high reactivity and volatiles were found to enhance gasification. The highest syngas heating values were achieved with PRB coal, since PRB coal is more reactive than bituminous coals.

[11] Ref. 10.

Southern Company, Orlando Utilities Commission, and Kellogg Brown and Root, recently submitted a proposal to DOE NETL for the Round 2 Clean Coal Power Initiative (CCPI) solicitation[12]. They propose to construct and demonstrate operation of a 285 MW coal-based transport gasifier plant in Orange County, Florida. The proposed facility would gasify sub-bituminous coal in an air-blown integrated gasification combined cycle power plant based on the KBR Transport Gasifier. Southern Company estimated the total cost for the project at $557 million ($1954/MW) and has requested $235 million of DOE funds to support the project.

The IGCC option is probably technically feasible for use in reducing $SO_2$, $NO_x$, PM, CO and VOC emissions from the new unit, but it is not considered the best application for PRB coal.

#### 9.5.3.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Emission rates for each of the combustion technologies are provided in Table 9-1.

**TABLE 9-1**
Comparison of Coal Combustion Technology Potential BACT Emission Rates
*Basin Electric Dry Fork Station Technology Evaluation*

| | Emission Rates for Coal Combustion Technologies (Lb/MMBtu) | | |
|---|---|---|---|
| Pollutant | PC (Potential BACT) | CFB (Potential BACT) | IGCC (Potential BACT) |
| $SO_2$ | 0.10 | 0.10 | 0.03 |
| $NO_x$ | 0.07 | 0.09 | 0.07 |
| $PM_{10}$ | 0.019 | 0.019 | 0.011 |
| CO | 0.15 | 0.15 | 0.03 |
| VOC | 0.0037 | 0.0037 | 0.004 |

#### 9.5.3.4 Step 4 – Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology.

Most of the PRB coal used for electricity generation is burned in pulverized coal (PC) plants. PC units experienced many problems during the initial use of PRB coals, but experience has resulted in development of PC boiler designs to successfully burn PRB coals. PC designs for PRB coal are based on the specific characteristics of the fuel such as moisture content, ash composition and softening temperature, and sulfur content.

CFB technology is an alternative combustion technique that could be considered for this power plant application. However, the proposed new unit emission rates are consistent with emission rates achievable with CFB boilers.

[12] Ref. 11.

IGCC is a promising technology, which presents the opportunity for electric generation at lower emissions of criteria air pollutants than conventional coal technology. However, at this time, significant technical uncertainty exists; at least one recent project ended in failure. No vendors offer complete IGCC packages, and as a result project owners must integrate the many components of the IGCC system and must develop projects with no emission guarantees from vendors. At the current time, in order for IGCC projects to satisfy the financial and risk criteria required to obtain PUC approval to pass projects costs onto ratepayers, tax credits, innovative financing, or other financial incentives are required.

An incremental cost analysis has been prepared for PC versus CFB technology and PC versus IGCC technology. A summary of the results is shown in Table 9-2. The detailed cost analysis is provided in Appendix E. The incremental cost difference between PC and CFB is $987 per additional ton of pollutant removed. CFB technology removes less overall tons of pollutants while having a slightly lower total annualized cost. The incremental cost difference between PC and IGCC is $24,767 per additional ton of pollutant removed. Basin Electric believes that the high additional cost of IGCC combustion technology is not warranted for this project based on the use of low sulfur coal and the limited additional tons of pollutants removed.

TABLE 9-2
Comparison of Coal Combustion Technology Economics
*Basin Electric Dry Fork Station Technology Evaluation*

| Factor | Costs ($) | | |
|---|---|---|---|
| | **PC** | **CFB** | **IGCC** |
| Total Installed Capital Costs | $ 482,000,000 | $ 497,000,000 | $ 720,000,000 |
| Total Fixed & Variable O&M Costs | $ 23,900,000 | $ 22,600,000 | $ 49,300,000 |
| Total Annualized Cost | $ 55,600,000 | $ 55,300,000 | $ 109,200,000 |
| Incremental Annualized Cost Difference: PC versus CFB, and PC versus IGCC | - | $ (300,000) | $ 53,700,000 |
| Incremental Tons Pollutants Removed: PC versus CFB, and PC versus IGCC | - | (324) | 2,166 |
| Incremental Cost Effectiveness per Ton of Additional Pollutant Removed: PC versus CFB, and PC versus IGCC | - | 987 | 24,767 |

### 9.5.3.5 Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. Based on a review of the technical feasibility, potential controlled emission rates and economic impacts of PC, CFB and IGCC combustion technologies, the PC-based plant design represents BACT for the proposed new unit.

SECTION 10.0

# Impact of Plant Size Increase

In December 2004, Basin Electric Power Cooperative (BEPC) announced plans to build a 250 MW (net) coal-based generation resource in Northeast Wyoming. In May 2005, based on a revised load forecast for Basin Electric's member cooperatives, the net plant output for the new coal unit was increased to 350 MW net. The technology comparison at this rating is virtually identical to the 250 MW design case.

## Impact on Plant Design and Heat Rate

A 250 MW net IGCC plant would most likely use two 7EA gas turbines and a small amount of duct firing of syngas in the HRSGs to generate the required export power to the grid based on the PRB coal fuel and the plant elevation of 4,250 feet. The gasifier would be sized to supply syngas to the Auxiliary Boiler for drying the high moisture PRB coal, syngas to the gas turbines, and syngas for duct-firing in the HRSGs.

A 350 MW net IGCC plant would most likely use two 7FA gas turbines and a larger amount of duct firing of syngas in the HRSGs to generate the required export power to the grid. The larger 7FA gas turbines used in the 350 MW plant are higher efficiency compared to the smaller 7EA gas turbines, however, this will probably be offset by the larger amount of syngas used for duct-firing in the larger power plant. Duct-firing lowers the overall plant efficiency of a gas turbine combined cycle power plant. Therefore, it is expected that the net plant heat rate will be comparable for the 250 MW and 350 MW plant sizes.

## Impact on Cost

The larger 350 MW IGCC plant is expected to have some cost savings on a $/kW installed capital cost basis due to economy of scale. However, this economy of scale cost savings will be matched by the similar economy of scale cost savings achieved by a PC or CFB unit when going from a 250 to 350 MW plant size.

SECTION 11.0

# Conclusions and Recommendations

## 11.1 Baseload Capacity

PC and CFB technologies are capable of achieving an 85 percent annual capacity factor, and are suitable for baseload capacity. The IGCC technology is only capable of achieving an 85 percent annual capacity factor for a baseload unit by adding redundant back-up systems or using natural gas as a backup fuel for the combustion turbine combined cycle part of the plant.

## 11.2 Commercially Available and Proven Technology

PC and APC technology is commercially available and proven for PRB coal. The CFB technology has been commercially demonstrated for bituminous, low sodium lignite and anthracite waste coals, however, long term commercial operation with PRB coal has not been demonstrated.

IGCC technology is still under development. All four commercial demonstration units that are operating in the U.S. and Europe were subsidized with government funding. Six of the thirteen second round Clean Coal Power Initiative (CCPI) proposals that were received and announced by DOE NETL in July 2004, were for demonstration IGCC plants to receive government cost sharing[13]. The goal of the DOE CCPI program is to assist industry with development of new clean coal power technologies. It is anticipated that IGCC will not be developed for full commercial use before the 2015 time period.

## 11.3 High Reliability

Both PC and CFB technologies have demonstrated high reliability. IGCC technology has demonstrated very low reliability in the early years of plant operation. Improved reliability has been recently demonstrated after design and operation changes were made to the facilities, however, the availability of IGCC units is still much lower than PC and CFB units.

## 11.4 Cost Effective

PC technology is the most cost effective for a new 250 MW PRB coal power plant in Northeast Wyoming. A PC unit will have the lowest capital and operating & maintenance cost of all three technologies evaluated. The CFB technology would have a slightly higher capital cost, but lower operating and maintenance cost compared to a PC unit. The IGCC technology would have a much higher capital, operating and maintenance cost compared to both the PC and CFB technologies.

[13] Ref. 11.

## 11.5 Summary

PC technology is capable of fulfilling Basin Electric's need for new generation, and is recommended for the Basin Electric Dry Fork Station Project. CFB technology meets Basin Electric's need, however, it lacks demonstrated long-term operating experience on PRB coal and in the final analysis would be more costly.

IGCC technology is also judged not capable of fulfilling the need for new generation. IGCC does not meet the requirement for a high level of reliability and long-term, cost-effective, and competitive generation of power. In addition to higher capital costs, there are problem areas, discussed previously, that have not demonstrated acceptable availability and reliability. The current approaches to improving reliability in these areas result in less efficient facilities, negatively impacting the cost-effectiveness. DOE has a Clean Coal Technology program with the goal of providing clean coal power-generation alternatives which includes improving the cost-competitiveness of IGCC. However, the current DOE time frame (by 2015) does not support Basin Electric's 2011 needs.

GCC offers the potential for a more cost effective means of $CO_2$ removal as compared to PC and CFB technologies should such removal become a requirement in the future. However, at this time, it is only speculative as to if such requirements will be enacted, when they will be enacted, and what they will consist of and apply to if enacted. The risk of installing a more costly technology, that has not been proven to be reliable and for which strong commercial performance guarantees are not available, is far too great for Basin Electric to take on for such speculative purposes.

## 11.6 Continuing Activities

### Planned conference attendance

Basin Electric plans to attend the 2005 Gasification Technologies Council annual conference in October, 2005, in San Francisco, CA.

### Canadian Clean Power Coalition

Basin Electric has been working closely with other lignite and sub-bituminous users in the Canadian Clean Power Coalition (CCPC) on IGCC technology and advanced "conventional" technologies such as oxy fuel firing and advanced amine scrubbing systems for low rank coals. The CCPC has funded feasibility studies from ConocoPhillips/Fluor, Shell and Future Energy. Basin Electric will monitor and review the results of these studies.

### Wilsonville PDSF

Basin Electric has been supporting the EPRI / Southern Company PDSF testing in Wilsonville, Alabama. Basin Electric will monitor and review the results of this testing.

### Future investigations

Basin Electric and their engineering consultants continue to review the ongoing performance of the four IGCC demonstration plants and monitor the status of commercial IGCC offerings.

SECTION 12.0

# References


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# Attachment C - "Dry Fork Station Air Quality Impacts to Soils and Vegetation," June 20, 2007

# Dry Fork Station Air Quality Impacts to Soils and Vegetation

PREPARED FOR: Basin Electric Power Cooperative

PREPARED BY: CH2M HILL

DATE: June 20, 2007

## Introduction

The following review of analyses of air quality impacts on soils and vegetation from the Dry Fork Station was prepared for Basin Electric Power Cooperative in light of comments on that topic filed with the Wyoming Department of Environmental Quality, Air Quality Division, by the Powder River Basin Resource Council and other environmental organizations (Environmental Coalition).

Impacts to soils and vegetation were evaluated in section 7.8.2 of the Basin Electric Dry Fork Station Air Construction Permit Application, November 2005 (Permit Application). This analysis is included under the "Additional Analyses" required under PSD rules (40 CFR 51.166(o)):

*The owner or operator shall provide an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial, and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value. Wyoming Air Quality Standards and Regulations, Chap. 6, §4 (b)(i)(B)(I).*

The Dry Fork Station analysis considered soils as well as native and commercial vegetation within the project area. No sensitive soils or native vegetation were identified, and oats and barley were the only crop species identified as sensitive. An evaluation of impacts on the sensitive crop species showed that potential concentrations of NOx were well below the injury thresholds determined by EPA criteria documentation (USEPA 1993).

Comments filed by the Environmental Coalition allege the permit application failed to include a site-specific inventory of soils and vegetation (including threatened or endangered species), that reliance on the EPA's 1980 Screening Levels is inadequate, and that there was a failure to analyze the impact of all pollutants. The comments rely heavily on the EPA Environmental Appeals Board's decision in the *Indeck Elwood* case in Illinois.

This memorandum summarizes the soils and vegetation analysis performed for the PSD application, including dispersion modeling results and specific inventories, and also discusses additional information regarding air quality impacts on soils and vegetation.

## Dry Fork Station Air Pollutant Impact Analysis

General dispersion modeling results are presented in sections 7.7.2 through 7.7.6 of the PSD application.

Conservative preliminary air pollutant dispersion modeling showed that Class II impacts for the following pollutants were below federal significance levels:

- CO
- $NO_2$
- $PM_{10}$

This same modeling estimated that concentrations of the following pollutants would be far below the federal monitoring de minimis levels:

- Lead
- Mercury
- Beryllium
- Fluorides

In addition, this modeling determined that ambient concentrations of the following pollutants would be well below the Wyoming Ambient Air Quality Standards (WAAQS):

- Fluorides

Because the preliminary impact analysis determined that 24-hour $SO_2$ impacts may be above the federal significance levels, a full-impact analysis was conducted for this pollutant that included other $SO_2$ sources within a 50 km radius of the proposed Dry Fork Station location. This full-impact analysis determined that the impacts would be well below the Class II PSD increment and the WAAQS. Dry Fork Permit Application at 7.7.6

Regarding ozone impacts, as discussed in section 7.8.4 of the Dry Fork PSD application, there are currently no approved regulatory modeling methods for determining ozone impacts for PSD sources.

The PSD application (section 7.9) also included a Tier I human risk evaluation that was performed for 67 hazardous air pollutants (HAPs). This evaluation included cancer, chronic, and acute risks. Although the dispersion modeling, exposure, and risk assumptions in a Tier I evaluation are quite conservative, no risks were identified.

**Analysis of Vegetation Impacts**

The Environmental Coalition contends that "there was no site specific inventory of soils or vegetation performed as part of the permit application," and infers that the Basin Electric relied blindly on the EPA's 1980 Screening Procedure. These allegations are false, and mischaracterize the analysis that was done. EPA's 1980 Screening Procedure was not utilized at all. As stated in the Dry Fork Permit Application at §7.8.2, a specific search was done for information regarding vegetation in the vicinity of the Dry Fork Station, relying both on the latest U.S. Department of Agriculture census and on the Wyoming GAP Analysis of land cover for Campbell County, Wyoming. USDA, 1979; Wyoming GAP, 2005. Based on these data, it was determined that of the species identified, only oats and barley have been identified as sensitive species that occur in this area. Because photosynthesis is inhibited in alfalfa and foliar injury to oats occurs at exposures to NOx and/or SOx above certain levels, levels where possible damage occurs was compared with modeled concentrations and the modeled concentrations were far below levels that might adversely affect these species.

This analysis is fully consistent with the EPA's Draft New Source Review Manual, October 1990 (NSR Manual), which states that an inventory should be done for all vegetation with commercial or recreational value, and that such information may be available from conservation groups, government agencies and universities. "For most types of soils and vegetation, ambient concentrations of criteria pollutants below the secondary national ambient air quality standards (NAAQS) will not result in harmful effects. However, there are sensitive species (e.g., soybeans and alfalfa) which may be harmed by long-term exposure to low ambient air concentrations of regulated pollutants for which there are no NAAQS." NSR Manual at D.5.

The NSR Manual approach was followed for the Dry Fork analysis. Ambient pollutant concentrations were modeled to be far below the levels of secondary NAAQS, indicating most species will be protected, and for sensitive species additional analysis was done to compare potentially harmful pollutant levels to modeled concentrations.

The Environmental Coalition appears to argue that impacts of a long list of pollutants on each and every species must be evaluated. The NSR Manual, however, notes that modeling compliance with secondary ambient standards is adequate for most species. As to sensitive species, further analysis was done for pollutants that are known to have potential adverse effects. The Environmental Coalition has identified no instance in which the Dry Fork analysis failed to analyze the impacts on a sensitive plant species of a pollutant known or suspected to have possibly harmful effects. And modeling predicted that concentrations of almost all pollutants will be below *de minimis* modeling or monitoring levels.

The Environmental Coalition also contends that, because no site-specific inventory of vegetation was performed, "it is impossible to know whether any endangered, threatened, or sensitive species are located in or around the plant site." In fact, we do know whether endangered, threatened or sensitive species are present. In addition to the analysis reported in the Dry Fork Permit Application, further inventories of the plant communities of the proposed power plant sites and the two transmission line route alternatives were conducted by EDAW in 2005 and 2006, the results of which are summarized in the Dry Fork Station Project Overview and Environmental Evaluation (EDAW, 2006) These inventories included federally listed endangered and threatened species and BLM sensitive species for Campbell and Sheridan Counties, obtained from the U.S. Fish and Wildlife Service.

In the USFWS letter, the Ute ladies'-tresses orchid (*Spiranthes diluvialis*) was named as the only listed or BLM sensitive plant species that potentially could occur within the proposed and alternative power plant and transmission line project areas. The following discussion summarizes the results of studies regarding Ute ladies'-tresses, including the occurrence of this species in Campbell or Sheridan Counties.

Ute ladies'-tresses populations are found on seasonally inundated river floodplains typically occurring on clayey-sand beds, sandy point bars, or thin alluvium over large cobbles, and soils had to be sufficiently stable and moist in the summer flowering season to support Ute ladies'-tresses orchid occurrences (Fertig et al. 2005). Based on the lack of suitable habitat, Ute ladies'-tresses orchid would not occur on the proposed or alternative power plant sites.

The Ute ladies'-tresses orchid was not observed during field surveys of the proposed or alterative transmission line corridors conducted in June 2006. Potential habitat for the orchid

DEQ/AQD 004244

is limited within the transmission line corridors. Most of the creeks are ephemeral, and this orchid is found primarily along perennial waterways within floodplains. Of the transmission line corridors that were evaluated, potential Ute ladies'-tresses orchid habitat was identified along segments X and W (Little Badger Creek) and segment F (Rawhide Creek).

Known populations of Ute ladies'-tresses in Wyoming have been found in Goshen County in the Horse watershed, and in Converse, Laramie, and Niobrara Counties in the Antelope and Niobrara headwaters watersheds. Note that these watersheds are all tributary to the North Platte River or the Cheyenne River, both of which flow east out of Wyoming. The Dry Creek Station is located in the Powder River Basin, which is tributary to the Yellowstone River to the north, and no Ute ladies'-tresses populations are known from anywhere in this major drainage basin. All Ute ladies'-tresses populations in Montana occur far to the west along tributaries to the Missouri River in the southwestern part of the state (Fertig 2000).

Multiple existing and potential threats to Ute ladies'-tresses have been identified (Fertig et al. 2005), but none of these is related to air quality.

Surveys conducted at the nearby Thunder Basin National Grassland (TBNG) and the Medicine Bow National Forest (MBNF) during 1998 also found no Ute ladies'-tresses. The Final Environmental Impact Statement (EIS) for the Revised Land and Resource Management Plan for the MBNF (USFS 2003) lists Ute ladies'-tresses as "extremely rare or not present." There are currently no known populations of any USFWS-designated threatened or endangered plant species on the TBNG or the MBNF, although a single candidate plant species (slender moonwort, *Botrychium lineare*) is known from the MBNF. Air quality is not cited as a potential threat to the slender moonwort. The EIS cites "nutrient enrichment" as a potential threat to one wetland plant species (lesser bladderwort, *Utricularia minor*) designated as a "Regional Forester's Sensitive Species." Although some nutrient enrichment of wetlands could result from air pollution, this impact is more predominantly attributed to runoff from fertilized agricultural lands into surface waters.

### Analysis of Soils Impacts

The Environmental Coalition also asserts there was no site-specific soils inventory. In fact, as discussed in the Permit Application, the Soil Survey for Campbell County, Wyoming, performed by the Soil Conservation Service of the U.S. Department of Agriculture, was consulted to determine soil types present in the area, and whether such soils are sensitive. Additional soils data are reported in the Dry Fork environmental evaluation by EDAW (2006). Other sources were consulted which observe that soils in the non-mountainous regions of Wyoming are typically alkaline and would not be sensitive to acidic deposition or impacts from the Dry Fork project. Consistent with the NSR Manual, this soils inventory fulfills the regulatory requirement. No sensitive soils having been identified, no further modeling or evaluation was needed.

Indeck-Elwood Power Plant

The Environmental Coalition quotes at length from the decision of the EPA Environmental Appeals Board (EAB) in *Indeck-Elwood* to argue that the EPA's 1980 Screening Procedure is inadequate. However, the soils and vegetation evaluation for the Dry Fork Station did not rely on the 1980 Screening Procedure, but rather on the process called for in the NSR Manual, which was cited with approval in *Indeck-Elwood*. PSD Appeal No. 03-04 at 45-46. Also, the Indeck-Elwood facility was to be developed in an industrial park that is immediately adjacent to the Midewin National Tallgrass Prairie (MNTP) in Illinois, in which listed and sensitive plant species were located, and, unlike the case at Dry Fork, both federal and state agencies had commented that air emissions from the Indeck Elwood facility would adversely impact or jeopardize listed or sensitive species

Summary

Contrary to the assertion of the Environmental Coalition, site-specific inventories of soils and vegetation were conducted, and impacts on sensitive species were evaluated. The evaluation was not done in accordance with the EPA's 1980 Screening Procedure criticized by the Environmental Coalition, but rather in accordance with the NSR Manual. The analysis described in the Permit Application was supplemented by additional soils and vegetation analyses which are reported in the environmental evaluation and briefly summarized herein. Modeled levels of all pollutants are below secondary ambient air quality standards, and almost all modeled levels are below *de minimis* modeling or monitoring levels. No sensitive soils or threatened, or endangered or sensitive vegetation have been identified that would experience adverse impacts from the Dry Fork Station air pollutant emissions

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