

MONTANA AIR QUALITY PERMIT

Issued To:	Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station 3521 Gabel Road, Suite 5 Billings, MT 59102	Permit: #3423-00 Application Complete: 3/8/06 Preliminary Determination Issued: 3/30/06 Department's Decision Issued: Permit Final: AFS #: 030-013-0038
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An air quality permit, with conditions, is hereby granted to Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station (SME-HGS), pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and Administrative Rules of Montana (ARM) 17.8.740, *et seq.*, as amended, for the following:

SECTION I: Permitted Facilities

A. Permitted Equipment

SME-HGS operates a gross 270-megawatt (MW) electrical power generating plant. The SME-HGS facility is a coal-fired steam/electric generating station incorporating a circulating fluidized bed boiler (CFB Boiler). Auxiliary power to operate the facility is estimated to be approximately 20 MW resulting in an approximate net power production capacity of 250 MW. Emissions from the CFB-Boiler are controlled by CFB limestone injection technology, a fabric filter baghouse (FFB), a hydrated ash re-injection system (HAR), and a selective non-catalytic reduction unit (SNCR). The total CFB-Boiler emission control strategy is characterized as an integrated emission control system (IECS). A complete list of permitted equipment/emission sources is contained in Section I.A of the permit analysis to this permit.

B. Plant Location

The SME-HGS plant encompasses approximately 720 acres of property and is located approximately 8 miles east of Great Falls, Montana, and approximately 1.5 miles southeast of the Morony Dam on the Missouri River. The legal description of the site is in Section 24 and 25, Township 21 North, Range 5 East, M.P.M., in Cascade County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 12, Easting 297.8 kilometers (km), and Northing 5,070.1 km. The site elevation is approximately 3,290 feet above sea level.

SECTION II: Conditions and Limitations

A. General Plant Requirements

1. SME-HGS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any sources installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 and ARM 17.8.752).

2. SME-HGS shall not cause or authorize emissions to be discharged into the atmosphere from haul roads, access roads, parking lots, or the general plant property without taking reasonable precautions to control emissions of airborne particulate matter (ARM 17.8.308 and ARM 17.8.752).
3. SME-HGS shall treat all unpaved portions of the haul roads, access roads, parking lots, or general plant area with water and/or chemical dust suppressant as necessary to maintain compliance with the reasonable precautions limitation in Section II.A.2 (ARM 17.8.752).
4. SME-HGS shall not cause or authorize the production, handling, transportation, or storage of any material unless reasonable precautions to control emissions of airborne particulate matter are taken. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.308 and ARM 17.8.752).
5. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Da (ARM 17.8.340 and 40 CFR 60, Subpart Da).
6. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Db (ARM 17.8.340 and 40 CFR 60, Subpart Db).
7. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Y (ARM 17.8.340 and 40 CFR 60, Subpart Y).
8. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart OOO (ARM 17.8.340 and 40 CFR 60, Subpart OOO).
9. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 63, Subpart DDDDD, Industrial/Commercial/Institutional/boiler and Process Heater MACT (ARM 17.8.342 and 40 CFR 63, Subpart DDDDD).
10. SME-HGS shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 63, Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE) MACT (ARM 17.8.342 and 40 CFR 63, Subpart ZZZZ).
11. SME-HGS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements of the Acid Rain Program contained in 40 CFR 72-78 (ARM 17.8.1202 and 40 CFR 72-78).
12. SME-HGS shall obtain a written coal analysis that is representative of each load of coal received from each coal supplier. The analysis shall contain, at a minimum, sulfur content, ash content, Btu value (Btu/lb), mercury content, and chlorine content (ARM 17.8.749).

13. SME-HGS shall obtain a written fuel oil analysis for each shipment of fuel oil received from each fuel oil supplier. The analysis shall contain, at a minimum, the sulfur content of the fuel oil and the vapor pressure of the fuel oil (ARM 17.8.749).

B. CFB Boiler Start-Up and Shutdown Operations

1. The requirements contained in Section II.B shall apply during start-up and shutdown operations. CFB start-up and shutdown operations shall be conducted as specified in the *CFB Boiler Start-Up and Shutdown Procedures* included in Attachment 3 of Permit #3423-00 (ARM 17.8.749).
2. CFB Boiler start-up operations, as described in Attachment 3, shall not exceed 48 hours from initial fuel feed to the CFB Boiler (ARM 17.8.749).
3. During start-up and shutdown operations, the CFB Boiler may combust coal with a sulfur content less than or equal to 1% sulfur by weight, fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight, or pipeline quality natural gas (ARM 17.8.752).
4. During start-up and shutdown operations, oxides of nitrogen (NO_x) emissions from the CFB Boiler stack shall not exceed 388 lb/hr (ARM 17.8.749).
5. During start-up and shutdown operations, carbon monoxide (CO) emissions from the CFB Boiler stack shall not exceed 194 lb/hr (ARM 17.8.749).

C. CFB Boiler

1. The CFB Boiler shall combust only coal with a sulfur content less than or equal to 1% sulfur by weight except during periods of start-up or shutdown (ARM 17.8.749 and ARM 17.8.752).
2. SME-HGS shall operate an IECS including CFB limestone injection technology, HAR technology, a SNCR unit, and a FFB for CFB Boiler emissions control except as specified in Attachment 3 during start-up and shutdown operations (ARM 17.8.752).
3. SME-HGS shall not cause or authorize to be discharged into the atmosphere from the CFB Boiler stack any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Da).
4. Filterable particulate matter (filterable PM) emissions from the CFB Boiler stack shall be limited to 0.012 lb/MMBtu and 33.25 lb/hr (ARM 17.8.752).
5. Particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM₁₀) emissions (filterable and condensable) from the CFB Boiler stack shall be limited to 0.026 lb/MMBtu and 72.04 lb/hr (ARM 17.8.752).
6. The CFB Boiler's PM₁₀ emission limit shall be used as a surrogate emission limit for radionuclides and trace metals (ARM 17.8.752).

7. Except during periods of start-up and shutdown, NO_x emissions from the CFB Boiler stack shall not exceed the following:
 - a. 0.10 lb/MMBtu based on a 1-hour average (ARM 17.8.749 and ARM 17.8.752);
 - b. 0.09 lb/MMBtu based on a 24-hour average (ARM 17.8.749 and ARM 17.8.752); and
 - c. 0.07 lb/MMBtu based on a rolling 30-day average (ARM 17.8.752).
8. Except during periods of start-up and shutdown, CO emissions from the CFB Boiler stack shall be controlled by proper boiler design and good combustion practices. CO emissions from the CFB Boiler stack shall not exceed 0.10 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).
9. Sulfur dioxide (SO₂) emissions from the CFB Boiler stack shall not exceed the following:
 - a. 0.057 lb/MMBtu based on a 3-hour average (ARM 17.8.749 and ARM 17.8.752);
 - b. 0.048 lb/MMBtu based on a 24-hour average (ARM 17.8.749 ARM 17.8.752); and
 - c. 0.038 lb/MMBtu based on a rolling 30-day average (ARM 17.8.752).
10. Volatile Organic Compounds (VOC) emissions from the CFB Boiler stack shall be controlled by proper boiler design and good combustion practices. VOC emissions from the Boiler stack shall not exceed 0.003 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).
11. Hydrochloric acid (HCl) emissions from the CFB Boiler stack shall not exceed 0.0021 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).
12. Hydrofluoric acid (HF) emissions from the CFB Boiler stack shall not exceed 0.0017 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).
13. Sulfuric Acid (H₂SO₄) mist emissions from the CFB Boiler stack shall not exceed 0.0054 lb/MMBtu averaged over any 1-hour time period (ARM 17.8.752).
14. Mercury Emissions
 - a. Following commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH), at the operator's choice, mercury emissions from the CFB Boiler shall not exceed 0.0000015 lb/MMBtu (1.5 pounds per trillion Btu (lb/TBtu)) based on a rolling 12-month average, or an emission rate equal to a 90% or greater reduction of mercury in the as-fired coal, as measured in lb/TBtu and based on a rolling 12-month average. Mercury emissions from the CFB Boiler shall be controlled by the IECS or, at SME-HGS's request and as may be approved by the Department of Environmental Quality (Department) in writing, an equivalent technology (equivalent in removal efficiency) (ARM 17.8.752).

- b. If SME-HGS is unable to comply with the mercury limits, within 18 months after commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH), SME-HGS shall install and operate an activated carbon injection control system or, at SME-HGS's request and as may be approved by the Department in writing, an equivalent technology (equivalent in removal efficiency) to comply with the applicable mercury emission limits (ARM 17.8.752).
15. Heat input to the CFB-Boiler shall not exceed 23,004,636 MMBtu during any rolling 12-month time period (ARM 17.8.749).
16. The CFB Boiler stack height shall, at a minimum, be maintained at 400 feet above ground level (ARM 17.8.749).

D. Auxiliary Boiler

1. The Auxiliary Boiler shall be limited to 850 hours of operation during any rolling 12-month time period (ARM 17.8.752 and 40 CFR 60, Subpart Db).
2. The Auxiliary Boiler shall combust only fuel-oil with a sulfur content less than or equal to 0.05% sulfur by weight, propane, or pipeline quality natural gas (ARM 17.8.752).
3. SO₂ emissions from the Auxiliary Boiler shall be limited to 12.63 lb/hr (ARM 17.8.749).
4. NO_x emissions from the Auxiliary Boiler shall be controlled by the installation and operation of dry low-NO_x (DLN) burners. NO_x emissions from the Auxiliary Boiler shall be limited to 46.80 lb/hr (ARM 17.8.749 and ARM 17.8.752).
5. CO emissions from the Auxiliary Boiler shall be controlled by proper boiler design and operation and good combustion practices. CO emissions from the Auxiliary Boiler shall be limited to 18.60 lb/hr (ARM 17.8.749 and ARM 17.8.752).
6. VOC emissions from the Auxiliary Boiler shall be controlled by proper boiler design and operation and good combustion practices (ARM 17.8.752).
7. PM₁₀ emissions from the Auxiliary Boiler shall be limited to 5.43 lb/hr (ARM 17.8.749).
8. The Auxiliary Boiler stack height shall, at a minimum, be maintained at 220 feet above ground level (ARM 17.8.749).

E. Coal Fuel Processing, Handling, Transfer, and Storage Operations

1. Visible emissions from any Standards of Performance for New Stationary Source (NSPS)-affected equipment shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Y).
2. All conveyors shall be covered and all outdoor conveyor transfer points shall be covered and vented to a FFB (ARM 17.8.752).

3. All railcar coal deliveries/transfers shall be unloaded within the Rail Unloading Building via belly-dump to a below grade hopper. The Railcar Unloading Building shall be vented to FFB DC1 and maintained under constant negative pressure when coal is being unloaded and conveyed within the building (ARM 17.8.752).
4. PM₁₀ emissions from FFB DC1 shall be limited to 0.005 gr/dscf (ARM 17.8.752).
5. All coal deliveries to the Railcar Unloading Building shall be transferred via below ground feeders to a belt conveyor (MC02) (ARM 17.8.752).
6. Transfer Tower 16 shall be enclosed and vented to FFB DC2 (ARM 17.8.752).
7. PM₁₀ emissions from FFB DC2 shall be limited to 0.005 gr/dscf (ARM 17.8.752).
8. The emergency coal pile shall be compacted and sprayed with water and/or chemical dust suppressant, as necessary, to maintain compliance with the reasonable precautions requirement and opacity limits (ARM 17.8.752).
9. Coal Silo (CS-1) shall be enclosed and vented to FFB DC2 (ARM 17.8.752).
10. The Coal Crusher House shall be vented to FFB DC3 and shall be maintained under constant negative pressure when processing coal (ARM 17.8.752).
11. The coal crushers (2), surge bin, and rotary feeders (2) shall be enclosed within the Coal Crusher House and vented to FFB D3 (ARM 17.8.752).
12. PM₁₀ emissions from FFB D3 shall be limited to 0.005 gr/dscf (ARM 17.8.752).
13. All coal transfers through the tripper system to the day bins located in the CFB Boiler house shall be enclosed and routed to FFB DC4 (ARM 17.8.752).
14. PM₁₀ emissions from FFB DC4 shall be limited to 0.005 gr/dscf (ARM 17.8.752).

F. Limestone and Lime Material Processing, Handling, Transfer, and Storage Operations

1. Visible emissions from any NSPS-affected crusher shall not exhibit an opacity of 15% or greater averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart OOO).
2. Visible emissions from any other NSPS-affected equipment, such as screens or conveyor transfers, shall not exhibit an opacity of 10% or greater averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart OOO).
3. All limestone material shall be delivered to the facility via covered bottom dumping haul-trucks and unloaded within a limestone material unloading drive-through building. The limestone material unloading drive-through building shall be maintained under constant negative pressure and vented through FFB DC5 when limestone material is being unloaded and conveyed within the drive-through building (ARM 17.8.752).

4. All conveyors shall be covered and all outdoor conveyor transfer points shall be covered and vented to FFB DC5 (ARM 17.8.752).
5. All limestone material transfers to the Bucket Elevator and the Limestone Silo shall be vented to FFB DC5 (ARM 17.8.752).
6. PM₁₀ emissions from FFB DC5 shall be limited to 0.005 gr/dscf (ARM 17.8.752).
7. Visible emissions from FFB DC5 shall not exhibit an opacity of greater than 7% averaged over 6 consecutive minutes (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart OOO).

G. Fly and Bottom-Ash Material Processing, Handling, Transfer, and Storage Operations

1. Fly-ash shall be pneumatically transferred from the CFB Boiler FFB to the Fly-Ash Silo (AS1) (ARM 17.8.752).
2. Bed-ash shall be pneumatically transferred from the CFB Boiler to the Bed-Ash Silo (AS2) (ARM 17.8.752).
3. PM₁₀ emissions resulting from the charging of AS1 and AS2 shall be controlled by fabric filter Bin vents DC6 and DC7, respectively (ARM 17.8.752).
4. Fly-ash and bed-ash shall be gravity-fed into haul trucks through a wet pug-mill for transfer to the on-site ash monofill/landfill (ARM 17.8.752).
5. Air displaced by ash loading into haul trucks shall be vented through AS1 and AS2 and associated bin vents DC6 and DC7, respectively (ARM 17.8.752).
6. PM₁₀ emissions from each bin vent DC6 and DC7 shall be limited to 0.01 gr/dscf (ARM 17.8.752).
7. Visible emissions from bin vent DC6 and DC7 shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.752).

H. Coal Thawing Shed Operations

1. The Coal Thawing Shed Heater shall be limited to 240 hours of operation during any rolling 12-month time period (ARM 17.8.749 and ARM 17.8.752).
2. The Coal Thawing Shed Heater shall combust only propane or pipeline quality natural gas (ARM 17.8.752).
3. NO_x, SO₂, CO, VOC, and PM₁₀ emissions from the Coal Thawing Shed Heater operations shall be controlled by proper design and operation, good combustion practices, and the combustion of propane and pipeline quality natural gas only (ARM 17.8.752).

I. Emergency Fire Pump Operations

1. The Emergency Fire Pump shall be limited to 500 hours of operation during any rolling 12-month time period (ARM 17.8.749 and ARM 17.8.752).

2. The Emergency Fire Pump shall combust only fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight (ARM 17.8.752).
3. NO_x, SO₂, CO, VOC, and PM₁₀ emissions from the Emergency Fire Pump shall be controlled by proper design and operation and good combustion practices (ARM 17.8.752).

J. Emergency Generator Operations

1. The Emergency Generator shall be limited to 500 hours of operation during any rolling 12-month time period (ARM 17.8.749 and ARM 17.8.752).
2. The Emergency Generator shall combust only fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight (ARM 17.8.752).
3. NO_x, SO₂, CO, VOC, and PM₁₀ emissions from the Emergency Generator shall be controlled by proper design and operation and good combustion practices (ARM 17.8.752).
4. NO_x emissions from the Emergency Generator shall be limited to 41.20 lb/hr (ARM 17.8.749 and ARM 17.8.752).
5. CO emissions from the Emergency Generator shall be limited to 2.70 lb/hr (ARM 17.8.749 and ARM 17.8.752).

K. Cooling Tower

1. PM₁₀ emissions from the Cooling Tower shall be controlled by drift eliminators (ARM 17.8.752).
2. The Cooling Tower drift rate shall be limited to 0.002% of the total circulating water flow (ARM 17.8.752).

L. Fuel Storage Tank

SME-HGS shall not store any liquid fuel with a vapor pressure greater than 3.5 kilopascals (kPa) in the 275,000-gallon capacity fuel storage tank (ARM 17.9.749).

M. Testing Requirements

1. CFB Boiler Testing Requirements
 - a. SME-HGS shall initially test the CFB Boiler for opacity within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, SME-HGS shall use the data from the continuous opacity monitoring system (COMS) to monitor compliance with the applicable opacity limit (ARM 17.8.749).

- b. SME-HGS shall initially test the CFB Boiler for filterable PM emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, additional testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

- c. SME-HGS shall initially test the CFB Boiler for PM₁₀ (filterable and condensable) emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

- d. SME-HGS shall initially test the CFB Boiler for NO_x emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing. SME-HGS shall conduct the initial performance source testing for NO_x and CO, concurrently (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, SME-HGS shall use the data from the NO_x continuous emissions monitoring system (CEMS) to monitor compliance with the applicable NO_x emission limits (ARM 17.8.105 and ARM 17.8.749).

- e. SME-HGS shall initially test the CFB Boiler for CO emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing. SME-HGS shall conduct the initial performance source testing for CO and NO_x, concurrently (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and 17.8.749).

- f. SME-HGS shall initially test the CFB Boiler for SO₂ emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart Da).

After the initial source test, SME-HGS shall use the data from the SO₂ CEMS to monitor compliance with the applicable SO₂ emission limits (ARM 17.8.749).

- g. SME-HGS shall initially test the CFB Boiler for HCl emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

- h. SME-HGS shall initially test the CFB Boiler for HF emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and 17.8.749).

- i. SME-HGS shall initially test the CFB Boiler for H₂SO₄ emissions within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the CFB Boiler, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

After the initial source test, additional testing shall continue on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

- j. Pursuant to 40 CFR 60.48a through 60.52a and 40 CFR 75, Subpart I, SME-HGS shall monitor compliance with the applicable mercury emission limit(s). Any mercury CEMS used must be operated in compliance with 40 CFR 60, Appendix B (ARM 17.8.105, ARM 17.8.749, 40 CFR 60, Subpart Da, and 40 CFR 75, Subpart I)

2. Coal Fuel, Limestone, and Ash Processing, Handling, Transfer, and Storage Operations Testing Requirements

- a. Compliance with the opacity limit for FFB DC1, controlling emissions from rail unloading material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).

- b. Compliance with the PM₁₀ emission limit for FFB DC1 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an annual basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).
- c. Compliance with the opacity limit for FFB DC2, controlling emissions from coal silo material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).
- d. Compliance with the PM₁₀ emission limit for FFB DC2 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).
- e. Compliance with the opacity limit for FFB DC3, controlling emissions from coal crusher material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).
- f. Compliance with the PM₁₀ emission limit for FFB DC3 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y).
- g. Compliance with the opacity limit for FFB DC4, controlling emissions from tripper deck plant silos material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than

180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y and Subpart OOO).

- h. Compliance with the PM₁₀ emission limit for FFB DC4 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Y and Subpart OOO).
- i. Compliance with the opacity limit for FFB DC5, controlling emissions from limestone material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart OOO).
- j. Compliance with the PM₁₀ emission limit for FFB DC5 shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart OOO).
- k. Compliance with the opacity limit for Bin vent DC6, controlling emissions from ash silo material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105 and ARM 17.8.749).
- l. Compliance with the opacity limit for bin vent DC7, controlling emissions from ash silo material transfers, shall be monitored by an initial performance source test conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue as required by the Department (ARM 17.8.105 and ARM 17.8.749).

3. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).
4. The Department may require further testing (ARM 17.8.105).

N. Operational Reporting Requirements

1. SME-HGS shall submit to the Department annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis.

Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. SME-HGS shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or that would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, at least 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).
3. All records compiled in accordance with this permit must be maintained by SME-HGS as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).
4. SME-HGS shall document, by month, the total heat input to the CFB Boiler. By the 25th day of each month, SME-HGS shall total heat input to the CFB Boiler for the previous month. The monthly information will be used to verify compliance with the rolling 12-month boiler heat input limitation (ARM 17.8.749).
5. SME-HGS shall document, by month, the hours of operation of the Auxiliary Boiler. By the 25th day of each month, SME-HGS shall total the operating hours of the Auxiliary Boiler for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).
6. SME-HGS shall document, by month, the hours of operation of the Emergency Generator. By the 25th day of each month, SME-HGS shall total the operating hours of the Emergency Generator for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).

7. SME-HGS shall document, by month, the hours of operation of the Emergency Fire Water Pump. By the 25th day of each month, SME-HGS shall total the operating hours of the Emergency Fire Water Pump for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).
8. SME-HGS shall document, by month, the hours of operation of the Coal Thawing Shed Heater. By the 25th day of each month, SME-HGS shall total the operating hours of the Coal Thawing Shed Heater for the previous month. The monthly information will be used to verify compliance with the applicable rolling 12-month limitation (ARM 17.8.749).
9. SME-HGS shall maintain on site the coal fuel and fuel oil analyses required under Section II.A and submit this information to the Department upon request (ARM 17.8.749).
10. SME-HGS shall maintain a record of CFB Boiler start-up operations. SME-HGS shall document the total start-up operating hours from initial fuel feed to the CFB Boiler for each start-up period. The information shall be submitted to the Department upon request. The information will be used to monitor compliance with the CFB Boiler start-up operating hour limit (ARM 17.8.749).
11. SME-HGS shall monitor and analyze the CFB Boiler mercury control performance data following commencement of commercial operations (as defined in 40 CFR 60, Subpart HHHH). By the 25th day of each month, SME-HGS shall summarize the applicable mercury emissions data (percent reduction and/or emission rate). SME-HGS shall submit this information to the Department quarterly, or according to another reporting schedule as may be approved by the Department. The information will be used to verify the IECS mercury control capabilities (ARM 17.8.749).

O. Continuous Emissions Monitoring Systems (CEMS/COMS)

1. SME-HGS shall install, operate, calibrate, and maintain CEMS as follows:
 - a. A CEMS for the measurement of SO₂ shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749 and 40 CFR 72-78).
 - b. A flow monitoring system to complement the SO₂ monitoring system shall be operated on the CFB Boiler stack (ARM 17.8.105 and 40 CFR 72-78).
 - c. A CEMS for the measurement of NO_x shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749 and 40 CFR 72-78).
 - d. A COMS for the measurement of opacity shall be operated on the CFB Boiler stack (ARM 17.8.105, ARM 17.8.749 and 40 CFR 72-78).
 - e. A CEMS for the measurement of oxygen (O₂) or carbon dioxide (CO₂) content shall be operated on the CFB-Boiler stack (ARM 17.8.105 and ARM 17.8.749).
 - f. A CEMS for the measurement of mercury shall be operated on the CFB-Boiler stack (ARM 17.8.105 and ARM 17.8.749).

2. SME-HGS shall determine CO₂ emissions from the CFB Boiler Stack by one of the methods listed in 40 CFR 75.10 (40 CFR 72-78).
3. All continuous monitors required by this permit and by 40 CFR Part 60 shall be operated, excess emissions reported, and performance tests conducted in accordance with the requirements of 40 CFR Part 60, Subpart A; 40 CFR Part 60, Subpart Da; 40 CFR Part 60, Appendix B (Performance Specifications #1, #2, and #3); and 40 CFR Part 72-78, as applicable (ARM 17.8.749 and 40 CFR 72-78).
4. On-going quality assurance for the gas CEMS must conform to 40 CFR Part 60, Appendix F (ARM 17.8.749).
5. SME-HGS shall inspect and audit the COMS annually, using neutral density filters. SME-HGS shall conduct these audits using the applicable procedures and forms in the EPA Technical Assistance Document: Performance Audit Procedures for Opacity Monitors (EPA-450/4-92-010, April 1992). The results of these inspections and audits shall be included in the quarterly excess emission report (ARM 17.8.749).
6. SME-HGS shall maintain a file of all measurements from the CEMS, and performance testing measurements: all CEMS performance evaluations; all CEMS or monitoring device calibration checks and audits; and adjustments and maintenance performed on these systems or devices, recorded in a permanent form suitable for inspection. The records shall be retained on site for at least 5 years following the date of such measurements and reports. SME-HGS shall supply these records to the Department upon request (ARM 17.8.749).
7. SME-HGS shall maintain a file of all measurements from the COMS, and performance testing measurements: all COMS performance evaluations; all COMS or monitoring device calibration checks and audits; and adjustments and maintenance performed on these systems or devices, recorded in a permanent form suitable for inspection. The records shall be retained on site for at least 5 years following the date of such measurements and reports. SME-HGS shall supply these records to the Department upon request (ARM 17.8.749).

P. Notification

1. Within 30 days after commencement of construction of the SME-HGS facility, SME-HGS shall notify the Department of the date of commencement of construction (ARM 17.8.749)
2. Within 30 days after commencement of construction of the CFB Boiler, SME-HGS shall notify the Department of the date of commencement of construction (40 CFR Part 60.7 and ARM 17.8.749)
3. Within 15 days after actual startup of the CFB Boiler, SME-HGS shall notify the Department of the date of actual startup (40 CFR Part 60.7 and ARM 17.8.749).
4. Within 30 days after commencement of construction of the Auxiliary Boiler, SME-HGS shall notify the Department of the date of commencement of construction (40 CFR Part 60.7 and ARM 17.8.749)

5. Within 15 days after actual startup of the Auxiliary Boiler, SME-HGS shall notify the Department of the date of actual startup (40 CFR Part 60.7 and ARM 17.8.749).
6. Within 30 days after commencement of construction of material handling/processing fabric filter baghouses DC1, DC2, DC3, DC4, and DC5, SME-HGS shall notify the Department of the date of commencement of construction of the affected fabric filter baghouse(s) (40 CFR 60.7 and ARM 17.8.749).
7. Within 15 days after actual startup of material handling/processing fabric filter baghouses DC1, DC2, DC3, DC4, and DC5, SME-HGS shall notify the Department of the date of actual startup of the affected fabric filter baghouse(s) (40 CFR 60.7 and ARM 17.8.749).
8. Within 30 days after commencement of construction of the ash silo fabric filter bin vents DC6 and DC7, respectively, SME-HGS shall notify the Department of the date of commencement of construction of the affected fabric filter bin vent(s) (ARM 17.8.749).
9. Within 15 days after actual startup of the ash silo fabric filter bin vents DC6 and DC7, respectively, SME-HGS shall notify the Department of the date of actual startup of the affected fabric filter bin vent(s) (ARM 17.8.749).

SECTION III: General Conditions

- A. Inspection – SME-HGS shall allow the Department’s representatives access to the facility at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS, COMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.
- B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if SME-HGS fails to appeal as indicated below.
- C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving SME-HGS of the responsibility for complying with any applicable federal or Montana statute or rule, except as specifically provided in ARM 17.8.740, *et seq.* (ARM 17.8.756).
- D. Enforcement – Violations of requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement action as specified in Section 75-2-401, *et seq.*, MCA, and ARM 17.8.763.
- E. Appeals – Any person or persons jointly or severally adversely affected by the Department’s decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department’s decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department’s decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department’s decision on the application is final 16 days after the Department’s decision is made.

- F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the source.
- G. Permit Fee – Pursuant to Section 75-2-220, MCA, as amended by the 2005 Legislature, failure by SME-HGS to pay the annual operation fee may be grounds for revocation of this permit, as allowed by that section and rules adopted thereunder by the Board.
- H. Construction Commencement – Construction must begin within 3 years after permit issuance and proceed with due diligence until the project is complete or Permit #3423-00 shall expire. If the permit expires, SME-HGS shall not commence construction until SME-HGS has applied for and received a new air quality permit pursuant to Sections 75-2-204 and 75-2-211, Montana Code Annotated, and ARM 17.8.740 *et seq.*, as amended (ARM 17.8.762).

INSTRUCTIONS FOR COMPLETING EXCESS EMISSION REPORTS (EER)

- PART 1** Complete as shown. Report total time during the reporting period in hours. The determination of plant operating time (in hours) includes time during unit start up, shut down, malfunctions, or whenever pollutants of any magnitude are generated, regardless of unit condition or operating load.

Excess emissions include all time periods when emissions, as measured by the CEMS, exceed any applicable emission standard for any applicable time period.

Percent of time in compliance is to be determined as:

$$(1 - (\text{total hours of excess emissions during reporting period} / \text{total hours of CEMS availability during reporting period})) \times 100$$

- PART 2** Complete as shown. Report total time the point source operated during the reporting period in hours. The determination of point source operating time includes time during unit start up, shut down, malfunctions, or whenever pollutants (of any magnitude) are generated, regardless of unit condition or operating load.

Percent of time CEMS was available during point source operation is to be determined as:

$$(1 - (\text{CEMS downtime in hours during the reporting period}^a / \text{total hours of point source operation during reporting period})) \times 100$$

a - All time required for calibration and to perform preventative maintenance must be included in the CEMS downtime.

- PART 3** Complete a separate sheet for each pollutant control device. Be specific when identifying control equipment operating parameters. For example: number of TR units, energizers for electrostatic precipitators (ESP); pressure drop and effluent temperature for baghouses; and bypass flows and pH levels for scrubbers. For the initial EER, include a diagram or schematic for each piece of control equipment.
- PART 4** Use Table I as a guideline to report all excess emissions. Complete a separate sheet for each monitor. Sequential numbering of each excess emission is recommended. For each excess emission, indicate: 1) time and duration, 2) nature and cause, and 3) action taken to correct the condition of excess emissions. Do not use computer reason codes for corrective actions or nature and cause; rather, be specific in the explanation. If no excess emissions occur during the quarter, it must be so stated.
- PART 5** Use Table II as a guideline to report all CEM system upsets or malfunctions. Complete a separate sheet for each monitor. List the time, duration, nature and extent of problems, as well as the action taken to return the CEM system to proper operation. Do not use reason codes for nature, extent or corrective actions. Include normal calibrations and maintenance as prescribed by the monitor manufacturer. Do not include zero and span checks.
- PART 6** Complete a separate sheet for each pollutant control device. Use Table III as a guideline to report operating status of control equipment during the excess emission. Follow the number sequence as recommended for excess emissions reporting. Report operating parameters consistent with Part 3, Subpart e.
- PART 7** Complete a separate sheet for each monitor. Use Table IV as a guideline to summarize excess emissions and monitor availability.
- PART 8** Have the person in charge of the overall system and reporting certify the validity of the report by signing in Part 8.

EXCESS EMISSIONS REPORT**PART 1 – General Information**

- a. Emission Reporting Period _____
- b. Report Date _____
- c. Person Completing Report _____
- d. Plant Name _____
- e. Plant Location _____
- f. Person Responsible for Review
and Integrity of Report _____
- g. Mailing Address for 1.f. _____

- h. Phone Number of 1.f. _____
- i. Total Time in Reporting Period _____
- j. Total Time Plant Operated During Quarter _____
- k. Permitted Allowable Emission Rates: Opacity _____
SO₂ _____ NO_x _____ TRS _____
- l. Percent of Time Out of Compliance: Opacity _____
SO₂ _____ NO_x _____ TRS _____
- m. Amount of Product Produced
During Reporting Period _____
- n. Amount of Fuel Used During Reporting Period _____

Attachment 2

PART 2 - Monitor Information: Complete for each monitor.

a. Monitor Type (circle one)

Opacity SO₂ NO_x O₂ CO₂ TRS Flow

b. Manufacturer _____

c. Model No. _____

d. Serial No. _____

e. Automatic Calibration Value: Zero _____ Span _____

f. Date of Last Monitor Performance Test _____

g. Percent of Time Monitor Available:

1) During reporting period _____

2) During plant operation _____

h. Monitor Repairs or Replaced Components Which Affected or Altered
Calibration Values _____

i. Conversion Factor (f-Factor, etc.) _____

j. Location of monitor (e.g. control equipment outlet) _____

PART 3 - Parameter Monitor of Process and Control Equipment. (Complete one sheet for each pollutant.)

a. Pollutant (circle one):

Opacity SO₂ NO_x TRS

b. Type of Control Equipment _____

c. Control Equipment Operating Parameters (i.e., delta P, scrubber
water flow rate, primary and secondary amps, spark rate)

d. Date of Control Equipment Performance Test _____

e. Control Equipment Operating Parameter During Performance Test

PART 4 - Excess Emission (by Pollutant)

Use Table I: Complete table as per instructions. Complete one sheet for each monitor.

PART 5 - Continuous Monitoring System Operation Failures

Use Table II: Complete table as per instructions. Complete one sheet for each monitor.

PART 6 - Control Equipment Operation During Excess Emissions

Use Table III: Complete as per instructions. Complete one sheet for each pollutant control device.

PART 7 - Excess Emissions and CEMS performance Summary Report

Use Table IV: Complete one sheet for each monitor.

PART 8 - Certification for Report Integrity, by person in 1.f.

THIS IS TO CERTIFY THAT, TO THE BEST OF MY KNOWLEDGE, THE
INFORMATION PROVIDED IN THE ABOVE REPORT IS COMPLETE AND
ACCURATE.

SIGNATURE _____

NAME _____

TITLE _____

DATE _____

Attachment 2

TABLE I
EXCESS EMISSIONS

<u>Date</u>	<u>Time</u>		<u>Duration</u>	<u>Magnitude</u>	<u>Explanation/Corrective Action</u>
	<u>From</u>	<u>To</u>			

Attachment 2

TABLE II

CONTINUOUS MONITORING SYSTEM OPERATION FAILURES

<u>Date</u>	<u>Time</u>		<u>Duration</u>	<u>Problem/Corrective Action</u>
	<u>From</u>	<u>To</u>		

Attachment 2

TABLE III

CONTROL EQUIPMENT OPERATION DURING EXCESS EMISSIONS

<u>Date</u>	<u>Time</u>		<u>Duration</u>	<u>Operating Parameters</u>	<u>Corrective Action</u>
	<u>From</u>	<u>To</u>			

Attachment 2

TABLE IV

Excess Emission and CEMS Performance Summary Report

Pollutant (circle one): SO₂ NO_x TRS H₂S CO Opacity

Monitor ID

Emission data summary ¹	CEMS performance summary ¹
<p>1. Duration of excess emissions in reporting period due to:</p> <ul style="list-style-type: none"> a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes <p>2. Total duration of excess emissions</p> <p>3. $\left[\frac{\text{Total duration of excess emissions}}{\text{Total time CEM operated}} \times 100 = \right]$</p>	<p>1. CEMS² downtime in reporting due to:</p> <ul style="list-style-type: none"> a. Monitor equipment malfunctions b. Non-monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes <p>2. Total CEMS downtime</p> <p>3. $\left[\frac{\text{Total CEMS downtime}}{\text{Total time source emitted}} \times 100 = \right]$</p>

¹ For opacity, record all times in minutes. For gases, record all times in hours. Fractions are acceptable (e.g., 4.06 hours)

² CEMS downtime shall be regarded as any time CEMS is not measuring emissions.

Attachment 3
CFB Boiler Start-Up and Shutdown Procedures
Permit #3423-00

The requirements contained in Section II.B of Montana Air Quality Permit #3423-00 shall apply during CFB Boiler start-up and shutdown operations. CFB Boiler start-up and shutdown operations shall be conducted as specified in this attachment.

I. CFB Boiler Startup

Startup of a circulating fluidized bed (CFB) boiler can take up to 48 hours depending on the initial furnace temperature and condition of the fluidized bed. During the startup process, the unit steps through a series of changes to reach full load firing on coal with the addition of limestone into the CFB furnace. During this process, particulate matter (PM), oxides of nitrogen (NO_x), and sulfur dioxide (SO₂) emissions may vary until air pollution control equipment can be operated at a minimum continuous load.

a. CFB Boiler Bed Material Preparation

The first step in the startup of a CFB involves loading the initial bed material into the furnace. Either sand or used bed ash is loaded into the bed utilizing a pneumatic system. This step can take several hours to complete, during which time there is no fuel combustion taking place. The emissions present during the ash loading cycle are particulate matter. The fabric filter baghouse will collect any of the particulate matter during this step.

b. Startup Hours 1-12

Once the bed material is loaded into the furnace, the fans are started and the CFB Boiler begins to fire on fuel oil. The fuel oil is utilized to warm up the bed material and the CFB Boiler components. The fuel oil usage is increased until the temperature inside the cyclone reaches approximately 1150°F. From a cold start, this process may take 14 hours. During this warm-up period NO_x is controlled through efficient low NO_x fuel oil burners; SO₂ is minimized through the use of low sulfur fuel oil; and PM emissions are controlled by the fabric filter. Carbon monoxide (CO) emissions may be higher than full load operation due to the combustion conditions in the furnace during this period. The firing rate is expected to be approximately 831 million British thermal units per hour (MMBtu/hr) (30% of the maximum CFB Boiler heat input rate of 2,771 MMBtu/hr).

c. Startup Hours 12-18

After approximately 12 hours of firing on fuel oil, coal and limestone are introduced into the furnace and the feed rate is increased over the next 2 hours until the coal becomes the primary fuel source. During this time both fuel oil and coal are combusted together. The fuel oil feed rate is slowly reduced and is eventually shut off. During this transition NO_x is controlled by the use of low NO_x fuel oil burners and the staged combustion of the coal. SO₂ is controlled by the use of low sulfur fuel oil and the addition of limestone to the fluidized bed. The fabric filter continues to control PM.

At approximately 50% of full load the NO_x is further reduced by adding ammonia injection via the Selective Non-catalytic Reduction (SNCR) system. In addition, approximately 4 hours after limestone is injected into the fluidized bed, the hydrated ash reinjection system is activated to further reduce SO₂ emissions. At this point all emissions control equipment is fully activated. The total time to reach a point where all air pollution control technologies are operating is approximately 18 hours from a cold start. Start-up operations are limited, by permit, to a maximum of 48 hours.

Attachment 3
CFB Boiler Start-Up and Shutdown Procedures
Permit #3423-00

II. CFB Boiler Shutdown

Several steps are required for a controlled shutdown of the boiler and the associated ancillary equipment. The first step of the process is to shut down the coal feed into the furnace. In order to accomplish this, the coal feed and firing rate is gradually reduced. As the temperature is reduced below the minimum requirements for the hydrated ash re-injection and SNCR systems, these systems are turned off. The furnace is brought down to the minimum coal firing rate. At this point the coal feed is completely shut off and the furnace is purged with air. The air will be used to gradually lower the boiler temperature for inspection or maintenance. Once the boiler is cooled off, the ID Fan will be turned off. If no access into the furnace is required, the bed ash will be left in the furnace area of the CFB Boiler. If access is required, the bed ash will be discharged and pneumatically conveyed to the ash silo, where it will be stored until the next startup. In the event that the boiler shutdown is only for a short period, and re-operation of the unit is anticipated, the fans will be turned off, and the ID Fan control damper will be closed in order to bottle up the furnace and maintain the maximum amount of heat.

Permit Analysis
Southern Montana Electric Generation and Transmission Cooperative –
Highwood Generating Station
Permit #3423-00

I. Introduction/Process Description

A. Permitted Equipment

Southern Montana Electric Generation and Transmission Cooperative – Highwood Generating Station (SME-HGS) operates a net 250-megawatt (MW) electrical power generating plant located approximately 8 miles east of Great Falls, Montana, and approximately 1.5 miles southeast of the Morony Dam on the Missouri River. The legal description of the site is in Section 24 and 25, Township 21 North, Range 5 East, M.P.M., in Cascade County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 12, Easting 297.8 kilometers (km), and Northing 5,070.1 km. The site elevation is approximately 3,290 feet above seal level.

The SME-HGS facility is a coal-fired steam/electric generating station incorporating a circulating fluidized bed boiler (CFB Boiler) with an average annual heat input value of 2,626 million British thermal units per hour (MMBtu/hr) and a maximum short-term heat input capacity of 2,771 MMBtu/hr to produce approximately 1.8 million pounds of steam per hour. The steam is routed to a steam turbine, which drives an electric generator capable of producing an estimated 270 gross MW of electrical power. Auxiliary power to operate the facility is estimated to be approximately 20 MW resulting in the approximate net power production capacity of 250 MW. The following equipment/emission sources are permitted for this facility:

- 2771 MMBtu/hr heat input capacity coal fired CFB Boiler (2626 MMBtu/hr average)
- 225 MMBtu/hr heat input capacity diesel fuel-oil, propane, or natural gas fired Auxiliary Boiler
- 2000 kilowatt (kW) emergency diesel fuel-oil fired generator set
- 230 Kw emergency diesel fuel-oil fired Emergency fire pump
- 40 MMBtu/hr heat input capacity propane/natural gas fired Coal Thawing Shed Heater
- Cooling Tower
- Fabric Filter Baghouse (FFB) DC1 controlling rail unloading material transfers
- FFB DC2 controlling coal silo material transfers
- FFB DC3 controlling coal crusher operation and material transfers
- FFB DC4 controlling tripper deck plant silos material transfers
- FFB DC5 controlling limestone material transfers
- Fabric Filter bin vent DC6 controlling fly ash silo (AS-1) material transfers
- Bin vent DC7 controlling bottom ash silo (AS-2) material transfers
- Emergency Coal Storage Pile
- Ash Storage/Disposal Monofill
- 275,000 gallon capacity diesel fuel-oil storage tank
- Haul Roads/vehicle traffic

B. Source Description

1. CFB Boiler

The CFB Boiler will combust low-sulfur coal except during periods of start-up and shutdown where pipeline quality natural gas, propane, or low-sulfur diesel fuel-oil may be combusted. Regulated pollutants emitted from the CFB-Boiler will be controlled by CFB

limestone injection technology, a fabric filter baghouse (FFB), a hydrated ash re-injection system (HAR), and a selective non-catalytic reduction unit (SNCR). The total CFB-Boiler emission control strategy is characterized as an integrated emission control system (IECS).

The CFB Boiler technology uses a bed of crushed coal and limestone and recycled heavy ash particles suspended (fluidized) in an upwardly flowing air stream. Air enters near the bottom of the furnace and is staged through air distribution nozzles to minimize the formation of NO_x . The coal and limestone are metered and fed into the furnace bed. Combustion takes place in the fluidized bed, which is limited in temperature to reduce the formation of NO_x . The fine particles of limestone react with the sulfur in the coal and reduce the formation of SO_2 . The heavier combustion byproduct particles are carried in the flue gas through the furnace, collected in a cyclone separator, and are then circulated back into the furnace.

The SNCR system is used to control NO_x emissions. Ammonia (NH_3) is injected into the cyclone separator and mixed with the flue gas. The NH_3 reacts with the flue gas to convert NO_x into nitrogen gas (N_2), and water vapor (H_2O). The HAR system is used to control SO_2 emissions. The HAR is a dry flue gas desulfurization process; the system mixes water with fly ash and available lime (produced during heating of the limestone in the CFB Boiler) to react with the SO_2 in the flue gas to form particulate, which is collected downstream in FFB. The FFB is used for particulate emissions control. The fabric filter consists of multiple fabric bags that capture lighter particles in the exhaust gases downstream of the cyclone separator. These lighter particles include fly ash and lighter solids created in the chemical reaction processes. Carbon monoxide (CO) and Volatile Organic Compounds (VOC) emissions will be controlled by best management practices (BMP) and staged combustion of air ensuring proper operation of the CFB Boiler. Limestone injection in the CFB Boiler and the HAR system, collectively, will also remove acid gases including sulfuric acid (H_2SO_4), hydrochloric acid (HCl) and hydrofluoric acid (HF). In addition, the FFB will reduce emissions of metals including antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, mercury, and manganese. A co-benefit of mercury emission reduction will result from the overall IECS design. Absorption of mercury will be realized in the CFB Boiler due to the source of unburned carbon, use of limestone injection, SNCR, and the HAR system. The mercury in particulate form will then be collected in the FFB. In addition, mercury specific emission controls may be required (see mercury BACT analysis and determination, Section III, Permit Analysis). After passing through the FFB, the flue gas will exit to atmosphere through the 400-foot tall CFB Boiler stack. The height of the stack was selected to minimize the visual impact of the plant while maintaining adequate dispersion.

2. Auxiliary Boiler, Emergency Generator, Emergency Fire Pump, and Coal Thawing Shed

The auxiliary boiler will combust #2 diesel fuel, natural gas, or propane and will only be in operation during periods of CFB Boiler startup, shutdown, commissioning and during extended downtimes of the CFB Boiler during winter months to aid in the prevention of freezing of the CFB Boiler components. The Emergency Generator and Emergency Fire Pump will combust only low-sulfur diesel fuel-oil and operate only during emergencies and during required maintenance. The Coal Thawing Shed Heater will only operate on propane or natural gas during times when the coal is frozen in the coal train cars.

3. Cooling Tower

A wet cooling tower will be used to dissipate the heat from the condenser by using the latent heat of water vaporization to exchange heat between the process and the air passing through the cooling tower. The cooling tower will be an induced, counter flow draft design equipped with drift eliminators. The average make-up water rate for the proposed cooling tower will be approximately 2,250 gallons per minute (gpm). Water will be delivered to the facility via pipeline from the Missouri River.

4. Coal Fuel Processing, Handling, Transfer, and Storage Operations

Facility operations will utilize several proposed conveyors, transfer points, and storage facilities to handle the coal fuel material required for the operation of the CFB Boiler. The coal storage and handling system begins with coal delivered by railcars to the SME-HGS facility. Coal deliveries are estimated to be two trains per week or approximately 22,000 tons of coal.

The coal delivery railcars will pass through the Coal Thawing Shed, which will thaw frozen wintertime coal shipments before the railcars enter the Rail Unloading Building. Inside the Rail Unloading Building the coal railcars will be unloaded via a belly dump into a below-grade hopper. From the hopper, the coal will be transferred onto a covered belt conveyor (MC02). The Rail Unloading Building will be vented to an induced draft FFB DC1, which will maintain a constant negative pressure within the building. FFB DC1 will provide emission control for coal transfers from the below-grade feeders to conveyor MC02. MC02 will deliver the coal to the enclosed Transfer Tower 16. The Transfer Tower will be vented to the induced draft FFB DC2 located near the coal silo. The Transfer Tower will direct the coal to either the coal silo or to the outdoor long-term coal storage pile (emergency coal pile). The emergency coal pile will store enough coal to supply the CFB Boiler for approximately one month and be used during interruptions in coal deliveries. The emergency coal pile will be compacted and sprayed with water or surfactant to minimize coal dust emissions. Coal transferred to the emergency coal storage pile will be diverted to the Coal Stackout Conveyor (CC01) and will then enter the Lowering Well where emissions will be controlled by the Lowering Well design. Coal will be reclaimed from the coal storage pile by below-grade vibrating reclaim hoppers and a belt feeder. The reclaimed coal will be moved onto the Coal Reclaim Conveyor (CC03) and returned to Transfer Tower 16. Coal not directed to the emergency coal pile or reclaimed from the emergency coal pile will be transferred to the Coal Transfer Conveyor (CC02) inside Transfer Tower 16. CC02 feeds the Coal Silo (CS-1), which is sized to hold coal for several days of CFB Boiler operations. The coal transfers associated with CC04 are controlled by FFB DC2 located at the coal silo. FFB DC2 will also control coal dust emissions from the transfer of coal from the feeder located at the bottom of CS-1 to Coal Feeder Conveyor (CC04). CC04 transfers coal to the Coal Crusher House which encloses a coal surge bin, two rotary feeders, and two coal crushers and is controlled by FFB DC3, which also controls emissions from the Coal Transfer Conveyor CC05. Crushed coal on CC06 is transferred to the Tripper System (comprised of the Tripper Conveyor and Traveling Tripper) and is controlled by FFB DC4.

5. Limestone Processing, Handling, Transfer, and Storage Operations

Covered, over-the-highway, bottom-dumping trucks will deliver limestone material to the SME-HGS facility and will be unloaded in a drive-through building, which is controlled by FFB DC5. The Limestone Transfer Conveyor (LC01) will move the delivered limestone to

the Limestone Bucket Elevator (LC02), and discharge into the Limestone Silo (LS1). LS1 loading and unloading limestone dust emissions from this silo will also be controlled by FFB DC5. Limestone unloaded from the silo will be transferred to a feed chute by the Limestone Weight Feeder (LC03). The feed chute dumps directly into the Limestone Mills, which feed directly into the furnace of the boiler.

6. Fly and Bed Ash Handling, Transfer, and Storage/Disposal Operations

Combustion of coal in the CFB Boiler will produce two types of dry ash: bed ash (20-30%) and fly ash (70-80%). Both fly ash and bed ash will be dry and will be collected in two separate ash silos. Fly ash collected by the baghouse will be pneumatically transferred to the fly ash silo (AS1). Air displaced by fly ash silo charging will be controlled by Bin-Vent DC6, while bed ash from the CFB Boiler will be transferred pneumatically to the bed ash silo (AS2) where emissions will be controlled by a bin vent DC7. Bed ash and fly ash will be gravity-fed into trucks through a pug mill where water and ash are mixed to reduce dust generation. Air displaced by ash loading into trucks will be vented through AS1 and AS2 and their associated bin vents DC6 and DC7, respectively. The ash will be transferred from AS1 and AS2 to trucks and disposed of in the on-site ash monofill. In addition to disposal on-site, SME-HGS is researching beneficial uses for the ash.

7. Fuel-Oil Storage Tank

The diesel fuel will be used for CFB Boiler startup, shut-down, and commissioning operations, auxiliary boiler operations, emergency generator operations, and emergency fire pump operations, and will be stored in an above-ground fuel tank. The tank will hold up to 275,000 gallons of #2 diesel fuel. The tank will be limited to the storage of fuels with a vapor pressure of 3.5 kilopascals (kPa) or less to avoid 40 CFR 60, Subpart Kb, applicability.

8. Haul Roads

Trucks will be used for the delivery of limestone and the transport of ash to the monofill. The facility will also have bulldozers and front-end loaders, which will be utilized to maintain the emergency coal storage pile. SME-HGS will use BMP, including water sprays, to reduce fugitive emissions from unpaved work areas and roadways.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the Administrative Rules of Montana (ARM) and are available, upon request, from the Department. Upon request, the Department will provide references for location of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 – General Provisions, including but not limited to:

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.
2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq.*, Montana Code Annotated (MCA).

SME-HGS shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.
5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to the following:

1. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
2. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
3. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
4. ARM 17.8.213 Ambient Air Quality Standard for Ozone
5. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
6. ARM 17.8.221 Ambient Air Quality Standard for Visibility
7. ARM 17.8.223 Ambient Air Quality Standard for PM₁₀

SME-HGS must maintain compliance with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.
2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, SME-HGS shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.
3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.
5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. This rule requires that no person shall burn liquid, solid, or gaseous fuel in excess of the amount set forth in this rule.
6. ARM 17.8.324 Hydrocarbon Emissions--Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.
7. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR 60, Standards of Performance for New Stationary Sources (NSPS). SME-HGS is an NSPS affected facility under 40 CFR 60 and is subject to the requirements of the following subparts:
 - a. 40 CFR 60, Subpart A. The general provisions provided in 40 CFR 60, Subpart A, apply to all equipment or facilities subject to any Subpart listed below
 - b. 40 CFR 60, Subpart Da. As applicable to CFB Boiler and associated affected equipment.
 - c. 40 CFR 60, Subpart Db. As applicable to Auxiliary Boiler and associated affected equipment.
 - d. 40 CFR 60, Subpart Y. As applicable to coal processing, handling, and storage equipment and activities.
 - e. 40 CFR 60, Subpart OOO. As applicable to limestone processing, handling, and storage equipment and activities.
 - f. 40 CFR 60, Subpart HHHH. Model rules for a Mercury Budget Trading Program.
9. ARM 17.8.341 Emission Standards for Hazardous Air pollutants. This source shall comply with the standards and provisions of 40 CFR 61, as appropriate.
10. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR 63, shall comply with the requirements of 40 CFR 63, as listed below:
 - a. 40 CFR 63, Subpart A. The general provisions provided in 40 CFR 63, Subpart A, apply to all equipment or facilities subject to any Subpart listed below:
 - b. 40 CFR 63, Subpart B. As applicable facility wide.
 - c. 40 CFR 63, Subpart ZZZZ. As applicable to the Emergency Generator.
 - d. 40 CFR 63, Subpart DDDDD. As applicable to the Auxiliary Boiler.

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.
2. ARM 17.8.402 Requirements. SME-HGS must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). The proposed height of the stacks for the SME-HGS CFB Boiler and Auxiliary Boiler are below the allowable GEP stack height and SME-HGS has demonstrated compliance with all applicable ambient air quality standards as part of the complete permit application for this permit.

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation, and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. SME-HGS submitted the appropriate permit application fee for the current permit action.
2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.
2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. SME-HGS has a PTE greater than 25 tons per year of PM, PM₁₀, NO_x, CO, SO₂, and VOC; therefore, an air quality permit is required.
3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.
5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration, or use of a source. SME-HGS submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. SME-HGS submitted an affidavit of publication of public notice for the December 7, 2005, issue of the *Great Falls Tribune*, a newspaper of general circulation in the Town of Great Falls in Cascade County, as proof of compliance with the public notice requirements.
6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.
7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.
8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.
9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving SME-HGS of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq.*
10. ARM 17.8.760 Additional Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those applications that require an environmental impact statement.
11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.
12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.
 14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of Intent to Transfer, including the names of the transferor and the transferee, is sent to the Department.
- G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:
1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.
 2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

This facility is a listed source because it is a fossil-fuel fired steam-electric generating plant having more than 250 MMBtu/hr heat input capacity. Furthermore, the facility's emissions of PM, PM₁₀, NO_x, SO₂, and CO are greater than 100 tons per year; therefore, the facility is a major source under the New Source Review Prevention of Significant Deterioration (PSD) program.

- H. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:
1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any source having:
 - a. PTE > 100 tons/year of any pollutant;
 - b. PTE > 10 tons/year of any one Hazardous Air Pollutant (HAP), PTE > 25 tons/year of a combination of all HAPs, or lesser quantity as the Department may establish by rule; or
 - c. PTE > 70 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (PM₁₀) in a serious PM₁₀ nonattainment area.
 2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing Air Quality Permit #3423-00 for SME-HGS, the following conclusions were made:

- a. The facility's PTE is greater than 100 tons/year for PM, PM₁₀, NO_x, SO₂, and CO.
- b. The facility's PTE is greater than 10 tons/year for any one HAP and greater than 25 tons/year for all HAPs.
- c. This source is not located in a serious PM₁₀ nonattainment area.
- d. This facility is subject to NSPS requirements under 40 CFR 60, Subpart(s) A, Da, Db, Y, and OOO.
- e. This facility is subject to NESHAP standards under 40 CFR 60, subpart DDDDD and ZZZZ, as applicable.
- f. This source is a Title IV affected source.
- g. This source is not a solid waste combustion unit.
- h. This source is not an EPA designated Title V source.

Based on the above information, the SME-HGS facility is a major source of air pollutants as defined under the Title V operating permit program; therefore, a Title V Operating Permit is required. SME-HGS submitted an application for a major source Title V operating permit concurrent with the submittal of the application for Montana Air Quality Permit #3423-00.

III. BACT Determination

A BACT determination is required for each new or modified source of emissions. SME-HGS shall install on the new or modified source of emissions the maximum air pollution control capability that is technically practicable and economically feasible, except that the BACT shall be utilized.

Under the current permit action, SME-HGS proposed a coal-fired power plant incorporating a CFB Boiler for the production of steam to be routed to a steam turbine, which in turn drives an electric generator capable of producing electrical power. The United States Environmental Protection Agency's (EPA) Draft New Source Review Workshop Manual (October 1990) (NSR Manual) states that, "historically, EPA has not considered the BACT requirement a means to re-define the design of the source when considering available control technologies." However, the NSR Manual goes on to indicate "...this is an aspect of the New Source Review – Prevention of Significant Deterioration permitting process in which states have the discretion to engage in a broader analysis if they so desire." Based on the analysis provided below, the Department does not believe that redefining the source is appropriate in this case.

In support of the Department's position on this issue, a recent EPA policy/guidance statement titled *Best Available Control Technology Requirements for Coal-Fired Power Plants*, authored by Stephen D. Page, Director, EPA Office of Air Quality, Planning, and Standards (December 13, 2005), provides that inclusion of technologies such as integrated gasification combined cycle (IGCC) in the BACT analysis for a coal-fired power plant, such as that proposed in this case, constitutes re-definition of the source and is not appropriate under the BACT analysis and determination process.

Despite the above-cited reasons for not requiring consideration of other energy production processes, during the research and development phase leading to the proposed SME-HGS project, SME-HGS evaluated various alternative energy technologies including the following: Wind; Solar -

Photovoltaic; Solar - Thermal; Hydroelectric; Geothermal; Biomass; Biogas; Municipal Solid Waste; Natural Gas Combined Cycle; Microturbines; Pulverized Coal (PC) Boilers; CFB Boilers; and IGCC. This analysis is compiled in a document created for the U.S. Department of Agriculture, Rural Utility Service (RUS) titled, *Alternative Evaluation Study* (AES). A copy of this document is available for review on the RUS website at www.usda.gov/rus/water/ees/eis.htm and in Appendix D of the SME-HGS application for this air quality permit. This document constitutes a detailed study of alternative energy technologies that were analyzed for future power requirements. The purpose of the AES, as stated in the AES document is "...to determine *an appropriate source of wholesale electric energy and related services post 2008...Provide an analysis of alternatives that SME-HGS has considered to meet its wholesale energy and related supply obligations currently met through the use of power purchase agreements...The alternatives studied by SME-HGS were evaluated in terms of cost effectiveness, technical feasibility, and environmental soundness.*"

Additional Evaluation of IGCC and PC Technology

As previously stated, the Department determined that re-defining the proposed CFB coal-fired power project is not appropriate in this case. However, because IGCC and PC technologies represent available and technically feasible electrical power production technologies using coal as fuel, the following information has been summarized to provide additional basis for rejecting these technologies as BACT for the proposed SME-HGS project based on technical, environmental, and economic factors.

IGCC Power Generation

Based on the analysis included in the SME-HGS application materials and independent Department research, the Department determined that IGCC represents an available and potentially technically feasible strategy for the production of electricity using coal. However, the Department determined that IGCC is technically, economically, and environmentally infeasible for the purpose of meeting the SME-HGS wholesale energy and related supply obligations to its energy cooperative customers.

As provided in the NSR Manual (Section B-19), an analysis of technical feasibility should include an evaluation of the capabilities of the technology for project specific application. At the time of draft permit issuance, IGCC has not been adequately demonstrated to provide acceptable reliability, with current approaches to improving reliability resulting in less efficient facilities thereby negatively impacting the cost-competitiveness of IGCC for a base-load power generation project. Currently, IGCC incurs an approximate 20% increase in project cost-effective values when compared to CFB power production projects. Therefore, the Department determined that the application of IGCC for the proposed SME-HGS project presents currently un-resolvable reliability concerns leading to unacceptable project cost increases.

Further, based on Department analysis of existing and currently operational similar sized IGCC plant operations, the Department determined that criteria pollutant emissions from IGCC plants, when compared to CFB technology, result in relatively little or no additional environmental protection. The Department understands that the carbon sequestration (greenhouse gas reduction) capabilities of the IGCC technology potentially represents a significant environmental benefit associated with the application of this technology when compared to historically prevalent coal-fired power plant projects (CFB and PC). However, greenhouse gasses, such as carbon dioxide (CO₂), are not currently regulated under the Montana or federal Clean Air Act. Therefore, because IGCC results in relatively little increased regulated environmental protection, the environmental benefits associated with IGCC greenhouse gas sequestration capabilities do not justify application of this technology for the proposed project.

As summarized above, the Department determined that, at this time, IGCC constitutes a technically, economically, and environmentally infeasible alternative electric power production alternative for the proposed SME-HGS project; therefore, IGCC is eliminated from further consideration under the BACT analysis and determination process.

PC-Boiler Power Generation

Based on the analysis included in the SME-HGS application materials and direct recent and historical Department experience in permitting PC-fired electrical power production projects, the Department determined that PC-fired electrical power production represents an available, technically feasible, and cost-effective strategy for the production of electricity using coal. However, the Department determined that PC-fired electrical power generation does not constitute BACT in this case considering the environmental benefits associated with the proposed CFB coal-fired power project when compared to a PC coal-fired power project.

Operation of a PC-fired boiler in place of the proposed CFB Boiler for the SME-HGS project would result in significantly increased emissions of SO₂, CO, PM₁₀, and total HAPs and relatively similar emissions of NO_x and mercury (specific HAP). Therefore, because SME-HGS proposed a CFB electrical power generation project and the CFB technology would result in less emissions of regulated air pollutants when compared to the PC-fired technology, the Department determined that PC-fired electrical power generation does not constitute BACT in this case.

Project BACT Applicability

The Department determined that the proposed CFB coal-fired power plant represents the most appropriate technology to supply energy to SME-HGS customers taking into consideration technical, environmental, and economic factors. Coal-fired electrical power generation, specifically CFB coal combustion is carried forward into the following BACT analysis and determination process. The following BACT analysis addresses available methods of controlling air pollutant emissions from the following affected equipment:

- CFB Boiler: SO₂, filterable PM, PM₁₀ (filterable and condensable), NO_x, CO, VOC, H₂SO₄, acid gasses (HCl and HF), trace metals, radionuclides, and mercury.
- Coal, Limestone, and Ash (Bottom and Fly Ash) Material Processing, Handling, Transfer, and Storage Operations: PM/PM₁₀
- Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater: PM₁₀, NO_x, CO, SO₂, and VOC.
- Cooling Tower: PM/PM₁₀
- Haul Roads/Truck Traffic: PM/PM₁₀

The Department reviewed the following control options, as well as previous BACT determinations for similar permitted sources in order to make the following pollutant specific BACT determinations.

A. CFB Boiler BACT Analysis and Determination

1. SO₂ Emissions

Sulfur oxide (SO_x) emissions from fossil fuel combustion consist primarily of SO₂. Additional compounds of SO_x also form at a much lower quantity and consist of sulfur trioxide (SO₃) and gaseous sulfates. These compounds form as the sulfur in the fossil fuel is oxidized during the combustion process. SME-HGS is proposing to use Powder River Basin (PRB) sub-bituminous coal as the CFB Boiler fuel source and, as such, has analyzed the use of low-sulfur coal for the proposed project.

Low sulfur coal is typically considered coal with sulfur content at or below 1.0% by weight. Sulfur content and heating content of coal can vary between coal mine and coal seam, which can impact SO₂ emissions from the source. High sulfur coal is typically between 1% and 5% sulfur by weight. Coal analyzed for the proposed project will typically have sulfur content less than 0.8% by weight and heating values greater than 8,600 Btu/lb.

A. Identification of Available SO₂ Control Strategies/Technologies

Several techniques can be used to reduce SO₂ emissions from CFB Boiler fossil fuel combustion. SO₂ control options can be divided into pre-combustion strategies (e.g., combusting low sulfur fuels, fuel blending, coal cleaning, etc.), combustion techniques, and post-combustion controls typically characterized as flue gas desulfurization (FGD) units (e.g., wet scrubbers, dry scrubbers, etc.). The following available SO₂ control options/technologies/strategies were evaluated for the proposed project:

- i. CFB Boiler with High-Sulfur Coal
- ii. CFB Boiler with Low-Sulfur Coal (Fuel Blending or Switching)
- iii. CFB Boiler with Limestone Injection
- iv. CFB Boiler with Coal Cleaning
- v. CFB Boiler with FGD
 - a. Wet Lime Scrubber
 - b. Wet Limestone Scrubber
 - c. Dual Alkali Wet Scrubber
 - d. Spray Dry Absorber
 - e. Dry-Sorbent Injection
 - f. Circulating Dry Scrubber
 - g. Hydrated Ash Re-injection (HAR)
- vi. CFB Boiler with Low-Sulfur Coal and Coal Cleaning
- vii. CFB Boiler with Low-Sulfur Coal and FGD
- viii. CFB Boiler with Low-Sulfur Coal Limestone Injection
- ix. CFB Boiler with High or Low-Sulfur Coal, Coal Cleaning, and FGD
- x. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, and Coal Cleaning
- xi. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, and FGD
- xii. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, Coal Cleaning, and FGD

The following text provides a brief overview of the above-cited SO₂ control options/technologies/strategies that have been evaluated for the proposed project.

i. CFB Boiler with High-Sulfur Coal

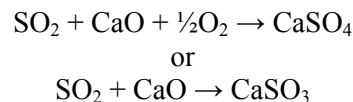
SO₂ emissions from a CFB Boiler with no control are strictly dependent on the sulfur content of the coal being fired. The coal for a CFB Boiler is crushed to a specific size and injected into the CFB Boiler. The coal mixes with the bed material and circulates through the boiler until all of the coal is combusted. The bed material can be made up of stone, sand, and/or limestone. The use of limestone as a bed material is a common industry practice as a first stage SO₂ control strategy.

ii. CFB Boiler with Low-Sulfur Coal (Fuel Blending or Switching)

Another potential control option for reducing SO₂ emissions is to reduce the amount of sulfur contained in the coal by using low-sulfur coal (e.g., current project proposal) or by blending low-sulfur coal with relatively higher sulfur coal (e.g., Midwestern United States bituminous coal). Low-sulfur coal is used as a means to decrease the SO₂ emissions without installing SO₂ add-on control devices. By blending low sulfur coal with high sulfur coal or by switching from high sulfur coal to a lower sulfur coal, SO₂ emissions will decrease. When low-sulfur coal is readily available, fuel blending or switching can be a cost-effective means to reduce SO₂ emissions. CFB Boilers are typically not sensitive (from an operational standpoint) to different types of coal or solid fuels. This is one of the benefits of a CFB Boiler.

iii. CFB Boiler with Limestone Injection

In a CFB Boiler, crushed limestone (CaCO₃) is fed to the combustor and becomes part of the solid medium that makes up the combustion bed. Within the combustion zone, lime (CaO) is formed by calcining the CaCO₃. SO₂ formed during the combustion process combines with the calcined CaO to form gypsum (CaSO₄), a stable byproduct, or CaSO₃ as shown in the following reactions:



The SO₂ removal equation shows that one mole of calcium is required to capture one mole of sulfur. Therefore, the theoretical minimum Ca/S ratio required for the removal of a given sulfur concentration is 1/1, assuming 100% utilization of the sorbent. However, the actual removal efficiency that can be achieved in practice for a given unit is dependent on several factors including the size and porosity of the lime, temperature of the combustion bed, residence time within the combustion bed, mixing, and uncontrolled SO₂ concentration. In practice, it has been found that approximately 50% of the SO₂ will be removed at a Ca/S ratio of 1. As the Ca/S ratio increases, a greater amount of SO₂ will be removed, but with diminishing return. Limestone injection is an integral part of the CFB Boiler process; however, the actual limestone injection rate varies from unit to unit as the sulfur in the coal or fuel varies.

iv. CFB Boiler with Coal Cleaning

Various coal cleaning processes may be employed to reduce the coal sulfur content. Physical coal cleaning removes mineral sulfur (such as pyrite) but is not effective in removing organic sulfur. Chemical cleaning and solvent refining processes are being developed to remove organic sulfur. Coal cleaning has generally been used on high mineral, high sulfur, coal for power plants without FGD systems with some success. In some studies, coal-cleaning processes have been noted to reduce the feed coal sulfur content by 1% in high sulfur coal with sulfur contents up to 5%. This equates to an approximate 20% reduction in total sulfur-in-coal. Coal cleaning requires water and/or chemicals for removing the sulfur, pyrite, and other materials; consequently, a wastewater stream is produced by the coal cleaning system, which must be treated before discharge from the facility.

v. CFB Boiler with FGD

Post-combustion methods for CFB Boilers mainly consist of FGD and are typically classified as either wet or dry systems. Wet and dry FGD are well-established SO₂ control options. Wet FGD removes SO₂ with a wet lime or limestone slurry as compared to dry FGD, which injects dry lime or limestone and produces a dry by-product that is removed with the fly ash in the particulate control device (e.g., fabric filter baghouse (FFB)). Dry FGD, as the name applies, does not use water and does not require a wastewater disposal system. The following text provides a brief overview of available FGD systems:

a. Wet Lime/Limestone Scrubber

The wet lime scrubbing process uses alkaline slurry made by adding lime (CaO) to water. The alkaline slurry is sprayed into the exhaust stream and reacts with the SO₂ in the flue gas. Insoluble calcium sulfite (CaSO₃) and calcium sulfate (CaSO₄) salts are formed in the chemical reaction that occurs in the scrubber. The salts are removed as a solid waste by-product. The waste by-product is mainly CaSO₃, which is difficult to dewater. Solid waste by-products from wet lime scrubbing are typically managed in dewatering ponds and landfills.

Wet limestone scrubbers are very similar to wet lime scrubbers. However, the use of limestone (CaCO₃) instead of CaO requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The CaCO₃ slurry process also requires a ball mill to crush the CaCO₃ feed.

Forced oxidation of the scrubber slurry can be used with either the lime or limestone wet FGD system to produce gypsum solids instead of calcium sulfite by-product. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the FGD. The gypsum by-product may be sold for other uses, reducing the quantity of solid waste that needs to be disposed of in a landfill.

Wet lime/limestone scrubbers can achieve SO₂ control efficiencies of approximately 95% or greater when used on boilers burning higher sulfur bituminous coals, but may be less efficient when the boiler is combusting lower sulfur coals, such as that proposed for the current project. The actual control efficiency of a wet lime/limestone FGD system depends on several factors, including the uncontrolled SO₂ concentration entering the scrubber.

b. Dual Alkali Wet Scrubber

Dual-alkali scrubbers use a sodium-based alkali solution to remove SO₂ from the combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagents absorb SO₂ from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, and the regenerated sodium solution is returned

to the absorber loop. The dual-alkali process requires lower liquid-to-gas ratios than scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units; however, additional regeneration and sludge processing equipment is necessary.

A sodium-based scrubbing solution, typically consisting of a mixture of sodium hydroxide, sodium carbonate, and sodium sulfite, is an efficient SO₂ control reagent. However, the high cost of the sodium-based chemicals may limit feasibility of such an installation on a generating unit size of 100 MW or larger utility boiler. In addition, the process generates a less stable sludge that can create material handling and disposal issues. The control efficiency is similar to the wet lime/limestone scrubbers at approximately 95% or greater. As with the wet lime/limestone scrubbers, control efficiencies are highly dependent upon the uncontrolled SO₂ concentration entering the scrubber.

c. Spray Dryer Absorber (SDA)

The typical SDA uses lime slurry and water injected into a tower to remove SO₂ from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry in order to produce a relatively dry by-product. The process equipment associated with an SDA typically includes an alkaline storage tank, mixing and feed tanks, an atomizer, spray chamber, particulate control device, and a recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce alkaline sorbent use. SDAs are a commonly used dry scrubbing method in large industrial and utility boiler applications. SDAs have demonstrated the ability to achieve greater than 95% SO₂ reduction. Again, control efficiencies are highly dependent upon the uncontrolled SO₂ concentration entering the scrubber.

d. Dry Sorbent Injection

Dry sorbent injection involves the injection of powdered or hydrated sorbent (typically alkaline) directly into the flue gas exhaust stream. Dry sorbent injection systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and injection device. The dry sorbent is typically injected countercurrent to the gas flow through a Venturi orifice. An expansion chamber is often located downstream of the injection point to increase residence time and contact efficiency. Particulates generated in the reaction are controlled in the system's particulate control device. SO₂ control efficiencies for dry sorbent injection systems are approximately 50%, but if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers. Once again, control efficiencies are highly dependent upon the uncontrolled SO₂ concentration entering the scrubber.

e. Circulating Dry Scrubber

A third type of dry scrubbing system, the circulating dry scrubber (CDS), uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2 . Flue gas passes through a Venturi orifice at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime where SO_2 is removed. The dry by-product produced by this system is routed with the flue gas to the unit's particulate removal system.

f. Hydrated Ash Re-Injection (HAR) System.

The HAR process is a modified dry FGD process developed to increase utilization of un-reacted lime (CaO) in the CFB ash and any free CaO left from the furnace burning process. The hydrated ash re-injection process will further reduce the SO_2 concentration in the flue gas. The actual design of a HAR system is vendor-specific and hydrated ash re-injection type systems may be referred to as a Flash Dry AbsorberTM (Alstom trade name) or a polishing scrubber.

In a hydrated ash re-injection system, a portion of the collected ash and lime is hydrated and re-introduced into a reaction vessel located ahead of the fabric filter inlet. In conventional boiler applications, additional lime may be added to the ash to increase the mixture's alkalinity. For CFB applications, sufficient residual CaO is available in the ash and additional lime is not required. It is estimated that potential SO_2 emissions would be reduced by approximately 90 to 95% in the CFB with an additional 60 to 80% reduction achieved with the addition of a HAR system. The overall control efficiency would be approximately 97% to 98% with low sulfur coal and even greater with high sulfur coal fuel.

vi. CFB Boiler with Low-Sulfur Coal and Coal Cleaning

As stated previously, coal cleaning is typically performed on high-sulfur coals. The economics of cleaning low-sulfur coal show this to be an expensive method with relatively little benefit of additional reduction in sulfur.

vii. CFB Boiler with Low-Sulfur Coal and FGD

Low-sulfur coal is typically used to reduce overall SO_2 emissions from a CFB Boiler. However, the control efficiency decreases as the inlet SO_2 decreases with a lower-sulfur coal.

viii. CFB Boiler with Low-Sulfur Coal Limestone Injection

As stated previously, limestone can be injected in the CFB Boiler as bed material, which can help reduce SO_2 emissions. Low sulfur coal would not require as much limestone injection as a high sulfur coal to achieve an equivalent SO_2 emission rate.

ix. CFB Boiler with High or Low-Sulfur Coal, Coal Cleaning, and FGD

As stated previously, coal cleaning can remove approximately 20% of the boiler SO₂ emissions. Coal cleaning is typically applied to high-sulfur coals on systems without FGD. When FGD systems are installed, coal cleaning is typically not justified due to limited additional SO₂ reduction realized for a relatively high cost.

x. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, and Coal Cleaning

As stated previously, coal cleaning is typically performed on high sulfur coals with no additional SO₂ control. The cost of cleaning coal prior to a CFB with limestone injection is expensive with relatively little benefit of reduction in SO₂ emissions through the reduction of sulfur-in-coal.

xi. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, and FGD

FGD systems can be added as a “polishing” scrubber on a CFB Boiler with limestone injection. This control option typically can remove SO₂ emissions at control efficiency greater than 97% with low-sulfur coal and can achieve higher control efficiency with a high sulfur coal. The CFB Boiler technology with low sulfur coal, limestone injection, and HAR FGD SO₂ control strategy has been proposed by SME-HGS for the project.

xii. CFB Boiler with High or Low-Sulfur Coal, Limestone Injection, Coal Cleaning, and FGD

As stated previously, coal cleaning is typically performed on high sulfur coals for use in boilers with no additional SO₂ control. The economics of cleaning coal prior to a CFB with limestone injection and FGD is expensive with very little benefit of reduction in sulfur.

B. Technical Feasibility Analysis

SME-HGS is proposing to use low sulfur coal with an average sulfur content of approximately 0.7% sulfur by weight. Therefore, although high sulfur coal is technically feasible, all control options for high sulfur coal are eliminated from further evaluation. Since coal cleaning is typically performed on high sulfur coals, and provides minimal additional benefit when performed on low sulfur coal, all control options with coal cleaning are eliminated from further evaluation.

The circulating dry scrubber has limited application, and has not been used on large CFB Boilers. Furthermore, circulating dry scrubber systems result in high particulate loading to the unit's particulate control device. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, electrostatic precipitators (ESP) are generally used for particulate control. For reasons further discussed in the filterable PM (filterable and condensable) BACT analysis for the CFB Boiler, the Department determined that FFB constitutes BACT for CFB Boiler particulate control. Based on limited technical data from non-comparable applications and engineering judgment, the Department determined that CDS is not technically feasible with a CFB Boiler equipped with FFB particulate control. Therefore, the CDS will not be evaluated further.

Although a dry sorbent injection system may be technically feasible, it is not practical for use with a CFB. The CFB flue gas contains excess un-reacted lime and heavy ash particles that will be re-injected back into the CFB combustion bed. A dry sorbent injection system would simply add additional unreacted lime to the flue gas. Furthermore, SO₂ control efficiencies for dry sorbent injection systems are typically around 50% on units with a much higher uncontrolled SO₂ concentration in the flue gas. If used in conjunction with a CFB unit (with a relatively low SO₂ concentration in the flue gas), the control efficiency would be expected to be something less than 50%. Because the dry sorbent injection system is not practical with a CFB, and because the control efficiency of the dry sorbent system is lower than the control efficiency of other post-combustion control options, the system will not be evaluated further.

Summary Table: SO₂ Control Option Infeasibility	
SO₂ Control Option	Basis for Infeasibility
All Control Options with High Sulfur Fuel	SME-HGS is proposing to use low sulfur coal
All Control Options with Low Sulfur Fuel and Coal Cleaning	Coal cleaning is considered ineffective with low sulfur coal because it is mostly organic sulfur and does not react to cleaning as well as the higher sulfur content bituminous coals.
CFB with or without Limestone Injection with Low Sulfur Coal and Dry Sorbent Injection	Not as effective an SO ₂ option as dual-alkali, SDA, or hydrated ash re-injection. Eliminated from further evaluation.
CFB with or without Limestone Injection with Low Sulfur Coal and Circulating Dry Scrubber	Limited actual experience and not considered technically feasible because of the high particulate loading and excess pressure drop across a FFB.

C. Ranking of Available and Technically Feasible SO₂ Control Options by Efficiency

Wet scrubbing systems (without additional control options) are capable of removing approximately 90-95% of SO₂ emissions from higher sulfur coals. Though various reagents such as lime, limestone, or magnesium-enhanced lime all have different SO₂ removal efficiencies, overall system efficiency is maintained by operating with a slurry feed rate that is appropriate for the reagent being used. For the present analysis, the wet FGD system will be evaluated with an upstream fabric filter baghouse (FFB) followed by a wet lime scrubber. Particulate control is required upstream from the scrubber to maintain scrubber efficiency.

Dry FGD systems are reported to be capable of removing up to 95% of the SO₂ in flue gas streams resulting from combustion of high-sulfur coal. These systems must include downstream particulate control equipment since the FGD adds particulate to the gas stream. FFBs and electrostatic precipitators (ESPs) provide essentially equivalent particulate control efficiency. The dry FGD system will be evaluated with an FFB since it potentially enhances SO₂ and sulfuric acid mist (H₂SO₄) removal efficiency. As the exhaust gas passes through a filter cake containing alkaline ash and un-reacted reagent, additional SO₂ is removed. For this reason, the system configuration of a dry FGD in combination with an ESP will not be further evaluated for the proposed project.

The combination of a CFB Boiler with limestone injection and an FGD can have an overall SO₂ control efficiency of approximately 97% to 98%. This level of collection efficiency is achieved due to the reaction time allowed for the lime in both the CFB furnace as well as the FGD.

Summary Table: SO₂ Control Option Rank by Efficiency		
SO₂ Control Option	Emission Rate (lb/MMBtu)^a	SO₂ Control Efficiency
CFB with Limestone Injection, Low Sulfur Coal, and Wet Lime/Limestone Scrubber	0.038	97.3%
CFB with Limestone Injection, Low Sulfur Coal, and Dual-Alkali Wet Scrubber	0.038	97.3%
CFB with Limestone Injection, Low Sulfur Coal, and Spray Dry Absorber	0.038	97.3%
CFB with Limestone Injection, Low Sulfur Coal, and Hydrated Ash Reinjection	0.038	97.3%
CFB with Limestone Injection, Low Sulfur Coal (Fuel Blending or Switching)	0.08	94.4%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Wet Lime Scrubber	0.10	93%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Wet Limestone Scrubber	0.10	93%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Dual-Alkali Wet Scrubber	0.16	88.7%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Spray Dry Absorber	0.16	88.7%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal and Dry Sorbent Injection	0.80	43.7%
CFB Boiler (without Limestone Injection) with Low Sulfur Coal (without control)	1.42	---
^a Based on a 30-day rolling average		

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following paragraphs evaluate environmental, economic, and energy impacts associated with the remaining SO₂ control options on a CFB Boiler with limestone injection. All control options/strategies without limestone injection have been eliminated from further BACT consideration because SME-HGS proposed limestone injection technology and because a CFB Boiler with limestone injection represents greater SO₂ control efficiency when compared to CFB without limestone injection.

i. Environmental Impacts

Wet FGD systems emit some level of mist that poses negative environmental impacts related to acid gas emissions (H₂SO₄, HCl, and HF), fine particulate emissions, and near and far-range visibility degradation. Dry FGD systems avoid these problems because the technology does not produce mist and

because emissions from the absorber must pass through a filter cake of alkaline material collected in the downstream FFB before exhausting to the atmosphere. Another negative environmental impact associated with a wet FGD system is related to water usage. A wet FGD system uses approximately 20% more water than a dry FGD.

Both wet and dry systems produce solid waste streams containing fly ash and spent lime or limestone and these wastes are generally disposed of in a landfill area or stored in surface impoundments. The wet dual-alkali system uses sodium-based chemicals, which generates a less stable sludge than wet lime/limestone scrubber sludge. This can create material handling and disposal issues of concern.

Even though wet FGD systems use more water and generate a wastewater sludge, wet FGD systems cannot be eliminated from further investigation under the BACT analysis and are thereby evaluated further for economic and energy impacts. The dual-alkali wet scrubber will be eliminated from further investigation due to the material handling and disposal issues (e.g., leachate polluting the ground water causing long-term storage issues) associated with the sludge byproducts.

ii. Economic Impacts

Department verified economic impacts associated with CFB Boilers for each of the above FGD systems were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Cost estimates were provided from commercial suppliers of this type of equipment. Where appropriate, constant operation and maintenance factors were identified and applied consistently to control options. As reported in the application, the cost effective value for CFB with limestone injection, low-sulfur coal, and wet lime/limestone scrubber is approximately \$27,365/ton SO₂ removed; the cost effective value for CFB with limestone injection, low sulfur coal, and SDA is approximately \$7939/ton SO₂ removed; and the cost effective value for CFB with limestone injection, low sulfur coal, and HAR is approximately \$4,054/ton SO₂ removed. Based on the cost-effective values provided above, CFB with limestone injection, low sulfur coal, and HAR is deemed economically feasible for the affected unit and all other control options are deemed economically infeasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

iii. Energy Impacts

Both wet and dry FGD systems require electricity to operate. The wet FGD system uses electricity primarily for the ID fan, re-circulation pumps, reagent handling, and for wet waste dewatering. The dry FGD uses electricity primarily for the ID fan, lime/limestone handling equipment and FFB blowers. Wet FGD system power consumption is approximately 40% greater than that of the dry FGD system. With a HAR system, there is no recirculation pump, wet waste dewatering and reduced power consumption for the reagent (lime/limestone) handling system. None of the control options are eliminated based on energy impacts.

E. SO₂ BACT Determination

SME-HGS proposed the use of CFB Boiler technology with limestone injection, low sulfur coal, and HAR, to maintain compliance with a proposed SO₂ BACT emission limit of 0.038 lb/MMBtu (30-day average). Based on Department verified information contained in the SME-HGS application for Permit #3423-00 and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed SO₂ emission control strategy and emission limit constitute BACT in this case. This BACT determined control option constitutes an approximate 97% SO₂ reduction efficiency.

Other recent SO₂ BACT determinations for coal-fired power plants were researched in the RACT/BACT/LAER Clearinghouse (RBLC) and Western US agency websites. The Department verified data from these websites is summarized in the application. The SME-HGS BACT determined SO₂ emission limit is at the low end of all other recently permitted similar source SO₂ BACT determinations, world-wide. The only facilities with permitted and BACT determined SO₂ emission limits lower than SME-HGS are the AES facility in Puerto Rico and the proposed NEVCO facility in Utah. The applicable SO₂ BACT emission limit for both of these facilities is 0.022 lb/MMBtu. To the best of the Department's knowledge, as of the date of permit issuance, compliance with the applicable SO₂ BACT emission limit had not been demonstrated at the AES facility or the NEVCO facility.

The Department determined that the CFB Boiler operating under the BACT determined control requirements is capable of meeting the established SO₂ BACT emission limit of 0.038 lb SO₂/MMBtu (30-day average). Further, the Department determined that the periodic SO₂ source testing, the applicable provisions contained in the Acid Rain Program (40 CFR 72-78), applicable continuous monitoring, and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted SO₂ BACT limit(s).

2. Filterable PM Emissions

Particulate matter emissions consist of filterable and condensable particulate. Filterable PM resulting from the proposed SME-HGS project is comprised of ash from the combustion of fuel, noncombustible metals present in the fuel, and unburned carbon resulting from incomplete combustion. Filterable PM is material that is in particulate form within the boiler stack and thus collects on the filter of a particulate sampling train. Condensable particulates include condensable organic compounds and minerals (in vapor form) that pass through the filter on a sampling train and are collected in glass impingers that contain a chilled wet solution to condense the vapors from the exhaust stream.

This BACT analysis focuses on control technologies for filterable PM. PM₁₀ (filterable and condensable) is addressed later in the BACT analysis for the proposed project (see PM₁₀ (filterable and condensable) BACT Analysis and Determination).

A. Identification of Available Filterable PM Control Strategies/Technologies

Several techniques can be used to reduce filterable PM emissions from fossil fuel combustion. Three of the most commonly available and effective methods for control of filterable PM emissions are listed below:

- i. Wet scrubbers,
- ii. Electrostatic precipitators (ESP), and
- iii. Fabric filter baghouses (FFB)

The above-cited control strategies and/or combinations thereof, as detailed in the following table, can be used to effectively control filterable PM/PM₁₀.

Summary Table: Available Filterable PM Control Options		
Emitting Unit	Control Option	Combined Control Option
CFB Boiler	Wet or Dry ESP	Wet Scrubber with Wet ESP
	FFB with Fiberglass Bags	
	FFB with Specialty Bags	Wet Scrubber with FFB
	Wet/Dry Scrubber	

A general description of the ESP, FFB, and wet scrubber control technologies is described below. Only the control device is described, not each control option listed above.

i. Wet Scrubbers

Wet scrubbers typically use water to impact, intercept, or diffuse a particulate-laden gas stream. With impaction, particulate matter is accelerated and impacted onto a surface area or into a liquid droplet through devices such as venturi or spray chamber. When using interception, particles flow nearly parallel to the water droplets, which allow the water to intercept the particles. Interception works best for submicron particles. Spray-augmented scrubbers and high-energy venturi employ this mechanism. Diffusion is used for particles smaller than 0.5 micron and where there is a high temperature difference between the gas and the scrubbing liquid. The particles migrate through the spray along lines of irregular gas density and turbulence, contacting droplets of approximately equal energy.

Six particulate scrubber designs are used in wet scrubber control applications: spray, wet dynamic, cyclonic spray, impactor, Venturi, and augmented. In all of these scrubbers, impaction is the main collection mechanism for particles larger than 3 microns. Since smaller sized particles respond to non-inertial capture, a high density of small liquid droplets is needed to trap the particles. This is done at the price of high-energy consumption due to hydraulic or velocity pressure losses (William Vatauvuk, *Estimating Costs of Air Pollution Control*, 1990). Wet scrubbers used specifically for particulate control are not commonly used on large utility boilers because of the high pressure drop to remove particulate to levels equivalent to those achieved with an FFB or ESP. Wet scrubbers are commonly designed for SO₂ removal instead of particulate control.

ii. ESP

An ESP is a particulate control device that uses electric forces to move particles out of the gas stream and onto collector plates. The particles are given an electric charge by forcing them to pass through the corona that surrounds a highly charged electrode, frequently a wire. The electrical field

then forces the charged particles to the opposite charged electrode, usually a plate. Solid particles are removed from the collection electrode by a shaking process known as “rapping.” ESPs may be configured in several ways including the plate wire precipitator, the flat plate precipitator, the tubular precipitator, the wet precipitator, and the two-stage precipitator. These descriptions are outlined in the EPA *OAQPS Cost Control Manual* for ESP control.

The plate wire precipitator is the most common variety. It is commonly installed on coal fired boilers, cement kilns, solid waste incinerators, paper mill recovery boilers, petroleum refining catalytic cracking units, sinter plants, and different varieties of furnaces. Plate wire precipitators are designed to handle large volumes of gas. The flat plate precipitator is designed to use flat plates instead of wires for high-voltage electrodes. Small particle sizes with low-flow velocities are ideal for the flat plate precipitator. The flat plate precipitator usually handles gas flows ranging from 100,000 to 200,000 actual cubic feet per minute (acfm). Tubular precipitators are typically parallel tubes with electrodes running along the axis of the tubes. Tubular precipitators have typical applications in sulfuric acid plants, coke oven byproduct gas cleaning, and steel sinter plants. Wet precipitators can be any of the three previously discussed precipitators but with wet collection plates instead of dry collection plates. A wet precipitator aids in further collection of particles by preventing the collected ash from being re-entrained in the exhaust stream during the rapping of the walls, a problem common to dry precipitators. The disadvantages are the complexity of handling the wash and disposal of the slurry.

Finally, two-stage precipitators are parallel in nature (i.e., the discharge and collecting electrodes are side by side). Two-stage precipitators are designed for indoor applications, low gas flows below 50,000 acfm, and submicrometer sources emitting oil mists, smokes, fumes, and other sticky particulates. Two-stage systems are specialized types of devices that are very limited in applications.

Dry ESPs may be used downstream of a dry FGD unit to collect the dry FGD media and the ash formed during fuel combustion. However, they do not enhance SO₂ or SO₃ control. Dry ESPs are not suited for use downstream of wet FGD systems due to the high moisture content of the gas stream and the resulting stickiness of the particles. Wet ESPs may be used downstream of a wet FGD unit to capture both residual flue gas particulate and H₂SO₄ that may have formed in the wet FGD unit.

iii. FFB

FFBs consist of one or more isolated compartments containing rows of fabric filter bags or tubes. The exhaust stream passes through the fabric where the filterable particulate is retained on the upstream face of the bags, while the cleaned gas stream is vented to the atmosphere or to another pollution control device. FFBs collect particle sizes ranging from submicron to several hundred microns at gas temperatures up to approximately 500°F. Specialty bags can be used to achieve lower particulate emission rates or with stack temperatures above 500°F. FFBs can be categorized by the types of cleaning devices

(shaker, reverse-air, and pulse-jet), direction of the gas flow, location of the system fan, and/or the gas flow quantity. Typically, the type of cleaning method distinguishes the FFB.

Advantages to FFBs are the high collection efficiency (in excess of 99%) and the collection of a wide range of particle sizes. The operational disadvantages of FFBs are limits on gas stream temperatures above 500°F (for typical installations), high-pressure drops, wet gas streams, and issues resulting from gas or particles that are corrosive and/or sticky in nature.

FFBs are not used downstream of a wet FGD system due to the high moisture content of the exhaust gas, which will saturate and ultimately plug the fabric filters. When used downstream of a dry FGD system, the FFB provides additional sulfur oxide control. The alkaline filter cake continues to react with and remove gaseous SO₂ and SO₃ as they pass through the filters. The alkaline filter cake also captures acid gas mist that may have formed in the exhaust system.

B. Technical Feasibility Analysis

Wet scrubbers designed for particulate control are technically infeasible on large utility boilers because of the high-pressure drops. FFB and ESP particulate control devices are commonly used on large utility boilers and are examined further for BACT applicability.

C. Ranking of Available and Technically Feasible Filterable PM/PM₁₀ Control Options by Efficiency

FFBs and ESPs have proven capabilities in removing greater than 99% of the filterable PM from the exhaust gas stream generated by processes similar to the SME-HGS CFB Boiler. FFBs are generally specified for use downstream of a dry FGD system. The following table ranks the filterable PM control efficiency for the specified control options.

Summary Table: Filterable PM Control Option Rank by Efficiency		
Filterable PM/PM₁₀ Technology	Emission Rate (lb/MMBtu)	Estimated Control Efficiency
CFB with FFB with Teflon-Coated Bags	0.012	99.85%
CFB with FFB with Fiberglass Bags	0.015	99.81%
CFB with ESP	0.018	99.77%
CFB with No Add-on Control	7.78	---

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following paragraphs evaluate environmental, economic, and energy impacts associated with the Filterable PM control options on a CFB Boiler with limestone injection.

i. Environmental Impacts

The predominant environmental impact from controlling particulate in an FFB or ESP is related to the fly ash that is collected. The fly ash needs to be properly handled and deposited. SME-HGS is proposing to dispose the fly ash and bed ash in an on-site monofill. Further, an ESP does not provide the additional co-benefit SO_2/SO_3 collection due to the alkaline filter cake on the bags, but has not been eliminated based on environmental impacts.

ii. Economic Impacts

Department verified economic impacts associated with filterable particulate control options were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Where appropriate, constant operation and maintenance factors were identified and applied consistently to control scenarios. Department verified and detailed information regarding economic impacts is contained in the application for this air quality permit.

The annual operating cost for Teflon-coated bags is approximately \$500,000 more than the operating cost for standard fiberglass bags. The increase in annual cost is mainly associated with more expensive bags, and a smaller portion of the annual cost increase is associated with additional operating and maintenance costs. Despite the increase in costs associated with the use of Teflon-coated bags, the Department determined that an emission limit of 0.012 lbs/MMBtu represents an achievable and cost-effective limit. As reported in the application, the annual cost-effective value for Teflon-coated bags for the proposed project is approximately \$83/ton filterable PM removed as compared to approximately \$78/ton filterable PM removed using standard fiberglass bags. Based on the cost-effective values provided above, all control options are deemed economically feasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

iii. Energy Impacts

Each of the control options require power in the form of fan horsepower to overcome the control device pressure drop. However, energy impacts do not eliminate any of the control options.

E. Filterable PM BACT Determination

SME-HGS proposed the use of FFB to maintain compliance with a proposed filterable PM BACT emission limit of 0.015 lb/MMBtu. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed FFB PM control strategy constitutes BACT in this case. However, the Department determined that the proposed emission limit of 0.015 lb/MMBtu does not constitute BACT in this case.

The FFB provides better particulate control than an ESP, is widely used in the coal-fired power generation industry, and was analyzed and is required as part of the SO_2 BACT control determination. An FFB on a CFB with limestone injection and HAR provides a co-benefit of SO_2/SO_3 control, whereas an ESP does not provide this co-benefit control.

The Department determined that maintaining compliance with a limit of 0.012 lbs/MMBtu constitutes BACT in this case. In the BACT analysis contained in the application, SME-HGS states that discussions with baghouse manufacturers and vendors indicates a limit of 0.012 lbs/MMBtu will not be guaranteed without significant increases in costs in order to cover any risks associated with performance guarantees and liquidated damages. However, the Department determined that the cost-effective values incurred by SME-HGS in order to meet a filterable PM emission limit of 0.012 lb/MMBtu are well within industry norms and constitute BACT in this case. Further, the Department determined that the BACT-determined FFB is capable of reducing visible emissions from the CFB Boiler stack to a level that will not exceed 20% opacity averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity. The Department determined that these opacity limits constitute BACT in this case.

Further, the BACT determined filterable PM emission limit and opacity limits are consistent with the values reported in the RBLC for other recently permitted and similar sources, including recently permitted sources permitted and operating in Montana. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT determined control requirements is capable of meeting the established filterable PM BACT emission limit of 0.012 lb/MMBtu and 33.25 lb/hr (0.012 lb/MMBtu * 2770.6 MMBtu/hr average boiler heat input capacity) and the visible emissions standard of less than 20% opacity averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity. Further, the Department determined that the periodic filterable PM source testing, continuous opacity monitoring, and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted filterable PM and opacity BACT limit(s).

3. NO_x Emissions

NO_x is formed by thermal oxidation of nitrogen in the combustion air and by oxidation of nitrogen in the fuel. Thermal NO_x is formed in the high temperature region of the flame or combustion zone of the affected combustion unit. The major factors influencing thermal NO_x formation are temperature, residence time within the combustion zone, and concentration of nitrogen and oxygen in the inlet air. The amount of fuel NO_x formed is wholly dependent on the amount of nitrogen compounds contained in the fuel.

A. Identification of Available NO_x Control Strategies/Technologies

Applicable NO_x control technologies can be divided into two main categories: combustion controls, which limit NO_x production, and post-combustion controls, which destroy NO_x after formation.

The following specific add-on technologies were identified as having the potential to reduce NO_x emissions from a CFB Boiler:

Emitting Unit	Individual Control Options	Dual Combined Control Options
CFB Boiler	Low Excess Air (LEA)	Combination of LEA, FGR, OFA, and LNB
	Flue Gas Recirculation (FGR)	
	Overfire Air (OFA)	Combination of LEA, FGR, OFA, and/or LNB and SCR
	Low NO _x Burners (LNB)	
	Selective Catalytic Reduction (SCR)	Combination of LEA, FGR OFA, and/or LNB and SNCR
	Selective Non-Catalytic Reduction (SNCR)	

A general description of the NO_x control options listed in the table above is described in the following text. Only the control device/strategy is described, not each control option listed above.

i. Low Excess Air (LEA)

LEA operation involves lowering the amount of combustion air to the minimum level compatible with efficient and complete combustion. Limiting the amount of air fed to the furnace reduces the availability of oxygen for the formation of fuel NO_x and lowers the peak flame temperature, which inhibits thermal NO_x formation.

Emissions reductions achieved by LEA are limited by the need to have sufficient oxygen present for flame stability and to ensure complete combustion. As excess air levels decrease, emissions of CO, hydrocarbons and unburned carbon increase, resulting in lower boiler efficiency. Other impediments to LEA operation are the possibility of increased corrosion and slagging in the upper boiler because of the reducing atmosphere created at low oxygen levels. This option cannot be utilized on CFB due to the level of air needed to fluidize the bed.

ii. Flue Gas Recirculation (FGR)

FGR is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizers or the air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through absorption of the combustion heat by relatively cooler flue gas. FGR also serves to reduce the O₂ concentration in the combustion zone. This option can not utilized on CFB due to the level of air needed to fluidize the bed.

iii. Overfire Air (OFA)

OFA allows staged combustion by supplying less than the stoichiometric amount of air theoretically required for complete combustion through the burners. The remaining necessary combustion air is injected into the furnace through overfire air ports. Having an oxygen-deficient primary combustion zone in the furnace lowers the formation of fuel NO_x. In this atmosphere, most of the fuel nitrogen compounds are driven into the gas phase. Combustion occurring over a larger portion of the furnace lowers peak flame temperatures. Use of a cooler, less intense flame limits thermal NO_x formation.

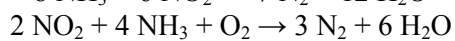
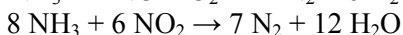
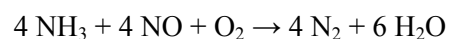
Poorly controlled OFA may result in increased CO and hydrocarbon emissions, as well as unburned carbon in the fly ash. These products of incomplete combustion result from a decrease in boiler efficiency. OFA may also lead to reducing conditions in the lower furnace that in turn may lead to corrosion of the boiler. This option cannot be utilized on CFB due to the level of air needed to fluidize the bed.

iv. Low NO_x Burners (LNB)

LNB integrate staged combustion into the burner creating a fuel-rich primary combustion zone. Fuel NO_x formation is decreased by the reducing conditions in the primary combustion zone. Thermal NO_x is limited due to the lower flame temperature caused by the lower oxygen concentration. The secondary combustion zone is a fuel lean zone where combustion is completed. LNB may result in increased CO and hydrocarbon emissions, decreased boiler efficiency, and increased fuel costs. This option cannot be utilized on CFB due to the level of air needed to fluidize the bed.

v. Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment technique that uses a catalyst to reduce NO and NO₂ to molecular nitrogen and water. Ammonia (NH₃) is commonly used as the reducing agent. The basic reactions are:

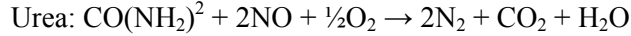


Ammonia is vaporized and injected into the flue gas upstream of the catalyst bed, and combines with NO_x at the catalyst surface to form an ammonium salt intermediate. The ammonium salt intermediate then decomposes to produce elemental nitrogen and water. The catalyst lowers the temperature required for the chemical reaction between NO_x and ammonia.

Technical factors that impact the effectiveness of this technology include the catalyst reactor design, operating temperature, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, and the potential for catalyst poisoning. SCR has been demonstrated to achieve high levels of NO_x reduction in the range of 80% to 90% control for a wide range of industrial combustion sources, including PC and stoker coal-fired boilers and natural gas-fired boilers and turbines. SCR has not been demonstrated on a CFB Boiler in the United States. Typically, installation of the SCR is upstream of the particulate control device (e.g., baghouse). However, calcium oxide (from a dry scrubber) in the exhaust stream can cause the SCR catalyst to plug and foul, which would lead to an ineffective catalyst. SCRs are classified as a low or high dust SCR. A low dust SCR is usually applied to natural gas combustion units or after a particulate control device. High dust SCR units can be installed on solid fuel combustion units before the particulate control device. However, a high dust SCR cannot be installed on a CFB Boiler prior to the particulate control device because the high alkaline particulate will contaminate and possibly plug the catalyst. Therefore, the exhaust stream after a particulate control device on a CFB Boiler would need to be reheated to maintain an effective operating temperature of the catalyst.

vi. Selective Non-Catalytic Reduction (SNCR)

SNCR involves the non-catalytic decomposition of NO_x to nitrogen and water. A NO_x reducing agent, typically ammonia or urea, is injected into the upper reaches of the furnace. Because a catalyst is not used to drive the reaction, temperatures of 1600°F to 2100°F are required. The basic reactions are:



Typical NO_x control efficiencies range from 40% to 60% depending on inlet NO_x concentrations, fluctuating flue gas temperatures, residence time, amount and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip, and presence of interfering chemical substances in the gas stream. SNCR has been applied to a number of different types of combustion sources. SNCR has been widely implemented for NO_x control on new coal-fired CFBs throughout the United States.

B. Technical Feasibility Analysis

LNB, OFA, LEA, and FGR are used to reduce flame temperature and reduce the thermal NO_x; therefore, these control options separately or in combination with another control option, including SCR and SNCR, are technically ineffective on a CFB Boiler that has inherently low combustion temperatures and relatively lower thermal NO_x emissions. These control options separately or in combination with another control option including SCR and SNCR are technically infeasible. The remaining NO_x control options cannot be eliminated based on technical infeasibility.

C. Ranking of Available and Technically Feasible NO_x Control Options by Efficiency

Various information sources evaluated by the Department through the NO_x BACT analysis process assigned varying NO_x control efficiencies for each of the identified available NO_x control technologies/strategies. The following analysis uses the average of expected control efficiencies reported for each strategy:

NO _x Control Option	NO _x Emission Rate (lb/MMBtu)	Estimated NO _x Control Efficiency
CFB Boiler with SCR	0.014	98.00%
CFB Boiler with SNCR ^a	0.07	90.00%
CFB Boiler without Controls	0.14	80.00%
^a SNCR provides approximately 50% control as compared to CFB without controls		

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text evaluates the environmental, economic, and energy impacts associated with the NO_x control options on a CFB Boiler.

i. Environmental Impacts

The environmental impacts from both SCR and SNCR result from the handling of the anhydrous ammonia. Spent catalyst from an SCR will have to be properly disposed as a possible hazardous waste. An SCR unit would have to be installed downstream of the baghouse to reduce fouling of the catalyst. Therefore, as an example, natural gas would have to be used to reheat the exhaust gas to optimal temperature for the SCR unit. The combustion of the natural gas would cause additional NO_x, CO, VOC, and PM₁₀ emissions into the atmosphere. Even though there are environmental concerns associated with SCR and SNCR, these NO_x control options cannot be eliminated based on these concerns.

ii. Energy Impacts

SCR would cause significant backpressure in the CFB Boiler leading to lost boiler efficiency and, thus, a loss of power production. Along with the power loss, SME-HGS would be subject to the additional cost of reheating the exhaust gas, which would be expensive at the current price of natural gas. The energy impacts from an SNCR are minimal and an SNCR does not cause a loss of power output from the facility. Even though these are energy impact concerns, the control options cannot be eliminated based on these concerns. The impacts of additional cost due to reheating the exhaust gas are included in the annual cost of operating an SCR unit, which is presented in the economic impact analysis.

iii. Economic Impacts

Department verified economic impacts associated with NO_x control options were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Cost estimates for SCR and SNCR were derived from Chapter 4 in the *OAQPS COST Control Manual* (EPA 452/B-02-001). Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual, and if data was not available from the manual, best engineering judgment was used. As reported in the application, the cost effective value for SNCR is approximately \$2137/ton of NO_x removed and the cost effective value for SCR is approximately \$12,562/ton of NO_x removed. Based on the cost-effective values provided above, SNCR is deemed economically feasible for the affected unit and SCR is deemed economically infeasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

E. NO_x BACT Determination

SME-HGS proposed the use of SNCR to maintain compliance with a proposed NO_x BACT emission limit of 0.07 lb/MMBtu (30-day rolling average). Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed NO_x emission control strategy and emission limit constitute BACT in this case. This BACT determined control option will provide an approximate 90% NO_x reduction efficiency.

SCR was eliminated based on the high cost per ton of NO_x removed. Further, since the SCR unit would have to be installed downstream from the permitted and BACT determined FFB to eliminate fouling and excessive loading of the catalyst, the CFB exhaust gas would need to be reheated. Reheating the exhaust gas is a significant factor in the high annual cost of SCR and leads to a substantial increase in emissions from the reheat process summarized. Finally, the Department is unaware of any CFB Boiler permitted or in operation in the United States, which has an SCR unit installed for NO_x emission control.

The BACT determined NO_x emission limit is equal to the lowest NO_x BACT emission rates contained in the RBLC. Further, two of the boilers permitted with NO_x BACT emission limits of 0.07 lbs/MMBtu, respectively, are CFB Boilers that employ SNCR. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established NO_x BACT emission limit of 0.07 lb NO_x/MMBtu (30-day rolling average). Further, the Department determined that the periodic NO_x source testing, continuous NO_x emission monitoring, and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted NO_x BACT limit(s).

4. CO Emissions

CO emissions from a CFB coal-fired boiler are typically controlled using proper design and combustion techniques. Typical CO control technologies (e.g., catalytic and thermal oxidizers) are available; however, they are not typically considered appropriate for coal-fired boilers because of high particulate loading, catalyst fouling, and/or high cost to reheat the exhaust gas.

A. Identification of Available CO Control Strategies/Technologies

The following control options are evaluated as available CO control options for the proposed SME-HGS project:

- i. CFB Boilers with Proper Design and Combustion (no add-on control); and
- ii. CFB Boilers Catalytic or Thermal Oxidizers.

The following text provides a brief overview of the above-cited CO control options/technologies/strategies that have been evaluated for the proposed project.

i. Proper Design and Combustion (No Add-On Control)

In an ideal combustion process, all of the carbon and hydrogen contained within the fuel is oxidized to carbon dioxide (CO₂) and water (H₂O). The emission of CO in a combustion process is the result of incomplete fuel combustion. Reduction of CO emissions can be accomplished by controlling the combustion temperature, residence time, and available oxygen. Normal combustion practice at the facility will involve maximizing the heating efficiency of the fuel in an effort to minimize fuel usage. This efficiency of fuel combustion will also minimize CO formation.

ii. Catalytic or Thermal Oxidation of Post-Combustion Gases

Oxidizers or incinerators use heat to destroy CO in the gas stream. Incineration is an oxidation process that ideally breaks down the molecular structure of an organic compound into carbon dioxide and water vapor.

Temperature, residence time, and turbulence of the system affect CO control efficiency. A thermal incinerator generally operates at temperatures between 1,450 and 1,600°F. Heat recovery between 35% and 70% can be realized with recuperative systems and up to 95% can be realized with regenerative systems. The thermal oxidation system analyzed for the main boiler is a regenerative thermal oxidation (RTO) system with 95% heat recovery. Regenerative systems are typically designed for exhaust flow rates between 10,000 and 100,000 standard cubic feet per minute (scfm). Recuperative systems are typically designed for exhaust flow rates between 500 and 50,000 scfm. Regenerative systems typically have higher capital costs than recuperative systems, but capital costs are typically offset by savings on auxiliary fuel use.

Catalytic incineration is similar to thermal incineration; however, catalytic incineration generally allows for oxidation at temperatures ranging from 600 to 1,000°F and can achieve up to 70% heat recovery. The catalyst systems are typically metal oxides such as nickel oxide, copper oxide, manganese dioxide, or chromium oxide. Noble metals such as platinum and palladium may also be used. Fixed bed or fluid bed catalytic incinerators can be used on combustion exhaust streams and can achieve up to 70% heat recovery. A fixed bed catalytic incinerator with 70% heat recovery is examined in this BACT analysis because of its comparatively lower capital cost.

B. Technical Feasibility Analysis

For the purposes of this BACT analysis, proper design and combustion control and catalytic and thermal oxidation are considered technically feasible, although oxidation is not typically applied to coal-fired boilers. No available CO control options are eliminated due to technical infeasibility.

C. Ranking of Available and Technically Feasible CO Control Options by Efficiency

Various information sources evaluated by the Department through the CO BACT analysis process assigned varying CO control efficiencies ranging from 70% control for good combustion practices to 95% for the CO oxidation control technologies/strategies. To be conservative, the SME-HGS application considered 90% control efficiency for the top oxidation control. The following table ranks the CO control options.

CO Control Option	CO Emission Rate (lb/MMBtu)	Estimated Control Efficiency
CFB Boiler with Thermal Oxidation	0.01	90%
CFB Boiler with Catalytic Oxidation	0.01	90%
CFB Boiler with Proper Design and Combustion Practices (no add-on control)	0.10	---

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text evaluates the environmental, economic, and energy impacts associated with the CO control options on a CFB Boiler.

i. Environmental Impacts

Catalytic oxidation results in adverse environmental impact from the handling of the spent catalyst and may have to be disposed of as a hazardous waste. A catalytic oxidation unit would have to be installed downstream of the FFB to reduce fouling of the catalyst; therefore, the exhaust gas would require reheating to achieve optimal CO reduction. The combustion of the additional fuel for reheating purposes would cause an increase in NO_x, SO₂, CO, VOC, and PM₁₀ emissions. However, the control options cannot be eliminated based on these concerns alone.

ii. Energy Impacts

The additional consumption of fuel to reheat the exhaust gas would result in energy impacts. With current market prices for fuel, this strategy would also be very expensive. Even though these energy impacts exist, the control options cannot be eliminated based on these concerns.

iii. Economic Impacts

Department verified economic impacts associated with CO control options were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Cost estimates for catalytic or thermal oxidation were derived from Section 3, Chapter 2 (9/2000) in the *OAQPS COST Control Manual*. Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual and if data was not available from the manual, best engineering judgment was used. As reported in the application, the cost effective value for thermal oxidation is approximately \$6916/ton of CO removed and the cost effective value for catalytic oxidation is approximately \$4373/ton of CO removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

E. CO BACT Determination

SME-HGS proposed the use of good combustion practices with no additional control to maintain compliance with a proposed CO BACT emission limit of 0.10 lb/MMBtu (1-hr average). Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed CO emission control strategy and emission limit constitute BACT in this case.

Catalytic and thermal oxidation were eliminated based on the high cost per ton of CO removed and because the increased fuel consumption associated with reheating the gas stream would result in additional environmental impacts.

The BACT determined CO emission limit is equal to the lowest CFB Boiler CO BACT emission rates contained in the RBLC. Two non-CFB boilers listed in the RBLC have lower emission limits, but these two sources do not have a control device and rely on good combustion practices for CO control. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established CO BACT emission limit of 0.10 lb CO/MMBtu (1-hr average). Further, the Department determined that the periodic CO source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted CO BACT limit(s).

5. VOC Emissions

VOC emissions from a CFB coal-fired boiler are typically controlled using proper design and combustion techniques that were identified in the CO BACT analysis. Typical VOC control technologies (e.g., catalytic and thermal oxidizers) are available; however, they are not typically considered appropriate for coal-fired boilers because of high particulate loading, catalyst fouling, or high cost to reheat the exhaust gas.

A. Identification of Available VOC Control Strategies/Technologies

The following control options were evaluated for the CO control options and will be evaluated for the VOC control options. A description of each control technology is provided in the CO BACT analysis:

- i. CFB Boilers with Proper Design and Combustion (no add-on control); and
- ii. CFB Boilers with Catalytic or Thermal Oxidizers.

B. Technical Feasibility Analysis

For the purposes of this BACT analysis, proper design and combustion control, catalytic oxidation, and thermal oxidation will be considered technically feasible, although oxidation is not typically applied to coal-fired boilers. No available VOC control options are eliminated due to technical infeasibility.

C. Ranking of Available and Technically Feasible VOC Control Options by Efficiency

Various information sources evaluated by the Department through the VOC BACT analysis process assigned varying VOC control efficiencies ranging from 70% for good combustion practices to 95% for the VOC oxidation control technologies/strategies. To be conservative, the SME-HGS application considered 90% control efficiency for the top oxidation control. The following table ranks the VOC control options.

VOC Control Option	CO Emission Rate (lb/MMBtu)	Estimated Control Efficiency
CFB Boiler with Thermal Oxidation	0.0003	90%
CFB Boiler with Catalytic Oxidation	0.0003	90%
CFB Boiler with Proper Design and Combustion Practices (no add-on control)	0.003	---

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text evaluates the environmental, economic, and energy impacts associated with the VOC control options on a CFB Boiler.

i. Environmental Impacts

Catalytic oxidation results in adverse environmental impact from the handling of the spent catalyst and may have to be disposed of as a hazardous waste. A catalytic oxidation unit would have to be installed downstream of the FFB to reduce fouling of the catalyst; therefore, the exhaust gas would require reheating to achieve optimal VOC reduction. The combustion of the additional fuel for reheating purposes would cause an increase in NO_x, SO₂, CO, VOC, and PM₁₀ emissions. However, the control options cannot be eliminated based on these concerns alone.

ii. Energy Impacts

The additional consumption of fuel would result in energy impacts from reheating the exhaust. With current market prices for natural gas, this strategy would also be very expensive. Even though these energy impacts exist, the control options cannot be eliminated based on these concerns.

iii. Economic Impacts

Department verified economic impacts associated with VOC control options were compared in the SME-HGS application using estimated annualized capital, operating, and maintenance costs. Cost estimates for catalytic or thermal oxidation were derived from Section 3, Chapter 2 (9/2000) in the *OAQPS COST Control Manual*. Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual, and, if data was not available from the manual, best engineering judgment was used. As reported in the application, the cost effective value for thermal oxidation is approximately \$222,928/ton of VOC removed and the cost effective value for catalytic oxidation is approximately \$142,546/ton of VOC removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected unit in this case. A detailed cost analysis is included in the application for this air quality permit.

E. VOC BACT Determination

SME-HGS proposed the use of good combustion practices with no additional control to maintain compliance with a proposed VOC BACT emission limit of 0.003 lb/MMBtu (1-hr average). Based on Department verified information

contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed VOC emission control strategy and emission limit constitute BACT in this case.

Catalytic and thermal oxidation were eliminated based on the high cost per ton of VOC removed and because the increased fuel consumption associated with reheating the gas stream would result in additional environmental impacts.

The BACT determined VOC emission limit is among the lowest CO BACT emission rates contained in the RBLC for PC or CFB Boiler technologies. Further, the permitted VOC BACT emission rate of 0.003 lb/MMBtu matches recently permitted VOC BACT limits permitted for operation in Montana. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established VOC BACT emission limit of 0.003 lb VOC/MMBtu (1-hr average). Further, the Department determined that the periodic VOC source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted VOC BACT limit(s).

6. H₂SO₄, Acid Gases (HCl and HF), Trace Metals, and Condensable PM₁₀ Emissions

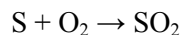
Sulfuric acid mist, acid gases (primarily HF and HCl), trace metals (including lead), and condensable PM₁₀ are grouped together in this BACT evaluation because these pollutants are a major component of condensable PM₁₀. Other inorganic and organic species (e.g., ammonium bisulfate and certain VOCs) can also contribute to condensable PM₁₀. Control options from a CFB boiler are typically limited to the available SO₂ and/or filterable PM/PM₁₀ control options.

H₂SO₄, acid gases (HCl and HF), trace metals (including lead), and condensable PM₁₀ generally form in the exhaust system of a boiler. The formation is dependent upon several factors including residence time within specific temperature ranges, flue gas moisture content, combustion conditions, and concentrations of chlorine, fluorine, and trace metals in the coal.

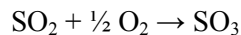
Sulfuric Acid Mist (H₂SO₄)

H₂SO₄ is typically created when SO₃ in the flue gas reacts with water. SO₃ is formed during the combustion process in a coal-fired boiler. H₂SO₄ mist in boiler flue gas generally forms in three phases as described below:

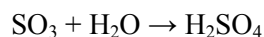
Sulfur in the boiler fuel oxidizes to form sulfur dioxide (SO₂).



A portion of the SO₂ further oxidizes to sulfur trioxide (SO₃).



SO₃ reacts with water in the exhaust stream or the atmosphere to form H₂SO₄.



Because H₂SO₄ mist is created in several steps, control strategies can be approached in a variety of ways that may be applied individually or in combination. Control strategies generally focus on reducing the amount of SO₂ and SO₃ in the flue gas, capturing sulfuric acid mist aerosol particles, and controlling exhaust system conditions to limit mist formation.

Acid Gases (HCl and HF)

Acid gases can be controlled to different degrees by standard control technologies for other criteria pollutants (primarily with SO₂ and filterable PM control technologies).

Trace Metals (Including Lead)

Depending on the physical and chemical properties of a metal and boiler combustion conditions, some metals can be emitted in the gas phase, while others may be emitted as particulates and will tend to be captured either in the fly or bed ash. Metals emitted from coal combustion include: arsenic, beryllium, cadmium, chromium, manganese, and lead and based on the physical and chemical properties of these listed metals, most would be emitted as particulate matter. A smaller percentage of these metals and other metals may also be emitted as volatiles and condensable particulates.

Condensable Particulate

Condensable particulate can be controlled to different degrees by controlling the components that make up condensable particulate (H₂SO₄ mist, acid gases, volatile trace metals, etc.) with standard control technologies for other criteria pollutants (primarily SO₂ and filterable PM control technologies).

A. Identification of Available H₂SO₄, Acid Gases (HCl and HF), Trace Metals, and Condensable PM₁₀ Emissions Control Strategies/Technologies

Available control technologies for H₂SO₄ mist, acid gases (HCl and HF), trace metals (including lead), and condensable PM₁₀ emissions from a CFB Boiler are listed below:

- i. Wet FGD;
- ii. Wet FGD followed by wet ESP;
- iii. Dry FGD followed by FFB or ESP; and
- iv. No additional add-on control.

The following text provides a brief overview of the above-cited control options/technologies/strategies that have been evaluated for the proposed project.

i. Wet FGD

Wet FGD is limited in its ability to control H₂SO₄ mist and acid gas emissions for two reasons. First, the moisture inherent in the system, combined with the sudden cooling created by the slurry spray, tends to create sulfuric acid mist and acid gases (two significant components of condensable PM₁₀). Second, because the condensable particulates are extremely small, they are not effectively captured by the washing action of the wet FGD. A wet FGD system would be expected to control sulfuric acid mist and acid gas (including HF) emissions with efficiency less than 25%.

ii. Wet FGD Followed by Wet ESP

Wet ESPs can control H_2SO_4 mist and acid gases with a very high efficiency. Not all of the SO_3 in the gas stream is converted to sulfuric H_2SO_4 mist, which results in an overall H_2SO_4 mist control efficiency for this system of approximately 90% (other acid gases will also be collected at an efficiency of 90%). Use of an FFB downstream of a wet scrubber is not technically feasible, the high moisture content of the flue gas exiting the scrubber would cause the filter cake to agglomerate, clogging the filter and making the filter cleaning extremely difficult.

iii. Dry FGD Followed by FFB or ESP

Dry FGD systems, including SDAs and fly-ash reinjection systems, are generally capable of controlling SO_3 (and H_2SO_4) and acid gases with an efficiency of at least 90%. As noted above, a particulate control device is required following a dry FGD system to collect the injected reagent particles. While ESPs and FFBs provide essentially the same level of particulate control, FFBs have the potential to enhance SO_2 , SO_3 , and HF removal efficiency as the exhaust gas passes through a filter cake containing alkaline ash and unreacted reagent. FFBs also have a high removal efficiency of trace metals and may provide some additional control for other acid gases.

B. Technical Feasibility Analysis

None of the identified available H_2SO_4 , acid gas (HCl and HF), trace metals (including lead), and condensable PM_{10} control technologies are technically infeasible. Therefore, no available control options are eliminated at this stage.

C. Ranking of Available and Technically Feasible H_2SO_4 , Acid Gas (HCl and HF), Trace Metals (including lead), and condensable PM_{10} Control Options by Efficiency

The following table summarizes the available control options, their respective potential control efficiency values, and their ranking for the purposes of this BACT analysis. Limited data is available on control efficiencies for these pollutants; therefore, the proposed CFB Boiler may not perform to the exact control efficiencies highlighted in the table.

Technology	H_2SO_4 Control Efficiency	Acid Gas Control Efficiency	Trace Metal Control Efficiency	Condensable PM_{10} Control Efficiency
Dry FGD & FFB or ESP	90%	80%	90%	90%
Wet FGD & Wet ESP	90%	90%	80%	90%
Wet FGD	25%	80%	70%	80%
No Add-On Control	---	---	---	---

The top two control alternatives potentially provide similar H_2SO_4 and condensable PM_{10} control efficiency, while the top two differ in acid gas and trace metal control efficiencies. Because SME-HGS proposes to implement one of these two top alternatives based on SO_2 and filterable PM BACT analysis, no further analysis is required for H_2SO_4 , acid gases, trace metals, and condensable PM_{10} control.

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The environmental, economic, and energy impacts associated with the available H₂SO₄, acid gas, trace metals, and condensable PM₁₀ control options are the same as the impacts addressed in the BACT analyses for SO₂ and filterable PM emissions. Because these control strategies have been determined to constitute BACT for SO₂ and filterable PM, no additional environmental, economic, and energy impacts will be realized through the control of H₂SO₄, acid gas, trace metals, and condensable PM₁₀, through utilization of these co-benefit control strategies.

E. H₂SO₄, Acid Gas, Trace Metals, and Condensable PM₁₀ BACT Determination

H₂SO₄

As previously stated, either of the two top technologies for H₂SO₄ mist control will reduce emissions by 90%. SME-HGS proposes a CFB Boiler combusting low sulfur coal with dry FGD followed by an FFB to maintain compliance with a proposed H₂SO₄ BACT emission limit of 0.0054 lb/MMBtu. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed H₂SO₄ emission control strategy and emission limit constitute BACT in this case.

This emission rate, although not the lowest, compares favorably to similar facilities in the RBLC and is lower than the BACT-determined emissions rates for the recently permitted Gascoyne CFB Boiler and the two most recent coal-fired utilities permitted for operation in Montana. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established H₂SO₄ BACT emission limit of 0.0054 lb/MMBtu over any 1-hour time period. Further, the Department determined that the periodic source testing and the applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT limit(s).

Acid Gases

As previously stated, either of the two top technologies for acid gas control will reduce emissions by 80% to 90%. SME-HGS proposes a CFB Boiler combusting low sulfur coal with dry FGD followed by an FFB to maintain compliance with a proposed HF BACT emission limit of 0.0017 lb/MMBtu and a proposed HCl BACT emission limit of 0.0021 lb/MMBtu. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed emission control strategy and emission limit(s) for HF and HCl, respectively, constitute BACT in this case.

These BACT-determined acid gas emission rates, although not the lowest, compare favorably to similar facilities in the RBLC, representing an average BACT emission rate for those sources contained in the RBLC. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established HF and HCl BACT emission limits of 0.0017 lb/MMBtu and 0.0021 lb/MMBtu over any 1-hour time period, respectively. Further, the Department determined that the periodic source testing and the applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT limit(s).

Trace Metals (including Lead)

As previously stated, either of the two top technologies for trace metals control will reduce emissions by 80% to 90%. SME-HGS proposes a CFB Boiler combusting low sulfur coal with dry FGD followed by an FFB as BACT for trace metals. SME-HGS proposes the PM₁₀ emission rate as a surrogate emission limit for trace metal emissions.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established PM₁₀ surrogate emission limit of 0.026 lb/MMBtu. Further, the Department determined that the periodic source testing (PM₁₀) and the applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT limit.

PM₁₀

The PM₁₀ emission rate is calculated based on the assumed components that make up the condensable PM₁₀ fraction plus the BACT-determined filterable PM emission limit. The following table presents the emissions rates for the components that are assumed to make up the condensable PM₁₀ fraction as well as the BACT-determined filterable PM emission rate.

Component	Emission Rate (lb/MMBtu)
HCl	0.0021
HF	0.0017
H ₂ SO ₄	0.0054
VOC	0.0030
Ammonium Bisulfate	0.0015
Trace Metals	0.0002
Organic Condensables	0.0005
Total Condensables	0.014
Filterable PM	0.012
PM ₁₀ Limit	0.026*
* PM ₁₀ BACT-determined emission limit equals the condensable PM ₁₀ fraction plus the BACT-determined filterable PM limit	

As previously stated, either of the two top technologies for the pollutants making up the condensable PM₁₀ fraction will reduce emissions by 80% to 90%. SME-HGS proposes a CFB Boiler combusting low sulfur coal with dry FGD followed by an

FFB to maintain compliance with a PM₁₀ emission limit of 0.026 lb/MMBtu. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed emission control strategy and the Department-established emission limit for condensable PM₁₀ constitutes BACT in this case.

The BACT-determined PM₁₀ emission rate, although not the lowest, compares favorably to similar facilities in the RBLC. The data from the RBLC website is summarized in the application.

The Department determined that the CFB Boiler operating under the BACT-determined control requirements is capable of meeting the established PM₁₀ emission limit of 0.026 lb/MMBtu. Further, the Department determined that the periodic source testing and the applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT limit(s).

7. Mercury Emissions

Coal contains trace levels of a variety of metals and other elements or compounds. Mercury is one of those trace elements. Emissions of mercury into the atmosphere have been identified as a health concern principally due to its capacity to react chemically with the environment to form a toxic compound – methyl mercury – that accumulates through the aquatic food chain with a potential to threaten human populations. Depending on its chemical form, mercury can persist in the atmosphere and travel vast distances before being deposited on terrestrial features.

When coal burns, mercury is released in one of three forms, or species: elemental mercury vapor, oxidized mercury vapor, or mercury adsorbed to the surface of a solid particle. The different species of mercury respond differently to different types of control technologies.

Elemental mercury is the most difficult of the three mercury species to control. To date, no technologies have been demonstrated in field-testing to consistently and significantly reduce elemental mercury emissions. Most research is focused on developing effective means for converting elemental mercury to one of the other two species of mercury.

Oxidized mercury is water soluble and generally more reactive than elemental mercury. Because of this, technologies for controlling SO₂ emissions have demonstrated promise for controlling oxidized mercury emissions as well. Research has shown a strong correlation between coal chlorine content and the proportion of oxidized mercury in coal combustion products. Under specific conditions, the addition of chlorine or other halides has been shown to promote mercury oxidation.

Particulate mercury may be controlled with FFBs and/or ESPs – devices commonly used to control particulate emissions from coal combustion processes. The proportion of particulate mercury emissions appears to be related to the amount of oxidized mercury. Oxidized mercury is more readily adsorbed to the surface of particles such as coal ash, FGD media, or activated carbon than is elemental mercury. Higher levels of unburned carbon (UBC) in the ash have also been shown to favor mercury adsorption.

Department of Energy, U.S. Environmental Protection Agency, and Industry Research

For the last several years the Department of Energy/National Energy Technology Laboratory (DOE/NETL) and the Electric Power Research Institute (EPRI) have evaluated mercury removal technologies for potential application to the power generation industry. However, the Department and SME-HGS have been unable to find research specifically evaluating control of mercury emissions from CFB Boilers.

A recent white paper from the EPA (“the technology review report”) describes and summarizes the status of test programs throughout the country aimed at understanding and improving capabilities for reducing mercury emissions from coal-fired electric generators (“*Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update*,” Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency; February 18, 2005). Results have varied greatly, from an actual increase of mercury emissions to over 90 percent mercury removal efficiency.

It has long been recognized that coal quality is a primary determining factor in mercury removal effectiveness. Bituminous coal generally contains higher levels of chlorine and UBC, and has therefore proven to provide enhanced capacity for mercury reduction. Conversely, subbituminous coal and lignite, often grouped as the single category of “low rank coal,” generally contain low concentrations of chlorine and UBC. Control of mercury emissions resulting from combustion of these fuels has proven to be highly variable.

Mercury emissions control research, as it relates to coal-fired power generation, has followed two general paths: characterizing and enhancing co-benefits from existing control equipment (sometimes referred to as “native capture”), and development of mercury-specific control technologies. The two paths at times intermingle since mercury-specific control technologies often must be used in tandem with native capture. For example, modified or standard powdered activated carbon injection (ACI) is one of the most promising mercury-specific control technologies under certain conditions. Once injected into the exhaust stream, however, it must be captured by a particulate emissions control device. Following are some concluding observations from the EPA’s technology review report:

- “Assuming sufficient RD&D of representative technologies, new and existing systems installed to control NO_x and SO₂ (e.g., SCR+FGD+FFB) have the potential to achieve 90%+ control of mercury for bituminous coal-fired boilers. Subbituminous and lignite systems appear to require mercury oxidation technology and/or additional advanced sorbents to achieve these levels.”
- “It is believed that ACI and enhanced multi-pollutant controls will be available after 2010 for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 60 and 90%. Also, optimized multi-pollutant controls may be available in the 2010-2015 timeframe for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 90 and 95%.”
- “The principle concerns relating to broad-scale use of mercury controls are the reliability of mercury reductions possible and the risks of adverse side effects. To the extent that required mercury reductions are within the capabilities of the technology with minimum risks of side effects, mercury controls could be

considered available. However, as discussed in this paper, there remain some questions regarding their performance relative to broad-scale use. These questions are being investigated in ongoing efforts.”

Project Coal Supply

SME-HGS is proposing to use Powder River Basin (PRB) subbituminous coal as the CFB Boiler fuel source. Specifically, SME-HGS is currently considering purchasing coal from one of the following three southeastern Montana coal mines: Spring Creek, Decker, and/or Absaloka coal mines. Coal quality data from two of these sources indicates average coal mercury content is 0.05-0.07 ppmw, compared with a national average of 0.17 ppmw (“Mercury in U.S. Coal – Abundance, Distribution, and Modes of Occurrence,” USGS Fact Sheet FS-095-01, September 2001; available at pubs.usgs.gov/fs/fs095-01/fs095-01.pdf). The upper 95 percent confidence level mercury content value from these coal analyses is 0.13 ppmw. The corresponding uncontrolled mercury emission rate, assuming all of the mercury in the coal is released to the atmosphere, would be 10.0 lb/TBtu or 230 lb/yr.

A. Identification of Available Mercury Control Strategies/Technologies

The following paragraphs describe alternative technologies that are being evaluated for feasibility and effectiveness of controlling mercury emissions from electric utility boilers as presented in the 2005 EPA technology review report. The technologies are grouped into the following categories:

- i. Native Controls:
 - a. Particulate Controls
 - b. SO₂ Controls
 - c. NO_x Controls
 - d. SDA/FFB Controls
- ii. Enhanced Controls
 - a. Fuel Blending
 - b. Oxidizing Chemicals
 - c. UBC Enhancement
 - d. Mercury Specific Catalyst
 - e. Improvement of Wet FGD Mercury Capture
- iii. Sorbent Injection: Add-on mercury control equipment; and
- iv. Additional Alternatives

The following text provides a brief overview of the above-cited control options/technologies/strategies that have been evaluated for the proposed project.

i. Native Controls

Native controls include mercury removal accomplished by existing controls for NO_x, SO₂, and particulate.

a. Particulate Controls

Survey and test data indicate that ESPs provide limited mercury emissions control. Because the control they do provide results from the capture of particulate-bound mercury, its effectiveness depends on the relative amount of particulate mercury speciation. FFBs have been demonstrated to be relatively more effective at controlling mercury emissions from bituminous and low rank coals. This appears to be due to the effect of the ash-cake that collects on the surface of the filters. The cake enhances gas-particle interactions, promoting adsorption of oxidized mercury and, where there is adequate chlorine, oxidation of elemental mercury.

b. SO₂ Controls

Wet FGD scrubbers have demonstrated mercury removal efficiencies ranging from less than 50% to approximately 75% for bituminous coal. No data were found that evaluated effectiveness when burning low rank coal. Because oxidized mercury – which is generally present in high proportion for bituminous coal – is water soluble, wet FGD removal effectiveness would be expected to be higher than has been observed. It is thought that wet FGD systems tend to promote chemical reduction of oxidized mercury to elemental mercury, resulting in subsequent re-emission.

While evaluations of mercury emissions from CFB Boilers do not appear in the literature, one of the primary advantages of CFB Boiler technology is the reduction of SO₂ emissions, which in turn may benefit mercury capture in the exhaust gas stream. Potential for mercury capture co-benefits associated with CFB technology will be addressed in a subsequent portion of this analysis.

c. NO_x Controls

SCR units appear to enhance oxidation of elemental mercury when burning bituminous coal, but limited data indicate marginal effectiveness when burning subbituminous coal.

d. SDA/FFB Systems

Emissions control systems consisting of spray dryer absorbers (SDAs) and FFBs have been demonstrated to provide over 90 percent mercury control efficiency for bituminous coal combustion. Average control efficiency when burning subbituminous coal is approximately 25 percent. This low effectiveness – less than has been observed with FFBs alone – is thought to be the result of HCl removal by the SDA. It is thought that bituminous coal contains enough excess chlorine that HCl scrubbing by the SDA is not a limiting factor for that coal rank.

ii. Enhanced Controls

Enhanced controls include mercury control strategies accomplished through the enhancement of existing controls.

a. Fuel Blending

Replacing a portion of PRB subbituminous coal with bituminous coal has been evaluated with mixed results (“Evaluation of Sorbent Injection for Mercury Control,” Quarterly Technical Report, Reporting Period: April 1, 2005 – June 30, 2005; Sharon Sjostrom; available at www.netl.doe.gov/coal/E&WRT/mercury/control-tech/sorbent-injection2.html). In one short-term test, mercury capture increased from approximately 25 percent to nearly 80 percent. At another facility, no additional mercury capture was observed.

b. Oxidizing Chemicals

Limited short-term testing has been conducted on the effects of introducing chlorine and other halogens into the combustion system. The test results vary depending on boiler type, coal quality, and downstream pollution control equipment. Test results show some promise for adding these chemicals with ACI to achieve high levels of mercury emission reduction. However, further evaluation of impacts to operations has been recommended in addition to further evaluation of effectiveness over various conditions and durations.

c. UBC Enhancement

Derivative data from field tests have provided evidence that increasing the portion of unburned carbon (UBC) in coal ash enhances mercury capture. Adjusting combustion conditions to increase ash UBC levels will require evaluation on a case-by-case basis of detrimental effects to boiler operation and efficiency.

d. Mercury-Specific Catalysts

Testing is ongoing regarding the effectiveness and feasibility of injecting oxidizing chemicals or employing catalyst systems designed to facilitate oxidation of elemental mercury.

e. Improvement of Wet FGD Mercury Capture

Limited testing has been conducted on the potential for SCR and an injected chemical additive to improve elemental mercury oxidation and to limit or eliminate chemical reduction of oxidized mercury in a wet FGD system. Results from the tests, which so far have been carried out only on bituminous coal, indicate that SCR and/or chemical additives can improve overall mercury capture in a wet FGD/ESP system firing bituminous coal.

iii. Sorbent Injection

Injection of various sorbents into the boiler exhaust stream has been the primary technology under evaluation that is specific to mercury control (i.e., it does not rely on a co-benefit of controlling some other pollutant). This technology was identified as having potential to reduce mercury emissions

from coal-fired electric utility boilers because of its successful history of application to waste incinerators for the same purpose. Sorbent injection technology used in waste incinerators is not directly transferable to electric utility boilers, however, due to significant differences in operational requirements and in exhaust gas characteristics such as mercury concentrations, chemical makeup, and volume.

As suggested by the name, sorbent injection technology works by providing active surfaces that promote adsorption of exhaust mercury. The result is particulate-bound mercury that can be captured by particulate emissions control equipment such as an ESP or FFB. Standard ACI has proven to be effective for improving mercury emissions from bituminous coal on a relatively consistent basis. Its effectiveness on subbituminous coal emissions is dependent upon facility and operating parameters, and has been consistently lower than that observed with bituminous coal. Recent research suggests that the levels of chlorine and sulfur in the combustion gases are key in determining mercury capture efficiency.

Several alternative injection media have been and continue to be evaluated to address deficiencies and concerns associated with ACI. One class of alternative media consists of standard ACI that has been treated with a halogen, most commonly boron. The treatment serves to enhance elemental mercury oxidation and overall mercury adsorption. Initial results from several short-term tests indicate that halogenated ACI could potentially be more effective at mercury removal than standard ACI over a range of parameters while offering other benefits. Several evaluations of this technology are ongoing, and additional tests are planned.

Other specialty sorbent materials have been identified and are being evaluated for specific applications. These materials are being developed and evaluated primarily for the purposes of reducing control costs and improving potential for beneficial use of the collected ash.

iv. Additional Alternatives

An additional mercury control alternative, one that was not discussed in the EPA technology review report, is to treat the coal in order to remove a portion of its mercury prior to combustion. A joint venture company, the Alaska Cowboy Coal Power Consortium, has demonstrated in small-scale tests that their process for drying low rank coals can also remove a portion of the coal's mercury content. It has yet to be demonstrated on a full scale.

B. Technical Feasibility Analysis

The NSR Manual describes two key criteria for determining whether an alternative control technology is technically feasible. According to the NSR Manual, a technology must be "available" and "applicable" in order to be considered technically feasible. A technology is available "if it has reached the licensing and commercial sales stage of development." An identified alternative control technique may be considered presumptively applicable if "it has been or is soon to be deployed (e.g., is specified in a permit) on the same or similar source type." The following paragraphs evaluate the technical feasibility of the alternative control technologies identified above by applying these criteria of availability and applicability.

i. Native Controls

Insofar as technologies applied to control emissions of other pollutants also provide mercury control co-benefits, these technologies are considered technically feasible.

ii. Enhancement of Existing Controls

None of the native control enhancement technologies described above have demonstrated widespread applicability to coal-fired utility boilers on a full-scale basis. Further, and more importantly, none have been evaluated on any level for applicability to CFB Boiler technology. For these reasons, identified native control enhancement technologies are considered to be technically infeasible for application to the SME-HGS. The Department has recently determined that mercury capture enhancement technologies are generally not technically feasible. In the analysis of a recent permit for a PC electrical utility boiler the Department stated: "The Department determined that enhanced FGD is not currently an available control strategy and thus is not a suitable candidate for a full-scale mercury BACT control system at this time" (Montana Air Quality Permit #3185-02, Final: 05/16/05; page 29).

iii. Sorbent Injection

While sorbent injection technology has been tested under a variety of conditions, it is still being evaluated as an applicable control technology for mercury emissions. Its applicability has not been demonstrated on a full-scale CFB Boiler. Based on two recently permitted coal-fired electrical generating units in Montana accepting conditions requiring ACI installation for mercury control and the availability of vendor guarantees on ACI, the Department determined that sorbent injection is available. The following citations provide further information regarding this determination. Also, under the current BACT analysis, SME-HGS proposed, and the Department required, mercury control equipment (IECS) that is equivalent to ACI/sorbent injection.

- The DOE Office of Fossil Energy has recently published a circular that describes ACI as the most promising near-term mercury control technology, but it qualifies that observation by stating that "the process applied to coal-fired boilers is still in its early stages and its effectiveness under varied conditions...is still being investigated." It further states, "technology to cost-effectively reduce mercury emissions from coal fired power plants is not yet commercially available" ("Mercury Emissions Control R&D," updated June 21, 2005; available at http://www.fossil.energy.gov/programs/powersystems/pollutioncontrols/overview_mercurycontrols.html).
- As noted above, the EPA technology review document concludes, "It is believed that ACI and enhanced multipollutant controls will be available after 2010 for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 60 and 90%. Also optimized multi-pollutant controls may be available in the 2010-2015 timeframe for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 90 and 95%"

(“Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update,” Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency; February 18, 2005).

iv. Additional Alternatives

Coal drying, with the co-benefit of mercury removal, has not been proven on a large scale and is not commercially available. It is therefore not technically feasible.

C. Ranking of Available and Technically Feasible Mercury Control Options by Efficiency

The only remaining alternative mercury control technologies are those that provide mercury control co-benefits while reducing emissions of other pollutants. As noted above, the native controls that have been evaluated for mercury control effectiveness are wet and dry (or semi-dry) FGD scrubbers for SO₂ control; ESPs and FFBs for particulate control; and, to a lesser extent, SCR for NO_x control. These systems, individually and in combination, have demonstrated wide variability with respect to mercury reduction efficiency – anywhere from zero to over 90 percent. Effectiveness depends largely on coal quality (especially chlorine content), but also on a host of other design and operational parameters.

SME-HGS is proposing to control NO_x emissions with an SNCR system, SO₂ emissions by CFB technology that employs limestone and hydrated ash reinjection, and particulate emissions with an FFB. The combined air pollution control system is referred to as an integrated emissions control system (IECS). As part of evaluating the performance of CFB in combusting PRB coal, SME-HGS conducted a pilot-scale test burn in February 2005. The test burn was conducted in an ALSTOM Power test facility using 80 tons of Montana PRB coal and 20 tons of Montana limestone (80 tons of coal would be combusted in approximately 30 minutes in the SME-HGS main boiler when firing at full capacity). A summary of the test results is included in Section 3.12 of the application for this air quality permit and a complete copy of the test burn report is in Appendix I of the application for this air quality permit.

The pilot test results indicate a potential for approximately 88% (0.7 lb/TBtu) mercury removal in a CFB combustor with HAR and fabric filter controls. This level of mercury control is much greater than most utility boilers burning subbituminous coal and utilizing native control systems. It is also near the high end of values observed in the many test programs that have been and are being conducted on subbituminous coal combustion in utility boilers. However, the test burn alone does not provide sufficient data to allow boiler manufacturers to confidently extrapolate the data and guarantee mercury emissions control in a full-scale CFB unit with IECS.

The Department has recently become aware of emissions testing at East Kentucky Power Cooperative Gilbert Unit 3 during the summer of 2005. This testing program included measurements of mercury emissions on a CFB Boiler equipped with an HAR, SNCR and FFB. Short-term testing results showed stack mercury

emissions of 1.0 lbs/Trillion Btu (TBtu) and 89.5% control of the input mercury from coal. While these test results are very promising, Gilbert Unit 3 burns eastern bituminous coal with a relatively high chlorine content (0.031% during test period) from many different sources in Kentucky and Illinois. For comparison, Spring Creek coal has a chlorine content of <0.01%. Recent research conducted by ADA-ES, with support from DOE/NETL, EPRI and industry partners, confirms that available chlorine is a key factor in oxidizing elemental mercury in the combustion gases and in controlling mercury emissions from PRB coal ("Full-Scale Evaluations of Mercury Control for Units Firing Powder River Basin Coals" Sjostrom, Sharon, *et al.*, ADA-ES, O'Palko, Andrew, USDOE/NETL, Chang, Ramsay, EPRI. DATE not given).

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

For a discussion of collateral economic, energy, and environmental impacts associated with the proposed CFB Boiler and associated controls, refer to previous sections of this BACT analysis.

E. Mercury BACT Determination

SME-HGS proposed a mercury emissions floor and to conduct continuous mercury-specific monitoring of the CFB Boiler technology including limestone injection, SNCR, HAR, and FFB control, collectively termed the integrated emission control system (IECS), as mercury BACT for the proposed project. Further, as necessary, SME-HGS proposed the installation and operation of additional mercury emissions control technologies to establish scientifically justifiable and site-specific mercury emissions reductions above and beyond the permitted and BACT determined mercury floor emissions levels. The SME-HGS proposed mercury emissions floor was a maximum mercury emission rate expressed as either:

- 80% mercury reduction, based on a 12-month rolling average, or
- 2.0 lb mercury/TBtu, based on a 12-month rolling average.

Based on Department verified information contained in the SME-HGS application for this air quality permit, including mercury specific source testing results obtained through the simulated and comprehensive combustion, performance, and emission testing program conducted prior to application, and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed mercury emission control strategy and mercury floor emission limit(s) do not constitute BACT in this case. Considering the above-cited information as well as a recent mercury specific BACT determination for a similar source permitted for operation in Montana, the Department determined that the appropriate mercury BACT emissions limit(s) for the proposed project incorporating the IECS is either:

- 90% mercury reduction, based on a 12-month rolling average, or
- 1.5 lb mercury/TBtu, based on a 12-month rolling average.

The two-part limit accounts for two complementary operational factors. First, coal quality is not constant, even within a given coal deposit. At the extremely low values under consideration, a small proportional change in coal mercury content can have a significant impact in compliance potential. Second, control efficiencies

generally decrease as inlet concentrations decrease, particularly as inlet concentrations become very low, as in the case of mercury concentrations in utility boiler exhaust. If SME-HGS should receive coal with higher than normal mercury content, it may be difficult to comply with the lb/TBtu limit, but compliance with the percent reduction requirement would be achievable. Conversely, if a particular coal supply contains less mercury than normal, the percent reduction requirement may be less readily attainable while the emission rate may be more so.

To confirm the performance of the CFB Boiler and IECS in reducing mercury emissions, SME-HGS will be required to monitor and analyze mercury control performance data after commencement of commercial operations and to report this information to the Department. The results of the final analysis will then be used to confirm compliance with the BACT-determined mercury emissions limit(s).

If the CFB Boiler operating with the IECS is unable to demonstrate compliance with the mercury limits established through the BACT determination, SME-HGS is required to achieve the BACT-determined mercury reductions/limits through the installation and operation of mercury-specific emission controls. Within 18 months after commencement of commercial operations, SME-HGS shall install and operate an activated carbon injection control system or, at SME-HGS's request and as approved by the Department, an equivalent technology (equivalent in removal efficiency) to comply with the applicable mercury BACT emission limits.

8. Radionuclide Emissions

Most natural materials, including coal, contain trace quantities of radioactive components. When coal is combusted, radionuclides are contained in the combustion gases. Radionuclides from a CFB Boiler are emitted primarily as particulate matter. Pollution control equipment that is used to remove PM as described in the CFB Boiler filterable PM BACT determination will also effectively remove radionuclides. The Department determined that radionuclides can be controlled by more than 95% with traditional PM/PM₁₀ control equipment (e.g., FFB or ESP).

A. Identification of Available Radionuclide Control Strategies/Technologies

The two most effective and available control options for radionuclides are an FFB and ESP as described in the CFB Boiler BACT determination for filterable PM emissions. Other less effective control options are also listed in the CFB Boiler BACT determination for filterable PM.

B. Technical Feasibility Analysis

FFB and ESP are technically feasible.

C. Ranking of Available and Technically Feasible NO_x Control Options by Efficiency

FFB and ESP control options have the capability of controlling radionuclides by more than 95%, although FFBs are slightly more effective, particularly for smaller particulate matter.

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

Both FFB and ESP would produce a solid waste stream, with a wet ESP creating a wet solid waste stream. No significant environmental, economic, or energy impacts are identified as being associated with the use of an FFB or ESP, although an ESP would require more energy than a FFB. In addition, when an FFB is downstream of a dry FGD unit, additional SO₂ is removed, along with acid gases and H₂SO₄ mist that have formed in the exhaust stream, thereby, providing additional co-benefit pollution control.

E. Radionuclide BACT Determination

SME-HGS proposed the use of an FFB as BACT for radionuclide emissions. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the FFB emission control strategy constitutes BACT for radionuclides in this case.

Because an FFB will achieve slightly better control than an ESP and FFB control is deemed BACT for filterable PM. The Department determined that the filterable PM BACT emission limit will act as a surrogate BACT emission limit for radionuclides. The BACT determination for radionuclides is consistent with previous Department BACT determinations for radionuclides. Further, the Department determined that the periodic source testing (filterable PM) and applicable recordkeeping and reporting requirements contained in the permit will adequately monitor compliance with the permitted BACT requirements.

B. Coal, Limestone, and Ash (Fly and Bed Ash) Material Handling and Storage Operations BACT Analysis and Determination

The following BACT determination was conducted for PM/PM₁₀ emissions resulting from both the handling and storage of coal, used as primary CFB Boiler fuel; limestone, used for CFB injection technology and SO₂ control; and ash (fly and bed-ash) produced by coal combustion in the CFB Boiler. The BACT analysis is broken down in to two parts including material handling operations and material storage operations.

1. Material Handling PM/PM₁₀ Emissions

Material handling at the SME-HGS facility includes the transfer and conveying of coal, limestone, and ash. PM/PM₁₀ emissions will be emitted from the conveying, handling, and transferring of these materials. The application for this permit lists all of the conveyors and material handling transfer points located throughout the SME-HGS facility.

Typically, limestone and coal are moved within a facility using belt conveyors and bucket elevators. Ash is typically moved via pneumatic conveyors. Both methodologies have the potential to create particulate emissions.

As the flow of material passes through the transfer or drop point to a conveyor, particulate emissions are generated. The quantity of particulate emissions generated by a transfer point varies with the volume of material passing through the point, the particle size distribution of the material, the moisture content of the material, and the exposure to prevailing winds at the transfer point. EPA's AP-42, Section 13.2.4 describes a

methodology and provides equations to calculate uncontrolled particulate emissions from both batch and continuous process transfers, or drop point transfers, with an emission factor rating of A, giving the equation the highest level of confidence.

A. Identification of Available PM/PM₁₀ Control Strategies/Technologies

Methods of controlling particulate emissions from conveyors and transfer points have been developed, which can significantly reduce emissions rates. These methods are based on several principles: reducing the amount or flowrate of material passing through the transfer point, passing larger sized material and minimizing the small particle size content of the material, increasing the moisture content of the material to increase agglomeration of fine material, and shielding or enclosing the transfer point to protect the transfer point from wind. Enclosures often include fan-powered FFB to collect any airborne particulate at a common point for re-use or disposal.

As previously stated, there are a number of available control technologies that can theoretically be employed to control PM/PM₁₀ emissions from materials handling sources. The following table summarizes available controls for PM/PM₁₀ emissions from conveyors and transfer points.

Technology	Description
Wet Dust Suppression / Wetted Material	A water spray or fogger adds water to the material being handled with or without surfactant. Emissions are prevented through agglomerate formation by combining small dust particles with larger particles or with liquid droplets. Water retained by the material prevents emissions from storage systems and downstream transfers.
Enclosure (including partial enclosure)	Structures or underground placement can be used to shelter conveyors and material transfer points from wind to prevent particulate entrainment. Enclosures can either fully or partially enclose the source.
Enclosure with ESP	Conveyors can be enclosed and have emissions-laden air collected from the enclosure and ducted to an ESP. An ESP uses electrical forces to move entrained particles in the air onto a collection surface. A cake of particulate forms on the collection surface, which is periodically “rapped” by a variety of means to dislodge the particulate, which drops down into a hopper for collection and disposal or reuse.
Enclosure with FFB	Conveyors are often enclosed and emissions-laden air is collected and ducted to the FFB. Pneumatic conveyors are typically sealed with the exception of a FFB or bin vent on the air discharge. In either case, the air-flow passes through tightly woven or felted fabric, causing particulates in the flow to be collected on the fabric by sieving and other mechanisms. As particulate collects on the filter, collection efficiency increases. However, as the dust cake thickness increases so does the pressure drop across the bags. Bags are intermittently cleaned by mechanisms such as shaking the bag, pulsing air through the bag, or temporarily reversing the airflow direction. Material cleaned from the bags is collected in a hopper at the bottom of the FFB.

B. Technical Feasibility Analysis

The technologies listed in the above table are considered technically feasible, with the following exceptions. Since the proposed emergency coal storage pile is not enclosed, having an enclosed transfer point to the pile is considered technically infeasible. As a result, adding FFB or ESP to the enclosure is also considered technically infeasible; therefore, these strategies are removed from further consideration for that transfer point.

Ash handling from temporary storage (e.g., silo) to permanent storage (e.g., monofill) by enclosure with ESP or FFB control is not an industry accepted practice. Fly ash consists primarily of fine particles, which easily become airborne, and bed ash has a significant portion of fine particles. These materials are not suitable for collection with these listed technologies, as the baghouse or ESP will pick up a significant portion of the material stream and quickly become overloaded. Therefore, these strategies are removed from further consideration for ash handling.

C. Ranking of Available and Technically Feasible PM/PM₁₀ Control Options by Efficiency

The following table summarizes the available control options, their respective potential control efficiency values, and their ranking for the purposes of this BACT analysis.

Technology	Estimated Control Efficiency	Rank
Enclosure with FFB	99.5%	1
Enclosure with ESP	Up to 99%	2
Enclosure	Varies with Degree of Enclosure 3-Sided Enclosure = 50% Complete Enclosure = 90%	3
Wet Dust Suppression (including water spray with or without surfactant and wet material)	50%	4
No Add-On Control	---	5

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text provides a brief discussion of the available control options and an analysis of BACT applicability in this case.

i. Enclosure with FFB

For most of the proposed sources, an enclosure with FFB dust collector control has been deemed technically feasible. FFB operations and maintenance are relatively simple. FFB are generally considered an industry standard for material transfer point particulate control and are deemed economically feasible in this case. Because FFB provides the highest level of control, no further evaluations are necessary for sources with proposed with FFB control.

ii. Enclosure with ESP

Because ESPs can theoretically attain up to 99% control efficiency, ESP control was evaluated. The ESP could only be used to control the limestone and ash particulate emissions and not for coal handling because of the high explosion potential of coal dust collection in an ESP. ESPs are not typically used for control of limestone or ash handling emissions due to the high initial costs of installation, complexity, and technical difficulty of operations. Costs associated with the technical obstacles have not been quantified in this analysis. Industry norms indicate, however, that use of ESPs for particulate control from material handling transfer points is unduly complex and cost prohibitive. Therefore, the use of enclosures with an ESP is eliminated from further consideration in this BACT analysis.

iii. Enclosures

Using enclosure structures or underground placement to shelter material from wind entrainment is often an economic means to control PM/PM₁₀ emissions. Enclosures can either fully or partially enclose the source and control efficiency is dependent on the level of enclosure. Enclosures are considered for the coal pile reclaim hopper, belt feeder and transfer to Conveyor CC03. All of this equipment is located underground, and covered by the coal pile. The emergency storage pile has no regularly scheduled use. Only a very small fraction of the total coal consumed at the SME-HGS facility is anticipated to go through the storage pile. As such, SME-HGS believes the cost of providing additional control by the installation of an enclosure is difficult to quantify and would result in relatively large cost/ton effectiveness figures. Complete enclosure provides the highest level of control of the remaining alternatives.

iv. Wet Dust Suppression

Wet dust suppression works by causing fine particles to agglomerate through the introduction of moisture into the material stream. The agglomerated particles resist entrainment by wind. Because use of wet dust suppression techniques, including fogging water spray with or without surfactant, can achieve control efficiency of 50% or greater, wet dust suppression was evaluated.

Wet dust suppression is not always a practical control alternative. Occasionally, moisture may interfere with further processing such as screening or grinding where agglomeration is counterproductive. In addition, application of additional moisture in fuel handling operations can increase fuel costs and/or cause upset combustion conditions. In some cases, water may not be readily available and piping water to the site may be cost-prohibitive. Finally, using water sprays when the temperatures are below freezing causes operational difficulties.

When using wet dust suppression, the decision to use or not to use surfactants is often somewhat discretionary and based on availability of a water source. Addition of surfactants to the water lowers its surface tension and improves wetting efficiency. As a result, less water is used and application is required less frequently. Wet dust suppression is particularly applicable to ash handling activities. Ash is often mixed with small quantities of water in a pug mill before disposal.

E. Material Handling PM/PM₁₀ Emissions BACT Determination

In summary, SME-HGS proposed the use of the highest level of control that is technically and practically feasible for the affected material handling PM/PM₁₀ emission sources.

Proposed BACT for coal, limestone, and ash handling conveyors will be partial or full enclosures. Coal/limestone belt conveyors will be partially enclosed with a cover that extends past the conveyor belt, or is fully contained within a building. The limestone bucket elevator conveyors will be fully enclosed, and the ash handling pneumatic conveyors will be fully enclosed and sealed.

SME-HGS proposes to use enclosures with FFB or bin vent control as BACT for PM/PM₁₀ on almost all of the material transfer emission points. Enclosure with a baghouse or bin vent provides the most effective control and is considered the industry norm for control of materials handling transfer points. Based on Department verified information contained in the application for this permit, the following exceptions to the material transfer point BACT determination of FFB or bin vent control apply in this case: Complete enclosure is BACT for PM/PM₁₀ on the transfer points at the emergency coal pile to reclaim hoppers, reclaim hopper to belt feeder, and belt feeder to Conveyor CC03 because FFB or ESP control would not be cost-effective due to the relatively low potential to emit of the sources since the transfer points are located beneath (i.e., underground) the emergency coal pile. Further, enclosures for these sources is the most cost effective control given the infrequent operation of the equipment.

Further, the Department determined that wet dust suppression constitutes BACT for PM/PM₁₀ emissions from the fly ash and bed ash conveyor and transfer emission points (removal from the silo). The FFB, ESP, and enclosure control options are technically infeasible. Wet dust suppression is proposed for ash handling after the pug mill for removal from the plant collection system. Wet dust suppression and partial enclosure (i.e., lowering well) are also proposed for the transfer of coal to the emergency coal storage pile because the FFB and ESP control options are practically infeasible for a single transfer point that will operate intermittently.

A review of the EPA's RBLC database shows that the proposed BACT presented in the sections above conforms to similar sources recently permitted under the PSD program. The data from the RBLC website is summarized in the application.

The Department determined that the affected material handling and transfer points operating under the proposed control requirements and the established FFB and bin vent emission limit(s) of 0.005 gr/dscf and 0.01 gr/dscf, respectively, constitute BACT in this case. Further, the Department determined that the periodic PM/PM₁₀ source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted material transfer BACT requirements.

2. Material Storage PM/PM₁₀ Emissions

Materials stored at the SME-HGS facility include coal, limestone, fly ash and bed ash. particulate emissions will be emitted from the storage of these materials. Storage of these materials in large quantities, as required by a coal-fired power plant of this size, has historically been accomplished with piles. More recently, control technologies have been applied to the storage of these materials.

Sections 13.2.4 and 13.2.5 of AP-42 describe the process by which storage piles generate fugitive particulate emissions. The quantity of particulate emissions generated by a storage pile varies with several factors, including wind speed acting upon the surface of the pile, threshold friction velocity of the pile, frequency of disturbance of the pile, and area of disturbance of the pile. Threshold friction velocity takes into account materials makeup of the pile, material size distribution and moisture content of the material in the pile. Emissions are only generated when the wind speed acting upon the pile exceeds the friction threshold velocity.

A storage pile of aggregate material, such as coal, limestone or ash, is typically composed of pieces of material of different sizes, including non-erodible elements of the material (greater than 1 cm in diameter) mixed with smaller, erodible material sizes, including silt. The pile surface has a finite availability of the erodible portion of material, which tends to be removed from the pile rapidly during a wind event. This is referred to as erosion potential of the pile. Since undisturbed piles quickly lose their erosion potential during a wind gust, emissions are significantly reduced until the pile is disturbed, when the erosion potential is restored. If a crust is formed on the pile due to erosion, precipitation, water spray or surfactant application, the emission potential is significantly reduced because of the resulting increase of the threshold friction velocity of the pile.

Methods of controlling particulate emissions from the storage of materials have been developed which can significantly reduce fugitive emissions from storage of materials. These methods are similar to the transfer point emissions reduction methods, and are based on several principles:

- Minimizing material transfers to and from the pile (pile disturbances),
- Storing larger sized material and minimizing the small particle size content of the material,
- Increasing the moisture content of the material to increase agglomeration and cementation of fine material to larger particles, and
- Shielding or enclosing the materials to protect from wind erosion

Enclosures may include fan-powered fabric filter baghouses or un-powered bin vent filters to collect airborne particulate.

A. Identification of Available PM/PM₁₀ Control Strategies/Technologies

A number of available control technologies can theoretically be employed to control PM/PM₁₀ emissions from materials storage. The following table summarizes available controls for PM/PM₁₀ emissions.

Technology	Description
Inactive Storage Pile with No Additional Control	An inactive storage pile minimizes or eliminates disturbances which reduces the erosion potential of the pile. It also allows a crust to form on the pile over time, which helps resist erosion by increasing the pile's threshold friction velocity.
Inactive Storage Pile with Wind Fence	An inactive pile with a wind barrier or wind fence builds upon the control listed above by reducing the wind speed that acts upon the pile surface. This minimizes the number of times that the wind velocity exceeds the threshold friction velocity, thereby reducing the number of emission events or the duration of emission events.

Inactive Storage Pile with a Permanent Wet Suppression System and Wind Fence	An inactive pile with compaction and wet suppression builds upon the control listed for an inactive storage pile alone. Compaction and wet suppression actively promote the formation of a crust on the pile by increasing the amount of agglomeration or cementing of the surface materials. This significantly increases the threshold friction velocity of the surface and reduces erosion potential. This strategy works especially well with materials that bond together with water application, such as ash. Wind fences may or may not be applied with this option depending on the additional control a wind fence may add to the overall control of this option.
Enclosure	Using structures or underground placement to shelter material from windentrainment. Enclosures can either fully or partially enclose the source.
Enclosure with FFB or Bin Vent	Emissions-laden air is collected from the enclosure and ducted to the FFB or bin vent. The flow passes through tightly woven or felted fabric, causing particulates in the flow to be collected on the fabric by sieving and other mechanisms. As particulate collects on the filter, collection efficiency increases. However, as the dust cake thickness increases so does the pressure drop across the bag.

B. Technical Feasibility Analysis

All of the potentially applicable control technologies listed above are considered technically feasible for the storage of coal, limestone, and ash.

C. Ranking of Available and Technically Feasible PM/PM₁₀ Control Options by Efficiency

The following table summarizes the available options, their respective potential effectiveness values, and their ranking for this BACT analysis.

Technology	Estimated Control Efficiency	Rank
Enclosure with FFB or bin vent	99.5%	1
Inactive Storage Pile with Permanent Wet Suppression System and Wind Fence	95%	2
Inactive Storage Pile with Wind Fence	Varies with Degree of Enclosure 3-Sided Enclosure = 50% Complete Enclosure = 90%	3
Enclosure	50%	4
Inactive Storage Pile with Best Management Practices	25-90%	5
Active Storage Pile with No Add-On Control	---	6

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The following text provides a brief discussion of the available control options and an analysis of BACT applicability in this case.

i. Enclosure with FFB or Bin Vent

If a storage system is completely enclosed, a FFB or bin vent can usually be added to the enclosure to more efficiently control particulate emissions. FFBs or bin vents on enclosures are generally considered an industry standard for particulate control on enclosed, active aggregate storage systems. Enclosures (silos) with bin vent control are proposed for short-term coal storage, limestone storage and short-term ash storage. SME-HGS proposes to use enclosure and FFB or bin vent control for all active coal, limestone, and ash storage.

ii. Enclosures

Using enclosure structures to shelter material from wind entrainment is often used to limit control particulate emissions from stored aggregate materials. Enclosures can either fully or partially enclose the source and control efficiency is dependent on the level of enclosure. Enclosures for aggregate materials often come in the form of walls around a pile, storage buildings or silos. Enclosures are generally not sealed and have emissions associated with adding and removing materials. Active storage piles are often enclosed. Inactive storage piles are generally not enclosed.

iii. Inactive Storage Pile with Permanent Wet Suppression System and Wind Fence

Applying wet dust suppression to an inactive pile contributes greatly to crust formation, which maximizes particle agglomeration on the pile surface. The agglomerated particles resist entrainment by wind on the pile surface, and minimize particulate emissions. Wet dust suppression is not without its drawbacks. Occasionally, moisture may interfere with further processing such as screening or grinding where agglomeration is counterproductive. In addition, application of additional moisture in fuel handling operations can increase fuel costs and/or cause upset combustion conditions. Using water sprays when the temperatures are below freezing causes operational difficulties. Piles are usually not watered when the ambient temperature is below freezing.

When using wet dust suppression, the decision to use or not to use surfactants is often somewhat discretionary and based on availability of a water source. Addition of surfactants to the water lowers its surface tension and improves wetting efficiency. As a result, less water is used and application is required less frequently. In the case of the coal pile, application of surfactants may be required to achieve 90% control efficiency.

iv. Inactive Storage Pile with Wind Fence

An inactive storage pile can be protected from prevailing winds with a wind barrier or wind fence. A properly designed wind barrier can effectively reduce wind speeds at the pile surface by 20 – 60%. The wind barrier should be as high as the pile, and at least as wide as the pile to achieve maximum effectiveness. Reducing wind speed acting on the pile surface reduces particle entrainment and thereby reduces particulate emissions from the stored material.

v. Inactive Pile with Best Management Practices

Using an inactive storage pile with best management practices generally includes initial compaction of material by bulldozer or other tracked heavy equipment, minimizing the number of pile disturbances, minimizing the frequency of pile disturbances, minimizing the surface area of the pile, and applying wet dust suppression to disturbed areas of the pile to help re-form a crust as necessary to reduce fugitive emissions.

vi. Active with No Additional Control

SME-HGS believes that it is not modern, standard industry practice to store coal or ash in an active pile without further emissions controls. Recent BACT determinations show that additional control on active or inactive piles is warranted.

SME-HGS proposes to use enclosure and baghouse or bin vent control for all active coal, limestone and ash storage. Since this option has the highest degree of particulate control, no economic analysis of this option has been performed for active storage. Economic impacts associated with the PM/PM₁₀ control options for inactive storage piles of coal and ash listed above were compared using estimated annualized capital, operating, and maintenance costs. Cost estimates were supplied by SME-HGS and its engineering contractors. If data was not available from SME-HGS, best engineering judgment was used. Detailed information regarding economic impacts is contained in the application for this air quality permit.

E. Material Storage PM/PM₁₀ Emissions BACT Determination

SME-HGS proposes to use a combination of enclosures (silos) with bin vent control for active storage of coal, limestone, and ash, and best management practices for the emergency coal storage and ash storage. Based on Department verified information contained in the SME-HGS application for this air quality permit and taking into consideration technical, environmental, and economic factors, the Department determined that the proposed PM/PM₁₀ emission control strategies and applicable emission limits constitute BACT in this case. The following table lists the proposed BACT control requirements and emissions limits, as applicable.

Material Stored	Method	Applicable Limit
Active Coal Storage	Coal Silo and Coal Bunkers with FFB Control	0.005 gr/dscf
Inactive Coal Storage – Emergency Coal Storage Pile	Inactive Storage Pile with Best Management Practices	NA
Limestone Storage	Limestone Silo and Limestone Bunkers with FFB Control	0.005 gr/dscf
Short-Term Ash Storage	Fly-Ash Silo and Bed-Ash with bin vent Control	0.01 gr/dscf
Long-Term Ash Storage	Inactive Storage Pile with Best Management Practices until Monofill is Capped	NA

Based on Department verified information contained in the application and taking into consideration technical, environmental, and economic factors, the Department determined that enclosure in silos with FFB or bin vent control for active coal, limestone, and short-term ash storage constitutes BACT in this case. Enclosure with FFB or bin vent control provides the highest level of particulate control, with reasonable costs and minimal adverse environmental impacts. Normal material flow consists of loading the coal and limestone bunkers on a daily basis from the enclosed coal and limestone silos, through the tripper conveyor system. The bunkers will be enclosed and controlled by baghouse DC4. The coal silo will be enclosed and controlled by baghouse DC2. The limestone silo will be enclosed and controlled by baghouse DC5. After the fly ash is removed from the FFB associated with the boiler exhaust gas stream, the ash will be temporarily stored in ash silo AS1, which is enclosed and controlled by a bin vent filter, DC6. Bed ash removed from the boiler will be temporarily stored in the bed ash silo AS2, which is enclosed and controlled by bin vent DC7.

Based on Department verified information contained in the application and taking into consideration technical, environmental, and economic factors, the Department determined that an inactive storage pile, with best management practices, including compaction and wet dust suppression as necessary (i.e., water truck application) constitutes BACT for emergency reserve storage of coal and long-term storage of ash prior to capping of the open on-site ash storage cell. SME-HGS will be submitting, separate from the air quality permit application, a solid waste management plan for the long-term storage of the ash in the monofill. Based on the emission inventory prepared for the SME-HGS facility, the inactive emergency coal storage pile is estimated to emit 1.63 tons per year of PM₁₀ (based on conservative emission calculations). Recent PSD permitting actions show this storage method constitutes BACT. The Department determined that the addition of a wind fence or permanent wet suppression system to the inactive coal pile yields a minimal additional control of particulate emissions once the coal pile is compacted and becomes encrusted. The cost analysis supplied in the application for this air quality permit shows that the control options with higher particulate control have extremely high costs on a dollar per ton of PM₁₀ removed basis. Detailed information regarding the cost analysis is contained in the application for this permit action. The Department determined that these costs are excessive and far above industry norms for PM₁₀ control. Therefore, all additional control options above best management practices for inactive coal storage have been eliminated from further consideration under this BACT analysis.

Based on Department verified information contained in the application, the Department determined that an inactive storage pile, with best management practices, including compaction and wet dust suppression as necessary (i.e., water truck application), constitutes BACT for storage of ash prior to capping of the open monofill cell. SME-HGS proposes to mix fly ash and bed ash with small quantities of water in the pug mill after removal from the ash silos. The ash-water mixture is hauled to the ash monofill, where it is pushed into location and compacted. Ash, when mixed with small quantities of water, forms a cement-like material that has very low wind erosion potential. The monofill is composed of cells, formed by excavating earthen material from the cell location and using that material to form a berm around the monofill cell. The monofill has a “built-in” wind barrier, due to the construction of the monofill cells, which are partially below grade and considered “bermed.”

Based on the emission inventory prepared for the SME-HGS facility, the inactive ash storage pile is estimated to emit 1.62 tons per year of PM₁₀ (based on conservative emission calculation equations). All of the additional controls identified in the application for this permit yield minimal particulate removal with extremely high cost effective values. Detailed information regarding the cost analysis is contained in the application for this permit action. Therefore, the BACT analysis eliminates these methodologies on an economic basis. Although the RBLC database does not explicitly show any BACT determinations for ash storage or disposal in a monofill, the Department determined that an inactive ash storage pile, with best management practices, including compaction and wet dust suppression as necessary (i.e., water truck application) constitutes BACT in this case.

The proposed BACT technologies conform to similar sources recently permitted under the PSD program that are listed in the RBLC database. The data from the RBLC website is summarized in the application.

The Department determined that the affected material storage emission sources operating under the proposed control requirements and the established FFB and bin vent emission limit(s) of 0.005 gr/dscf and 0.01 gr/dscf, respectively, constitute BACT in this case. Further, the Department determined that the periodic PM/PM₁₀ source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted material storage BACT requirements.

C. Cooling Tower PM/PM₁₀ Emissions BACT Analysis and Determination

A wet cooling tower will be used at the SME-HGS facility to dissipate waste heat from the generating system. The proposed cooling tower will be a fan-induced draft, counter-flow design. Latent heat of water evaporation is used to provide the cooling effect. The design circulating water rate is 102,800 gallons per minute (gpm). Approximately 2,250 gpm of the cooling water will be evaporated by the cooling tower.

The cooling tower provides direct contact between the cooling water flow and air passing through the tower. Some of the cooling water becomes entrained in the air stream and carried out of the tower as water droplets (in liquid phase). Water lost in the liquid phase is known as “drift.” The drift loss is independent of water lost to evaporation. When the drift droplets evaporate, dissolved solids crystallize and create particulate emissions. The particulate emissions consist of mineral matter and chemicals used for corrosion control in the piping systems. PM/PM₁₀ emissions from the cooling tower are estimated in the emissions inventory at 13.5 tons per year.

Factors that affect PM/PM₁₀ emission rates from wet cooling towers include: air and water flow patterns, the amount of total dissolved solids (TDS) in the cooling cycle water, circulating water volumes, the number of cooling tower concentration cycles and operation and maintenance practices.

1. Identification of Available PM/PM₁₀ Control Strategies/Technologies

The Department is only aware of one control technology for PM₁₀ emissions from wet cooling towers: drift eliminators. Drift eliminators work by intercepting as many water droplets as possible from the airflow leaving the cooling tower, thus minimizing PM₁₀

emissions. Drift eliminators are designed to cause sudden directional changes to the air flow and the inertia of the water droplets causes them to impact the eliminator surfaces. The drift is then collected and returned to the cooling water flow. The drift eliminators also help minimize the amount of make-up water required for the cooling tower cycle operation. High efficiency drift eliminators of modern design can control the drift to less than 0.005% of the cooling tower circulating water flow.

2. Technical Feasibility Analysis

Drift eliminators are technically feasible and commonly employed for wet cooling tower operations such as that proposed by SME-HGS.

3. Ranking of Available and Technically Feasible PM/PM₁₀ Control Options by Efficiency

Add-on PM/PM₁₀ control would result in no additional control of PM/PM₁₀ emissions resulting from wet cooling tower operations. The only available PM/PM₁₀ control strategy/technology identified for the proposed cooling tower is a drift eliminator. Drift eliminators are capable of an approximate 90% reduction in particulate emissions resulting from wet cooling tower operations.

4. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

The cooling tower design proposed by SME-HGS incorporates high efficiency drift eliminators. Because this control technology has the highest PM/PM₁₀ control efficiency, no further analysis is required.

5. Cooling Tower PM/PM₁₀ Emissions BACT Determination

The top technology (drift eliminators), for cooling tower PM/PM₁₀ control will reduce emissions by at least 90%. SME-HGS proposes to install, operate and maintain high efficiency drift eliminators on the cooling tower. The proposed design includes a drift rate of 0.002% circulating flow. The resulting potential PM/PM₁₀ emission rate is 3.09 lb/hr, or 13.52 tons per year. This is equivalent to a normalized rate of 0.50 pounds of PM₁₀ emitted per million gallons of circulating water (lbs/MMgal).

The BACT determined PM/PM₁₀ emission rate of 0.002% of circulating flow is one of the lowest values reported in the RBLC for other recently permitted and similar sources. The data from the RBLC website is summarized in the application.

The Department determined that the installation, operation and maintenance of high efficiency drift eliminators on the cooling tower and a PM/PM₁₀ emission limit of 0.002% of circulating flow constitute BACT in this case. Further, the Department determined that the periodic PM/PM₁₀ source testing and the applicable recordkeeping and reporting requirements will adequately monitor compliance with the permitted material storage BACT requirements.

D. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed BACT Analysis and Determination

The following BACT analysis evaluates NO_x, CO, SO₂, PM/PM₁₀, and VOC emissions from the intermittent and limited use of the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater for support and emergency operations at the SME-HGS facility.

The Auxiliary Boiler will run on #2 diesel fuel-oil, natural gas, or propane and will only be operated during startup, shutdown, commissioning of the CFB Boiler and during extended downtimes of the CFB Boiler during the winter months to aid in the prevention of freezing of the CFB Boiler components. The Emergency Generator and Emergency Fire Pump will run only on #2 diesel fuel oil and operate only during emergencies and during required equipment maintenance. The Coal Thawing Shed Heater will operate only on propane or natural gas during times when the coal is frozen in the coal train cars.

1. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed NO_x Emissions

NO_x will be formed during the combustion of natural gas, propane, or diesel fuel in the Auxiliary Boiler, Emergency Generator, Emergency Firewater Pump, and Coal Thawing Shed Heater. Three fundamentally different mechanisms produce NO_x during the combustion of hydrocarbon fuels. The formation of NO_x is dominated by the thermal mechanism, which involves the thermal dissociation and subsequent reaction of nitrogen (N₂) and oxygen (O₂) molecules in the combustion air. Most of the “thermal NO_x” is formed in the high temperature flame zone near the burners or in the combustion chambers. The amount of thermal NO_x formed is directly proportional to oxygen concentration, peak temperature, and time of exposure to peak temperature. Virtually all thermal NO_x is formed in the region of the flame at the highest temperature. Maximum thermal NO_x production occurs at a slightly lean fuel-to-air ratio due to the excess availability of oxygen for reaction with the nitrogen in the air and fuel.

A second mechanism for the formation of NO_x, termed “prompt NO_x,” occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals present in the fuel. The prompt NO_x reactions occur within the flame and are usually negligible when compared to the amount of thermal NO_x. However, prompt NO_x levels may become significant when technologies are applied that control thermal NO_x to ultra-low levels.

A third mechanism, “fuel NO_x,” stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. The contribution of this mechanism to the total NO_x depends entirely on the nitrogen content in the fuel. For natural gas, propane, and fuel oil, the contribution of fuel NO_x is usually negligible.

A. Identification of Available NO_x Control Strategies/Technologies

NO_x emissions from the Auxiliary Boiler, Emergency Generator, Emergency Firewater Pump, and Coal Thawing Shed Heater can be reduced by several different methods. The following list presents methods listed in the RACT/BACT/LAER database and other technologies that are applicable to natural gas combustion processes:

- i. Selective Catalytic Reduction (SCR);
- ii. Selective Non-Catalytic Reduction (SNCR);
- iii. Low Temperature Oxidation (LoTOx);
- iv. Dry Low NOX (Staged Combustion);
- v. Non-Selective Catalytic Reduction (NSCR);
- vi. Wet Controls;
- vii. Innovative Catalytic Systems (SCONOX and XONON);
- viii. Process Limitations; and
- ix. Proper Design (no additional control).

These control technologies may be applied individually or in combination. A brief discussion of each type of control technology that was not presented in the Main Boiler NO_x BACT is presented below.

i. SCR

A detailed discussion of SCR NO_x control technology is included in the CFB Boiler NO_x BACT analysis.

ii. SNCR

A detailed discussion of SNCR NO_x control technology is included in the CFB Boiler NO_x BACT analysis.

iii. Low Temperature Oxidation (LoTO_x)

Oxygen and nitrogen are injected at ~380°F to transform NO and NO₂ into N₂O₅ using an ozone generator and a reactor duct. N₂O₅, which is soluble, dissociates into N₂ and H₂O in a wet scrubber. Requirements of this system include a wet scrubber, oxygen, and a cooling water supply. Scrubber effluent treatment must also be provided. The estimated control efficiency of the system is 80-90%.

iv. Dry Low NO_x

Dry technologies may be identified as dry low NO_x (DLN) burners, dry low emissions (DLE), or SoLoNO_x. These technologies incorporate multiple stage combustors that may include premixing, fuel-rich zones that reduce the amount of O₂ available for NO_x production, fuel-lean zones that control NO_x production through lower combustion temperatures, or some combination of these. A quench zone may also be present to control gas temperature. Almost all new process heaters/boilers presently being manufactured incorporate these technologies into their combustor designs to some extent. These systems typically result in 40-60% reduction in NO_x.

v. Non-Selective Catalytic Reduction

An NSCR unit controls NO_x emissions by using available CO and residual hydrocarbons in the exhaust of a rich-burn internal combustion engine as an NO_x reducing agent. Without the catalyst, in the presence of oxygen, the hydrocarbons will be oxidized instead of reacting with the NO_x. As the excess hydrocarbon and NO_x pass over a honeycomb or monolithic catalyst (usually a combination of noble metals such as platinum, palladium, and/or rhodium), the reactants are reduced to N₂, H₂O, and CO₂.

The noble metal catalyst usually operates between 800°F and 1,200°F; therefore, the unit would normally be mounted near the engine exhaust to maintain a high enough temperature to allow the various reactions to occur. In order to achieve maximum performance, 80% to 90% reduction of NO_x concentration, the engine must burn a rich fuel mixture, causing the engine to operate less efficiently. The NSCR can only be applied to rich-burn engines and not to the Auxiliary Boiler.

vi. Wet Controls

Water or steam injection technology has been well demonstrated to suppress NO_x emissions from gas turbines, but it is not commonly used to control NO_x on process heaters or boilers. The injected fluid increases the thermal mass by dilution and thereby reduces peak temperatures in the flame zone. NO_x reduction efficiency increases as the water-to-fuel ratio increases. For maximum efficiency, the water must be atomized and injected with homogeneous mixing throughout the combustor. This technique reduces thermal NO_x , but may actually increase the production of fuel NO_x . Depending on the initial NO_x levels, wet injection may reduce NO_x by 60% or more.

vii. Innovative Catalytic Systems

Innovative catalytic technologies integrate catalytic oxidation and absorption technology. In the SCONO_x process, CO and NO are catalytically oxidized to CO_2 and NO_2 ; the NO_2 molecules are subsequently absorbed on the treated surface of the SCONO_x catalyst. Ammonia is not required. The limited emissions data for this process reflects that there is an associated increase in HAP emissions when applying this technology. SCONO_x technology has recently been applied to combined cycle turbine generation facilities, since steam produced by a heat recovery steam generator (HRSG) is required in the process.

The XONON system is applicable to diffusion and lean-premix combustors. It utilizes a flameless combustion system where fuel and air react on a catalyst surface, preventing the formation of NO_x while achieving low CO and unburned hydrocarbon emission levels. The overall combustion system consists of the partial combustion of the fuel in the catalyst module followed by completion of combustion downstream of the catalyst. Initial partial combustion produces no NO_x and downstream combustion occurs in a flameless homogeneous reaction that produces almost no NO_x . The system is totally contained within the combustor and is not an add-on control device. This technology has not been fully demonstrated.

viii. Process Limitations

The amount of NO_x and other pollutants formed by fossil fuel combustion can be reduced proportionately by limiting operating hours or reducing fuel consumption.

B. Technical Feasibility Analysis

Innovative catalytic systems typically installed on combustion turbines are technically infeasible to install on the Auxiliary Boiler, Emergency Generator, Emergency Firewater Pump, and Coal Thawing Shed Heater.

LoTOx and wet controls are technically impractical on the Auxiliary Boiler, Emergency Generator, Emergency Firewater Pump, and Coal Thawing Shed Heater as these types of control options have never been installed on emergency use equipment and equipment in intermittent use. SCR and SNCR are classified as

technically infeasible on small emergency use equipment. These controls are brought forward for the Auxiliary Boiler and Coal Thawing Shed Heater since these units are planned to operate more frequently and potentially for longer durations than the emergency equipment.

DLN technology is technically infeasible on spark or compression ignition reciprocating internal combustion engines. Therefore, DLN is eliminated from use on the Emergency Generator and Emergency Firewater Pump.

NSCR technology is technically infeasible on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because an NSCR technology requires a lean oxygen exhaust stream (<1% O₂). These four units will operate with a rich oxygen exhaust stream.

C. Ranking of Available and Technically Feasible NO_x Control Options by Efficiency

The following table ranks the available and technically feasible control options according to control effectiveness and includes the no additional add-on control and process limitations control strategies.

NO_x Control Option	Auxiliary Boiler and Coal Thawing Shed Heater Control Efficiency	Emergency Generator and Emergency Fire Water Pump Control Efficiency
SCR	80-90%	Technically Infeasible
NSCR	Technically Infeasible	Technically Infeasible
DLN (Auxiliary Boiler only)	40-60%	Technically Infeasible (Except Coal Thawing Shed Heater)
SNCR	40-60%	Technically Infeasible
Process Limitations	Varies with Limitation	Varies with Limitation
Proper Design (no additional Control)	N/A	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No environmental or energy impacts exist for the NO_x control options for the Auxiliary Boiler or Coal Thawing Shed Heater that would eliminate the control option. The application provides a detailed economic evaluation for the Auxiliary Boiler. No economic cost analysis is provided for the Coal Thawing Shed Heater because the only add-on control option is a DLN burner, which will be employed on the heater.

The control efficiency used for the SCR was 90%, SNCR was 50%, and DLN was 50%. The DLN equipment cost for the Auxiliary Boiler was provided by Nebraska Boilers, and the DLN equipment cost for the Coal Thawing Shed Heater was based on a ratio of the Auxiliary Boiler DLN cost and the heat input values for the Auxiliary Boiler and Coal Thawing Shed Heater. The SCR and SNCR equipment costs were derived from equations in OAQPS Section 4 – NO_x Controls (10/2000). Capital costs were annualized at 10% for 10 years as recommended by OAQPS. As reported in the application, the Auxiliary Boiler cost effective value for SCR is approximately \$36,925/ton of NO_x removed; for SNCR the cost effective value is approximately \$18,514/ton NO_x removed; and for DLN the cost effective value is

approximately \$1341/ton NO_x removed. The Coal Thawing Shed Heater cost effective value for SCR is approximately \$158,172/ton of NO_x removed; for SNCR the cost effective value is approximately \$179,635/ton NO_x removed; and for DLN the cost effective value is approximately \$16,678/ton NO_x removed. Based on the cost-effective values provided above, the Department determined that DLN constitutes a cost-effective control option for the Auxiliary Boiler in this case. Further, based on the cost-effective values provided above, all control options are deemed economically infeasible for the Coal Thawing Shed Heater in this case. A detailed cost analysis is included in the application for this air quality permit.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed NO_x Emissions BACT Determination

Based on the annual cost-effectiveness of DLN, the Department determined that NO_x BACT control for the Auxiliary Boiler is DLN burners with process limits in this case. Further, based on Department verified information contained in the application for this air quality permit and the NO_x BACT analysis summarized previously, the Department determined that NO_x BACT for the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater is proper design and combustion practices and process limitations. The unit specific process limitations are included in the following table.

Combustion Unit	Process Limitation	Annual Hours of Operation
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any NO_x emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will only operate during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the Emergency Fire Water Pump and Coal Thawing Shed Heater operations do not warrant emission limitations due to limited potential NO_x impact associated with enforceable limitations. However, in order to protect the ambient air quality impact analysis conducted for this air quality permit, the Department determined that non-BACT NO_x emission limit(s) of 46.79 lb/hr (1-hr averaging time) for the Auxiliary Boiler and 41.20 lb/hr (1-hr averaging time) for the Emergency Generator are necessary.

2. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed CO Emissions

A. Identification of Available CO Control Strategies/Technologies

Control of CO and VOC can be achieved through oxidation of post-combustion gases with or without a catalyst. The following is a list of available CO control technologies:

- i. Oxidation Catalyst;
- ii. Thermal Oxidation;
- iii. NSCR;
- iv. Process Limitations; and
- v. Proper Design (no additional control).

The oxidation catalyst and thermal oxidation control options are described in detail in the CFB Boiler BACT analysis. NSCR has been described in the NO_x BACT analysis in the previous section. NSCR has the ability to control NO_x and CO from rich-burn internal combustion engines.

B. Technical Feasibility Analysis

NSCR technology is technically infeasible on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because an NSCR technology requires a lean oxygen exhaust stream (<1% O₂). These four affected units will operate with a rich oxygen exhaust stream. The other available CO control options are technically feasible.

C. Ranking of Available and Technically Feasible CO Control Options by Efficiency

The following table ranks the control options according to control effectiveness.

CO Control Options for Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater	Percent Reduction
Catalytic Oxidation	80-90%
Thermal Oxidation	80-90%
Process Limitation	Varies with Limitation
Proper Design and Operation (no add-on control)	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No environmental or energy impacts exist for the CO control options for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater that would eliminate the control option. The application for this air quality permit provides an economic evaluation for the four affected emitting units. The control efficiency for thermal and catalytic incineration is 90% and equipment costs were derived from the equation in OAQPS Chapter 2 – Incinerators (9/2000). Capital costs were annualized at 10% for 10 years as recommended by OAQPS. As reported in the application, the Auxiliary Boiler cost effective value for thermal oxidation is approximately \$78,794/ton of CO removed

and the catalytic oxidation cost effective value is approximately \$64,829/ton CO removed. The Emergency Generator cost effective value for thermal oxidation is approximately \$157,653/ton of CO removed and the catalytic oxidation cost effective value is approximately \$280,198/ton CO removed. The Emergency Fire Water Pump cost effective value for thermal oxidation is approximately \$354,202/ton of CO removed and the catalytic oxidation cost effective value is approximately \$585,551/ton CO removed. The Coal Thawing Shed Heater cost effective value for thermal oxidation is approximately \$163,320/ton of CO removed and the catalytic oxidation cost effective value is approximately \$253,926/ton CO removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected units in this case. A detailed cost analysis is included in the application for this air quality permit.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed CO Emissions BACT Determination

Based on Department verified information contained in the application for this air quality permit and the CO BACT analysis summarized previously, the Department determined that CO BACT for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed is proper design and combustion practices and the process limitations included in the following table.

Combustion Unit	Process Limitation	Annual Hours of Operation
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any CO emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will only operate during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater operations do not warrant emission limitations due to limited potential CO impact associated with enforceable limitations. However, in order to protect the ambient air quality impact analysis submitted with the application for this air quality permit, the Department determined that a non-BACT CO emission limit of 18.6 lb/hr (1-hr averaging time) for the Auxiliary Boiler is necessary.

3. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed SO₂ Emissions

A. Identification of Available SO₂ Control Strategies/Technologies

The following is a list of available SO₂ control technologies.

- i. Wet or dry FGD;
- ii. Low sulfur fuels;
- iii. Process limitations; and
- iv. No additional control.

Wet and dry flue gas desulfurization control options are described in the SO₂ CFB Boiler BACT. Using low sulfur fuels such as propane, pipeline quality natural gas, and low sulfur diesel is an effective SO₂ emissions control strategy.

B. Technical Feasibility Analysis

Wet and dry FGD on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater are considered technically infeasible because these emitting units will be intermittently operating on gaseous or liquid fuel with low sulfur concentrations. Wet and dry FGD are typically employed on solid fuel or gaseous and liquid fuel that have high sulfur contents and high potential SO₂ emissions. Natural gas, propane, and #2 diesel fuel oil are required by regulation to have relatively low sulfur concentrations. Therefore, the Department determined that wet and dry FGD control options are considered technically infeasible for the control of SO₂ from the affected units in this case.

C. Ranking of Available and Technically Feasible SO₂ Control Options by Efficiency

The following table ranks the available and feasible SO₂ control options according to control effectiveness.

SO ₂ Control Options	Percent Reduction
Low Sulfur Fuels	Varies
Process Limitations	Varies with Limitation
No Additional Controls	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No economic, environmental, or energy impacts exist for the available and feasible SO₂ control options that would eliminate the control options from further evaluation. An economic analysis is not provided for the remaining control options listed because SME-HGS proposed the use of low sulfur fuels and process limitations.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed SO₂ Emissions BACT Determination

Based on Department verified information contained in the application for this air quality permit and the SO₂ BACT analysis summarized previously, the Department determined that SO₂ BACT for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed is the combustion of low sulfur fuels only and the process limitations included in the following table.

Combustion Unit	Process Limitation	Annual Hours of Operation
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any SO₂ emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will only operate during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater operations do not warrant emission limitations due to limited potential SO₂ impact associated with enforceable limitations. However, in order to protect the ambient air quality impact analysis submitted with the application for this air quality permit, the Department determined that an effects-based non-BACT SO₂ emission limit of 12.63 lb/hr (3-hr averaging time) for the Auxiliary Boiler is necessary.

4. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed PM/PM₁₀ Emissions

A. Identification of Available PM/PM₁₀ Control Strategies/Technologies

The following is a list of available PM/PM₁₀ control technologies.

- i. Fabric Filter Baghouse;
- ii. Electrostatic Precipitator;
- iii. Low Ash Fuels;
- iv. Process Limitations; and
- v. No Additional Control.

Fabric filter baghouses and ESPs are described in the PM/PM₁₀ Main Boiler BACT.

B. Technical Feasibility Analysis

Fabric filter baghouses are technically infeasible control options for the emergency generator and emergency fire water pump because the exhaust temperature is too hot for fabric filter bags. The remaining available control options are assumed to be technically feasible for the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater. All of the available control options are technically feasible for the Auxiliary Boiler.

C. Ranking of Available and Technically Feasible PM/PM₁₀ Control Options by Efficiency

The following table ranks the available and feasible PM/PM₁₀ control options according to control effectiveness.

PM/PM₁₀ Control Technology	Percent Reduction
FFB (Auxiliary Boiler and Coal Thawing Shed)	99%+
ESP (Auxiliary Boiler and Coal Thawing Shed)	99%+
Low Ash Fuels	Varies with Limitation
Process Limitations	Varies with Limitation
No Additional Controls	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No environmental, or energy impacts exist for the PM/PM₁₀ control options that would eliminate the control options for any of the affected emitting units. An economic impact analysis is provided for FFB and ESP control options for the Auxiliary Boiler and Coal Thawing Shed Heater based on cost data provided in the EPA fact sheets for FFB and ESP control. As reported in the application, the Auxiliary Boiler cost-effective value for FFB is approximately \$153,981/ton PM/PM₁₀ removed and the cost-effective value for ESP is approximately \$230,971/ton PM/PM₁₀ removed. The Coal Thawing Shed Heater cost-effective value for FFB is approximately \$922,141/ton PM/PM₁₀ removed and the cost-effective value for ESP is approximately \$1,383,212/ton PM/PM₁₀ removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected units in this case. A detailed cost analysis is included in the application for this air quality permit.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed PM/PM₁₀ Emissions BACT Determination

Based on Department verified information contained in the application for this air quality permit and the PM/PM₁₀ BACT analysis summarized previously, the Department determined that PM/PM₁₀ BACT for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed is process limitations, as indicated in the following table.

Combustion Unit	Process Limitation	Annual Hours of Operation
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any PM/PM₁₀ emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will only operate during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater operations do not warrant emission limitations due to limited potential PM/PM₁₀ impact associated with enforceable limitations. However, in order to protect the ambient air quality impact analysis submitted with the application for this air quality permit, the Department determined that a non-BACT PM/PM₁₀ emission limit of 3.22 lb/hr (24-hr averaging time) for the Auxiliary Boiler is necessary.

5. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed VOC Emissions

A. Identification of Available VOC Control Strategies/Technologies

Control of VOC and CO can be achieved through oxidation of post-combustion gases with or without a catalyst. The following is a list of available VOC control technologies.

- i. Oxidation Catalyst;
- ii. Thermal Oxidation;
- iii. Process Limitations; and
- iv. Proper Design (no additional control).

The oxidation catalyst and thermal oxidation VOC control options are described in detail in the CFB Boiler BACT analysis.

B. Technical Feasibility Analysis

Thermal and catalytic oxidation as well as process limits are considered technically feasible for all of the affected units.

C. Ranking of Available and Technically Feasible VOC Control Options by Efficiency

The following table ranks the control options according to control effectiveness.

VOC Control Options for Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater	Percent Reduction
Catalytic Oxidation	80-90%
Thermal Oxidation	80-90%
Process Limitation	Varies with Limitation
Proper Design and Operation (no add-on control)	N/A

D. Evaluation of Control Technologies Including Environmental, Economic, and Energy Impacts

No environmental or energy impacts exist for the VOC control options for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater that would eliminate the control option. The application for this air quality permit provides an economic evaluation for the four affected emitting units. As reported in the application, the Auxiliary Boiler cost effective value for thermal oxidation is approximately \$1,198,837/ton of VOC removed and the catalytic oxidation cost effective value is approximately \$983,985/ton VOC removed. The Emergency Generator cost effective value for thermal oxidation is approximately \$1,206,310/ton of VOC removed and the catalytic oxidation cost effective value is approximately \$980,693/ton VOC removed. The Emergency Fire Water Pump cost effective value for thermal oxidation is approximately \$3,317,579/ton of VOC removed and the catalytic oxidation cost effective value is approximately \$4,098,854/ton VOC removed. The Coal Thawing Shed Heater cost effective value for thermal oxidation is approximately \$2,462,650/ton of VOC removed and the catalytic oxidation cost effective value is approximately \$3,724,499/ton VOC removed. Based on the cost-effective values provided above, all control options are deemed economically infeasible for the affected units in this case. A detailed cost analysis is included in the application for this air quality permit.

E. Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed VOC Emissions BACT Determination

Based on Department verified information contained in the application for this air quality permit and the VOC BACT analysis summarized previously, the Department determined that VOC BACT for the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed is proper design with process limitations, included in the following table.

Combustion Unit	Process Limitation	Annual Hours of Operation
Auxiliary Boiler	Start-Up, Shutdown and Commissioning Operation Only	850
Emergency Generator	Emergency Use and Required Equipment Maintenance Operation Only	500
Emergency Fire Water Pump	Emergency Use and Required Equipment Maintenance Operation Only	500
Coal Thawing Shed Heater	Necessary Coal Thawing Operation Only	240

SME-HGS did not propose any VOC emission limits (BACT or otherwise) on the Auxiliary Boiler, Emergency Generator, Emergency Fire Water Pump, and Coal Thawing Shed Heater because these units will only operate during limited situations. The Department determined that the enforceable process limits and fuel specifications constitute BACT for the affected units. Further, the Department determined that the affected unit operations do not warrant emission limitations due to limited potential VOC impact associated with enforceable limitations.

E. Vehicle Traffic/Haul Roads PM/PM₁₀ Emissions BACT Analysis and Determination

Fugitive PM/PM₁₀ emissions will be generated at the SME-HGS facility by vehicle travel in and around the plant site. The Department determined that SME-HGS must use reasonable precautions to limit the fugitive emissions of airborne particulate matter on haul roads, access roads, parking areas, and the general plant property. SME-HGS proposed to pave the roads and parking areas around the main complex of buildings at the site to allow for unimpeded traffic flow during wet and muddy conditions. The roads further from the site complex (e.g., the haul road to the ash monofill) will be unpaved.

As previously discussed, SME-HGS proposed to use a combination of paved and unpaved roads at the site. The Department determined that best management practices including the application of water and/or chemical dust suppressants, as necessary, to the unpaved roads and the sweeping of paved roads, as necessary, constitutes BACT in this case. This is common industry practice and is typically considered BACT for fugitive road dust resulting from vehicle traffic at industrial sites.

The control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

IV. Emission Inventory

ton/year											
Emission Source	PM	PM ₁₀	NO _x	SO _x	CO	VOC	Pb	Hg	HCl	HF	H ₂ SO ₄
CFB Boiler (2626 MMBtu/hr)	138.0	299.1	805.2	437.1	1150.2	34.5	0.28	0.02	24.15	19.55	62.11
Aux. Boiler (225 MMBtu/hr)	1.4	1.4	19.9	5.4	7.9	0.5	---	---	---	---	---
Emergency Generator	0.13	0.13	10.3	0.3	0.7	0.2	---	---	---	---	---
Emergency Fire Water Pump	0.04	0.04	0.9	0.03	0.2	0.03	---	---	---	---	---
Coal Thawing Shed	0.03	0.03	1.0	0.00	0.17	0.03	---	---	---	---	---
Car Unloading Baghouse (DC1)	24.4	24.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Silo Baghouse (DC2)	3.6	3.6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Crusher Baghouse (DC3)	2.8	2.8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tripper System Baghouse (DC4)	3.8	3.8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Limestone Baghouse (DC5)	5.0	5.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fly-Ash Silo Bin Vent (DC6)	1.5	1.5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bed-Ash Silo Bin Vent (DC7)	1.4	1.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal Pile Dressing	1.7	0.3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergency Coal Pile Transfers	3.4	1.6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergency Coal Pile Storage	3.3	1.6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ash Landfill (Truck Dump)	3.2	1.6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower	13.53	13.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Heavy Truck Traffic	4.8	1.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Building Heaters	0.28	0.28	9.72	0.01	1.32	0.35	---	---	---	---	---
Fuel Oil Storage Tank	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00
Total Emissions	212	363	847	443	1161	36	0.28	0.02	24.15	19.55	62.11
A complete emission inventory for Permit #3423-00 is on file with the Department											

CFB Boiler Emissions

Heat Input: 2626.1 MMBtu/hr (Average Annual Heat Input – SME-HGS Information)
Hours of Operation: 8760 hr/yr (Annual Potential)

Filterable PM Emissions

Emission Factor: 0.012 lb/MMBtu (BACT Limit Permit #3423-00)
Calculations: $2626.1 \text{ MMBtu/hr} * 0.012 \text{ lb/MMBtu} = 31.51 \text{ lb/hr}$
 $31.51 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 138.03 \text{ ton/yr}$

PM₁₀ Emissions (filterable and condensable)

Emission Factor: 0.026 lb/MMBtu (BACT Limit Permit #3423-00)
Calculations: $2626.1 \text{ MMBtu/hr} * 0.026 \text{ lb/MMBtu} = 68.28 \text{ lb/hr}$
 $68.28 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 299.06 \text{ ton/yr}$

NO_x Emissions

Emission Factor: 0.07 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: $2626.1 \text{ MMBtu/hr} * 0.07 \text{ lb/MMBtu} = 183.83 \text{ lb/hr}$
 $183.83 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 805.16 \text{ ton/yr}$

SO_x Emissions

Emission Factor: 0.038 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: $2626.1 \text{ MMBtu/hr} * 0.038 \text{ lb/MMBtu} = 99.79 \text{ lb/hr}$
 $99.79 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 437.09 \text{ ton/yr}$

CO Emissions

Emission Factor: 0.10 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: $2626.1 \text{ MMBtu/hr} * 0.10 \text{ lb/MMBtu} = 262.61 \text{ lb/hr}$
 $262.61 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 1150.23 \text{ ton/yr}$

VOC Emissions

Emission Factor: 0.003 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: $2626.1 \text{ MMBtu/hr} * 0.003 \text{ lb/MMBtu} = 7.88 \text{ lb/hr}$
 $7.88 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 34.51 \text{ ton/yr}$

Hg Emissions

Emission Factor: 2.00E-06 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: $2626.1 \text{ MMBtu/hr} * 2.00\text{E-}06 \text{ lb/MMBtu} = 0.0053 \text{ lb/hr}$
 $0.0053 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 0.023 \text{ ton/yr}$

HCl Emissions

Emission Factor: 0.0021 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: $2626.1 \text{ MMBtu/hr} * 0.0021 \text{ lb/MMBtu} = 5.51 \text{ lb/hr}$
 $5.51 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 24.15 \text{ ton/yr}$

HF Emissions

Emission Factor: 0.0017 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.0017 lb/MMBtu = 4.46 lb/hr
4.46 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 19.55 ton/yr

H₂SO₄ Emissions

Emission Factor: 0.0054 lb/MMBtu (Annual BACT Limit Permit #3423-00)
Calculations: 2626.1 MMBtu/hr * 0.0054 lb/MMBtu = 14.18 lb/hr
14.18 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 62.11 ton/yr

V. Existing Air Quality

The air quality classification for the SME-HGS project area is “Unclassifiable or Better than National Standards” (40 CFR 81.327) for the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants. However, the facility will locate in an area that has recently been re-designated attainment for CO under a limited maintenance plan. The SME-HGS facility has not been identified in any studies as impacting the previous CO nonattainment area.

Under the requirements of the PSD program, SME-HGS was required to conduct modeling to determine pollutant-specific pre-monitoring applicability. Because air modeling showed that the concentration of PM₁₀ exceeded the level identified in ARM 17.8.818(7), SME-HGS was required to conduct on-site pre-monitoring for this pollutant. SME-HGS collected PM₁₀ pre-monitoring data at the proposed site from November 12, 2004, through November 11, 2005. The following table lists the background monitoring data from the SME-HGS PM₁₀ monitoring site. The measured PM₁₀ values establish the baseline concentrations and PPdemonstrate compliance with all applicable ambient air quality standards.

PM₁₀ Pre-monitoring Results

Pollutant	Avg. Period	High Impact (ppm)	High Impact (µg/m ³)	HSH Impact (ppm)	HSH Impact (µg/m ³)	Ambient Standard ^a (µg/m ³)	% of Standard
PM ₁₀	24-hr	-----	23	-----	19	150	13
	Annual	-----	7	-----	-----	50	14

^a MAAQS and NAAQS

VI. Ambient Air Impact Analysis

The nearest PSD Class I area is the Gates of the Mountains Wilderness Area located approximately 53 miles [85 kilometers (km)] southwest of the proposed site. Impacts have also been evaluated at the following other Class I areas within 250 km of the site: Scapegoat Wilderness Area, Bob Marshall Wilderness Area, Glacier National Park, Mission Mountains Wilderness Area, UL Bend Wilderness Area, and Anaconda Pintler Wilderness Area. Bison Engineering, Inc. (Bison) submitted modeling on behalf of SME-HGS.

Emissions of NO_x, SO₂, CO, PM₁₀ and Pb were modeled to demonstrate compliance with the NAAQS and Montana Ambient Air Quality Standards (MAAQS) and the PSD increments. The modeling was performed in accordance with the methodology outlined in the Draft New Source Review Workshop Manual, EPA, October 1990 (NSR Manual), and Appendix W of 40 CFR 51, Guideline on Air Quality Models (revised), April 15, 2003. SME-HGS's Class II modeling used five years of surface and upper air meteorological data (1984, 1986-1991) collected at the Great Falls Airport National Weather Service (NWS) station.

SME-HGS submitted a significant impact analysis based on emissions from all proposed SME-HGS sources. The modeled SME-HGS impacts are compared to the applicable Class II significant impact levels (SIL's) in Table 1. The SILs are contained in Table C-4 of the NSR Manual. The impacts exceed the SIL's for PM₁₀, NO_x and SO₂; therefore, a cumulative impact analysis is required for these pollutants to demonstrate compliance with the NAAQS/MAAQS. The radius of impact (ROI) for each pollutant and averaging period is included in Table 1.

Table 1: SME Class II Significant Impact Modeling

Pollutant	Avg. Period	Modeled Conc. (µg/m ³)	Class II SIL ^a (µg/m ³)	Significant (y/n)	Radius of Impact (km)
PM ₁₀	24-hr	18.7	5 (1) ^b	Y	3.0
	Annual	3.1	1	Y	1.4
NO _x ^c	Annual	1.6	1	Y	0.7
CO	1-hr	662	2,000	N	-----
	8-hr	26.9	500	N	-----
SO ₂	3-hr	13.6	25	N	-----
	24-hr	7.4	5 (1) ^b	Y	0.7
	Annual	0.24	1	N	-----
O ₃	Net Increase of VOC: 36.5 tpy. Less than 100 tpy, source is exempt from O ₃ analysis.				

^a All concentrations are 1st-high for comparison to SIL's.

^b If a proposed source is located w/in 100 km of a Class I area, an impact of 1 µg/m³ on a 24-hour basis is significant.

^c Significant impact area (SIA) based on NO_x impact (rather than NO₂).

NAAQS/MAAQS modeling was conducted for PM₁₀, SO₂, and NO_x. CO impacts from SME-HGS alone were below the modeling significance level and no additional modeling was conducted for CO emissions. The full ambient impact analysis included emissions from other industrial sources in the Great Falls area.

Modeling results are compared to the applicable NAAQS/MAAQS in Table 2. Modeled concentrations show the impacts from SME-HGS and off-site sources and include the background values. As shown in Table 2, the modeled concentrations are below the applicable NAAQS/MAAQS.

Table 2: SME-HGS NAAQS/MAAQS Compliance Demonstration

Pollutant	Avg. Period	Modeled Conc. ^a (µg/m ³)	Backgrnd Conc. (µg/m ³)	Ambient Conc. (µg/m ³)	NAAQS (µg/m ³)	% of NAAQS	MAAQS (µg/m ³)	% of MAAQS
PM ₁₀	24-hr	10.5	23	33.5	150	22	150	22
	Annual	3.2	7	10.2	50	20	50	20
NO ₂	1-hr	240 ^b	75	315	-----	-----	564	56
	Annual	2.0 ^c	6	8.0	100	8.0	94	8.5
SO ₂	1-hr	87.2	35	122	-----	-----	1,300	9.4
	3-hr	42.7	26	68.7	1,300	5.3	-----	-----
	24-hr	6.3	11	17.3	365	4.7	262	6.6
	Annual	0.8	3	3.8	80	4.8	52	7.3
Pb	Quarterly ^d	0.0005	Not. Avail.	0.0005	1.5	0.03		
	90-day ^d	0.0005	Not. Avail.	0.0005	-----	-----	1.5	0.03

^a Concentrations are high-second high values except annual averages and SO₂ 1-hr, which is high-6th-high.

^b One-hour NO_x impact is converted to NO₂ by applying the ozone limiting method, as per DEQ guidance.

^c Annual NO_x is converted to NO₂ by applying the ambient ratio method, as per DEQ guidance.

^d SME reported the 24-hour average impact for compliance demonstration.

Cumulative impact modeling, including emissions from all PSD increment-consuming sources in the Great Falls area, was used to demonstrate compliance with the Class II PSD increments for PM₁₀, NO_x and SO₂. Class II increment modeling results are compared to the applicable PSD increments in Table 3.

Table 3: Class II PSD Increment Compliance Demonstration

Pollutant	Avg. Period	Met Data Set	Modeled Conc. (µg/m ³)	Class II Increment (µg/m ³)	% Class II Increment Consumed	Peak Impact Location (UTM Zone 12)
PM ₁₀	24-hr	Great Falls 1988	10.5	30	35%	(497701, 5266846)
	Annual	Great Falls 1987	3.2	17	19%	(497701, 5267036)
SO ₂	3-hr	Great Falls 1987	11.0	512	2.1%	(497100, 526076)
	24-hr	Great Falls 1991	6.3	91	6.9%	(497290, 5268077)
	Annual	Great Falls 1987	0.4	20	2.0%	(497386, 5268078)
NO ₂	Annual ^b	Great Falls 1988	1.7	25	6.8%	(497386, 5268078)

a – Compliance with short-term standards is based on high-second-high impact.

b – Annual NO_x impacts are compared to the NO₂ standards.

SME-HGS submitted CALPUFF modeling to determine concentration, visibility and deposition impacts at the Class I areas within 250 km of the project site. CALMET was used to prepare meteorological data for input to CALPUFF. Meteorological data inputs to CALMET are included in Table 4.

Table 4: CALPUFF MET Data

Input Data Parameter	Model Year		
	1990	1992	1996
Number of Surface Stations	14	13	13
Number of Upper Air Stations	7	7	5
Number of Precipitation Stations	98	99	92
MM4/MM5 Data Grid Size	80 km	80 km	36 km

SME-HGS modeled PM₁₀, SO₂, and NO_x emissions from the SME-HGS project, and compared SME-HGS impacts to EPA's proposed Class I SIL's. SME-HGS's impacts exceeded the Class I SO₂ SILs at the Gates of the Mountain and Scapegoat Wilderness Areas. Modeling of PM₁₀ and NO_x emissions did not show any exceedances of the Class I SILs at any of the Class I areas. Cumulative impact modeling for SO₂, including all PSD increment-consuming sources, was provided for the Class I areas. Results of the Class I cumulative impact modeling are included in Table 5 and show that the cumulative modeled concentrations are lower than the Class I PSD increments.

Table 5: Class I PSD Increment Compliance Demonstration, Peak Impacts

Pollutant	Avg. Period	Met Data Period	SME Modeled Conc. (µg/m ³)	Non-SME Modeled Conc. (µg/m ³)	Total Modeled Conc. (µg/m ³)	% Class I Increment Consumed
Gates of the Mountains						
SO ₂	3-hr	July 23, 1996	1.08	1.26	2.34	9.4%
	24-hr	March 5, 1996	0.25	0.29	0.54	11%
Scapegoat Wilderness Area						
SO ₂	24-hr	April 11, 1990	0.21	0.36	0.57	11%

a – Compliance with short-term standards is based on high-first-high impact.

SME-HGS used the CALPUFF modeling results and the CALPOST program to determine deposition values in the Class I areas. The results are shown in Table 6 and are compared to the deposition level of concern identified in the Federal Land Managers Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000). None of the modeled deposition impacts exceeded the FLAG level of concern. The Department concluded that no additional analysis of deposition impacts is needed.

Table 6: SME-HGS CALPUFF Deposition Modeling Results

Class I Area	1990		1992		1996	
	N (kg/ha/yr)	S (kg/ha/yr)	N (kg/ha/yr)	S (kg/ha/yr)	N (kg/ha/yr)	S (kg/ha/yr)
Ana-Pintler	0.0003	0.0004	0.0001	0.0002	0.0002	0.0002
Bob Marsh.	0.001	0.001	0.001	0.001	0.001	0.001
Gates Mtns.	0.002	0.002	0.002	0.002	0.002	0.003
Glacier NP	0.0003	0.0003	0.0003	0.0003	0.001	0.001
Mission Mtns	0.0002	0.0003	0.0005	0.001	0.0004	0.001
Scapegoat	0.001	0.001	0.001	0.001	0.002	0.002
UL Bend	0.002	0.002	0.001	0.002	0.002	0.002
FLAG Level of Concern	0.005	0.005	0.005	0.005	0.005	0.005

SME-HGS provided an analysis of the impact of the proposed project on air quality related values (AQRV) in the Class I and Class II areas. The effects of deposition on sensitive plant species and the effects of trace elements deposition on soils, plants, and animals were found to be below

guideline levels contained in the USEPA screening guideline (EPA 450/2-81-078). The Department and affected FLMs have concluded that lake acidification analyses were not necessary because there are no sensitive lakes in the project impact area.

A visibility impact assessment is required under ARM 17.8.825 and ARM 17.8.1103, which states that the visibility requirements are applicable to the owner or operator of a proposed major stationary source, as defined by ARM 17.8.802(22). ARM 17.8.1106(1) requires that “the owner or operator of a major stationary source “...demonstrate that the actual emissions (including fugitive emissions) will not cause or contribute to adverse impact on visibility within any federal Class I area or the Department shall not issue a permit.”

SME-HGS provided a visibility impact assessment as required under ARM 17.8.825 and ARM 17.8.1103 using the CALPUFF/CALPOST modeling system. CALPOST compares visibility impacts from the modeled source(s) to pre-existing visual range at the affected Class I areas and calculates a percent reduction in background extinction ($\% \Delta B_{\text{ext}}$). The results of SME-HGS’s final visibility analysis are included in Table 7 and show six days in which the modeled $\% \Delta B_{\text{ext}}$ values from SME were $\geq 5\%$. Cumulative impact modeling was performed for those days to determine the $\% \Delta B_{\text{ext}}$ value from all the existing permitted PSD increment-consuming sources that could contribute to visibility reduction. The modeling showed four days with cumulative modeled $\% \Delta B_{\text{ext}}$ value greater than 10%.

Table 7: SME Final Visibility Results (Refined Methodology)

Class I Area	Met Data Year	Max. ΔB_{ext} 24-hr Average	Number of Days $\% \Delta B_{\text{ext}} \geq 5.0\%$	Peak Cumulative $\% \Delta B_{\text{ext}}$
Bob Marshall Wilderness Area	1990	1.57	0	NA
	1992	6.90	1	14.45
	1996	9.92	2	19.21
Gates of the Mountains Wilderness Area	1990	5.62	1	5.63
	1992	4.32	0	NA
	1996	5.77	1	15.05
Glacier National Park	1992	3.92	0	NA
	1996	1.21	0	NA
Scapegoat Wilderness Area	1990	2.31	0	NA
	1992	4.30	0	NA
	1996	5.31	1	13.65
UL Bend Wilderness Area	1992	2.09	0	NA
	1996	4.47	0	NA

The Department reviewed the visibility analysis and determined that the SME-HGS project alone and the cumulative impact of all permitted PSD increment-consuming sources will not cause or contribute to an adverse impact on visibility. The proposed emissions will not result in visibility impairment which the Department determines does, or is likely to, interfere with the management, protection, preservation, or enjoyment of the visual experience of visitors within the affected federal Class I area. This determination takes into account the geographic extent, intensity, duration, frequency, and time of visibility impairment, and how these factors correlate with times of visitor use of the federal Class I area, and the frequency and occurrence of natural conditions that reduce visibility.

UConclusion

The preceding analysis represents a summary of predicted ambient air quality impacts resulting from the proposed SME-HGS project. A comprehensive and complete dispersion modeling analysis demonstrating compliance with all applicable increments and standards is on file with the Department. Based on this analysis, the Department determined that the proposed project operating in compliance with the applicable requirements contained in Permit #3423-00 is expected to maintain compliance with all applicable increments and standards as required for permit issuance.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted a private property taking and damaging assessment and determined there are no taking or damaging implications.

VIII.Environmental Assessment

The proposed SME-HGS project is subject to review under the requirements of the Montana Environmental Policy Act. A comprehensive draft environmental impact statement (EIS) is scheduled for issuance in May, 2006.

Permit Analysis Prepared By: M. Eric Merchant, MPH

Date: March 29, 2006

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