BEFORE THE ENVIRONMENTAL QUALITY COUNCIL
STATE OF WYOMING

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

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

Schlichtemeir Affidavit

EXHIBIT N

DEPARTMENT OF ENVIRONMENTAL QUALITY
DIVISION OF AIR QUALITY

Permit Application Analysis, NSR-AP-3546

February 5, 2007

COMPANY:	Basin Electric Power Cooperative
MAILING ADDRESS:	1717 East Interstate Avenue Bismarck, ND 58503
RESPONSIBLE OFFICIAL:	Jerry Menge Air Quality Program Coordinator (701) 355-5655
FACILITY NAME:	Dry Fork Station
FACILITY LOCATION:	Highway 59, Approximately 7 Miles North Northeast of Gillette, Campbell County, WY
TYPE OF FACILITY:	Coal Fired Electric Power Generating Station
REVIEWED BY:	Stewart Griner – Air Quality Engineer Cole Anderson – Air Quality Engineer Don Watzel – Air Quality Specialist

PURPOSE OF APPLICATION:

Basin Electric submitted an application 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. A map of the proposed site location is included in Appendix A.

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 application identified the following emission units:

Emission Unit Number	Emission Unit Name
ES1-01	Unit 1 Main Boiler (8,301 MMBtu/hr PC Boiler)
ES1-02	Auxiliary Boiler (134 MMBtu/hr, Natural Gas Fired)
ES1-03	360 hp Diesel Fire Pump
ES1-04	Auxiliary Cooling Tower
ES1-05	2377 hp Diesel Emergency Generator
ES1-06	8.36 MMBtu/hr Inlet Gas Heater
ES1-07	Coal Storage Silo #1 Dust Collector
ES1-08	Coal Storage Silo #2 Dust Collector
ES1-09	Coal Storage Silo #3 Dust Collector
ES1-10	Coal Crusher House Dust Collector
ES1-11	Plant Coal Silo Transfer Bay Dust Collector
ES1-12	Pebble Lime Storage Silo Dust Collector
ES1-13	Pebble Lime Day Silo Bin Vent Filter
ES1-14	Lime Hydrator Mixer Dust Collector #1
ES1-15	Lime Hydrator Mixer Dust Collector #2
ES1-16	Hydrated Lime Crusher Dust Collector #1
ES1-17	Hydrated Lime Crusher Dust Collector #2
ES1-18	Hydrated Lime Silo #1 Bin Vent Filter
ES1-19	Hydrated Lime Silo #2 Bin Vent Filter
ES1-20	Activated Carbon Silo Bin Vent Filter
ES1-21	Fly Ash/FGD Waste Silo Separator/Filter Exhaust
ES1-22	Fly Ash/FGD Waste Silo Bin Vent Filter
FS1-01	Fly Ash/FGD Waste Truck Loading
FS1-02	Fly Ash/FGD Waste Haul Roads
FS1-03	Ash/FGD Waste Landfill
FS1-04	Bottom Ash Handling Haul Roads
—	Emergency Coal Truck Unloading Hopper

EMISSIONS SUMMARY:

Potential emissions for the PC Boiler are shown in the following table:

PC Boiler – Potential Emissions

Pollutant	Emission Rate (lb/MMBtu)	Emissions (lb/hr)	Emissions (tpy)
NO_X	0.05 (12 month avg.)	190.1 (30-day avg.)	832.4
SO_2	0.08 (12 month avg.)	304.1 (30-day avg.)	1331.8
CO	0.15	570.2	2497
PM_{10}	0.0120	45.6	199.8
VOC	0.0039	14.8	64.9
HAPs[1]	—	8.2	36.0
Mercury[2]	—	—	0.16
Ammonia[3]		9.8	42.8

[1] 14.1 tpy hydrogen chloride, 11.5 tpy hydrogen fluoride, 9.8 tpy organic, and 0.5 tpy trace metal HAPs.
[2] Based on NSPS limit of 97×10^{-6} lb/MW-hr, 12 month rolling average.
[3] Based on a maximum of 5 ppm_v ammonia slip.

Other Combustion Sources – Potential Emissions

Unit No	Emission Unit	NO_X (tpy)	SO_2 (tpy)	CO (tpy)	PM_{10} (tpy)	VOC (tpy)
ES1-02	134 MMBtu/hr Auxiliary Boiler[1]	5.4	0.08	10.7	1.0	0.7
ES1-03	360 hp Diesel Fire Pump[2]	1.0	0.2	0.5	0.03	0.2
ES1-05	2377 hp Diesel Emergency Generator[2]	6.3	0.2	3.4	0.2	0.4
ES1-06	8.36 MMBtu/hr Inlet Gas Heater[3]	1.0	0.01	0.8	0.08	0.06
Total		13.7	0.5	15.4	1.3	1.4

1 0.04 lb/MMBtu NO_X, 0.0006 lb/MMBtu SO_2, 0.08 lb/MMBtu CO, 0.0075 lb/MMBtu PM_{10}, and 0.0054 lb/MMBtu VOC. Annual emissions based on 2000 hours per year.

2 NO_X, PM_{10}, and CO based on Tier II emissions from 40 CFR Subpart 89. SO_2 and VOC based on AP-42. Annual emissions based on 500 hours per year.

3 0.1 lb/MMBtu NO_X, 0.0006 lb/MMBtu SO_2, 0.08 lb/MMBtu CO, 0.0075 lb/MMBtu PM_{10}, and 0.0054 lb/MMBtu VOC. Limited to 2500 hours per year.

Material Handling and Fugitive PM/PM_{10} Sources – Potential Emissions

Unit No.	Emission Unit	PM (tpy)	PM_{10} (tpy)
ES1-04	Auxiliary Cooling Tower[1]	1.1	0.3
ES1-07, 08, 09, 10, and 11	Coal Handling Dust Collectors[2]	16.7	16.7
ES1-12, 13, 14, 15, 16, 17, 18, and 19	Lime Handling Dust Collectors[2]	8.9	8.9
ES1-20	Activated Carbon Silo[2]	0.1	0.1
ES1-21 and 22	Fly Ash/FGD Waste Silo[2]	0.4	0.4
FS1-01	Fly Ash/FGD Waste Truck Loading[3]	<0.1	<0.1
FS1-02	Fly Ash/FGD Waste Haul Roads[4]	0.2	<0.1
FS1-03	Ash/FGD Waste Landfill[5]	1.8	0.4
FS1-04	Bottom Ash Haul Road[4]	<0.1	<0.1
Total		29.2	26.8

1 Estimate based on 17,000 gpm, 6000 mg/l TDS, and 0.005% drift loss.

2 Based on 0.005 gr/dscf.

3 Based on AP-42 and loading trucks inside a building.

4 Based on Division's Guideline for Fugitive Dust Emission Factors for Mining Activities, 50% control for water sprays on unpaved roads, and 85% control for paved roads.

5 Based on AP-42.

CHAPTER 6, SECTION 4 - PSD APPLICABILITY:

The proposed facility is subject to Prevention of Significant Deterioration (PSD) review under Chapter 6, Section 4 of the Wyoming Air Quality Standards and Regulations (WAQSR) because it is classified as a "major emitting facility." Fossil-fuel fired steam electric plants of more than two hundred and fifty million Btu/hour heat input with the potential to emit one hundred tons per year or more of any regulated pollutant are considered "major emitting facilities" under Chapter 6, Section 4(a)(i) of the WAQSR. Potential emission rates from the proposed facility and the PSD significance levels are shown in the following table:

Comparison to PSD Thresholds

Pollutant	Potential Emission Rate (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required?
NO_X	846.1	40	Yes
SO_2	1332.3	40	Yes
CO	2512.4	100	Yes
PM/PM_{10}	230.3/227.9	25/15	Yes
VOC	66.3	40	Yes
H_2SO_4	41:6	7	Yes
Lead	0.03	0.6	No
Fluorides	11.5	3	Yes
Total Reduced Sulfur (including H_2S)	Negligible	10	No
Mercury[1]	0.16	0.1	Yes
Beryllium[1]	0.004	0.0004	Yes

[1] Mercury and Beryllium are excluded from federal PSD regulations since 1990 per Section 112(b)(6) of the Clean Air Act but still included in WAQSR, Chapter 6, Section 4(a)(xxi).

The proposed facility is subject to a Prevention of Significant Deterioration (PSD) review consisting of the following:

1) A Best Available Control Technology (BACT) analysis is required for all regulated pollutant emitted in significant amounts.

2) An ambient air quality impact determination is required for all regulated pollutants emitted in significant amounts and any other pollutants required by the Administrator.

3) An increment consumption analysis is required for regulated pollutants based on allowable emission rates as well as increment consuming emissions from other sources in the region. The total deterioration determined from this analysis must comply with the allowable increments established for PM_{10}, SO_2, and NO_X for the classification of the area (i.e. Class I or Class II) in which the increment consumption is predicted.

4) An analysis is required to assess the impairment to visibility, soils, and vegetation resulting from the facility and general commercial, residential, industrial, and other growth associated with the facility.

CHAPTER 6, SECTION 2 - BEST AVAILABLE CONTROL TECHNOLOGY (BACT):

A best available control technology (BACT) analysis is required for NO_X, SO_2, PM/PM_{10}, CO, VOC, H_2SO_4, fluorides, mercury, and beryllium because each of these pollutants is emitted above PSD significant emission rates.

PC Boiler - NO_X

Basin Electric evaluated the following emission control technologies:

1. Selective Catalytic Reduction (SCR) - SCR is a post combustion control technique in which the flue gas is combined with vaporized ammonia in the presence of a catalyst and NO_X is reduced to nitrogen and water.

2. Selective Non-Catalytic Reduction (SNCR) - SNCR is similar to SCR in that it involves the injection of a reducing agent such as ammonia or urea into the flue gas stream. The reduction chemistry, however, takes place without the aid of a catalyst. SNCR systems rely on appropriate injection temperatures, proper reagent/gas mixing and prolonged retention time in place of the catalyst. SNCR systems are very sensitive to temperature changes and typically have lower emissions reduction (up to fifty or sixty percent) and higher ammonia slip. Basin Electric did not further consider SNCR because of the lower emissions reduction.

3. Low NO_X Burners with overfire air – These technologies reduce peak combustion temperatures therefore lowering NO_X emissions.

Basin Electric proposed SCR combined with Low NO_X Burners/overfire air. This represents the top control technology so no further evaluation of other control technologies is required. Basin Electric originally proposed an emission level of 0.07 lb/MMBtu and SCR combined with Low NO_X Burners/overfire air was evaluated at a number of different emission levels as discussed below.

The lowest emission rate for a PSD permit shown in EPA's RACT/BACT/LAER Clearinghouse (RBLC) is 0.067 lb/MMBtu for Newmont Mining Unit 1 in Nevada. It is worthwhile to note that this limit is based on a 24 hour average and an equivalent 30 day average limit would be less. A review of other recently permitted facilities revealed four PC boilers achieving emission levels below 0.05 lb/MMBtu using SCR combined with Low NO_X burners/overfire air. W.A. Parish Generating Station Units 5, 6, 7 and 8 in Houston, Texas have achieved 30 day rolling average NO_X emissions of less than 0.05 lb/MMBtu for one to two years, depending on the unit. Although these units are in a severe ozone non-attainment area and are permitted under the non-attainment NSR program rather than PSD, they are relevant because they use the same control technology proposed for this facility. A permit recently proposed by EPA Region 9 for Desert Rock Energy Center in New Mexico contains a NO_X emission limit of 0.06 lb/MMBtu, 24 hour average. Discussions with catalyst vendors indicate that a limit of 0.06 lb/MMBtu, 24 hour average, is at least as stringent as a limit of 0.05 lb/MMBtu, 30 day average. It is also noteworthy that the application for Desert Rock Energy Center specifies New Mexico sub-bituminous coal and states that lower NO_X emissions may be achievable with Powder River Basin Coal. Based on actual emissions below 0.05 lb/MMBtu for the four W.A. Parish Units and the proposed limit for Desert Rock Energy Center, the Division concludes that an emission limit of 0.05 lb/MMBtu is technically feasible. As a result of these findings, the Division requested Basin Electric to evaluate 30 day average emission limits of 0.05 and 0.06 lb/MMBtu.

In response, Basin Electric evaluated the variability in actual emission levels for W.A. Parish Generating Station Units 5 and 6 and then added two standard deviations to the actual 30 day rolling average emissions to determine values they consider feasible emission limits. Basin Electric provided a table comparing actual average emission levels (design targets) with values they consider a feasible emission limit (design target plus two standard deviations) as follows:

Actual Average Emission Level [Design Target] (lb/MMBtu)	Design Target Plus Two Standard Deviations (lb/MMBtu)
0.04	0.056
0.043	0.06
0.05	0.07
0.057	0.08
0.064	0.09

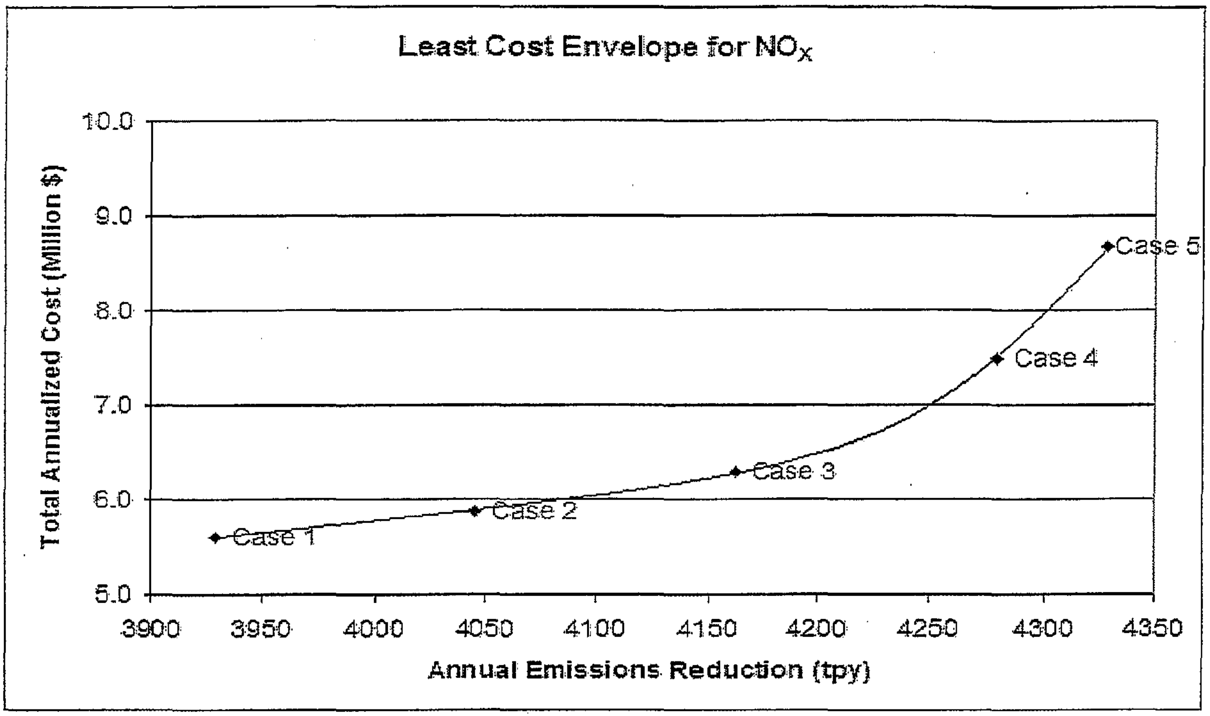
Based on this evaluation, Basin Electric stated that 0.056 lb/MMBtu is the lowest feasible emission limit. The Division noted that W.A. Parish Units 5 and 6 are actually emitting approximately 0.030 to 0.045 lb/MMBtu on a 30 day average. It was not clear to the Division, at this point in the review, what a reasonable margin would be between the design target emission level and an emission limit. The Division, therefore, decided to base the cost analysis on design target emission levels.

An analysis of cost effectiveness for the design target emission levels in the previous table was performed and the results are shown below. The emissions reduction is the difference between a baseline emission rate of 0.30 lb/MMBtu using Low NO_X Burners with overfire air and the controlled emission rate using SCR. 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 lower emission levels have higher annualized costs due to additional layers of catalyst, larger ammonia delivery systems, increased ammonia use, and more frequent catalyst changes. The Division considers the average cost effectiveness to be reasonable for all options.

Average Cost Effectiveness for NO_X

Case	Design Target Emission Level	Emissions Reduction (tpy)	Total Annualized Cost (Million $)	Average Cost Effectiveness ($/tons removed)
1	SCR @ 0.064 lb/MMBtu	3929.0	5.6	1,424
2	SCR @ 0.057 lb/MMBtu	4045.6	5.9	1,453
3	SCR @ 0.05 lb/MMBtu	4162.1	6.3	1,511
4	SCR @ 0.043 lb/MMBtu	4278.6	7.5	1,751
5	SCR @ 0.04 lb/MMBtu	4328.6	8.7	2,004

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. 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 least cost envelope is shown below:



All of the options are on the curve and are, therefore, dominant options. The incremental cost effectiveness for all the 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 NO_X

Options Compared	Incremental Emissions Reduction (tpy)	Incremental Increase in Total Annualized Cost ($)	Incremental Cost Effectiveness ($/ton)
Case 1 and Case 2	117	285,000	2,446
Case 2 and Case 3	117	409,300	3,512
Case 3 and Case 4	117	1,200,700	10,303
Case 4 and Case 5	50	1,185,900	23,744

The draft 1990 New Source Review Workshop Manual also discusses how to determine an adverse economic impact and states that, "undue focus on incremental cost effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the cost effectiveness, in terms of dollars per ton removed, is well within the normal range of acceptable BACT costs." In this case, the average cost effectiveness for all options is clearly within the range the Division has considered acceptable. The Division considers the incremental cost effectiveness of $10,303/ton reasonable for an additional 117 tpy emission reduction but does not consider an incremental cost effectiveness of $23,744/ton reasonable for an additional 50 tpy emission reduction. Therefore, the incremental cost effectiveness is considered reasonable for a design target emission level of 0.043 lb/MMBtu (Case 3).

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

1. Emission guarantees below 0.05 lb/MMBtu are associated with high ammonia (NH_3) slip values that cause problems elsewhere in the plant. Excess NH_3 slip reacts with SO_3 in the flue gas to generate ammonium sulfate and ammonium bisulfate which deactivate the SCR catalyst, contribute to pluggage of the downstream air heater, and may result in an increase in particulate matter emissions. A portion of the excess NH_3 slip will be captured with the fly ash and may result in ammonia off-gassing during handling and in the landfill.

2. Increasing the catalyst activity to increase NO_X reduction or reduce NH_3 slip may result in additional conversion of SO_2 to SO_3 and react with water in the flue gas to form sulfuric acid mist. The additional SO_3 may also increase generation of ammonium sulfate and ammonium bisulfate with the associated problems described above.

3. Emission levels will increase somewhat during catalyst change outs. Catalysts are typically changed by moving the second layer of catalyst (second to come in contact with the flue gas) into the first layer position and putting fresh catalyst in the second layer position. This is done one section at a time while the plant is on line and results in somewhat higher emissions during the change out.

As a result of these discussions, Basin Electric agreed to an annual average emission limit of 0.05 lb/MMBtu with a 30 day rolling average limit of 190.1 lb/hr (based on 3,801 MMBtu/hr and 0.05 lb/MMBtu). Basin Electric stated that the performance target (i.e. design target) will be in the range of 0.04 lb/MMBtu with 3.5 to 5.0 ppm NH_3 slip (maximum) and 1.5% SO_2 to SO_3 oxidation (maximum). Basin Electric accepted emission limits close to the design target due to the nature of the limits and the averaging periods. The annual average lb/MMBtu limit minimizes the effects of emission spikes. The lb/hr limit for the 30 day averaging period provides more flexibility than a lb/MMBtu limit 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.

The Division concludes that SCR combined with Low NO_X Burners and overfire air with emission limits of 0.05 lb/MMBtu, annual average, and 190.1 lb/hr, 30 day average, represents BACT for NO_X.

PC Boiler - SO_2

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). Although a CDS unit may be able to achieve a slightly higher SO_2 removal efficiency than a spray dryer/absorber, there are only two units operating in the United States and both have experienced problems with severe corrosion and high lime consumption (approximately twice that for a spray dryer/absorber) and high energy costs (approximately 1/3 higher than a spray dryer/absorber). Due to the technical and operational problems with CDS, this technology was not considered further.

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.

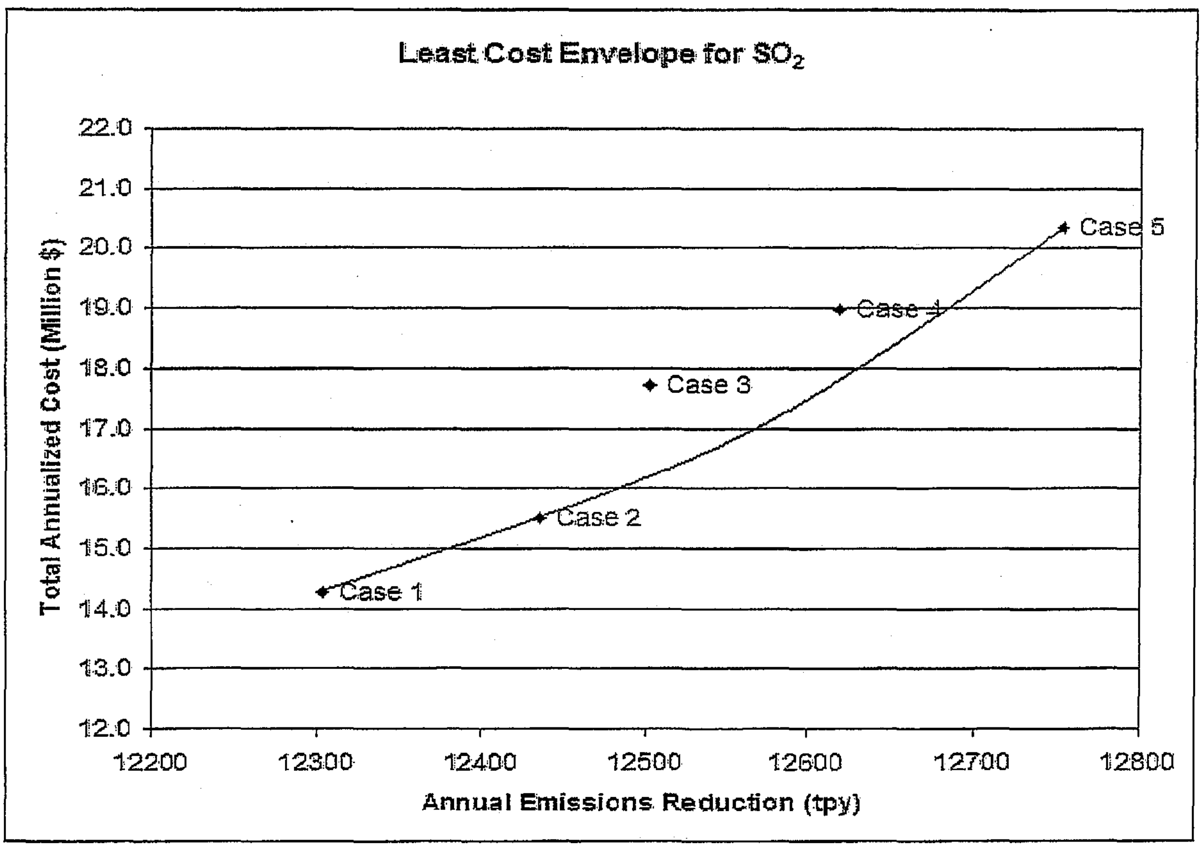
Basin Electric provided an analysis of cost effectiveness for wet FGD with emission limits of 0.07, 0.08, and 0.09 lb/MMBtu and for SDA with emission limits of 0.09 and 0.10 lb/MMBtu. As previously discussed, Basin Electric added a 23% margin to the 0.073 lb/MMBtu design target emission level for SDA 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[1]	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.

The Division concludes that SDA with emission limits of 0.08 lb/MMBtu, annual average, and 304.1 lb/hr, 30 day average, represents BACT for SO_2.

PC Boiler - PM/PM_{10}

The following BACT analysis is for filterable PM/PM_{10} emissions. Although EPA includes both filterable PM_{10} and condensible particulate matter in their definition of PM_{10}, the Division is not aware of any control technologies that have been identified as BACT for controlling condensible particulate matter. A BACT analysis cannot be performed and a BACT emission limit cannot be set without relating it to a specific control technology. Condensible particulate matter emissions were included in the ambient air quality modeling, however, to ensure compliance with ambient standards. As discussed in the following section on ambient air quality, Basin Electric modeled a total PM_{10} emission rate of 76 lb/hr from the PC Boiler stack. 45.6 lb/hr was assumed to be filterable PM_{10} and the remainder assumed to be condensible particulate matter. The modeling results show that total PM_{10} concentrations are less than the significant impact levels for both the 24-hour and the annual standard. The Division is requiring EPA Method 202 testing to determine the emission rate of condensible particulate matter. If the results are higher than the assumptions used in the modeling, the Division will assess the need for additional modeling.

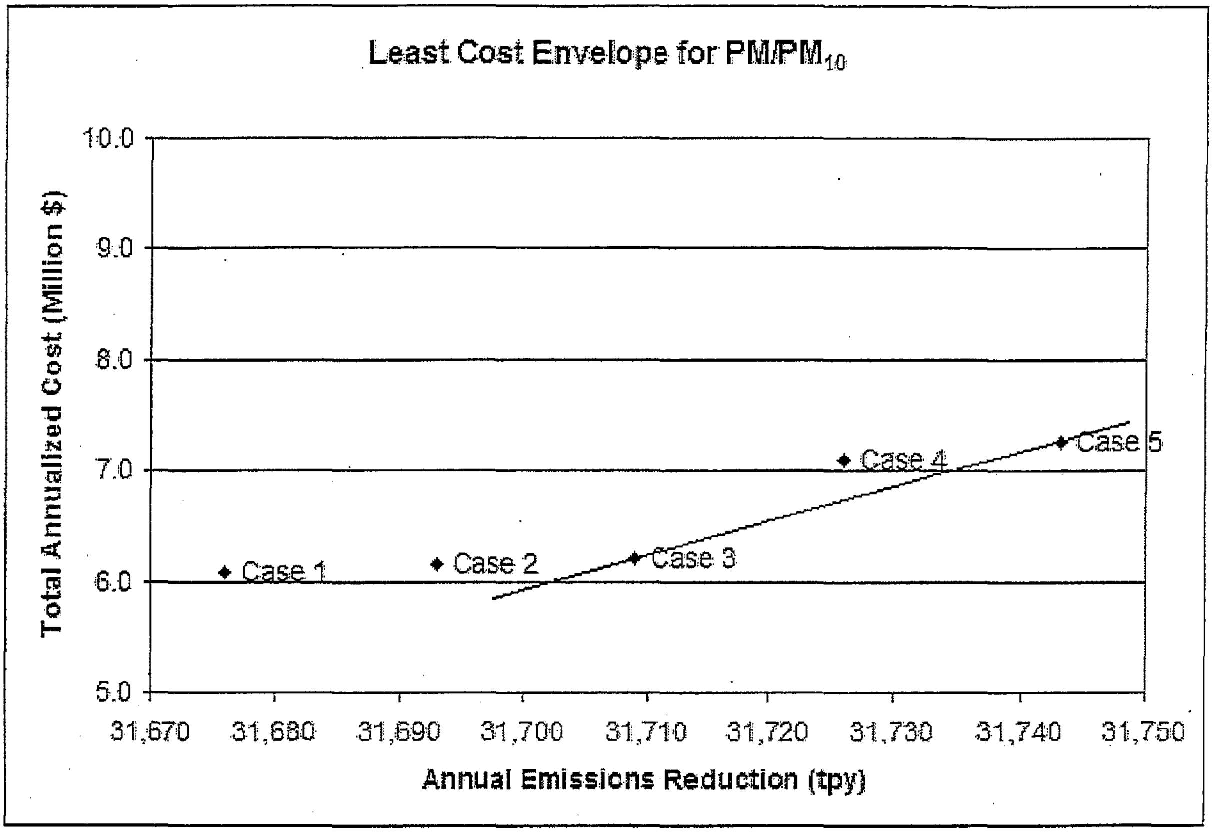
Basin Electric evaluated fabric filters with emission limits from 0.010 to 0.014 lb/MMBtu for control of filterable particulate matter and provided an analysis of cost effectiveness. The application states that an emission limit of 0.012 lb/MMBtu can be achieved using fiberglass or PPS (polyphenylene sulfide) filter bags, emission limits from 0.010 to 0.011 lb/MMBtu would likely require specialty filter bags such as P-84 polyimide or teflon, and that vendor guarantees are not currently available for emission levels below 0.010 lb/MMBtu. The results of the analysis are therefore shown in the following table for 30 day average emission limits from 0.010 to 0.014 lb/MMBtu.

The emissions reduction is the difference between an estimated uncontrolled emission rate of 1.92 lb/MMBtu and the controlled emission rate using fabric filters. 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 PM/PM_{10}

Case	Controls	Emissions Reduction (tpy)	Total Annualized Cost (Million $)	Average Cost Effectiveness ($/tons removed)
1	FF @ 0.014 lb/MMBtu	31,676	6.1	192
2	FF @ 0.013 lb/MMBtu	31,693	6.1	194
3	FF @ 0.012 lb/MMBtu	31,709	6.2	196
4	FF @ 0.011 lb/MMBtu	31,726	7.1	224
5	FF @ 0.010 lb/MMBtu	31,743	7.3	229

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.



Case 3 (0.012 lb/MMBtu) and 5 (0.010 lb/MMBtu) are the dominant options and the incremental cost effectiveness between these 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 PM/PM_{10}

Options Compared	Incremental Emissions Reduction (tpy)	Incremental Increase in Total Annualized Cost (Million $)	Incremental Cost Effectiveness ($/ton)
Cases 3 and 5	34	1.05	30,771

The Division considers an incremental cost effectiveness of $30,771/ton to be excessive for a 34 tpy reduction. The Division concludes that Fabric Filters with an emission limit of 0.012 lb/MMBtu for filterable PM/PM_{10} represents BACT.

PC Boiler – CO and VOC

Basin Electric evaluated the following emission control technologies:

1. Catalytic Oxidation – Catalytic Oxidation is used for CO and VOC control primarily on natural gas fired turbines but has not been demonstrated in practice for coal fired boilers. In addition to oxidizing CO and VOC, an oxidation catalyst will also convert a portion of the SO_2 to SO_3. The SO_3 can form sulfuric acid leading to corrosion problems or combine with ammonia from the SCR and cause fouling problems. Additionally, oxidation catalysts are generally designed for a maximum particulate loading in the range of 50 mg/m^3 and the particulate loading prior to the fabric filter will be in excess of 5000 mg/m^3. Although an oxidation catalyst could be installed downstream of the fabric filter, this would require reheating the flue gas from approximately 165°F to greater than 600°F leading to significant energy and economic impacts. For these reasons, catalytic oxidation is considered technically infeasible and is not reviewed further.

2. Combustion Controls – Basin Electric proposed good combustion controls with emission limits of 0.15 lb/MMBtu for CO and 0.0037 lb/MMBtu for VOC as BACT.

Measures taken to minimize the formation of NO_X inhibit complete combustion and tend to increase emissions of CO and VOC and a review of recently issued PSD permits does not show any BACT determinations using post combustion controls for CO or VOC from PC boilers. Therefore, the Division concurs that good combustion controls with an emission limit of 0.15 lb/MMBtu represents BACT for CO and good combustion controls with an emission limit of 0.0037 lb/MMBtu represents BACT for VOC.

PC Boiler - Sulfuric Acid Mist (H_2SO_4)

Basin Electric proposed a lime spray dryer/absorber as BACT for SO_2 and related compounds such as H_2SO_4. A percentage of the SO_2 in the flue gas will be oxidized to SO_3 which can combine with moisture to form H_2SO_4. The proposed lime spray dryer/absorber will remove both SO_2 and H_2SO_4 and Basin Electric estimated an emission rate of 0.0025 lb/MMBtu H_2SO_4. This emission rate equates to 9.5 lb/hr and 41.6 tpy. The Division concludes that the proposed lime spray dryer/absorber with an SO_2 emission limit of 0.073 lb/MMBtu, 30 day average, represents BACT for sulfuric acid mist.

PC Boiler – Beryllium

Beryllium is excluded from federal PSD regulations since 1990 per Section 112(b)(6) of the Clean Air Act but is still included in WAQSR Chapter 6, Section 4(a)(xxi). The fate of beryllium compounds through a PC boiler and post combustion air quality control devices is similar to that of coal ash. Some of the beryllium will be retained in the bottom ash while most will be collected in the particulate collection device. Basin Electric estimates that the controlled beryllium emissions from the fabric filter will be 0.00097 lb/hr, and 0.004 tpy based on 99% removal in the fabric filter. The Division concludes that a fabric filter with a PM/PM_{10} emission limit of 0.012 lb/MMBtu, 30 day average, represents BACT for beryllium.

PC Boiler - Fluorides

Basin Electric proposed a spray dryer/absorber and fabric filter for control of hydrogen fluoride, the primary form of fluorides emitted from a PC boiler. Hydrogen fluoride will react with lime (the reagent for the spray dryer/absorber) to form calcium fluoride which can be removed with the fabric filter. Basin Electric estimates a removal efficiency of 90% resulting in hydrogen fluoride emission rates of 2.62 lb/hr and 11.5 tpy. The Division concludes that a spray dryer/absorber with an SO_2 emission limit of 0.073 lb/MMBtu followed by a fabric filter with a PM/PM_{10} emission limit of 0.012 lb/MMBtu represents BACT for fluorides.

PC Boiler - Mercury

Mercury is excluded from federal PSD regulations since 1990 per Section 112(b)(6) of the Clean Air Act but is still included in WAQSR Chapter 6, Section 4(a)(xxi). This pollutant is subject to BACT review under WAQSR Chapter 6, Section 2. Basin Electric proposed the NSPS limit of 97×10^{-6} lb/MW-hr (0.16 tpy) and to perform a one year mercury optimization study at this facility beginning approximately six months after startup.

Recent PSD permits for sub-bituminous coal fired PC boilers include Intermountain Power Generating Station in Delta, Utah, Newmont Nevada Mining Unit 1 in Dunphy, NV, Xcel Energy Comanche Unit 3 in Pueblo, CO, and MidAmerican Energy CBEC Unit 4 in Council Bluffs, IA. The permits for the first three facilities all contain mercury emission limits of 20×10^{-6} lb/MW-hr, 12 month average. The permit for MidAmerican Energy CBEC Unit 4 contains a mercury emission limit of 1.7×10^{-6} lb/MMBtu, three test average, which equates to 16.5×10^{-6} lb/MW-hr. The MidAmerican Energy and Xcel permits include provisions for testing and evaluation of a mercury control system and the MidAmerican Energy permit can be reopened if the results from the evaluation demonstrate that a change is necessary. It should be noted that the limits in these permits are based on Case by Case MACT or legal agreements rather than PSD BACT.

Based on emission limits in recently issued PSD permits, the Division concludes that 20×10^{-6} lb/MW-hr, 12 month average, represents a target emission rate for mercury. The Division also understands that Basin Electric will perform a mercury optimization study at Dry Fork Station. Therefore, the permit will limit mercury emissions to 97×10^{-6} lb/MW-hr and require installation and operation of a control system with a target emission rate of 20×10^{-6} lb/MW-hr. Basin Electric will be required to submit a protocol for the mercury optimization study including proposed control techniques, operational parameters, test methods, and procedures and to perform the mercury optimization study for one year. The permit for this facility will be reopened to revise the mercury limit or add operational parameters as deemed appropriate by the Division based on the results of the study and the revisions will go through the public review process.

PC Boiler – Ammonia (Chapter 6, Section 2)

BACT is required for ammonia under WAQSR Chapter 6, Section 2(c)(v). The application estimates ammonia slip of 3.5 ppm to 5.0 ppm (maximum) for the proposed NO_X emission limit of 0.05 lb/MMBtu, annual average, and states that ammonia emissions from a well controlled SCR system can likely be limited to 10 ppm_v or less. TXU Generation Company recently submitted applications to the Texas Commission on Environmental Quality for eight (8) new PC boilers with proposed NO_X limits of 0.05 lb/MMBtu, 12 month rolling average. These applications state that ammonia concentration in the exhaust gas stream is not expected to exceed 3 ppm_v on an annual average and 10 ppm_v on a short term basis. EPA Conditional Test Method 27 (CTM-027), used to test for ammonia, is based on a short term sample and the Division concludes that 10 ppm_v ammonia on a short term basis represents BACT for ammonia.

Material Handling – PM/PM_{10}

Basin Electric proposed enclosures vented to fabric filters with an emission limit of 0.005 gr/dscf as BACT for coal, lime, and ash handling and storage. A wet handling system will be used for economizer, bottom ash, and mill reject loadout. The Division concurs that enclosures and fabric filters with an emission limit of 0.005 gr/dscf and a wet handling system for loadout represents BACT for material handling.

Haul Roads and Ash Disposal Landfill – PM/PM_{10}

Basin Electric proposed water sprays and chemical dust suppressants as BACT for the haul roads and ash disposal landfill. The Division concurs that water sprays and chemical dust suppressants represents BACT for these sources.

Emergency Coal Truck Unloading Hopper – PM/PM_{10}

Basin Electric proposed bottom dump haul trucks and portable water sprays and/or fogging systems as BACT for the emergency coal truck unloading hopper. Due to the emergency nature of this facility, the Division concurs that bottom dump haul trucks and portable water sprays and/or fogging systems represent BACT.

Auxiliary Cooling Tower – PM_{10}

Basin Electric proposed mist eliminators with 0.005% drift loss and the Division considers this to represent BACT for PM_{10}.

134 MMBtu/hr Natural Gas Fired Auxiliary Boiler – NO_X and CO

Basin Electric proposed Low NO_X burners with Flue Gas Recirculation (FGR) and an emission limit of 0.04 lb/MMBtu as BACT for NO_X and an emission limit of 0.08 lb/MMBtu as BACT for CO. This boiler will be limited to 2000 hours per year. Selective Catalytic Reduction was eliminated as economically infeasible based on an average cost effectiveness of $18,900/ton removed. The Division concurs that Low NO_X burners with Flue Gas Recirculation (FGR) and an emission limit of 0.04 lb/MMBtu represents BACT for NO_X and an emission limit of 0.08 lb/MMBtu represents BACT for CO for this 134 MMBtu/hr heater limited to 2000 hours per year.

8.36 MMBtu/hr Natural Gas Fired Inlet Gas Heater – NO_X and CO

Basin Electric proposed emission limits of 0.10 lb/MMBtu NO_X and 0.08 lb/MMBtu CO for the inlet gas heater. The heater will be used a maximum of 2000 hours per year. Low NO_X burners were eliminated as economically infeasible based on an average cost effectiveness of $58,000/ton removed. Due to the small size and limited hours, the Division concurs that emission limits of 0.10 lb/MMBtu NO_X and 0.08 lb/MMBtu CO represent BACT for this 8.36 MMBtu/hr heater limited to 2000 hours per year.

2377 hp Diesel Emergency Generator and 360 hp Diesel Fire Pump

Basin Electric proposed EPA Tier II emissions from 40 CFR Subpart 89 as BACT for the 2377 hp diesel emergency generator and 360 hp diesel fire pump. Tier II emission rates for these engines are 4.8 g/hp-hr NO_X + VOC, 2.6 g/hp-hr CO, and 0.15 g/hp-hr PM_{10}. These engines will be limited to 500 hours per year. The Division concurs that EPA Tier II emission rates represent BACT for the emergency diesel engines.

CHAPTER 5, SECTION 2 - NEW SOURCE PERFORMANCE STANDARDS (NSPS):

New Source Performance Standards Subparts Da and Y are applicable to the proposed facility in accordance with WAQSR, Chapter 5, Section 2.

Subpart Da - PC Boiler

Subpart Da applies to electric utility steam generating units capable of combusting more than 250 MMBtu/hour heat input for which construction or modification is commenced after September 18, 1978. The proposed PC boiler will have a maximum heat input of 1300 MMBtu/hr.

Particulate Matter: Subpart Da limits particulate emissions from coal fired plants to 0.03 lb/MMBtu and 99.9% reduction of potential combustion concentration, or 0.015 lb/MMBtu, or 0.14 lb/MW-hr. Opacity is limited to 20% (6 minute average) except for one six minute period per hour of not more than 27%. The proposed emission limit of 0.012 lb/MMBtu will show compliance with the NSPS particulate matter emission limit. Section 60.47Da(a) requires the operation of a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere.

Sulfur Dioxide: Subpart Da limits SO_2 emissions from the coal-fired boiler to either 1.4 lb/MW-hr or a 95% reduction of potential emissions. Compliance with the Subpart Da emission limitation and percent reduction requirements are both determined on a 30 day rolling average basis.

The proposed boiler emission limit of 304.1 lb/hr, 30-day average, equates to 0.8 lb/MW-hr at full load (385 MW) and will demonstrate compliance with the NSPS emission limitation. SO_2 inlet and outlet continuous emission monitoring is required under Subpart Da to demonstrate compliance with the emission limit and percent reduction requirements across the control device. Subpart Da also requires the operation of a continuous monitoring system to measure oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxide emissions are monitored.

Nitrogen Oxides: The NSPS NO_X emission limit for sources constructed after July 9, 1997 is 1.0 lb/megawatt-hour gross energy output (30 day rolling avg.). The proposed NO_X emission limit of 190.1 lb/hr (30 day rolling average) corresponds to 0.5 lb/megawatt-hour at full load (385 MW) and will demonstrate compliance with the NSPS emission limitation.

NO_X continuous emission monitoring, a continuous flow monitoring system, and a wattmeter to continuously record gross electrical output in megawatt-hours are required under Subpart Da. Subpart Da also requires the operation of a continuous monitoring system to measure oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxide emissions are monitored.

Mercury: There are two NSPS standards that regulate mercury as follows:

1. Subpart Da limits mercury emissions from PC boilers burning subbituminous coal to 97×10^{-6} lb/MW-hr for units located in a county-level geographical area receiving less than or equal to 25 inches per year mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data. The Division reviewed the most recent USDA 30 year data and the proposed location receives less than 25 inches of annual precipitation. This facility will be limited to the NSPS limit of 97×10^{-6} lb/MW-hr, 12 month rolling average, and the target emission level is 20×10^{-6} lb/MW-hr. Compliance is demonstrated through CEM's (or sorbent trap monitoring) and there are Record Keeping and Reporting Requirements.

2. Subpart HHHH is the Hg Budget Trading Program. This Subpart incorporates a cap and trade program based on the Acid Rain Program (Part 75) beginning in 2010. Wyoming Air Quality Standards and Regulations, Chapter 14, Sections 1 and 4 incorporates Subpart HHHH and the proposed facility will be subject to this rule.

Subpart Y - Coal Handling Facilities

Subpart Y applies to coal preparation plants which process more than 200 tons per day with facilities that are constructed or modified after October 24, 1974. Subpart Y limits opacity to less than 20% from all coal processing and conveying equipment, coal storage systems, and coal transfer and loading systems (including the emergency coal truck unloading hopper) at this facility.

CHAPTER 5, SECTION 3 - NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPS):

On March 29, 2005, EPA issued a final rule entitled "Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units from the Section 112(c) List." Due to this rule, "Coal- and Oil-Fired Electric Utility Steam Generating Units" is no longer a source category requiring a MACT standard. Therefore, NESHAPs and Case-by-Case MACT do not apply to Coal- and Oil-Fired Utilities.

40 CFR 63, Subpart ZZZZ, ***National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*** – The 2377 hp diesel emergency generator is an affected source under Subpart ZZZZ because it has a site rating of more than 500 brake horsepower and is located at a major source of hazardous air pollutants. The emergency generator also meets the definition of an emergency stationary Reciprocating Internal Combustion Engine (RICE) and does not have to meet emission or operational limitations under this subpart. Initial notifications are required under 40 CFR 63.6645(d).

40 CFR 63, Subpart DDDDD, ***National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*** – The 8.36 MMBtu/hr Inlet Gas Heater and 134 MMBtu/hr Auxiliary Boiler and are affected units under Subpart DDDDD. The 8.36 MMBtu/hr Inlet Gas Heater is classified in the small gaseous fuel subcategory under Subpart DDDDD and there are no emission limits or work practice standards for this subcategory. The 134 MMBtu/hr Auxiliary Boiler is classified in the large gaseous fuel subcategory and this subpart limits CO emissions to 400 ppm (30-day rolling average) and requires a CEM to monitor CO emissions for new or reconstructed gaseous fuel process heaters with a heat input capacity of 100 MMBtu/hr or greater. The Auxiliary Boiler is limited to 0.08 lb/MMBtu CO which corresponds to approximately 100 ppm_v (3% O_2, dry basis).

CHAPTER 6, SECTION 5 – PERMIT REQUIREMENTS FOR CONSTRUCTION AND MODIFICATION OF NESHAPs SOURCES:

WAQSR Chapter 6, Section 5(a)(ii)(C) contains notification and application requirements for construction and modification of affected NESHAP sources (emission units). The 8.36 MMBtu/hr Inlet Gas Heater and 134 MMBtu/hr Auxiliary Boiler are subject to Subpart DDDDD and the 2377 hp diesel emergency generator is subject to Subpart ZZZZ as discussed above. The application provides notification in accordance with the procedures in Chapter 5, Section 3(k)(ii) and includes all the information in Chapter 6, Section 5(a)(iii) as required by Chapter 6, Section 5(a)(ii)(C).

CHAPTER 6, SECTION 3 - OPERATING PERMIT:

The proposed facility will be a major source as defined by Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations (WAQSR). Basin Electric is required to file a complete application to obtain an operating permit within 12 months after commencing operation.

PROJECTED IMPACT ON AMBIENT AIR QUALITY:

PSD Modeling Applicability:

An applicant submitting a permit application under PSD regulations for a proposed major source or modification must assess the existing air quality for each regulated air pollutant that it emits in its affected area, as well as demonstrate compliance with Wyoming Ambient Air Quality Standards (WAAQS) and Prevention of Significant Deterioration (PSD) increments. Additionally, at the request of the National Parks Service (NPS), which is the affected Federal Land Manager (FLM) of the Class I areas that are closest to the proposed modification, Basin Electric Power Cooperative (the applicant) was required to assess Air Quality Related Values (AQRVs) and visibility at the nearest Class I areas, which are Wind Cave and Badlands National Parks in South Dakota. In addition, the applicant assessed impacts at the Northern Cheyenne Indian Reservation in southern Montana.

NEAR-FIELD MODELING ANALYSIS

The applicant performed a significance modeling analysis to determine the air quality impacts from the operation of the proposed Dry Fork power plant. Emissions of carbon monoxide (CO), nitrous oxides (NO_x), sulfur dioxide (SO_2), and particulate matter 10 microns or less (PM_{10}) from the main boiler stack, the auxiliary boiler stack, bottom ash removal, and the associate coal handling sources were modeled and highest calculated ambient impacts were compared to established significant impact levels. The significance analysis was completed using version 3 of the Industrial Source Complex model (ISC3) with the Plume Rise Model Enhancements (PRIME) algorithms. Additional cumulative modeling analyses for SO_2 were required, as discussed in the results of the significance model, based on the modeled impacts provided by the applicant.

Model Justification:
The applicant used the Environmental Protection Agency (EPA) Industrial Source Complex 3rd generation model (ISC3), version 04269 to assess the air quality impacts on receptors within 50 kilometers of the facility. The recommended regulatory default settings were used in all model runs. Options used in the ISC simulations were rural dispersion coefficients with no exponential decay, final plume rise, stack tip downwash, default wind profile exponents, default vertical potential temperature gradients, and calms processing routines.

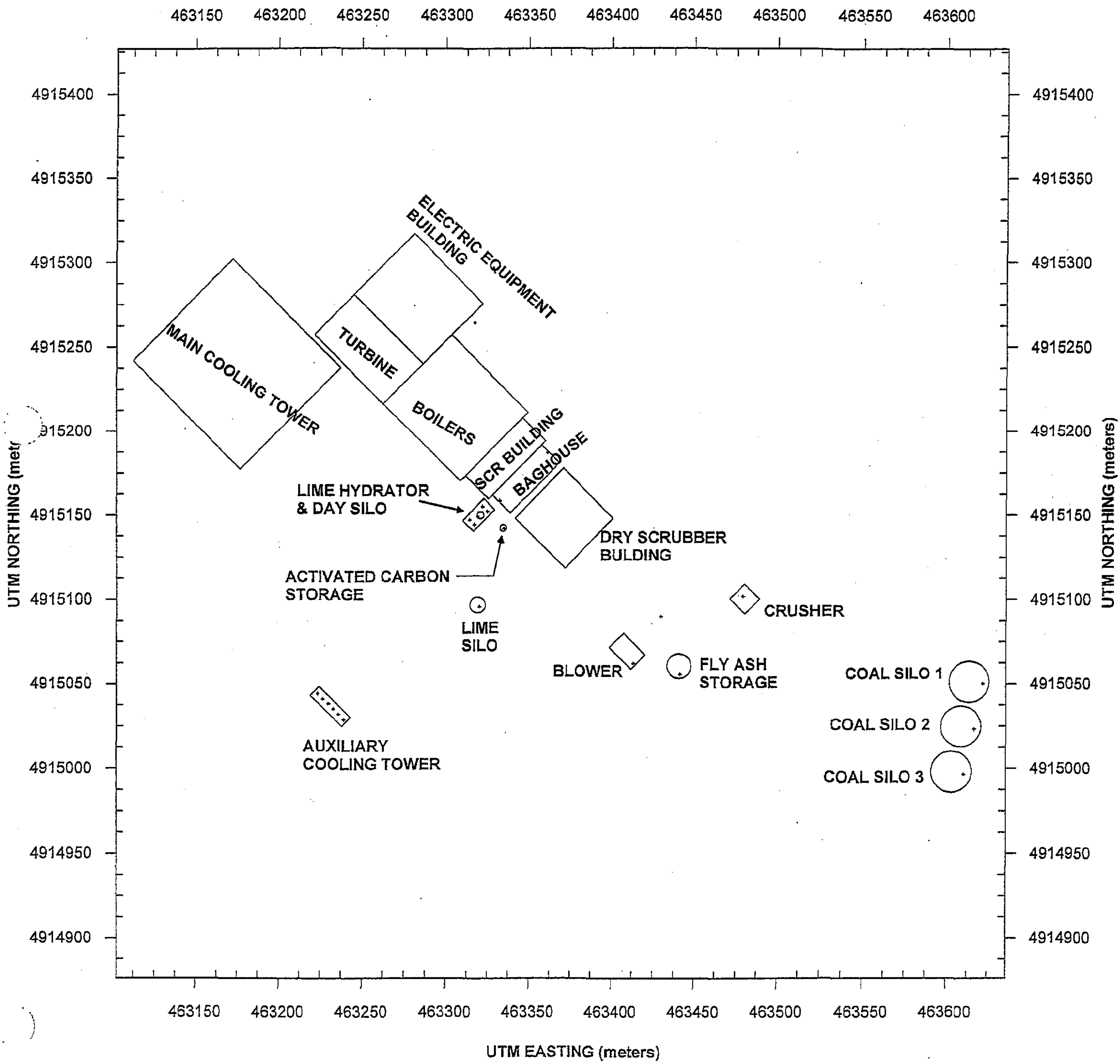
ISC3 version 04269 includes the PRIME model to calculate ground-level pollutant concentrations resulting from the influence of nearby buildings. PRIME was developed by the Electric Power Research Institute (EPRI) as a robust, continuous numerical model as a replacement for existing downwash calculation methods. PRIME calculates fields of turbulence intensity, wind speed, and the slopes of the mean streamlines as a function of the projected building dimensions. These fields gradually decay to ambient values downwind of the building. Coupled with a numerical plume rise model and these field values, PRIME determines the change in plume centerline location with downwind distance and the rate of plume dispersion to calculate ground-level pollutant concentrations. A plot of the proposed building configuration is shown in Figure 1.

The topography in the geographic area can be characterized as complex terrain due to some terrain elevations being greater than stack top elevations. In the past, EPA has specified that the preferred model for complex terrain in an industrial setting with multiple sources is ISC3. On November 9, 2005, EPA published a revision to 40 CFR Part 51 Appendix W "Guideline on Air Quality Models" in which the American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC) Model (AERMOD) replaced ISC3 as the preferred model. The current version of AERMOD (04300) includes the PRIME model to calculate downwash induced pollutant impacts. The rule became effective on December 9, 2005. EPA authorized a one-year implementation period granting the discretionary authority to approve the use of ISC3 for modeling analyses through December 9, 2006. CH2M Hill, on behalf of Basin Electric Power Cooperative, proposed the use of ISC3-PRIME for near-field modeling analyses of NO_x, SO_2, CO, PM_{10}, HF, and HAPs in their modeling protocol for this application, which was approved by the Division on October 10, 2005.

Meteorological Data:
Modeling simulations for the Dry Fork main and auxiliary boiler exhaust stacks were run using hourly surface meteorological data collected from the period of January 1, 2002 through December 31, 2002 at the nearby Basin Electric Power Company meteorological tower. The tower was instrumented with

BASIN ELECTRIC POWER COOPERATIVE
DRY FORK POWER PLANT
PROPOSED FACILITY LAYOUT

FIGURE 1



DEQ/AQD 001452

sensors at 2 meters, 10 meters, 50 meters, and 100 meters, and was located approximately 12 miles southeast of Gillette, Wyoming. Meteorological data from the 100 meter anemometer were used to develop the hourly data used in the near-field modeling analysis. The topography and climatology at the meteorological monitoring site are similar to the project site and representative of the geographical area surrounding the proposed Dry Fork power plant. Two weeks of data in August of 2002 were missing due to an elevator failure on the tower. The applicant substituted wind speed data collected at the Gillette airport for the missing hours. A power law extrapolation was used in accordance with Volume II of the ISC3 User's Guide to adjust 10 meter wind speed data from the airport to the 100 meter anemometer height for the missing data that were substituted.

An average of the wind flow data statistics for this data set indicates the winds originate from the northwest direction 26% of the time and from the southwest 28% of the time. The annual average wind speed is 7.64 meters per second or approximately 17.1 miles per hour. The percentage of calm winds for this data set equates to 0.10%, or equivalently, 9 calm hours. A wind rose of the 100 meter data is provided in Appendix B.

Wind speed data collected from the 10 meter sensor on the tower was used to model particulate sources for the 24-hour averaging period. Winds originate from the southwest direction 32% of the time. The annual average wind speed is 5.53 meters per second or approximately 12.4 miles per hour. The percentage of calm winds for this data set equates to 0.18%, or equivalently, 16 calm hours. A wind rose of the 10 meter data is also provided in Appendix B.

Upper air data from Rapid City, South Dakota, were merged with the surface meteorological data. Twice-daily upper air soundings collected at the Rapid City airport (World Meteorological Organization Station 72662) were obtained from the National Climatic Data Center (NCDC) for the January 1, 2002 through December 31, 2002 time period. If a single AM or PM mixing height was missing, a linear interpolation of valid data from the previous day and the following day was used to substitute for the missing value. If more than one AM or PM value was missing, the seasonal average value from the Holzworth reference (EPA, 1972) was used as a substitute.

Hourly 10 meter surface meteorological data collected at the existing Eagle Butte mine were used to model the low-level PM_{10} sources from the Dry Fork power plant. Meteorological data used in these modeling analyses were based on hourly measured values of wind speed, wind direction, and stability class collected at the Eagle Butte Mine meteorological monitoring site during a six year period, from 1995 through 2000. Hourly surface meteorological data collected at the Eagle Butte Mine are representative of meteorological conditions that exist throughout the area that comprises the "North Group" of mines. The meteorological station at the Eagle Butte Mine is located approximately 3 miles northwest of the proposed Dry Fork power plant.

An average of the wind statistics for the Eagle Butte 1995-2000 data set indicates the predominant winds originate from the northwest and north-northwest directions approximately 22% of the time, and from the south-southeast, and south directions approximately 26% of the time. The annual average wind speed is 5.7 meters per second (m/s) or equivalently, 12.8 miles per hour (mph). There were 7 calm hours out of 52,608 hours (six years). Twice-daily upper air soundings were collected at the Rapid City, South Dakota, airport and were processed for this time period and merged with the hourly data. A wind rose summarizing all six (6) years of Eagle Butte meteorological data is provided in Appendix B.

Emissions:
In the following table are the emissions rates used by the applicant in the near field ambient impact analysis. While not required by the Division, the applicant modeled PM_{10} emissions accounting for both filterable and condensible emissions. All modeled sources except the auxiliary boiler and Fly Ash/FGD Waste handling emissions were based on 8760 hours of operation. The auxiliary boiler will be limited to 2000 hours of operations per years. Particulate emissions from the Fly Ash/FGD Waste handling were based on 12 hours of operation per day, during the hours of 6 AM to 6 PM as accounted for in the model.

Criteria Pollutant Emissions from Boilers

Source	NO_x Emission Rate (lb/hr)	CO Emission Rate (lb/hr)	SO_2 Emission Rate (lb/hr)	PM_{10} Emission Rate (lb/hr) [1]
Main Boiler	260	557	380	76
Auxiliary Boiler [2]	1.7	14.7	0.08 [3]	1.0

[1] Total PM_{10} emissions modeled to account for condensible emissions (45.6 lb/hr filterable and 30.4 lb/hr condensible).
[2] Limited to 2000 hours of annual operation.
[3] Not included in the SO_2 SIL since the Main Boiler impact alone was significant.

Particulate Emissions (Excluding Boilers)

Source	PM/PM_{10} Emission Rate (lb/hr)
Auxiliary Cooling Tower	0.06
Coal Storage Silo 1 Dust Collector	0.59
Coal Storage Silo 2 Dust Collector	0.59
Coal Storage Silo 3 Dust Collector	0.38
Coal Crusher House Dust Collector	1.08
Plant Coal Silo Transfer Bay Dust Collector	1.17
Pebble Lime Storage Silo Bin Vent Filter	0.03
Pebble Lime Day Silo Bin Vent Filter	0.04
Lime Hydrator Mixer Dust Collector No. 1	0.20
Lime Hydrator Mixer Dust Collector No. 2	0.20
Hydrated Lime Crusher Dust Collector No. 1	0.70
Hydrated Lime Crusher Dust Collector No. 2	0.70
Hydrated Lime Silo 1 Bin Vent Filter	0.07
Hydrated Lime Silo 2 Bin Vent Filter	0.07
Activated Carbon Silo Bin Vent Filter	0.03
Fly Ash/FGD Waste Silo Separator/Filter Exhaust	0.05
Fly Ash/FGD Waste Silo Bin Vent Filter	0.05
Fly Ash/FGD Waste Disposal Truck Loading	<0.01
Haul Roads	0.03
Fly Ash/FGD Waste Landfill	0.02

The applicant provided a load analysis for the main boiler emissions at 103%, 75%, and 50% loadings for all averaging periods. Using an emission rate of 1 gram/second, the highest modeled short term impacts occurred when the exit gas velocity was the lowest or when the boiler operated at a 50% loading. Therefore a 50% boiler loading was used to model CO emissions and 3-hour SO_2 emissions. For 24-hour PM_{10} and SO_2 emissions a gas exit velocity corresponding to 75% boiler load was used to model the unit because it is more representative of annual operations. Annual PM_{10}, SO_2, and NO_x emissions were modeled using a 100% loading for the main boiler.

Good Engineering Practice Analysis:
Section 123 of the Clean Air Act defines Good Engineering Practice (GEP), with respect to stack heights, as "the height necessary to insure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies or wakes which may be created by the source itself, nearby structures or nearby terrain obstacles." In accordance with Chapter 6, Section 2(d) of the WAQSR, sources cannot model stack heights above GEP when showing compliance with an Ambient Air Quality Standard or increment.

The following equation, listed in Chapter 6, Section 2(d)(i)(B) of WAQSR, was used to determine GEP for sources at Dry Fork:

(Equation 1) $H_{(GEP)} = H + 1.5L$

H = the height of nearby structure(s) measured from the ground level elevation at the base of the stack

L = the lesser dimension (height or width) of, the source, or nearby structure

GEP Stack Height Determinations

Source ID	Source Description	Proposed Stack Height (m)	GEP Stack Height (m)
ES1_01	Unit 1 Main Boiler	152.4	167.64
ES1_02	Auxiliary Boiler	70.71	167.64
ES1_041	Auxiliary Cooling Tower	4.57	167.64
ES1_042	Auxiliary Cooling Tower	4.57	167.64
ES1_043	Auxiliary Cooling Tower	4.57	167.64
ES1_044	Auxiliary Cooling Tower	4.57	167.64
ES1_045	Auxiliary Cooling Tower	4.57	167.64
ES1_046	Auxiliary Cooling Tower	4.57	167.64
ES1_07	Coal Storage Silo 1 Dust Collector	54.86	167.64
ES1_08	Coal Storage Silo 2 Dust Collector	54.86	167.64
ES1_09	Coal Storage Silo 3 Dust Collector	54.86	167.64
ES1_10	Coal Crusher House Dust Collector	47.55	167.64
ES1_11	Plant Coal Silo Transfer Bay Dust Collector	64.01	167.64
ES1_12	Pebble Lime Storage Silo Bin Vent Filter	30.48	167.64
ES1_13	Pebble Lime Day Silo Bin Vent Filter	24.38	167.64
ES1_14	Lime Hydrator Mixer Dust Collector No. 1	26.82	167.64
ES1_15	Lime Hydrator Mixer Dust Collector No. 2	26.82	167.64
ES1_16	Hydrated Lime Crusher Dust Collector No. 1	26.82	167.64
ES1_17	Hydrated Lime Crusher Dust Collector No. 2	26.82	167.64
ES1_18	Hydrated Lime Silo 1 Bin Vent Filter	29.57	167.64
ES1_19	Hydrated Lime Silo 2 Bin Vent Filter	29.57	167.64
ES1_20	Activated Carbon Silo Bin Vent Filter	26.21	167.64
ES1_21	Fly Ash/FGD Waste Silo Separator/Filter Exhaust	9.75	167.64
ES1_22	Fly Ash/FGD Waste Silo Bin Vent Filter	28.96	167.64

As shown in the table, the stack height for Dry Fork sources are less than the calculated GEP height, therefore direction specific building dimensions from the latest version of the EPA Building Profile Input Program (BPIP) were included in the ISC3 simulations to account for downwash effect from nearby structures.

Receptor Grid:
Discrete Cartesian receptors were placed along the fence line of the facility using 50 meter intervals. Four additional rectangular receptor grids were placed around the facility out to a distance of 50 kilometers. Grid spacing for the receptors used in the modeling analyses were:

1) 100 meters between receptors from the main boiler out to a distance of 1 kilometer
2) 500 meters between receptors from 1 kilometer out to 10 kilometers
3) 1,000 meters between receptors from 10 kilometers out to 50 kilometers from the main boiler

A composite of the three (3) receptors grid above and a supplement grid of 100-meter spacing around the highest modeled impact not located on the facility fenceline was used in the PSD Class II SILs analyses for NO_x, PM_{10}, SO_2, and the Hazardous Air Pollutants (HAPs) modeling analyses. The CO modeling analysis used the same receptor grid as was used for the other pollutants without the addition of a supplementary 100-meter grid since the CO impact was less than 5% of the SIL. A modified version of the composite receptor grid used in the SIL analyses was used in the WAAQS analysis for SO_2 and the PSD Class II Increment analysis for 24-hour averaged SO_2 impacts. Since the radius of impact for 24-hour averaged SO_2 from Dry Fork was 9.1 kilometers, the revised receptor grid only extended out 9.1 kilometers. The receptor spacing remained the same as in the SIL analysis out to 5 kilometers. Starting 5 kilometers from the main boiler stack, receptors were spaced 1,000 meters apart up to the edge of the receptor grid 9.2 kilometers from the Dry Fork main boiler stack. The receptor grid included 3 additional fine receptor grids with 100 meter receptor spacing to encompass first highest and second highest modeled SO_2 impacts in the WAAQS analysis and PSD Class II Increment analysis. The receptor grid used for the 24-hour averaged SO_2 WAAQS analysis and PSD Class II Increment analysis is shown in Figure 2.

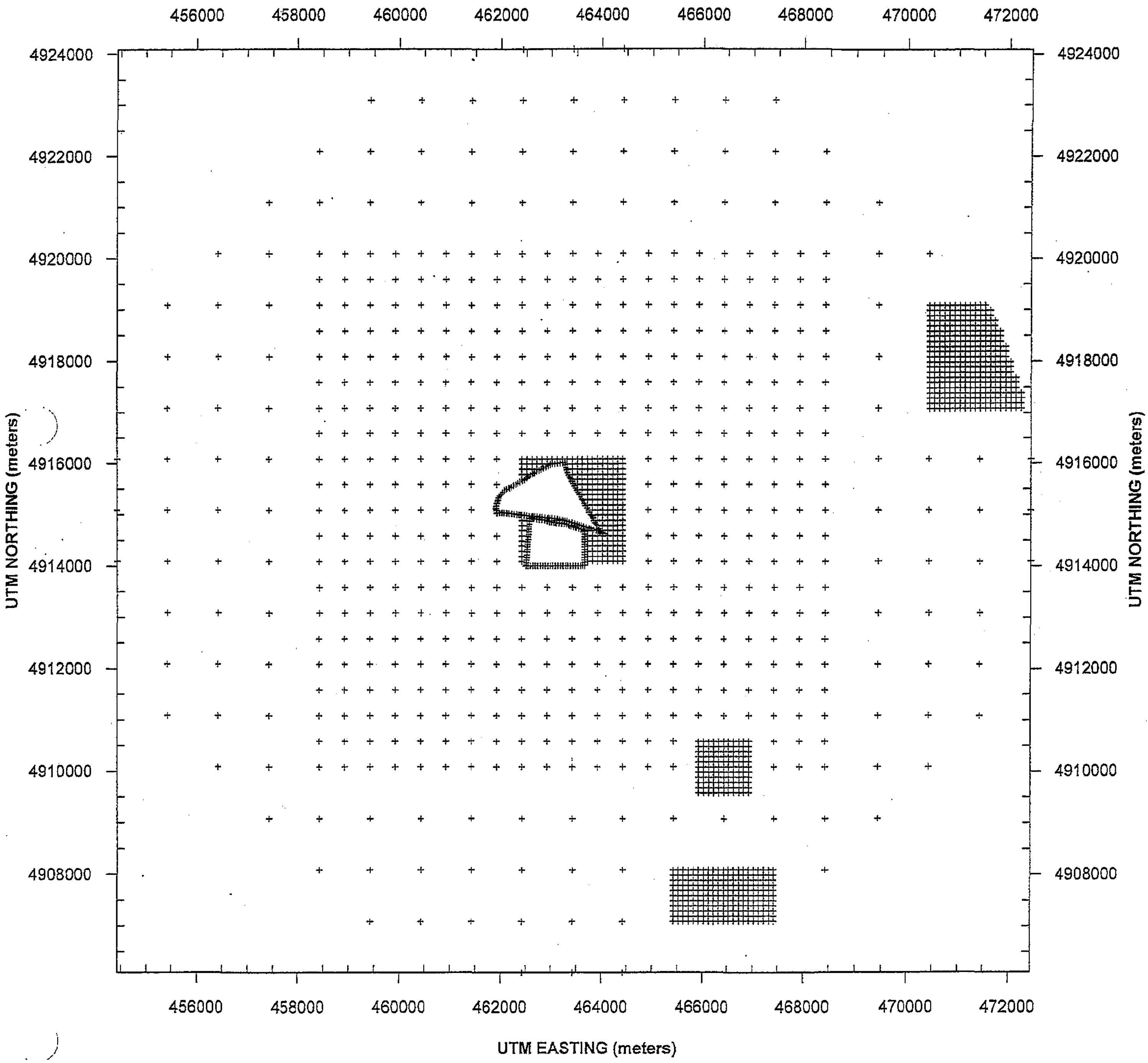
Receptor elevations used in the modeling analyses were extrapolated from electronic data contained in USGS Digital Elevation Model (DEM) files. These files were obtained from the National Elevation Dataset (NED) with a spatial resolution of 10 meters. Missing data were filled in using elevations from DEM files with 30 meter resolution. The elevation of the DEM grid cell in which the receptor was located was used for receptor elevations. Receptor elevations were not interpolated from the original DEM files.

Class II Significant Impact Analyses
EPA guidance contained in the New Source Review Workshop Manual, October 1990, states that in the event that the maximum modeled ambient impact of a proposed emissions increase is below the appropriate ambient air quality significance level for all locations and averaging periods, the EPA does not require any further NAAQS or PSD Class II Increment analyses for that pollutant. The designated PSD Class II SILs, as specified by the EPA, and in WAQSR, Chapter 6, Section 2(c)(ii)(A) are provided in the table below. Additionally, if the maximum modeled impacts are below established pre-construction monitoring de minimis concentrations, the applicant may not be required to perform one year of ambient monitoring prior to receiving a preconstruction permit.

The 100 meter Basin Electric meteorological data was used to model high level releases from the main boiler stack and the auxiliary boiler to determine the significant impact level from the facility. It was used to determine modeled impacts for all averaging periods for CO, NO_x, and SO_2 emissions from the stacks. Low level PM/PM_{10} emissions from the facility were modeled using 10 meter wind speed data

BASIN ELECTRIC POWER COOPERATIVE
DRY FORK POWER PLANT
COMPOSITE RECEPTOR GRID FOR
WAAQS AND PSD CLASS II INCREMENT ANALYSES

FIGURE 2



from the Basin Electric meteorological site for 24-hour average period. Annual averaged PM/PM_{10} modeled impacts were calculated using six (6) years of meteorological data collected at the Eagle Butte site which are commonly used to modeled annual particulate emissions from coalmines near the Dry Fork power plant.

Maximum modeled NO_x, CO, SO_2, and PM_{10} impacts from Dry Fork power plant and the respective SILs are shown in the table below. The maximum predicted ambient air concentrations of NO_x, CO, and PM_{10} are all less than the significance levels for Class II areas for all applicable averaging periods. Therefore, no further modeling analyses for NO_x, CO, or PM_{10} are required. Additionally, the model predicted impacts are also below the significant monitoring concentrations for all four (4) criteria pollutants and no pre-construction monitoring was required.

PSD Class II Significant Impact Analysis Results

Pollutant	Averaging Period	Dry Fork Maximum Impact ($\mu g/m^3$)	SILs ($\mu g/m^3$)	Dry Fork Impact Exceeds SILs (Yes/No)	Monitoring De Minimis Levels ($\mu g/m^3$)	Dry Fork Impact Exceeds De Minimis Levels (Yes/No)
NO_x	Annual	0.8	1	No	14	No
CO	8-hour	22.1	500	No	575	No
	1-hour	108.6	2,000	No	--	No
SO_2	Annual	0.4	1	No	--	No
	24-hour	5.8	5	Yes	13	No
	3-hour	21.1	25	No	--	No
PM_{10}	Annual	0.8	1	No	--	No
	24-hour	4.8	5	No	10	No

Based on the applicant's significant impact analysis using the 2002 meteorological data from Basin Electric's monitoring site, the only criteria pollutant with a modeled impact above a PSD Class II SIL is SO_2, for the 24-hour averaging period. The Radius of Impact (ROI) for 24-hour averaged SO_2 was approximately 9.1 kilometers. PSD guidance recommends a distance of 50 km be added onto the ROI to define the maximum distance to use for compiling the cumulative emission source inventory for the WAAQS and PSD Class II Increment analyses. Additional sources of SO_2 out to 60 kilometers were included in the cumulative analyses.

In addition to the cumulative WAAQS analysis and the cumulative PSD Class II SO_2 Increment analysis for short term 24-hour SO_2 emissions, the Division required the applicant to provide a modeling assessment of Hydrogen Fluoride (HF) emissions from the Dry Fork power plant and a Tier 1 risk assessment of emitted Hazardous Air Pollutants (HAPs).

WYOMING AMBIENT AIR QUALITY STANDARDS (WAAQS) ANALYSIS

♦ Sulfur Dioxide (SO_2) ♦

The applicant modeled the proposed SO_2 emissions from the boiler at the Dry Fork facility, along with SO_2 emissions from eight (8) sources within 60 kilometers of the facility to determine compliance with the 24-hour WAAQS for SO_2 of 260 μg/m³. The emission rates and stack parameters modeled for these nine (9) modeled SO_2 sources are listed below.

Modeled SO_2 Sources in the WAAQS Analysis

Facility/Source Name	Source Modeling ID	SO_2 Emission (lb/hr)	Stack Height (m)	Exit Temperature (K)	Exit Velocity (m/s)	Release Diameter (m)
Basin Electric Power Cooperative – Dry Fork	ES1_01	380.1	152.4	350	25.65	5.94
Black Hills Corporation - WYGEN 3	ES3_01	156.0	121.01	344.3	27.64	3.12
Black Hills Corporation - WYGEN 2	ES2_01	156.0	121.01	344.3	27.64	3.12
Black Hills Corporation - WYGEN 1	WYGEN1	203.2	89.9	342	27.44	2.82
Black Hills Corporation - Neil Simpson Unit 1	NSU1	351.6	76.2	443	22.04	1.83
Black Hills Corporation - Neil Simpson Unit 2	NSU2	203.2	89.9	342	27.45	2.82
PacifiCorp - Wyodak Plant	WYDK	2052.4	122	358	22.56	6.1
KFx Incorporated - K Fuels Plus Plant	EP28	51.7	76.2	419	18.13	2.18
Fx Incorporated - K Fuels Plus Plant	EP29	51.7	76.2	419	18.13	2.18

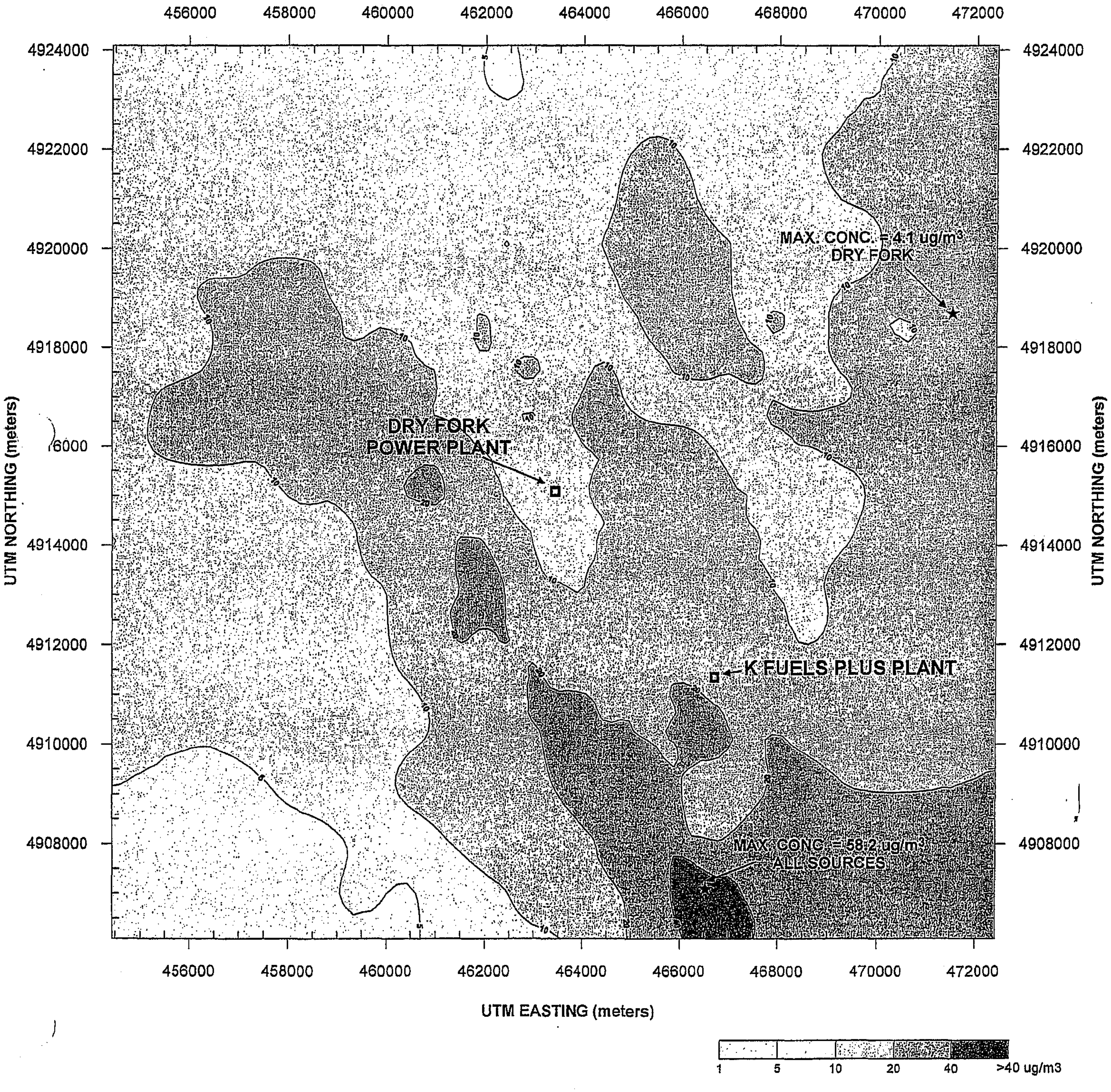
The highest second highest (HSH) modeled 24-hour ambient SO_2 concentration from all sources was 58.2 μg/m³, located at 466530 east, 4907090 north. The SO_2 contribution from Dry Fork at the maximum impact receptor location during the same 24-hour period was less than 5 μg/m³, therefore the Dry Fork Power Plant is not a significant contributor to the cumulative HSH modeled SO_2 impact. Dry Fork's HSH of 4.1 μg/m³, located at 471530 east, 4918690 north, occurred in January of 2002.

SO_2 background values used in the Wyoming Ambient Air Quality Standards (WAAQS) modeling analysis for SO_2 were obtained from the Black Hills Power Station ambient monitor (AQS Site ID 56-005-0857). The monitor is located approximately 12 kilometers southeast of Dry Fork. Monitored ambient SO_2 concentrations from 2002 through 2004 were reviewed and the highest second high concentration for each averaging period was selected as the background SO_2 concentration. The highest second high SO_2 concentration for the 24-hour (55.0 μg/m³) averaging periods both occurred in the fourth quarter of 2002.

Modeling results from the WAAQS analysis for SO_2 indicate that the ambient air quality impacts from all SO_2 sources in the project area, including the applicable background concentrations, are below the 24-hour WAAQS for SO_2. Based on the results of this analysis, the Division is satisfied that the WAAQS for SO_2 will be protected. Results of the WAAQS modeling analysis for SO_2 are provided in the following tables. An Isopleth plot of the 24-hour model predicted SO_2 concentration near the Dry Fork power plant is shown in Figure 3.

BASIN ELECTRIC POWER COOPERATIVE
DRY FORK POWER PLANT
24-HOUR AVERAGED SO_2 WAAQS ANALYSIS
SO_2 CONCENTRATION ISOPLETHS

FIGURE 3



Highest Second Highest 24-hour SO_2 Modeling Results for WAAQS Analysis

Receptor Location (Zone 13) X (m)	Y (m)	24-Hour HSH SO_2 Conc. (μg/m³)	24-Hour Background SO_2 Conc. (μg/m³)	24-Hour Total SO_2 Conc. (μg/m³)	24-Hour SO_2 WAAQS (μg/m³)	Percent of 24-hour WAAQS for SO_2
466530	4907090	58.2	55.0	113.2	260	44%

CLASS II INCREMENT ANALYSIS

♦ Sulfur Dioxide (SO_2) ♦

The applicant performed a cumulative 24-hour Class II SO_2 increment modeling analysis for the area near the Dry Fork power plant, as required in Chapter 6 Section 4(b)(i)(A)(I). Using proposed emissions for Dry Fork and current allowable emission rates for seven (7) additional sources, the applicant calculated HSH impacts of SO_2 for the 24-hour averaging period. Emission rates and stack parameters for the seven (7) sources are listed in the table below. Baseline emissions from two (2) facilities: Black Hills Corporation's Neil Simpson Unit 1 and PacifiCorp's Wyodak Plant were not included in the PSD Class II Increment analysis. Both facilities were constructed prior to the major source baseline date of January 6, 1975. Neil Simpson Unit 1, a 293 MMBtu/hr pulverized coal Foster Wheeler boiler, was constructed in 1969. Wyodak Unit 1, a 4,100 MMBtu/hr dry bottom wall-fired boiler, was constructed in 1972, but did not become operational and begin generating commercial power until 1978.

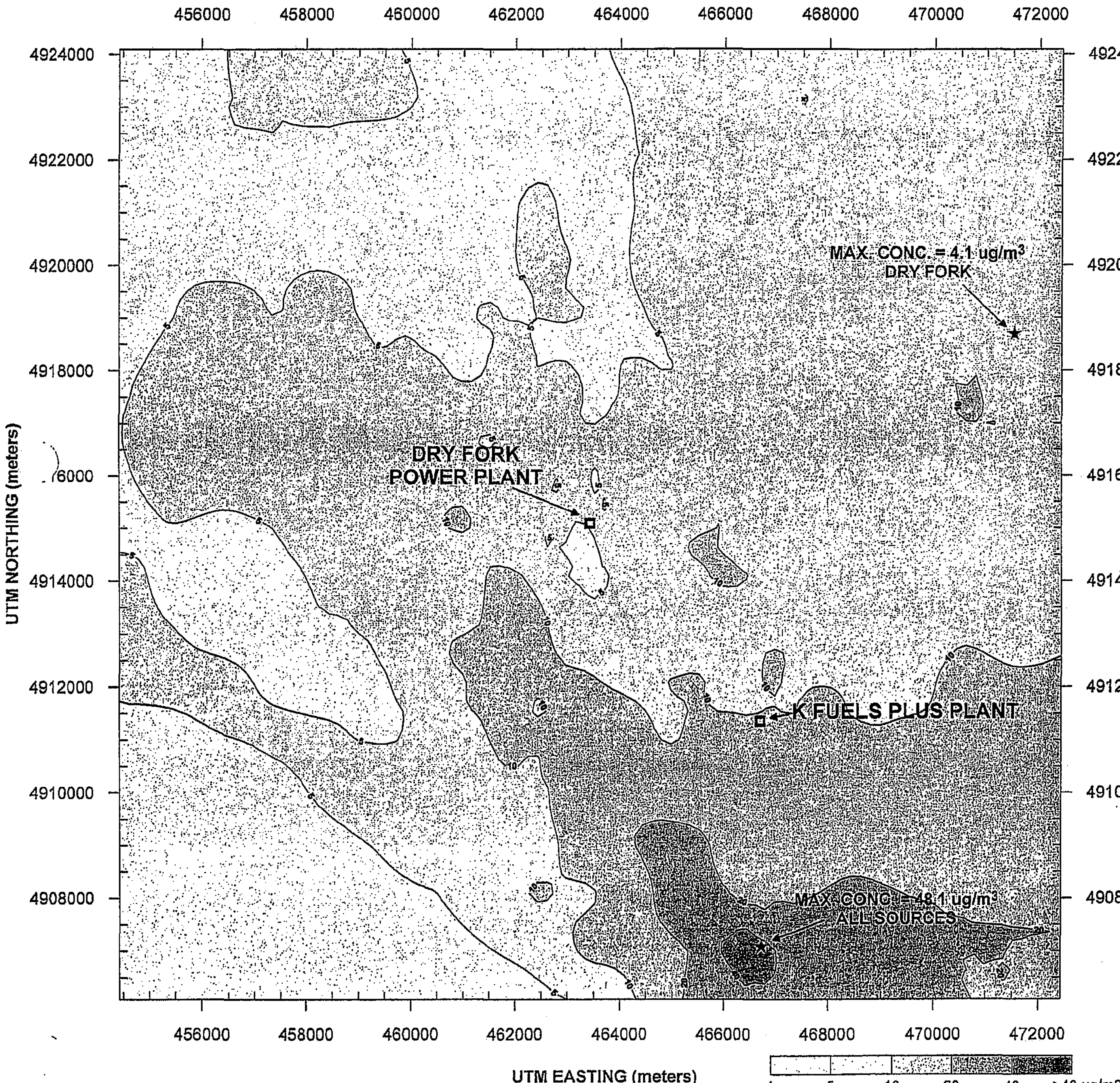
Modeled SO_2 Sources in the Class II Increment Analysis

Facility/Source Name	Source Modeling ID	SO_2 Emission (lb/hr)	Stack Height (m)	Exit Temperature (K)	Exit Velocity (m/s)	Release Diameter (m)
Basin Electric Power Cooperative – Dry Fork	ES1_01	380.1	152.4	350	25.65	5.94
Black Hills Corporation - WYGEN 3	ES3_01	156.0	121.01	344.3	27.64	3.12
Black Hills Corporation - WYGEN 2	ES2_01	156.0	121.01	344.3	27.64	3.12
Black Hills Corporation - WYGEN 1	WYGEN1	203.2	89.9	342	27.44	2.82
Black Hills Corporation - Neil Simpson Unit 1	NSU1	351.6	76.2	443	22.04	1.83
Black Hills Corporation - Neil Simpson Unit 2	NSU2	203.2	89.9	342	27.45	2.82
KFx Incorporated - K Fuels Plus Plant	EP28	51.7	76.2	419	18.13	2.18
KFx Incorporated - K Fuels Plus Plant	EP29	51.7	76.2	419	18.13	2.18

The highest second high 24-hour SO_2 increment concentration from Dry Fork was 4.1 μg/m³, located at 471530 east, 4918690 north occurring on February 22. The highest second high modeled 24-hour SO_2 increment concentration from all sources was 52.5 μg/m³, located at 466730 east, 4907090 north on May 20. The HSH impact is approximately 58% of the 91 μg/m³ 24-hour PSD Class II SO_2 Increment. The applicant demonstrated that the SO_2 PSD Class II Increment in the area surrounding the Dry Fork power plant is less than the allowable PSD Class II 24-hour Increment, as shown in the table below. A plot of the modeled PSD Class II Increment near the facility is shown in Figure 4.

BASIN ELECTRIC POWER COOPERATIVE
DRY FORK POWER PLANT
24-HOUR AVERAGED SO_2 PSD CLASS INCREMENT ANALYSIS
SO_2 CONCENTRATION ISOPLETHS

FIGURE 4



Highest Second Highest 24-hour SO_2 Modeling Results for Class II Increment Analysis

Receptor Location (Zone 13) X (m)	Y (m)	24-Hour HSH SO_2 Conc. (μg/m³)	24-Hour SO_2 Increment (μg/m³)	Percent of 24-hour Increment for SO_2
470580	4901510	52.5	91	58%

WYOMING AMBIENT AIR QUALITY STANDARDS (WAAQS) ANALYSIS

♦ Hydrogen Fluoride (HF) ♦

Total fluoride emissions, assumed to be hydrogen fluoride (HF), from the proposed Dry Fork power plant are estimated to be 11.2 tpy. HF emission factors were based on an average expected coal analysis from the Dry Fork Mine, a heat input to the boiler of 3,701 MMBtu/hr, and an annual load factor of 100% percent. HF emissions may be controlled through the use of lime spray dryer absorbers in the flue gas desulfurization (FGD) system in conjunction with a fabric filter. HF acid gases may react with lime, calcium oxide (CaO), in the SO_2 scrubbing process. The resulting particulate, calcium fluoride (CaF_2), can then be removed by the fabric filter thereby reducing HF emissions from the boiler stack.

The proposed HF emissions were modeled to determine the maximum 12-hour, 24-hour, 7-day, and 30-day concentrations of HF on the ambient air quality using an exist velocity corresponding to a 50% boiler load, which gives the highest short-term impact. ISCST3 does not have an option for calculating impacts for a 7-day averaging period. Therefore, the 24-hour impacts were assumed to conservatively represent the 7-day impacts. The maximum predicted HF impacts are summarized in the table below. Based on the results of this analysis, it is apparent that the modeled impacts of HF are well below Wyoming's standards, and no violations of the Wyoming HF standards were predicted.

Maximum Modeled Hydrogen Fluoride Impacts

Averaging Period	Dry Fork Modeled Impact (μg/m³)	HF WAAQS (μg/m³)	Percent of WAAQS for HF
12 hours	0.08	3.0	3%
24 hours	0.06	1.8	4%
7 days [1]	0.06	0.5	12%
30 days [2]	0.009	0.4	3%

[1] 24-hour impact used conservatively for the 7-day averaging periods.
[2] Monthly concentrations reported in the modeled results.

HAZARDOUS AIR POLLUTANTS (HAPs) ANALYSIS

Basin Electric Power Cooperative estimated HAP emissions for the main boiler using a coal analysis from the Dry Fork Mine, emission factors form AP-42, and engineering estimates. Short term HAP emission rates were based on a peak boiler load of 103% and a heat input of 3, 801 MMBtu/hr. Annual HAP emission rates were calculated based on a boiler load of 100% and a heat input for 3,701 MMBtu/hr, which represents worst case annual operations. Total annual HAP emissions from the Dry Fork main boiler were estimated at 34.8 tpy. Of those, 25.0 tpy were acid gas HAPs (HCl and HF), 9.3 tpy are organic HAPs, and 0.5 tpy are trace metal HAPs. A total of sixty-seven (67) HAPs were addressed in the risk assessment. A table of the emission rates for all sixty-seven (67) HAPs is shown below.

Hazardous Air Pollutant Emission Rates

Pollutant	Emission Rate (tpy)	Pollutant	Emission Rate (tpy)
Organic HAPs		**Organic HAPs**	
Biphenyl	0.00172	Ethylene dibromide	0.00121
Acenaphthene	0.00052	Formaldehyde	0.242
Acenaphthylene	0.00025	Hexane	0.0677
Anthracene	0.00021	Isophorone	0.586
Benzo(a)anthracene	0.00008	Methyl bromide	0.162
Benzo(a)pyrene	0.00004	Methyl chloride	0.535
Benzo(b,j,k)fluoranthene	0.00011	Methyl ethyl ketone	0.394
Benzo(g,h,i)perylene	0.00003	Methyl hydrazine	0.172
Chrysene	0.0001	Methyl methacrylate	0.0202
Fluoranthene	0.00072	Methyl tert butyl ether	0.0353
Fluorene	0.00092	Methylene chloride	0.293
Ideno(1,2,3-cd)pyrene	0.00006	Phenol	0.0162
Naphthalene	0.0131	Propionaldehyde	0.384
Phenanthrene	0.00273	Tetrachloroethylene	0.0434
Pyrene	0.00033	Toluene	0.242
5-Methyl chrysene	0.00002	1,1,1-Trichloroethane	0.0202
Acetaldehyde	0.576	Styrenes	0.0252
Acetophenone	0.0151	Xylenes	0.0374
Acrolein	0.293	Vinyl acetate	0.00767
Benzene	1.31	**Acid Gas HAPs**	
Benzyl chloride	0.707	Hydrochloric Acid	13.8
Bis(2-ethylhexyl)phthalate	0.0737	Hydrofluoric Acid	11.2
Bromoform	0.0394	**Trace Metallic HAPs**	
Carbon disulfide	0.131	Antimony	0.0134
2-Chloroacetophenone	0.00707	Arsenic	0.0134
Chlorobenzene	0.0222	Beryllium	0.00401
Chloroform	0.0596	Cadmium	0.00267
Cumene	0.00535	Chromium	0.0401
Cyanide	2.52	Cobalt	0.0267
2,4-Dinitrotoluene	0.00028	Lead	0.0267
Dimethyl sulfate	0.0485	Manganese	0.107
Ethyl benzene	0.0949	Mercury	0.0468
Ethyl chloride	0.0424	Molybdenum	0.0134
Ethylene dichloride	0.0404	Nickel	0.0535

The applicant performed a Tier 1 inhalation risk assessment for the Dry Fork power plant using EPA's risk assessment guidance contained in the **Air Toxics Risk Assessment Reference Library, Volume 2: Facility-Specific Assessment**, (EPA document EPA-453-K-04-001B). A Tier 1 risk assessment is a conservative screening assessment by which the chronic carcinogenic, chronic noncarcinogenic, and acute noncarcinogenic risks can be compared to a unitless reference level. Chronic carcinogenic exposure concentrations are compared to an incremental cancer risk of 1, which represents a possibility of one person developing cancer per million people exposed by inhaling the same pollutant concentration. Chronic noncarcinogenic exposure concentrations and acute noncarcinogenic exposure concentrations are compared to a hazard quotient of 1, which represents a ratio of the exposure concentration to a reference pollutant concentration that is an estimate of a continuous inhalation exposure to the human population that is likely to be without an appreciable risk of detrimental effects during a lifetime.

The applicant modeled an emission rate of 1 g/s using ISC3-PRIME and the 2002 100 meter Basin meteorological data set to calculate maximum 1-hour and annual ambient air quality impacts within the receptor grid used for the PSD Class II SILs analyses. The maximum modeled annual impact occurred when the boiler was operating at 100% load and the maximum modeled short term impact occurred when the boiler was operating at 103% load. Chronic carcinogenic maximum exposure concentrations were calculated by multiplying the annual maximum modeled concentration based on the 1 g/s emission rate by each individual HAP emission rate. An inhalation unit risk factor, which quantifies the number of people that could potentially contract cancer per million people in an average population, was obtained for each known or suspected carcinogen. The maximum exposure risk was then calculated for each HAP by multiplying each maximum model predicted annual concentration by the unit risk factor, and multiplying this estimated value by one million to determine the risk on the basis of 1 in a million. The sum of all individual chronic carcinogenic risks was less than 0.2, below the screening threshold of 1. The five (5) HAPs with the highest individual risks account for over 99% of the total chronic carcinogenic risk. They are listed in the table below.

Significant Chronic Carcinogenic Contributors

Pollutant	Dry Fork Emission (g/s)	Dry Fork Predicted HAP Concentrations ($\mu g/m^3$)	Unit Risk Factor $1/(\mu g/m^3)$	Calculated Risk (risk/million)
Chromium	1.15×10^{-3}	9.87×10^{-6}	1.20×10^{-2}	0.118
Arsenic	3.85×10^{-4}	3.29×10^{-6}	4.30×10^{-3}	0.014
Benzyl Chloride	2.03×10^{-2}	1.74×10^{-4}	4.90×10^{-5}	0.009
Benzene	3.77×10^{-2}	3.23×10^{-4}	7.80×10^{-6}	0.003
Beryllium	1.15×10^{-4}	9.87×10^{-7}	2.40×10^{-3}	0.002
Sum of the calculated risk from the top 5 chronic carcinogens				0.146

Chronic noncarcinogenic exposure concentrations were calculated by multiplying the maximum modeled annual ambient air impact concentration by each HAP emission rate. Exposure concentrations were then divided by a pollutant-specific reference concentration to calculate the hazard quotient. The reference concentration is a gross estimate of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of harmful effects during a lifetime. Summing the individual hazard quotients, the chronic noncarcinogenic risk estimate was 0.8, below the screening level of 1. Six (6) HAPs account for 93% of all chronic noncarcinogenic risk. They are listed in the table below.

Significant Chronic Noncarcinogenic Contributors

Pollutant	Dry Fork Emission (g/s)	Dry Fork Predicted HAP Concentrations (mg/m^3)	Reference Concentration (mg/m^3)	Hazard Quotient
Acrolein	8.91×10^{-3}	1.06×10^{-5}	2.00×10^{-5}	0.528
Manganese	3.25×10^{-3}	3.86×10^{-6}	5.00×10^{-5}	0.0771
Hydrofluoric Acid	3.30×10^{-1}	3.92×10^{-4}	1.40×10^{-2}	0.0281
Hydrochloric Acid	4.07×10^{-1}	4.83×10^{-4}	2.00×10^{-2}	0.0241
Nickel	1.63×10^{-3}	1.93×10^{-6}	9.00×10^{-5}	0.0214
Arsenic	4.07×10^{-4}	4.82×10^{-7}	3.00×10^{-5}	0.0161
Sum of the hazard quotients from the top 6 chronic noncarcinogens (unitless)				0.695

Acute noncarcinogenic exposure concentrations were calculated by multiplying the maximum modeled 1-hour ambient air impact concentration by each HAP emission rate. Exposure concentrations were then divided by a pollutant-specific acute dose-response concentration to calculate the acute hazard quotient. Acute dose-response concentrations were collected from several sources: U.S. Environmental Protection Agency Acute Exposure Guideline Levels, the U.S. Department of Health and Human Services Agency for Toxic Substances and Disease Registry (ATSDR), the U.S. Department of Health and Human Services National Institute for Occupational Safety and Health, the U.S. Department of Energy Emergency Removal Program guidelines, the U.S. Department of Energy Temporary Emergency Exposure Limits, and California EPA Reference Exposure Levels. The most stringent of the six (6) sources of pollutant exposure levels was used as the acute dose-response concentration to calculate each pollutant acute hazard quotient.

Summing the individual acute hazard quotients, the acute noncarcinogenic risk estimate was less than 0.003, well below the screening level of 1. Seven (7) HAPs account for 92% of all acute noncarcinogenic risk. They are listed in the table below.

Significant Acute Noncarcinogenic Contributors

Pollutant	Dry Fork Emissions (g/s)	Dry Fork Predicted HAP Concentrations (mg/m^3)	Most Stringent Acute Dose-Response Value (mg/m^3)	Hazard Quotient
Hydrofluoric Acid	3.30×10^{-1}	3.92×10^{-4}	0.24	0.00163
Benzene	3.99×10^{-2}	4.73×10^{-5}	0.16	0.00030
Hydrochloric Acid	4.07×10^{-1}	4.83×10^{-4}	2.1	0.00023
Benzyl Chloride	2.15×10^{-2}	2.55×10^{-5}	0.24	0.00011
Acrolein	8.91×10^{-3}	1.06×10^{-5}	0.11	0.00009
Cyanide	7.67×10^{-2}	9.10×10^{-5}	2.5	0.00004
Methyl Bromide	2.08×10^{-4}	7.25×10^{-6}	0.19	0.00004
Sum of the hazard quotients from the top 7 acute noncarcinogens (unitless)				0.00244

Exposure concentrations in the Tier 1 risk assessment for Dry Fork were based on emission estimates and maximum modeled near-field ambient impacts from the main pulverized coal boiler. Reference concentrations used calculate risk were the most stringent of the concentrations available. Cumulative chronic carcinogenic risk, chronic noncarcinogenic risk, and acute noncarcinogenic risk were all below the respective screening value of 1.

SOILS AND VEGETATION ANALYSIS

Basin Electric Power Cooperative researched the soils and vegetation classifications in the project area. The dominant vegetation in the area is Wyoming big sagebrush, mixed prairie grasses, and dry land crops. Soil types in the project area are classified as plains, dissected plains, and floodplain soils, and are typically alkaline soils. Oaks 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.

NAAQS, or equivalently, the WAAQS have been established to protect public health and welfare from any adverse effects of criteria pollutants. The modeling analyses for NO_2, SO_2, PM_{10}, and HF indicate that the ambient air quality impacts are below the respective WAAQS. Based on the modeling analyses and literature review submitted in the application, it is expected that the operation of the proposed Dry Fork power plant will not adversely impact soils and vegetation in the near vicinity.

SECONDARY AMBIENT AIR IMPACTS ASSOCIATED WITH THE PROJECT

Secondary growth is an indicator of potential increases in air quality pollution levels and changes in ambient air quality due to population increases, and is related to the amount of increased vehicle traffic, the addition of new commercial and industrial facilities, and domestic fuel usage.

Basin Electric Power Cooperative reported that there will be a temporary increase of up to approximately 623 workers in the local labor force during the construction phase of Dry Fork. Most of these workers will commute from nearby towns, resulting in a temporary increase in transportation-related emissions. After the construction phase is complete, up to 75 additional permanent positions will be added to operate the power plant. The 2000 Census reported 33,698 people living in Campbell County. Adding 75 new positions at the Dry Fork power plant may increase the county population by less than 0.3%. Therefore, the proposed Dry Fork power plant is not expected to cause significant commercial, residential, or secondary industrial growth-related ambient air impacts.

Near-Field Modeling Analysis Summary:

The modeling analysis indicates that the model predicted concentrations for all applicable averaging periods of NO_2, CO, and PM_{10} are below the PSD Class II modeling significance levels. 3-hour SO_2 and annual SO_2 modeled concentrations are also below the applicable PSD Class II modeling significance level. Modeled cumulative 24-hour SO_2 concentrations for Dry Fork and sources in the near vicinity are below the applicable 24-hour Wyoming Ambient Air Quality Standards and the PSD Class II Increments. Based on results of this analysis, the Dry Fork power plant is expected to be in compliance with all applicable ambient standards and PSD Class II Increments.

FAR-FIELD MODELING ANALYSIS

Congress has established certain areas, such as wilderness areas and national parks for which the PSD regulations provide special protection of the air quality resources from the impacts of various types of anthropogenic (man-made) pollution. The Division considers 100 kilometers (km) to be a representative distance whereby the emissions from a proposed major source or major modification has the potential to significantly affect a Class I area; the Dry Fork project is located at a distance greater than 100 km from the three (3) nearest Class I areas, which are Wind Cave and Badlands National Park in South Dakota, and Northern Cheyenne Indian Reservation (NCIR) in southern Montana. Wind Cave and Badlands National Parks are managed by the National Parks Service (NPS).

The distance from the Dry Fork project to these three (3) Class I areas are provided below, and is depicted along with the composite receptor grids used in the Class I area modeling analyses, as shown in Figure 7:

UTM Coordinates Dry Fork	Wind Cave	Badlands NP	N. Cheyenne I.R.
(Zone 13: 463,406, 4,915,229)	180 km	220 km	135 km

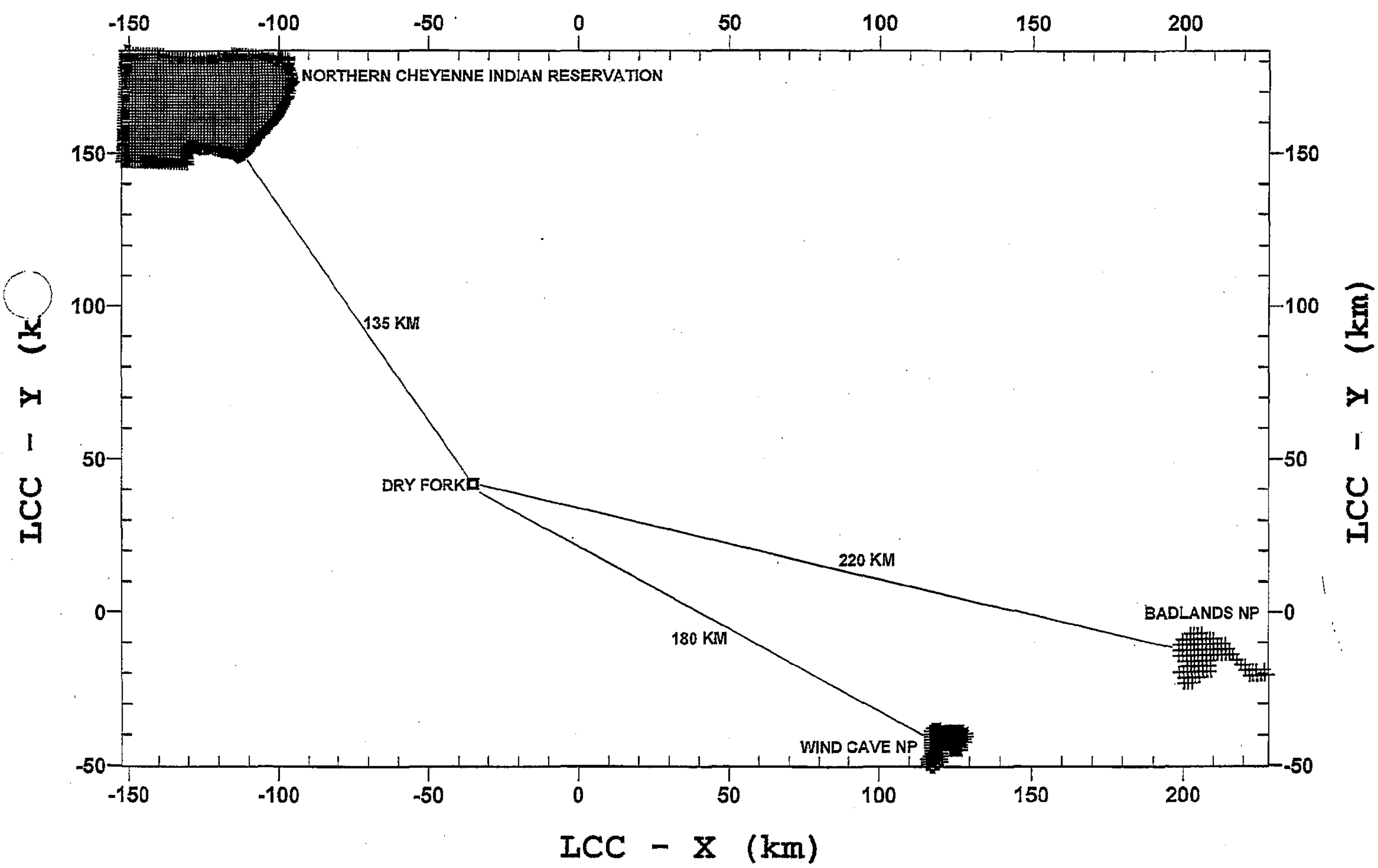
Although the Dry Fork project is located at a distance greater than 100 kilometers from the nearest Class I areas, through discussions with the National Park Service, and by agreement, it was determined that the applicant would be required to submit a Class I area significant impact analysis, as well as analyses of the impacts to visibility, and assess the significance of nitrogen and sulfur deposition from the proposed construction using the CALPUFF modeling system.

Model Justification:

To evaluate potential impacts at receptors farther away than 50 km from the Dry Fork plant, the applicant used the CALPUFF model, which is a Long Range Transport (LRT) model. The CALPUFF modeling system consists of a meteorological data pre-processor (CALMET), an air dispersion model (CALPUFF), which uses meteorological data processed by the CALMET model, and a post-processor program (CALPOST), which is used to average and report concentrations or wet/dry deposition flux results based on hourly concentration (or deposition) values estimated by CALPUFF. The CALPUFF model was developed as a non-steady-state air quality modeling system for assessing the effects of pollutants on air

DRY FORK
DISTANCE TO CLASS I AREAS

FIGURE 7



quality due to LRT, and has recently been designated as an Appendix A model in the Guideline on Air Quality Models for assessing the effects of multiple primary and secondarily formed pollutants.

Specifically, the current EPA version of the CALPUFF modeling system was used to conduct the far-field modeling assessments, formerly the beta test version. The current version reflects changes to the original release version of the CALPUFF modeling system that have been identified and reported to the model developer. The current version of the CALPUFF modeling system was recently accepted by the EPA. The changes made to the beta-test versions address known problems with the current official release of the CALPUFF modeling system which have been identified in four (4) modules of the CALPUFF modeling system: CALMET, READ62, SMERGE, and CALPUFF. The latest version was updated July 16, 2004.

CALMET Model:
CALMET is a diagnostic wind model that develops hourly wind and temperature fields in a three-dimensional gridded modeling domain based on meteorological inputs provided, including surface and upper air observations from multiple meteorological monitoring stations in the CALMET domain. Associated two-dimensional fields such as mixing height, land use and land cover, and surface roughness of the terrain are included in the files as inputs to the CALMET model. CALMET utilizes a diagnostic wind field generator to adjust the winds using objective analysis procedures, parameterized treatments of diurnal slope flows, kinematic terrain effects, terrain blocking effects, a divergence minimization procedure, and a micro-meteorological model for overland and overwater boundary layers to produce a uniform homogenous wind field.

Additionally, the CALMET model can utilize gridded analysis fields from various mesoscale models such as MM5 to better represent regional wind flows and slope/valley circulations. The CALMET model allows the user to "weight" various terrain influence parameters in the vertical and horizontal directions by defining the radius of influence for surface and upper air station observations in the CALMET modeling domain to better characterize localized meteorological conditions. Version 5.53a, Level 040716 of the CALMET model was used by the applicant to generate the resulting CALMET wind fields that were used in the CALPUFF modeling analyses.

CALPUFF Model:
CALPUFF is a multi-layer, multi-species, non-steady state Lagrangian puff dispersion model which can simulate the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF can use the three-dimensional wind fields developed by the CALMET model (refined mode), or single surface and upper air station data in a format consistent with the meteorological file used to drive the ISCST3 steady-state dispersion model (screening mode). All far-field modeling assessments, including the significance analysis, acid deposition and visibility modeling analyses were completed using the CALPUFF model in a refined mode.

CALPUFF uses terrain-following coordinates and has several options available to consider terrain effects in predicting ground-level concentrations. CALPUFF also has the ability to treat sub-grid scale complex terrain features, and contains a puff splitting algorithm that is based on the dividing streamline concept, as calculated internally by the model. CALPUFF also has the ability to incorporate several optional methods for estimating dispersion coefficients based on similarity theory, turbulence measurements, Pasquill-Gifford or McElroy-Pooler dispersion coefficients.

CALPUFF contains algorithms for near-source effects such as building downwash, transitional plume rise, partial plume penetration, sub-grid scale terrain interactions, as well as longer range effects such as vertical wind shear, wet scavenging, dry deposition, and chemical transformation using aqueous-phase or dry-phase chemistry. CALPUFF can accommodate arbitrarily-varying point source and gridded area emissions. Most of the algorithms in CALPUFF contain options to treat the physical processes associated with the air quality analysis at different levels of detail depending on the switches used in the model simulation. Version 5.711a, Level 040716 of the CALPUFF model was used in the far-field modeling analyses.

POSTUTIL Model:
POSTUTIL is a post-processing program that processes CALPUFF concentration and wet/dry flux files; the POSTUTIL post-processor handles weighted concentrations of various modeled species, and the HNO_3 =>NO_3 partition. The POSTUTIL model operates on one or more output data files from CALPUFF to sum, scale, repartition (nitrates), and/or compute species derived from those that are modeled, and outputs selected species to a single file for CALPOST processing. The applicant used POSTUTIL to post-process the CALPUFF predicted hourly wet and dry deposition fluxes of nitrate species from the proposed modification to derive total nitrate deposition fluxes, which were then processed by CALPOST to calculate total annual nitrogen (N) deposition due to NO_x, HNO_3, and the ammonium ion (NH_4) from ammonium nitrate (NH_4NO_3) and ammonium sulfate ($(NH_4)_2SO_4$). Version 1.31, Level 030528 of the POSTUTIL model was used in the applicant's far-field modeling analyses.

CALPOST Model:
CALPOST is a post-processing program that is designed to read the CALPUFF binary-formatted output files and POSTUTIL output files, and produce ranked tabulations of selected pollutant concentrations for computing time-averaged concentrations and deposition fluxes predicted by the CALPUFF model. In addition to using CALPOST to post-process the deposition fluxes of total nitrogen (N) and total sulfur (S), the applicant used CALPOST to post-process the CALPUFF predicted NO_x, HNO_3, and NO_3 concentrations with the hourly relative humidity data to determine visibility impacts from the proposed modification. Version 5.51, Level 030709 of the CALPOST model was used in the applicant's far-field modeling analyses.

Computational & Sampling Grids:
The computational grid used to define the modeling domain for the far-field analyses was developed by the Division in 2002 for the WYGEN 2 analysis. This same computational grid was used for each of the three meteorological years (2001, 2002, and 2003) that were modeled in the far-field analyses. The computational grid consists of 168 (east-west) by 118 (north-south) 4 km x 4 km grid cells covering the source region, as well as all the Class I and Class II sensitive areas of interest, with a sufficient buffer zone for potential recirculation or flow reversal effects to be evaluated; the aerial extent of the computational grid is 672 km x 472 km.

In defining the vertical resolution of the wind field, the applicant used nine (9) levels to resolve the mixing depth with fine resolution used for the lower layers, and coarser resolution used for layers aloft. The nine (9) vertical levels (NZ) that were defined by the applicant in the CALMET simulations were as follows (ZFACE = 0, 20, 50, 100, 250, 500, 750, 1000, 1500, and 3500 meters). The Division, in re-running the CALMET wind field, and subsequent far-field modeling analyses, used the CALMET wind field recently developed for the BART exemption modeling analyses, which uses ten (10) vertical levels (ZFACE = 0, 20, 40, 100, 200, 350, 500, 750, 1000, 2000, and 3500 meters). Effectively, the Division's wind field enhances the vertical resolution between 200 and 500 meters, which is the approximate range of the effective stack height of the Dry Fork boiler stack. All of the results reported in this analysis were based on using the Division's wind field.

Due to the size of this computational grid, the curvature of the earth must be taken into account when calculating distances. To account for the earth's curvature in the modeling domain, the grid cells are identified using a Lambert Conic Conformal (LCC) projection; the locations of sources and receptors used in the CALPUFF analyses were converted to this projection to maintain the correct georeference.

The reference coordinates of the southwest corner of grid cell (1,1) used in generating the computational grid were (-350, -250), and are in units of in kilometers (km). The values of XLAT1 and XLAT2, which are [30 degrees N (latitude), 60 degrees N (latitude)], respectively, are used in conjunction with the reference coordinates to map these coordinates into the Lambert Conic Conformal (LCC) projection. All LCC coordinates are based on the applicant's computational grid with an origin of (0,0) and are based on the values of RLAT0 and RLON0, which are (44.0 degrees north latitude, 105.0 degrees west longitude).

Discrete receptors for the CALPUFF modeling have been made available by the National Park Service (NPS) for PSD Class I areas around the country; the receptors specified by the NPS for the Wind Cave and Badlands Class I areas were used in the applicant's far-field modeling analyses. The NPS database does not include the Northern Cheyenne Indian Reservation. For this Class I area, a finer resolution receptor grid was provided by the Division, which includes receptors along the boundary and interior area of the NCIR; this receptor grid resolution is approximately 1 km. This particular receptor grid for the NCIR was employed in the latest NCIR modeling analysis using AERMOD, which was reviewed by both the Montana DEQ and EPA Region VIII with respect to Class I SO_2 increment consumption at the NCIR. The number of receptors used in the CALPUFF modeling analyses for Badlands and Wind Cave National Parks totaled 100 and 189 receptors, respectively, and the number of receptors used in the CALPUFF modeling analysis for the Northern Cheyenne Indian Reservation was 2,044 receptors.

Additionally, the applicant used discrete receptors around Devils Tower National Monument, a Class II area, that were generated at approximately 1 km resolution along the boundary and throughout the interior of the monument, totaling 19 receptors. The Division also considered pollutant impacts at two other Class II areas, Jewel Cave and Mount Rushmore; each had a single receptor added to represent these Class II areas. Terrain elevations for the 289 discrete receptors that make up the sampling grid for Badlands NP and Wind Cave NP were based on the extraction routine used by the NPS in developing their Class I area receptor grids; the terrain data were obtained from United States Geological Survey (USGS) 1:250,000 scale (1 degree) Digital Elevation Models (DEMs). Elevation data for each DEM point are provided in latitude and longitude (seconds), and the corresponding elevation (meters). Spacing of the DEM data points is three (3) arc-seconds in both the north-south and east-west directions.

Meteorological Data:

Based on current EPA guidance contained in the document; Guideline on Air Quality Models, which took effect on April 15, 2004, for Long Range Transport and complex winds applications, the use of less than five (5), but at least three (3) years of assimilated mesoscale meteorological data is required. Three (3) years of MM5 data, (2001, 2002, and 2003) were used to initialize the corresponding CALMET "initial guess" wind fields. All three years of MM5 data were developed using 36 km resolution. Surface data for 2001-2003 were obtained from the National Climatic Data Center. This surface data originated from the available stations from the National Weather Service's (NWS) Automated Surface Observation

System (ASOS) network within the modeling domain. Upper air data was obtained from Rapid City, South Dakota to adjust the Step 2 wind field. The Rapid City station was chosen because it is located between the Dry Fork source and two of the Class I areas in question, and is representative of the area. Other upper air stations in the region were located outside the CALMET modeling domain or near the edge of the domain, and were considered too distant, and consequently not used in the modeling analysis.

The geophysical, prognostic, surface air, upper air, and precipitation data were processed and merged into the required files to generate the necessary CALMET.DAT files to run three (3) years of CALPUFF model simulations. The resulting processed CALMET.DAT files contain gridded fields of u, v wind components, mixing heights, PGT stability categories, micro-meteorological parameters, and precipitation data based on the meteorological data input to the CALMET diagnostic wind model to produce the three-dimensional wind fields. The LCC definition used to define coordinate locations for the sources, receptors, and meteorological sites was the same for each of the three (3) meteorological data years.

Emission Rates and Stack Parameters:

Stack parameters for the emission sources that were represented in the applicant's significant impact analysis, visibility analysis, and acid deposition analysis are provided in Table 6.

Table 6
Stack Parameters and Emission Rates for New Sources

Source	LC-X Coordinate (km)	LC-Y Coordinate (km)	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Base Vel. (m/s)	Stack Temp. (deg. K)	Emission Rates SO2 lb/hr	SO4 lb/hr	NOx lb/hr	PM10 lb/hr	OC lb/hr
DRY FORK	-35.191	41.79	152.4	1295	5.94	25.65	350	380.1	10.4	266.1	51.5	1.9
Total Emissions (TPY):								**1664.8**	**45.6**	**1165.5**	**225.6**	**8.3**

Class I Area Significant Impact Analysis:

Guidance contained in the Federal Register/Vol. 61, No. 142/ Tuesday, July 23, 1996/Proposed Rules was proposed by the U.S. EPA to determine whether a new source has an insignificant ambient impact on a Class I area. This guidance introduced a set of Class I area Significant Impact Levels (SILs) to be used as the metric for assessing the ambient impacts at Class I areas from potentially insignificant sources; the Class I SILs are based on a percentage of the Class I increments for each respective averaging period. In the EPA's Proposed Rules, a new source or proposed modification which can be shown, using air quality models, to have ambient impacts below De Minimis levels would not be required to conduct a comprehensive Class I increment consumption analyses for each applicable criteria pollutant.

The proposed EPA Class I Significant Impact Levels (SILs) for NO_2, SO_2, and PM_{10} used in this analysis are provided below:

Criteria Pollutant	Averaging Period	Class I SIL
NO_2	Annual	0.1 ug/m^3
SO_2	3-hour	1.0 ug/m^3
SO_2	24-hour	0.2 ug/m^3
SO_2	Annual	0.1 ug/m^3
PM_{10}	24-hour	0.3 ug/m^3
PM_{10}	Annual	0.2 ug/m^3

In the Class I area significance analysis, the Division's review demonstrated that maximum modeled concentrations from the Dry Fork plant were below all respective Class I SILs for each pollutant at Wind Cave NP and Badlands NP for each year. However, for the Northern Cheyenne Indian Reservation, the modeling analysis demonstrated that the 24-hr significance level for SO_2 was exceeded with the 2002 and 2003 meteorology. The results of the Division's analysis are provided below:

Class I Significance Analysis: Significant Impact of Dry Fork ($\mu g/m^3$)						
Class I Area	**Annual NO_2**	**3-hour SO_2**	**24-Hour SO_2**	**Annual SO_2**	**24-Hour PM_{10}**	**Annual PM_{10}**
2001						
Wind Cave NP	0.003	0.35	0.16	0.009	0.006	0.0003
Badland NP	0.001	0.27	0.08	0.006	0.002	0.0001
Northern Cheyenne Indian Reservation	0.003	0.71	0.19	0.009	0.013	0.0005
2002						
Wind Cave NP	0.002	0.41	0.15	0.011	0.005	0.0004
Badland NP	0.002	0.25	0.11	0.007	0.002	0.0002
Northern Cheyenne Indian Reservation	0.002	0.65	**0.21**	0.006	0.011	0.0003
2003						
Wind Cave NP	0.004	0.35	0.13	0.012	0.004	0.0005
Badland NP	0.001	0.18	0.07	0.007	0.001	0.0001
Northern Cheyenne Indian Reservation	0.002	0.72	**0.23**	0.007	0.010	0.0004
Class I Significance Levels	**0.1**	**1.0**	**0.2**	**0.1**	**0.3**	**0.2**

When the applicant used their wind field, the maximum modeled impacts for the Dry Fork plant for 2001-2003 were below all Class I modeling significance levels (SIL) for all pollutants at Wind Cave NP and Badlands NP. However, for the Northern Cheyenne Indian Reservation (NCIR), the applicant's modeling analysis demonstrated that the 3-hour significance level for SO_2 was exceeded with 2003 meteorology. In addition, the 24-hour significance level for SO_2 was exceeded with the 2001 and 2003 meteorology.

As a result of the Division's modeling exceedances for 24-hr SO_2, a cumulative SO_2 increment consumption analysis at Northern Cheyenne Indian Reservation was performed, using an expanded version of the wind field.

The CALMET/CALPUFF modeling domain was expanded to include more distant sources, and was centered on the Northern Cheyenne Indian Reservation; the applicant's expanded CALMET/CALPUFF modeling domain consisted of 150 x 150 grid cells covering a region 600 km x 600 km, based on a grid cell resolution of 4 km. All technical options used in the original analysis for Dry Fork were also used in the cumulative modeling analysis. Additional surface and precipitation stations were used in the development of the expanded domain to provide sufficient surface and precipitation data within the expanded domain. No additional upper air observations were used in the development of the expanded domain.

For the cumulative analysis, the applicant included several emission sources located within a 300 km radius of Northern Cheyenne Indian Reservation, which included sources located in southern Montana, northern Wyoming, and southwest North Dakota. The only source in North Dakota included in the analysis was 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 Northern Cheyenne Indian Reservation; 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 of the low emissions and the large distance away from the Northern Cheyenne Indian Reservation, these sources of SO_2 were not included in the cumulative Class I area increment consumption analysis.

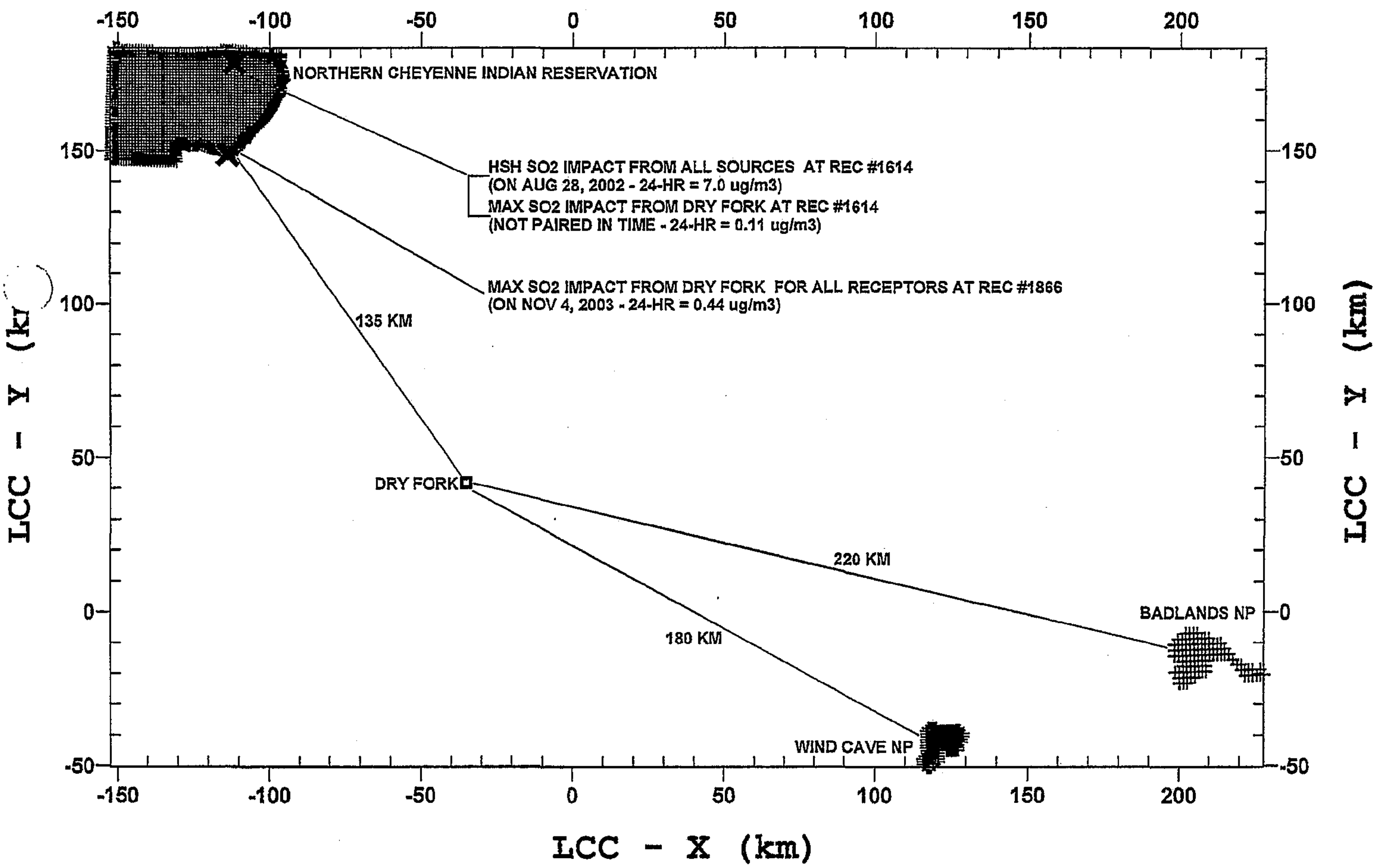
Results of the cumulative analysis showed there were modeled exceedances of the 24-hour Class I SO_2 increment predicted by the CALPUFF model for the 2002 and 2003 years of meteorology. Therefore, the Division evaluated the significance of the Dry Fork plant, paired in space and time, at the times and at the receptor locations where each exceedance was predicted in 2002 and 2003. The cumulative results were sorted on the receptors and respective time periods where the highest second high (HSH) modeled concentration exceeded the 24-hr Class I SO_2 increment. The maximum modeled impact from the Dry Fork plant were then compared to the EPA proposed 24-hour Class I significance level for SO_2 to determine if the Dry Fork plant contributed significantly to any modeled exceedance of the Class I SO_2 increment, with the impacts paired in space and time. For both 2002 and 2003, the Dry Fork plant had insignificant impacts with respect to the model predicted exceedances of the 24-hour SO_2 Class I increment. It was concluded, as a result, that the impacts from Dry Fork do not contribute significantly to any of the modeled SO_2 exceedances at the Northern Cheyenne Indian Reservation. The applicant's results are provided below, with graphical results provided in figure 8:

Cumulative Modeled Class I SO_2 Increment Consumption in Northern Cheyenne I.R. (Dry Fork-only project max-impact contribution in parentheses)	
Year of Meteorology	**Highest 2nd-high 24-hour SO_2**
2001	4.9 (0.19) μg/m³
2002	7.0 (0.11) μg/m³
2003	5.8 (0.20[1]) μg/m³
Class I SO_2 Increment	**5 μg/m³**
Class I Modeling SIL	**0.2μg/m³**

[1] Dry Fork-only project max-impact contribution rounded up to 0.20 ug/m3.

DRY FORK
REFINED LEVEL CALPUFF 24-HR SO2 CLASS I INCREMENT ANALYSIS

FIGURE 8



Class II Area Significant Impact Analysis:
The applicant compared the CALPUFF model predicted concentrations of all criteria pollutants at Devils Tower, with additional consideration by the Division at Jewel Cave and Mt. Rushmore. Approximate distances are provided below:

UTM Coordinates-Dry Fork	Devils Tower	Jewel Cave	Mt. Rushmore
(Zone 13: 463,406, 4,915,229)	65 km	150 km	146 km

The review of the significance analysis, based on using the Division's CALMET wind field, demonstrates that the maximum modeled concentrations from the Dry Fork plant produced impacts that were well below the respective Class II SILs for all applicable pollutants at Devil's Tower, Jewel Cave, and Mount Rushmore, for all three (3) years that were modeled. Therefore, no cumulative analyses were required. The results of this analysis are provided below:

Class II Significance Analysis: Significant Impact of Dry Fork

Class II Area	Annual NO_2	3-hour SO_2	24-Hour SO_2	Annual SO_2	24-Hour PM_{10}	Annual PM_{10}
2001						
Devils Tower	0.020	2.00	0.40	0.04	0.04	0.003
Jewel Cave	0.005	0.66	0.22	0.01	0.01	0.0006
Mount Rushmore	0.003	0.28	0.07	0.009	0.002	0.0003
2002						
Devils Tower	0.03	2.40	0.67	0.06	0.07	0.006
Jewel Cave	0.006	0.80	0.28	0.02	0.01	0.0008
Mount Rushmore	0.004	0.50	0.15	0.01	0.004	0.0003
2003						
Devils Tower	0.03	2.00	0.67	0.05	0.07	0.005
Jewel Cave	0.007	0.87	0.31	0.02	0.02	0.0009
Mount Rushmore	0.004	0.45	0.17	0.01	0.007	0.0004
Class II Significance Levels	**1.0**	**25.0**	**5.0**	**1.0**	**5.0**	**1.0**

Visibility Analysis:
The change in visible light extinction, or change in visibility from the Dry Fork plant was based on the CALPUFF modeled concentrations of primary and secondary pollutants emitted as a result of the proposed construction. Secondary pollutants include: nitrate (NO_3), sulfate (SO_4) and particulate (filterable and condensable).

The proposed NO_x, SO_x, and particulate emission rates, along with the stack parameters for the emission sources that were represented in the applicant's visibility analysis are provided in Table 6.

CALPOST Method 2 and Method 6 were used in the visibility analysis. CALPOST Method 2 was used to post-process hourly relative humidity values from the surface data file, which is the recommended CALPOST post-processing method provided in the Federal Land Managers Air Quality Workgroup's (FLAG) Phase I Report, (December 2000) for a refined CALPUFF visibility analysis. In CALPUFF and CALPOST, relative humidity data are used as a surrogate for cloud water and water vapor to account for the formation of, and hygroscopic growth of secondarily-formed particles, such as sulfates and nitrates. Specifically, the relative humidity data are used in a CALPUFF visibility modeling in two ways:

In the CALPUFF chemical transformation module that forms sulfate and nitrate, based on the relative humidity adjustment factor [*f*(RH)] that is applied to ammonium sulfate (SO_4) and ammonium nitrate (NO_3) concentrations is used to estimate visible light extinction from the source ($b_{ext,source}$):

Where: $$b_{ext,source}(SO_4+NO_3) = 3 \times f(RH) \times \{[SO_4] + [NO_3]\}$$

The *f*(RH) relative humidity adjustment factor is particularly important as at high relative humidity levels, small changes in relative humidity can make large changes in the modeled visibility impacts from sulfates and nitrates. For example, based on the current Tang relative humidity adjustment factor curve, an increase in relative humidity of 5% and 8% from a 90% RH level will increase the f(RH) value by a factor of approximately 2 and 4, respectively.

Background light extinction ($b_{ext,bkgd}$) values due to natural aerosols in the atmosphere for the Class I areas of interest were calculated within CALPOST using the equation:

$$b_{ext,bkgd} = b_{hygroscopic} \times f(RH) + b_{NonHygroscopic} + Rayleigh$$

Where: $b_{hygroscopic}$, $b_{NonHygroscopic}$, and Rayleigh light scattering components are provided in Appendix 2.B of the FLAG Phase I Report.

In the FLAG Phase I Report, the values for $b_{hygroscopic}$ (0.6 Mm^{-1}), $b_{NonHygroscopic}$, (4.5 Mm^{-1}), and Rayleigh scattering (10 Mm^{-1}) are identical for the Wind Cave and Badlands National Parks; these specified values are intended to represent the current FLAG-recommended estimates of "natural background" for these two (2) Class I areas and the Class II areas. The background extinction values were not provided for Northern Cheyenne Indian Reservation. It was assumed, however, that the background extinction provided in the FLAG document for Badlands NP and Wind Cave NP will also apply to the Northern Cheyenne Indian Reservation.

Hourly ozone data were used in the analysis. The ozone data was compiled from Thunder Basin National Grasslands in Wyoming, located 32 miles north of Gillette, and the Robbinsdale site near Rapid City, South Dakota. The applicant compiled all available data from these sites into a model-ready ozone input file. For periods of missing data, monthly default values were input into CALPUFF. Default values were determined by the monthly averages from all available data, which included data from a National Park Service (NPS) station at Badlands National Park. The highest monthly average for a given month from all three stations was used as the default value.

The model predicted visibility impacts were based on the maximum-modeled 24-hour average sulfate (SO_4), nitrate (NO_3), and particulate concentrations ($\mu g/m^3$) predicted by the CALPUFF model. The nitrate and sulfate transformation rates were computed internally by the CALPUFF model using the MESOPUFF II chemistry scheme, which assumes that all nitrate and sulfate flux fully convert to ammonium sulfate ($(NH_4)_2SO_4$) and ammonium nitrate ($(NH_4)NO_3$). The 24-hour source light extinction ($b_{ext,source}$), expressed in inverse Megameters (Mm^{-1}) was determined by the CALPOST model using the following equation:

$$b_{ext,source} = ((1.375*SO_4^{=} + 1.29*NO_3^{-}*f(RH))*3) + PM_{10}*0.6 + OC*4 + EC*10$$

Where:

1.375	=	ratio of ammonium sulfate to sulfate molecular weights
1.29	=	ratio of ammonium nitrate to nitrate molecular weights
f(RH)	=	hourly relative humidity factor for a given hour
3	=	light scattering efficiency for nitrates and sulfates (m^2/gram)
0.6	=	light scattering efficiency for coarse part PM_{10}-$PM_{2.5}$ (m^2/gram)
4	=	light scattering efficiency for organic carbon (m^2/gram)
10	=	light scattering efficiency for elemental carbon (m^2/gram)

The 24-hour average source and seasonal background extinction, expressed in Mm^{-1}, were used to estimate the corresponding 24-hour average change in light extinction by the following equation:

$$\Delta b_{ext}^{\%} = (b_{ext,source}/b_{ext,bkgd})*100$$

Where: $\Delta b_{ext}^{\%}$ is the incremental change in visibility, expressed in percent (%)

Using Method 2, the maximum CALPUFF predicted 24-hour concentrations of SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10} and SOA were used to calculate the change in light extinction resulting from the impact of the Dry Fork plant. The change in visible light extinction was compared to a five percent (5%) and 10 percent (10%) change in light extinction over the seasonal estimated natural background extinctions for the Wind Cave NP, Badlands NP, and Northern Cheyenne Indian Reservation (IR). The results of this analysis for the year with the maximum impacts (2003) are provided below:

Dry Fork Visibility Analysis Using 2003 Meteorology

Class I Area	CALPOST Method 2			CALPOST Method 6		
	Maximum (%)	# Days > 5%	# Days > 10%	Maximum (%)	# Days > 5%	# Days > 10%
Wind Cave NP	5.6	2	0	4.9	0	0
Badlands NP	10.7	5	1	7.3	3	0
N. Cheyenne	32.3	3	1	13.4	1	1

Based on the CALPUFF modeling analysis for the proposed construction using 2003 meteorology and using CALPOST Method 2, the results of this analysis indicate that there are two (2) predicted days with a modeled change in visibility over 5 % at Wind Cave NP. There are five (5) days predicted to have greater than 5% change in visibility at Badlands NP along with one (1) day predicted to have greater that 10% change in visibility. Finally, three (3) days were predicted to have greater than 5% change in visibility at Northern Cheyenne Indian Reservation in addition to one (1) day with a visibility change greater than 10%. The Division also compared the results of CALPOST Method 2 to CALPOST Method 6. Monthly f(RH) values for the Method 6 analysis were taken from the document, Guidance for Tracking Progress Under the Regional Haze Rule, Table A-2. Method 6 results showed that the number of days with a modeled change in visibility greater than 5% at Wind Cave NP decreased from two (2) to zero (0) using the 2003 meteorology. In addition, the number of days with a modeled change in visibility greater than 5% at Badlands NP decreased from five (5) to three (3), and the days over 10% change in visibility decreased from one (1) to zero (0). Finally, the number of days with a modeled change in visibility greater than 5% at Northern Cheyenne decreased from three (3) to one (1); days with a visibility change greater than 10% did not change. It should be noted that modeled NO_x emission rate is higher than the limit proposed through the BACT analysis.

Acid Deposition Analysis:

Emissions of nitrogen- and sulfur-based pollutants have the potential to convert to nitrate and sulfate compounds in the atmosphere, and can be deposited as nitric and sulfuric acids into sensitive lakes and other water bodies, and increase the acidity of these water bodies; nitrogen and sulfur that is deposited in a dry deposition mode may also contribute to acid deposition impacts. All of the effects of acid deposition are not well known, however, large amounts of acidic deposition can significantly affect soils, vegetation, lake chemistry and aquatic habitats of sensitive species.

Typically, an assessment of the change in the acidity of a sensitive water body is based on analyzing the nitrogen-based and sulfur-based compounds that enters the water body. The CALPUFF model was used to estimate the hourly wet and dry deposition fluxes of nitrate species from the proposed project emissions, and those impacts were compared to threshold sensitivity deposition values provided by the National Park Service.

The emission rates of nitrogen- and sulfur-based pollutants modeled in this analysis, along with the corresponding stack parameters for the emission sources represented in the deposition significance analysis are provided in the Table 6.

Analysis of Deposition of Total Nitrogen and Sulfur

The applicant conducted an analysis of the effects of deposition of total nitrogen (N) and total sulfur (S) from the proposed Dry Fork plant based on a technique by which total nitrogen (N) and total sulfur (S) deposition rates can be estimated from annual average modeled concentrations of nitrogen- and sulfur-based pollutants. Specifically, total nitrogen (N) deposition rates were calculated based on the dry deposition rate of nitrogen oxides (NO_x), nitric acid (HNO_3), and nitrate (NO_3), and total sulfur (S) deposition rates were calculated based on the dry deposition rates of sulfur dioxide (SO_2) and sulfate (SO_4), as estimated from the CALPUFF model.

The CALPUFF model predicted total (S) and total (N) deposition rates were compared to the Deposition Analysis Threshold (DAT) values for total S and total N, which are 0.005 kg/hectare/year. These DAT values were developed by the National Park Service (NPS) and the U.S. Fish and Wildlife Service for the Western U.S., and presented as part of the FLAG Phase I Report in a guidance document entitled, Guidance on Nitrogen Deposition Analysis Thresholds, which is located at the following Internet URL:

(http://www2.nature.nps.gov/air/Permits/flag/docs/N_SDATGuidance.pdf)

A summary of the maximum modeled annual total (N) impacts from all years of meteorology used in this analysis indicate that the model predicted deposition rates were below the DAT of 0.005 kg/hectare/year for all Class I areas of interest for all three years that were modeled. However, modeled total (S) deposition exceeded the DAT threshold at Northern Cheyenne Indian Reservation for the years 2001 and 2003, and for all three years modeled at Wind Cave NP. The maximum-modeled deposition impacts for the worst-case year (2003) are provided in the following table:

Deposition Significance Analysis: Maximum Total S and Total N Deposition Rates				
Class I Area	**Annual Nitrogen Deposition (kg/hectare/yr)**	**Annual Sulfur Deposition (kg/hectare/yr)**	**Deposition Analysis Threshold (kg/hectare/yr)**	**Below DAT Criterion (Yes/No)**
Wind Cave NP	0.002	0.007	0.005	**No**
Badlands NP	0.001	0.003	0.005	Yes
Northern Cheyenne	0.002	0.007	0.005	**No**

Summary:

The applicant submitted an analysis of the modeled ambient impacts from the proposed Dry Fork Station Project including: near-field modeling analyses, which demonstrated that the impacts from these two sources were above the short-term Class II modeling significance levels (3-hour and 24-hour) for SO_2. As a result, the applicant has submitted a cumulative Class II SO_2 increment analysis which demonstrated that the maximum modeled cumulative SO_2 concentrations were below the respective Class II SO_2 3-hour and 24-hour increments.

Additionally, the applicant conducted far-field modeling analyses to evaluate the significance of the modeled air quality impacts from the proposed construction with respect to the EPA proposed Class I Significant Impact Levels (SILs) for NO_2, SO_2, and PM_{10}. The results demonstrated that the 24-hr SO_2 Class I SIL would be exceeded with 2002 and 2003 meteorology. As a result, a cumulative Class I SO_2 increment analysis was performed, which demonstrated that the Dry Fork plant will not cause or contribute to any Class I PSD increment exceedance. The far-field analyses also included an assessment of impacts to visibility and deposition from the proposed construction. Through the far-field modeling analyses, the applicant has demonstrated that the proposed Dry Fork plant will not cause an exceedance of the allowable Class I PSD increment.

The model predicted change in visibility due to the proposed Dry Fork plant, using CALPOST Method 2, was above 5% on two (2) days at Wind Cave NP, above 5% on five (5) days and above 10% on one (1) day at Badlands NP, and above 5% on three (3) days and above 10% on one (1) day at the Northern Cheyenne Indian Reservation. Using Method 6, the number of days with a modeled change in visibility greater than 5% at Wind Cave NP decreased from two (2) to zero (0) using the 2003 meteorology. The number of days with a modeled change in visibility greater that 5% at Badlands NP decreased from five (5) to three (3), and days with greater than a 10% change in visibility decreased from one (1) to zero (0). The number of days with a modeled change in visibility greater than 5% at Northern Cheyenne decreased from three days (3) to one (1), with no change in days with a modeled change in visibility greater than 10% (one).

The modeled levels of atmospheric deposition of total (N) from the proposed construction were below the Deposition Analysis Thresholds specified by the Federal Land Managers at all three Class I areas of interest. However, the total sulfur (S) deposition at Northern Cheyenne Indian Reservation was predicted to exceed the DAT in 2001 and 2003, and for all three years modeled at Wind Cave NP.

CONCLUSION:

The Division is satisfied that the facility will comply with all applicable Wyoming Air Quality Standards and Regulations. The Division is proposing to issue a permit with the following conditions:

1. Authorized representatives of the Division of Air Quality be given permission to enter and inspect any property, premise or place on or at which an air pollution source is located or is being constructed or installed for the purpose of investigating actual or potential sources of air pollution, and for determining compliance or non-compliance with any rules, regulations, standards, permits or orders.

2. All substantive commitments and descriptions set forth in the application for this permit, unless superseded by a specific condition of this permit, are incorporated herein by this reference and are enforceable as conditions of this permit.

3. As a major source, defined by Chapter 6, Section 3 (b)(xvii) of the WAQSR, Basin Electric shall file a complete application to obtain an operating permit within 12 months after commencing operations.

4. All notifications, reports and correspondence required by this permit shall be submitted to the Stationary Source Compliance Program Manager, Air Quality Division, 122 West 25th Street, Cheyenne, WY 82002 and a copy shall be submitted to the District Engineer, Air Quality Division, 1866 South Sheridan Avenue, Sheridan, WY 82801.

5. Owner or operator shall furnish the Administrator written notification of: (i) the anticipated date of initial startup not more than 60 days or less than 30 days prior to such date, and; (ii) the actual date of initial start-up within 15 days after such date in accordance with Chapter 6, Section 2(i) of the WAQSR.

6. The date of commencement of construction shall be reported to the Administrator within 30 days of such date. The permit shall become invalid if construction or modification is not commenced within 24 months of the date of permit issuance or if construction is discontinued for a period of 24 months or more in accordance with Chapter 6, Section 2(h) of the WAQSR. The Administrator may extend such time period(s) upon a satisfactory showing that an extension is justified.

7. Performance tests shall be conducted 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.

8. Prior to any performance testing or monitor certification testing required by this permit, a test protocol shall be submitted to the Division for approval, at least 30 days prior to testing. Notification of the test date shall be provided to the Division fifteen (15) days prior to testing. Results of the tests shall be submitted to this office within 45 days of completing.

9. Emission rates shall not exceed levels in the following tables:

PC Boiler (ES1-01) Allowable Emissions

Pollutant	lb/MMBtu	lb/MW-hr	lb/hr	tpy
NO_X	0.05 (12 month rolling)	1.0 (30-day rolling)[1]	190.1 (30-day rolling)	832.4
SO_2	0.08 (12 month rolling)	1.4 (30-day rolling)[1]	380.1 (3-hr block) 304.1 (30-day rolling)	1331.8
PM/PM_{10}	0.012[2]	–	45.6	199.8
CO	0.15	–	570.2	2497
Hg	–	97×10^{-6} (12 month rolling)[1]	–	0.16

[1] NSPS Subpart Da Limit
[2] Filterable PM/PM_{10}

Auxiliary Boiler and Inlet Gas Heater Allowable Emissions

Unit No.	Emission Unit	NO_X (lb/MMBtu)	NO_X (lb/hr)	NO_X (tpy)	CO (lb/MMBtu)	CO (lb/hr)	CO (tpy)
ES1-02	134 MMBtu/hr Auxiliary Boiler[1]	0.04	5.4	5.4	0.08	10.7	10.7
ES1-06	8.36 MMBtu/hr Inlet Gas Heater[2]	0.1	0.8	1.0	0.08	0.7	0.8

[1] Annual emissions based on 2,000 hours.
[2] Annual emissions based on 2,500 hours.

Material Handling PM/PM_{10} Allowable Emissions

Unit No.	Emission Unit	gr/dscf	lb/hr	tpy
ES1-07	Coal Storage Silo 1 Dust Collector (13,704 dscfm)	0.005	0.6	2.6
ES1-08	Coal Storage Silo 2 Dust Collector (13,704 dscfm)	0.005	0.6	2.6
ES1-09	Coal Storage Silo 3 Dust Collector (8,849 dscfm)	0.005	0.4	1.7
ES1-10	Coal Crusher House Dust Collector (25,216 dscfm)	0.005	1.1	4.7
ES1-11	Plant Coal Silo Transfer Bay Dust Collector (27,408 dscfm)	0.005	1.2	5.1
ES1-12	Pebble Lime Receiving Silo Bin Vent Filter (728 dscfm)	0.005	0.03	0.1
ES1-13	Pebble Lime Day Silo Bin Vent Filter (1,001 dscfm)	0.005	0.04	0.2
ES1-14	Lime Hydrator Mixer Dust Collector No. 1 (4,698 dscfm)	0.005	0.2	0.9
ES1-15	Lime Hydrator Mixer Dust Collector No. 2 (4,698 dscfm)	0.005	0.2	0.9
ES1-16	Hydrated Lime Dust Collector No. 1 (16,380 dscfm)	0.005	0.7	3.1
ES1-17	Hydrated Lime Dust Collector No. 2 (16,380 dscfm)	0.005	0.7	3.1
ES1-18	Hydrated Lime Silo 1 Bin Vent Filter (1,729 dscfm)	0.005	0.07	0.3
ES1-19	Hydrated Lime Silo 1 Bin Vent Filter (1,729 dscfm)	0.005	0.07	0.3
ES1-20	Activated Carbon Silo Bin Vent Filter (728 dscfm)	0.005	0.03	0.1
ES1-22	Fly Ash/FGD Waste Silo Separator/Filter Exhaust (1,092 dscfm)	0.005	0.05	0.2
ES1-22	Fly Ash/FGD Waste Silo Bin Vent Filter (1,138 dscfm)	0.005	0.05	0.2

10. Mercury emissions from the PC Boiler shall be addressed as follows:

A) A one year mercury optimization study shall be performed at this facility with a target emission rate of no more than 20×10^{-6} lb/MW-hr, 12 month rolling average. A protocol for the study shall be submitted the Division for review and approval prior to commencement of the study. The protocol shall include a description of control technique(s) to be employed including type of sorbent, if applicable, and proposed operational parameters (e.g. carbon injection rate), test methods, and procedures. The optimization study shall commence no later than 90 days after initial startup. The results of the study shall be submitted to the Division within 30 days of completion of the study.

B) A mercury control system shall be installed and operated at this facility within 90 days of initial startup. This permit will be reopened to revise the mercury limit in condition 9 and/or add operational parameters to this condition based on the results of the mercury optimization study.

11. Opacity shall be limited as follows:

A) Visible emissions from the PC boiler (ES1-01) shall be limited to 20% opacity (6-minute average) except for one 6-minute period per hour of not more than 27 percent opacity in accordance with NSPS, Subpart Da, 40 CFR 60.42Da(b).

B) Coal conveyors shall be operated and maintained such that the conveyor enclosures and transfer points exhibit no visible emissions in accordance with 40 CFR part 60, Appendix A, Method 22.

C) Opacity shall be limited to less than 20% from all coal processing and conveying equipment, coal storage systems, and coal transfer and loading systems in accordance with NSPS, Subpart Y, 40 CFR 60.252(c) as determined by 40 CFR Part 60, Appendix A, Method 9.

D) Opacity from any other source of emissions at this facility shall be limited to 20% opacity in accordance with WAQSR, Chapter 3, Section 2(a) as determined by 40 CFR Part 60, Appendix A, Method 9.

12. Initial performance tests, required by Condition 7 of this permit, shall consist of the following:

PC Boiler (ES1-01):

A) NO_X - 30 day rolling average - Initial testing and compliance determination shall follow 40 CFR 60.48Da, 60.49Da, and 60.50Da.

B) SO_2 - EPA Method 6C or equivalent EPA Reference Methods shall be used to determine initial compliance with the SO_2 3 hour emission limit. Tests shall consist of 3 runs of 3 hours each.

C) SO_2 - 30 day rolling average/Percent Reduction Requirements - Initial testing and compliance determination shall follow 40 CFR 60.48Da, 60.49Da, and 60.50Da.

D) PM/PM_{10} - Testing shall follow 40 CFR 60.50Da to determine initial compliance with the lb/MMBtu limit established in this permit.

E) Opacity - EPA Method 9 and the procedures in WAQSR, Chapter 5, Section 2(i) shall be used to determine initial compliance with opacity limits in this permit.

F) CO - Three 1 hour tests following EPA Reference Methods 1-4 and 10 or equivalent EPA Reference Methods shall be used to determine initial compliance with the CO emission limit in this permit.

Auxiliary Boiler (ES1-02) and Inlet Gas Heater (ES1-06):

A) NO_X - Three 1-hour tests following EPA Reference Methods shall be employed to determine initial compliance with the lb/MMBtu and lb/hr NO_X emission limits established by this permit.

B) CO - Three 1 hour tests following EPA Reference Methods shall be employed to determine initial compliance with the lb/MMBtu and lb/hr CO emission limits established by this permit.

Material Handling:

A) PM/PM_{10} - Three 1 hour tests following EPA Methods 1-5, front half only, shall be employed to determine initial compliance with the particulate emission limits established by this permit.

B) Opacity - Testing for emission units not subject to 40 CFR 60, Subpart Y shall be conducted in accordance with WAQSR Chapter 6, Section 2(j) and shall consist of three (3) 6-minute averages of the opacity as determined by Method 9 of 40 CFR 60, Appendix A.

Testing for emission units subject to Subpart Y shall follow the requirements of Chapter 5, Section 2(i) of the WAQSR.

13. The following testing shall be performed in accordance with Conditions 7 and 8:

A) PC Boiler Stack shall be tested to determine NH_3 emissions following EPA Conditional Test Method 27 (CTM-027) or equivalent methods. Results of the tests shall be reported in units of lb/hr and ppmv on a dry basis corrected to 3 percent O_2.

B) PC Boiler exhaust shall be tested at the PC Boiler Stack to determine total fluoride emissions following EPA Method 13A, 13B, or equivalent methods. Results of the tests shall be reported in units of lb/hr.

C) PC Boiler exhaust shall be tested at the PC Boiler Stack to determine hydrogen chloride emissions following EPA Method 26 or equivalent methods. Results of the tests shall be reported in units of lb/hr.

D) PC Boiler exhaust shall be tested at the PC Boiler Stack to determine emissions of metals (antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium) using EPA Method 29 or equivalent methods. Results of the tests shall be reported in units of lb/hr.

E) PC Boiler stack shall be tested to determine sulfuric acid mist (H_2SO_4) emissions following EPA Method 8 or equivalent methods. Results of the tests shall be reported in units of lb/hr. Sulfur dioxide (SO_2) emission rates shall be determined during the H_2SO_4 tests and reported.

F) PC Boiler exhaust shall be tested at the PC Boiler Stack to determine condensible particulate matter emissions with three 1 hour tests following EPA Reference Method 202. Results of the tests shall be reported in units of lb/hr.

14. Within 90 days of initial startup, the following in-stack continuous emission monitoring (CEM) equipment shall be used on the PC Boiler stack to demonstrate continuous compliance with the emission limits set forth in this permit:

A) Basin Electric shall install, calibrate, operate, and maintain a monitoring system, and record the output, for measuring NO_X emissions discharged to the atmosphere in units of lb/MW-hr, lb/MMBtu and lb/hr. The NO_X monitoring system shall consist of the following:

i) A continuous emission NO_X monitor located in the PC boiler stack.

ii) A continuous flow monitoring system for measuring the flow of exhaust gases discharged into the atmosphere.

iii) A watt meter to measure gross electrical output in megawatt-hours on a continuous basis.

iv) An in-stack oxygen or carbon dioxide monitor for measuring oxygen or carbon dioxide content of the flue gas at the location NO_X emissions are monitored.

B) Basin Electric shall install, calibrate, operate, and maintain a SO_2 monitoring system, and record the output, for measuring emissions discharged to the atmosphere in units of lb/MMBtu and lb/hr. The SO_2 monitoring system shall consist of the following:

i) A continuous emission SO_2 monitor located in the PC boiler stack.

ii) A continuous flow monitoring system for measuring the flow of exhaust gases discharged into the atmosphere.

iii) An in-stack oxygen or carbon dioxide monitor for measuring oxygen or carbon dioxide content of the flue gas at the location SO_2 emissions are monitored.

C) Basin Electric shall install, calibrate, operate, and maintain a mercury CEM in accordance with 40 CFR 60 Subpart Da, and record the output, for measuring emissions discharged to the atmosphere in units of lb/MW-hr and lb/hr. As an alternative, Basin Electric may use a sorbent trap monitoring in accordance with 40 CFR 60 Subpart Da and record emissions discharged to the atmosphere in units of lb/MW-hr and lb/hr.

D) Basin Electric shall install, calibrate, operate, and maintain a monitoring system, and record the output, for measuring the opacity of the emissions discharged to the atmosphere.

E) Each continuous monitor system listed in this condition shall comply with the following:

i) NSPS Subpart Da, Standards of Performance for Electric Utility Steam Generating Units (40 CFR 60.49Da).

ii) Monitoring requirements of WAQSR, Chapter 5, Section 2(j) including the following:

a) 40 CFR 60, Appendix B, Performance Specification 1 for opacity, Performance Specification 2 for NO_X and SO_2, Performance Specification 3 for O_2 or CO_2, and Performance Specification 12 for mercury. The monitoring systems must demonstrate linearity in accordance with Division requirements and be certified in both concentration (ppm_v) and units of the standard (lb/MMBtu, lb/MW-hr and lb/hr).

b) Quality Assurance requirements of 40 CFR 60, Appendix F.

c) Basin Electric shall develop and submit for the Division's approval a Quality Assurance plan for the monitoring systems listed in this condition within 90 days of initial startup.

15. Following the initial performance tests, compliance with the NO_X, SO_2, Hg, and opacity limits for the PC Boiler set forth in this permit shall be determined with data from the continuous monitoring systems required by Condition 14 of this permit as follows:

A) Exceedances of the limits shall be defined as follows:

i) Any 12 month rolling average which exceeds the lb/MMBtu NO_X or SO_2 limits as calculated using the following formula:

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

Where:

C = 1-hour average emission rate (lb/MMBtu) for hour "h" calculated using valid data from the CEM equipment required in Condition 14 and the procedures in 40 CFR 60, Appendix A, Method 19. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j).
E_{avg} = Weighted 12 month rolling average emission rate (lb/MMBtu)
n = The number of unit operating hours in the 12 month period with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j).

ii) Any 30-day rolling average which exceeds the lb/MW-hr NO_X or SO_2 limits calculated in accordance 40 CFR 60.48Da, 60.49Da, and 60.50Da.

iii) Any 30-day rolling average calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment required in Condition 14 which exceeds the lb/hr NO_X or SO_2 limits established in this permit. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). The 30-day average emission rate shall be calculated at the end of each boiler operating day (as defined in 40 CFR 60.41Da) as the arithmetic average of hourly emissions with valid data during the previous 30-day period.

iv) Any 3-hour block average of SO_2 calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment required in Condition 14 which exceeds the lb/hr limit established in this permit. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). The 3-hour average emission rate shall be calculated at the end of each 3-hour operating block as the arithmetic average of hourly emissions with valid data during the previous three operating hours.

v) Any 12 month rolling average of mercury (Hg) emissions which exceeds the lb/MW-hr limit calculated in accordance 40 CFR Part 60, Subpart Da.

vi) Any 6-minute average opacity, except for one 6-minute period per hour of not more than 27 percent opacity, in excess of 20 percent in accordance with 40 CFR 60.42Da(b).

B) Basin Electric shall comply with all reporting and record keeping requirements as specified in WAQSR Chapter 5, Section 2(g) and 40 CFR Part 60, Subpart Da. All excess emissions shall be reported using the procedures and reporting format specified in WAQSR Chapter 5, Section 2(g). In addition, reporting and record keeping requirements for the 30-day rolling lb/MW-hr NO_X and SO_2 limits, the 12 month rolling Hg limit, and the opacity limit shall follow the requirements in 40 CFR 60.51Da and 60.52Da.

16. Basin Electric shall comply with the following maintenance and inspection requirements for the coal conveyors:

A) Daily inspections shall be conducted at each of the coal conveyor enclosures and transfer points. Basin Electric shall utilize a daily check form to document daily inspections. A representative form shall be submitted to and approved by the Division prior to utilization. Upon approval, the form will be incorporated as part of the permit. The form may be revised without administratively amending the applicable permit, but revisions shall be approved by the Division prior to implementation.

B) Basin Electric shall institute a monthly preventative maintenance plan for each of the coal conveyor enclosures. A representative plan shall be submitted to and approved by the Division prior to utilization. Upon approval, the plan will be incorporated as part of the permit. The monthly preventative maintenance plan may be revised without administratively amending the applicable permit, but revisions shall be approved by the Division prior to implementation.

17. Basin Electric shall comply with all applicable requirements of 40 CFR 60 Subpart Da for the PC Boiler.

18. Basin Electric shall comply with all applicable requirements of 40 CFR 60 Subpart Y for all coal processing and conveying equipment, coal storage systems, and coal transfer and loading systems.

19. Basin Electric shall comply with all applicable requirements of 40 CFR 63, Subpart ZZZZ for the 2377 hp diesel emergency generator.

20. Basin Electric shall comply with all applicable requirements of 40 CFR 63, Subpart DDDDD for the 8.36 MMBtu/hr Inlet Gas Heater and 134 MMBtu/hr Auxiliary Boiler.

21. The 2377 hp diesel emergency generator and 360 hp diesel fire pump shall comply with the following:

    A) The emergency generator and fire pump shall be certified to meet U.S. EPA Tier II emission standards. Records of the certification shall be maintained and made available to the Division upon request.

    B) The emergency generator and fire pump shall each be limited to 500 hours of operation per year. Records documenting the annual operating hours shall be maintained and made available to the Division upon request.

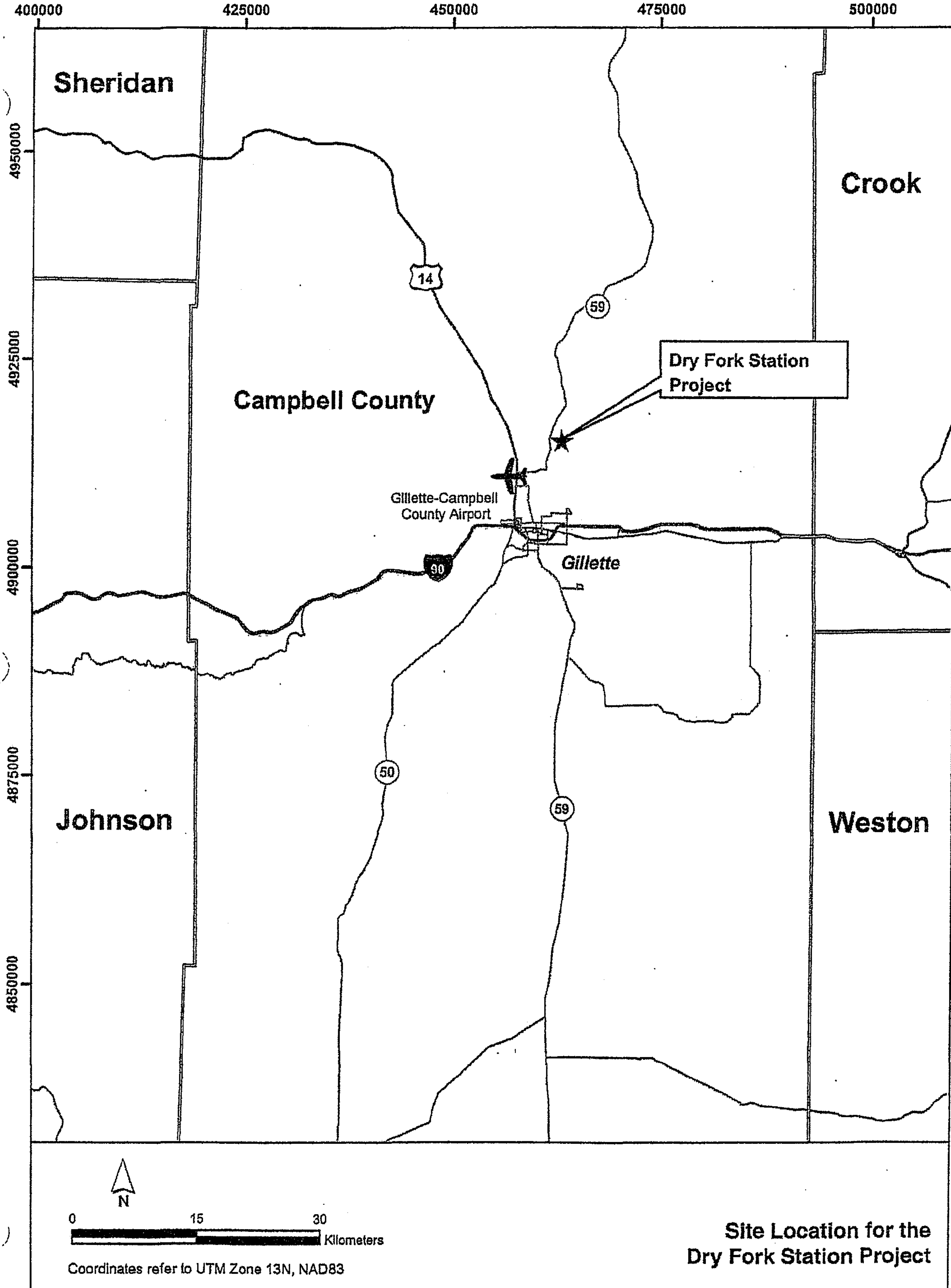
22. Basin Electric shall use a wet handling system for ash/FGD waste load-out. The moisture content of the ash/FGD waste shall be maintained at a high enough concentration to prevent visible emissions from the haul trucks transporting the ash/FGD waste to the landfill. Basin Electric shall record and maintain records of the quantity of water supplied to the wet handling system and the quantity of ash/FGD waste loaded each calendar month. At the end of each calendar month, Basin Electric shall calculate the moisture content of the ash/FGD waste by dividing the mass of water used by the mass of ash/FGD waste and water combined. Ash/FGD waste shall be entirely enclosed in the haul trucks whenever the wet handling system is not operating. Basin Electric shall maintain records of dates that the wet handling system is not operating and whether or not haul trucks are covered.

23. Unpaved haul roads will be treated with suitable chemical dust suppressants in addition to water to control fugitive dust emissions. All treated roads will be maintained on a continuous basis to the extent that the surface treatment remains viable as a control measure.

24. Basin Electric shall comply with acid rain program regulations in WAQSR, Chapter 11, Section 2.

25. Records required by any applicable regulation or permit condition shall be maintained for a minimum period of five (5) years and shall be readily accessible to Division representatives.

Appendix A
Map of Facility Location



DEQ/AQD 001493

* Map produced by the applicant.

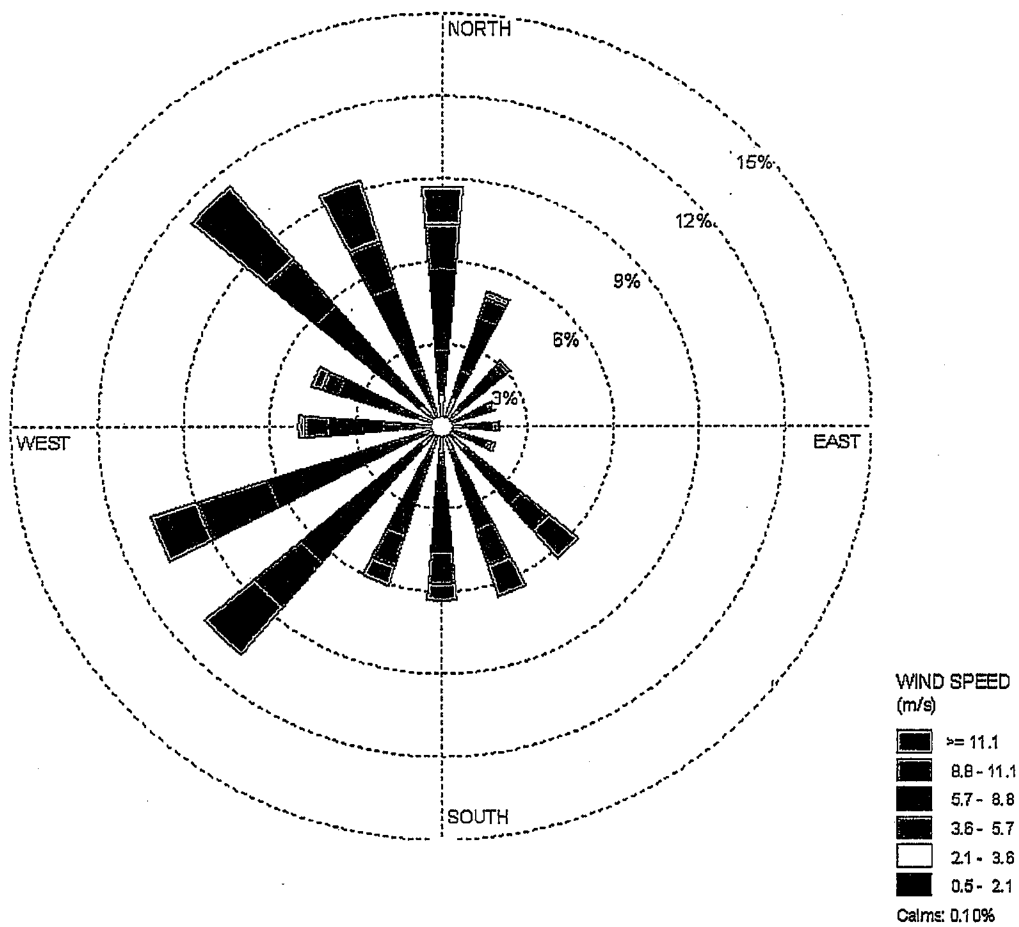
Appendix B

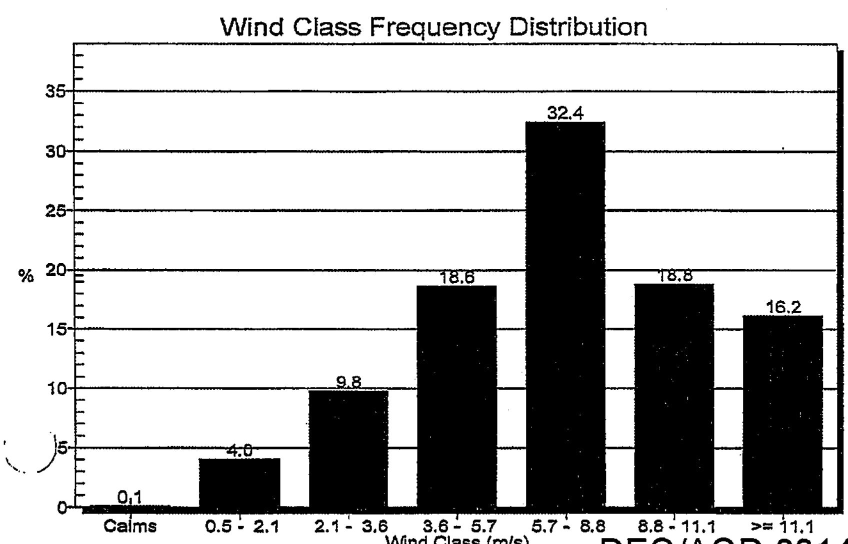
2002 Basin Electric Meteorological Wind Rose Plots

&

1995-2000 Eagle Butte Meteorological Wind Rose Plot

WIND ROSE PLOT:	DISPLAY:
Basin Electric Power Cooerative - Dry Fork Power Plant 2002 100 meter Basin Electric Meteorological Data Set	Wind Speed Direction (blowing from)

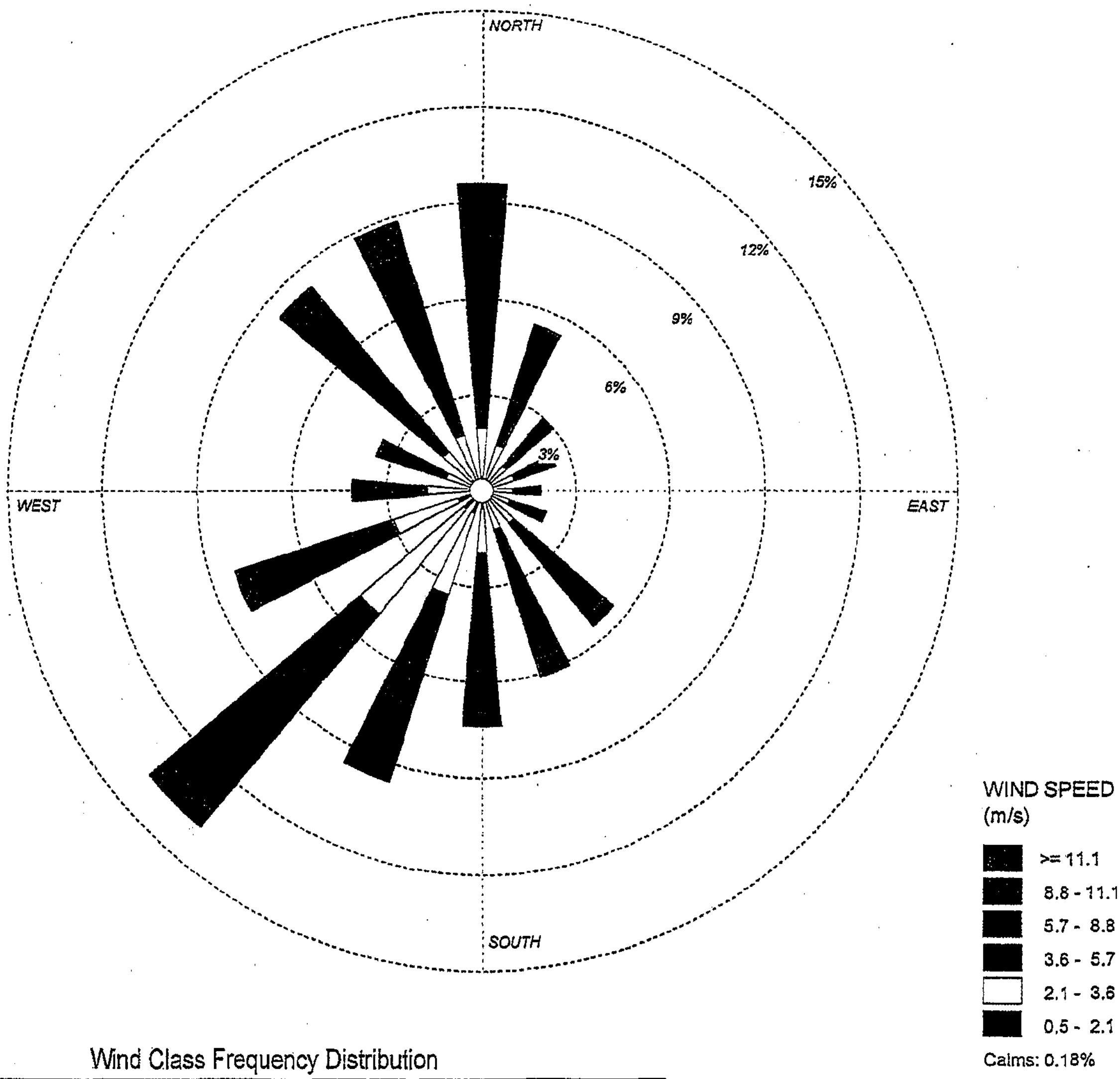


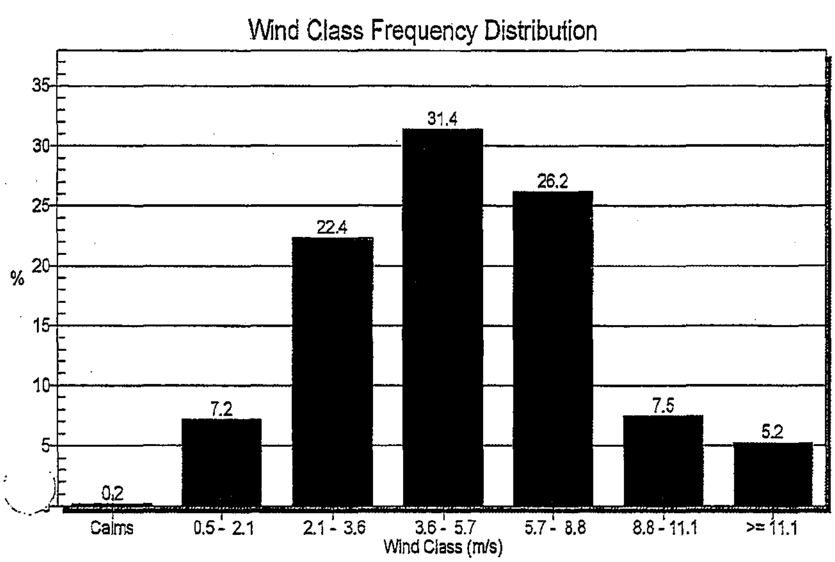


DATA PERIOD:	
2002 Jan 1 - Dec 31 00:00 - 23:00	
CALM WINDS: 9 (0.10%)	TOTAL COUNT: 8666 hrs.
AVG. WIND SPEED: 7.64 m/s	Missing Hours: 94

DEQ/AQD 001495

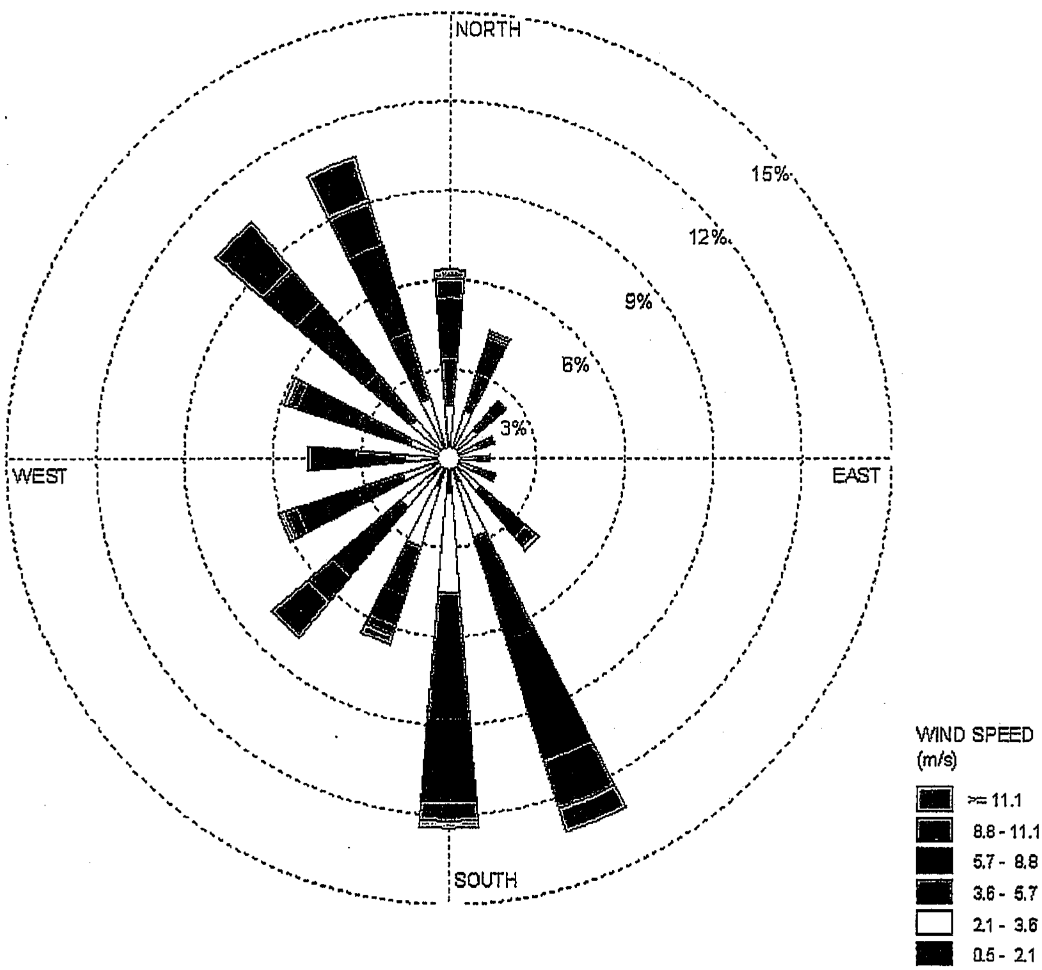
WIND ROSE PLOT:	DISPLAY:
Basin Electric Power Cooperative - Dry Fork Power Plant **2002 10 meter Basin Electric Meteorological Data Set**	**Wind Speed** **Direction (blowing from)**



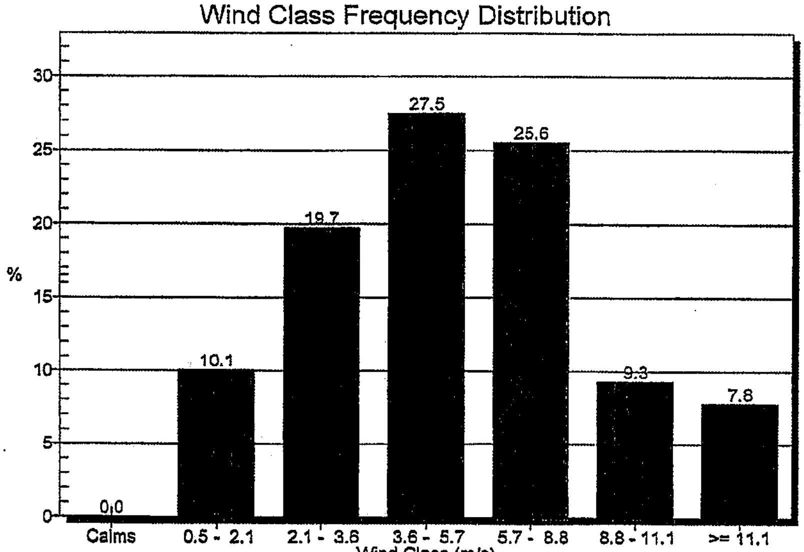


DATA PERIOD:	
2002 **Jan 1 - Dec 31** **00:00 - 23:00**	
CALM WINDS:	TOTAL COUNT:
16 (0.18%)	8696 hrs.
AVG. WIND SPEED:	Missing Hours:
5.53 m/s	64

WIND ROSE PLOT:	DISPLAY:
Basin Electric Power Cooperative - Dry Fork Power Plant **1995-2000 Eagle Butte Meteorological Data Set**	Wind Speed Direction (blowing from)



Wind Class Frequency Distribution



DATA PERIOD:

1995 1996 1997 1998 1999 2000

CALM WINDS:	TOTAL COUNT:
7 (0.01%)	**52608 hrs.**

AVG. WIND SPEED:

5.76 m/s

DEQ/AQD 001497