Air Pollution Control
40 CFR 52.21(i)
Prevention of Significant Deterioration Permit to Construct
Final Statement of Basis
for Permit No. PSD-OU-0002-04.00
August 30, 2007

Deseret Power Electric Cooperative
Bonanza Power Plant, Waste Coal Fired Unit
Uintah & Ouray Reservation
Uintah County, Utah

In accordance with requirements at 40 CFR 124.7, the Region 8 office of the U.S. Environmental Protection Agency (EPA) has prepared this Statement of Basis describing the issuance of a Prevention of Significant Deterioration (PSD) permit to Deseret Power Electric Cooperative. This Statement of Basis discusses the background and analysis for the PSD permit for construction of a new Waste Coal Fired Unit (WCFU) at Deseret Power's Bonanza power plant, and presents information that is germane to this permit action.

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I. Introduction

Deseret Power Electric Cooperative ("Deseret Power") has applied to the Region 8 office of the U.S. Environmental Protection Agency (EPA) for a Federal Clean Air Act permit to construct a waste-coal-fired electric utility generating unit at its existing Bonanza power plant, near Bonanza, Utah. The request for a permit was made under regulations promulgated pursuant to the Clean Air Act, titled "Prevention of Significant Deterioration" of air quality (PSD), in Title 40, section 52.21, of the Code of Federal Regulations (CFR).

The Bonanza plant is within the exterior boundaries of the Uintah and Ouray Indian Reservation. Since there is no EPA-approved tribal permitting program on the Reservation under the Clean Air Act, the Bonanza plant is under Federal permitting jurisdiction. The existing plant is a major stationary source as defined in Federal PSD rules at 40 CFR 52.21. The new unit will constitute a "major modification" to the existing plant, as defined in PSD rules. The specific pollutants for which the modification will be major are listed in section V.B and again in section VI.C of this Statement of Basis.

The proposed new Waste Coal Fired Unit (WCFU) will have a rated heat input capacity not to exceed 1,445 million British thermal units per hour (MMBtu/hr) and a rated electrical output capacity not to exceed 110 megawatts. The WCFU will consist of a single Circulating Fluidized Bed (CFB) boiler and associated equipment. Proposed emission controls for the CFB boiler, for satisfying PSD requirements for Best Available Control Technology (BACT), will consist of:

- a fabric filter baghouse for control of filterable particulate matter (PM), including particulate matter with an aerodynamic diameter smaller than 10 microns (PM_{10}),
- limestone injection and a dry scrubber (spray dry absorber) for sulfur dioxide (SO_2) control and sulfuric acid (H_2SO_4) control,
- Selective Non-Catalyic Reduction (SNCR) for nitrogen oxides (NO_x) control,
- a combustion control system for carbon monoxide (CO) control, and
- a combination of limestone injection, dry scrubber and fabric filter baghouse for control of condensible PM.

The CFB boiler will be designed to be fired on waste coal obtained from Deseret's existing Deserado mine about 35 miles away. The waste coal is an unavoidable byproduct of the coal washing process used to supply washed coal to the existing 500-megawatt Unit 1 at Bonanza plant. If waste coal is not available due to emergencies, run-of-mine (ROM) coal or washed coal from the mine will be utilized in the WCFU. Deseret Power has also requested operating flexibility, in the EPA permit, to blend ROM coal with the waste coal, at up to a 50/50 ratio by weight, as needed at any time, such as in the event of operational difficulties arising from use of waste coal as sole fuel, or in the event of unexpected difficulties in meeting BACT emission limits.

The existing Bonanza Unit 1 was constructed under a Federal PSD permit issued in February of 1981. The permit was updated and re-issued in February of 2001. The permit for the new WCFU will be issued as a separate PSD permit.

A more detailed description of the waste coal fired project may be found in section IV below. A description of emission control options considered and determination of emission limits may be found in section VI. A description of the air quality impact analysis may be found in section VIII.

II. Authority

40 CFR 52.21, Prevention of Significant Deterioration (PSD): Requirements under §52.21 to obtain a Federal PSD preconstruction permit apply to construction of new major stationary sources ("major" as defined in §52.21), as well as to major modifications of existing major stationary sources (Amajor modification@ as defined in §52.21). EPA is charged with direct implementation of these provisions where there is no approved State or Tribal implementation plan for implementation of the PSD regulations. Pursuant to section 301(d)(4) of the Clean Air Act (42 U.S.C. § 7601(d)), EPA is authorized to implement the PSD regulations at §52.21 in Indian country. The Bonanza power plant, where this proposed project will be located, is 35 miles southeast of Vernal, Utah, near Bonanza, Utah in Uintah County, and within the exterior boundaries of the Uintah and Ouray Indian Reservation. As stated in section I above, the existing plant is a major stationary source and the proposed project will be a major modification.

40 CFR 124, Procedures for Decision Making: Federal administrative permitting standards at 40 CFR part 124, *Procedures for Decision Making*, provide requirements for several environmental permit programs, including the PSD program. General administrative procedures are codified in Part 124, including those that relate to the PSD program. Federal PSD permit actions, such as issuing, modifying, reissuing, or terminating permits, are addressed in 40 CFR 124, Subpart A, *General Program Requirements*. Part 124 also includes requirements that pertain to draft permits, Statement of Basis, Fact Sheets, public notices of permit actions, public comment periods, handling of public comments and requests for public hearings, handling of public hearings, and appeals of PSD permit decisions. Requirements in Part 124 that provide for public review and involvement in this proposed action will be used by EPA in its decision making.

In particular, the administrative requirements of 40 CFR § 124, Subpart C, *Specific Procedures Applicable to PSD Permits*, will be followed. Specifically, whenever a major source=s air emissions might affect a Class I area, 40 CFR § 124.42, *Additional Procedures for PSD Permits Affecting Class I Areas*, states that the Regional Administrator must provide notice of receipt of a permit application to the Federal Land Manager and the Federal official charged with direct responsibility for management of lands within such area. A copy of the permit application for this project was provided by the permit applicant directly to the National Park Service and the U.S. Forest Service, at the same time the application was submitted to the EPA. A copy of the permit application was also provided by the permit applicant to the Ute Indian Tribe.

III. Public Notice, Comment, Hearings and Appeals

Public notice for the draft PSD permit was published in late June, 2006, in the Salt Lake Tribune (Salt Lake City, UT), the Vernal Express (Vernal, UT), the Uintah Basin Standard (Roosevelt, UT), the Grand Junction Sentinel (Grand Junction, CO) and the Rio Blanco Herald Times (Meeker/ Rangely, CO). The public comment period extended until July 29, 2006.

During the public comment period, States, Tribes, local governmental agencies, and the public were given the opportunity to review a copy of the permit application, analysis, draft permit prepared by EPA, draft Statement of Basis for the permit, and permit-related correspondence. Copies of these documents were available for review at the US EPA Region 8, Air and Radiation Program Office, in Denver, Colorado, as well as at Uintah County Clerk's Office in Vernal, Utah, as well as at the Ute Indian Tribe, Environmental Programs Office, in Fort Duchesne, Utah. A copy of the draft permit and draft Statement of Basis was also available during public comment period on EPA website at: http://www.epa.gov/region8/air, under the heading "Topics of Interest."

In accordance with 40 CFR 52.21(q), *Public participation*, any interested person was afforded the opportunity to submit written comments on the draft permit during the public comment period and to request a public hearing.

In accordance with 40 CFR 124.13, *Obligation to raise issues and provide information during the public comment period*, anyone, including the permit applicant, who believes any condition of the draft permit is inappropriate, or that EPA's tentative decision to prepare a draft permit for the WCFU is inappropriate, must raise all reasonable ascertainable issues and submit all arguments supporting the commenter's position, by the close of the public comment period. Any supporting materials submitted must be included in full and may not be incorporated by reference, unless the material has been already submitted as part of the administrative record in the same proceeding or consists of state or federal statutes and regulations, EPA documents of general applicability, or other generally available reference material. An extension of the 30-day public comment period may be granted if the request for an extension adequately explains why more time is needed to prepare comments.

During the public comment period, one comment letter and one comment e-mail were received by EPA that expressed concerns with the draft permit and/or Statement of Basis. The comment letter, received on July 28, 2006, was from a group of seven environmental organizations: Western Resource Advocates, Environmental Defense, Utah Chapter of the Sierra Club, Southern Utah Wilderness Alliance, Western Colorado Congress, Wasatch Clean Air Coalition, and HEAL Utah. The comment e-mail, received on July 26, 2006, was from Kathy Van Dame, representing the Wasatch Clean Air Coalition.

Comment letters supporting the proposed WCFU project were received from the mayors of seven Utah municipalities: Salem City, Spanish Fork, Provo, Manti City, St. George, Nephi and Levan. Since these letters did not express any concerns with the draft PSD permit, EPA does not consider a response necessary.

A copy of the final permit and final Statement of Basis are available on the above-mentioned EPA website, as well as public comments received on the draft permit package, EPA's responses to public comments, and permit-related correspondence extending from the date that the draft permit was issued until the date that the final permit was issued.

In accordance with 40 CFR 124.15, *Issuance and Effective Date of Permit*, the permit shall become effective immediately upon issuance as a final permit, if no comments request a change in the draft permit. If changes are requested, the permit shall become effective thirty days after issuance of a final permit decision, unless review is requested on the permit under §124.19 (permit appeals). Notice of the final permit decision shall be provided to the permit applicant and to each person who submitted written comments or requested notice of the final permit decision. Since commenters requested changes in the draft permit, the effective date listed in the final permit is thirty days after permit issuance.

In accordance with 40 CFR 124.19, *Appeal of RCRA, UIC, and PSD Permits*, any person who filed comments on the draft permit or participated in the public hearing may petition the Environmental Appeals Board, within 30 days after the final permit decision, to review any condition of the permit decision. Any person who failed to file comments or failed to participate in the public hearing on the draft permit may petition for administrative review only to the extent of changes from the draft to the final permit decision.

The permit and Statement of Basis represent an Agency action to issue a Federal PSD permit to Deseret Power Electric Cooperative for the addition of the Waste Coal Fired Unit at Bonanza Power Plant, under Title I, Part A, *Air Quality Emission Limitations*, and Part C, *Prevention of Significant Deterioration of Air Quality*, of the Clean Air Act, as amended. For completeness, this Statement of Basis should be read in conjunction with the PSD permit.

Any requirements established by this permit for the gathering and reporting of information are not subject to review by the Office of Management and Budget (OMB) under the Paperwork Reduction Act, because this permit is not an "information collection request" within the meaning of 44 U.S.C. § 3502(4), 3502(11), 3507, 3512 and 3518. Furthermore, this permit and any information-gathering and reporting requirements established by this permit are exempt from OMB review under the Paperwork Reduction Act because it is directed to fewer than ten persons, 44 U.S.C. § 3502(4) and 3502(11); 5 CFR § 1320.5(a).

IV. Project Description

A. Location

The proposed WCFU will be located at the existing Bonanza Power Plant, approximately 35 miles southeast of Vernal, Utah, near Bonanza, Utah in Uintah County. This location is within the exterior boundaries of the Uintah and Ouray Indian Reservation. The UTM coordinates for the proposed CFB boiler stack are 646192 meters East and 4438740 meters North. The latitude and longitude coordinates for the stack are 40^{o} 05' 11" North and 109^{o} 16' 48" West. The proposed project will be located in an attainment area for all pollutants. The closest non-attainment area, Utah County, which is located approximately 125 miles west of the proposed facility, is in non-attainment for PM_{10}.

The proposed WCFU will be located at an elevation of 5,030 feet above Mean Sea Level (MSL). Elevated terrain surrounds the Bonanza plant. The closest elevated terrain, the East Tavaputs Plateau, is located approximately 6 miles south of the plant. The East Tavaputs Plateau is oriented in a southwest-northeast direction with elevations ranging from approximately 6,000 to 8,000 feet MSL. Another area of elevated terrain, located northeast of the plant, is Raven Ridge. Raven Ridge, oriented southeast to northwest, has elevations ranging from 6,000 to 6,350 feet MSL. The Blue Mountain Plateau, located approximately 17 miles northeast of the plant, has elevations ranging from 6,000 to 8,500 feet.

B. Existing Facility and PSD Permitting History

As stated earlier in this Statement of Basis, the existing Bonanza power plant is a major stationary source, as defined in Federal PSD rules at 40 CFR 52.21. The existing plant consists of a single electric utility generating unit currently rated at approximately 500 megawatts, known as Unit 1. The existing Unit 1 is a pulverized coal-fired boiler fueled by washed bituminous coal from the company's Deserado mine, approximately 35 miles east of the plant. The plant is the sole user of coal from the mine. Emission controls for existing Unit 1 consist of a baghouse for PM/PM_{10} control, a wet scrubber for SO_2 control, and low-NO_x burners for NO_x control.

On February 4, 1981, EPA Region 8 issued a Federal PSD permit for initial construction of Bonanza Power Plant, which at the time was planned to consist of two 400-megawatt units, and was permitted as such. Only one unit was built. After EPA approved Utah's PSD permitting program in the early 1980's, the State of Utah issued its own PSD permit for Unit 1, later revised to account for modifications that upgraded Unit 1 to approximately 500 megawatts. In late 1997, as a result of a Federal court decision, EPA Region 8 asserted Federal jurisdiction over Bonanza Power Plant and issued an updated Federal PSD permit for Unit 1 on February 4, 2001, replacing the 1981 Federal permit. There is currently no Federal PSD permit in effect for construction of Bonanza Unit 2.

C. Company Contacts

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D. Process Description

The proposed WCFU will utilize circulating fluidized bed (CFB) combustion technology. Control of SO_2, NO_x and acid gases (including H_2SO_4) in the combustion chamber is one of the major advantages of this technology over conventional pulverized coal fired boilers. Additional emission controls are described later in this Statement of Basis. The electricity generated by the WCFU will be supplied to the Bonanza substation.

The major components of the proposed WCFU include:

- Combustion and generating systems,
- Exhaust systems and pollution control equipment,
- Emergency power,
- Coal and limestone material handling and storage systems,
- Cooling water systems, and
- Ash disposal systems.

Principal components of a CFB boiler include primary and secondary air fans, combustor, cyclone/solids separator, superheater, economizer, air heater and induced draft fan. The CFB boiler will supply superheated steam to the extraction/condensing turbine to drive an electrical generator and supply cycle and plant auxiliary steam through uncontrolled extraction from the turbine. The boiler heat input design capacity at maximum load will be no more than 1,445 million British Thermal Units per hour (MMBtu/hr). The boiler will be fueled by western bituminous waste coal obtained from the company's nearby Deserado mine. If waste coal is not available in emergencies, ROM coal or washed coal from the Deserado Mine will be utilized (explained further below).

Combustion in the CFB boiler takes place in a vertical chamber called the combustor. The crushed coal and limestone are introduced into the combustor, fluidized and burned at temperatures of approximately 1550 F (1500 – 1650 F). The pulverized limestone reacts with the sulfur dioxide released from the burning fuel to form calcium sulfate (gypsum). This is the initial stage of SO_2 emission control. The bed material in the combustor consists primarily of mineral matter from the fuel, gypsum and excess calcined lime.

Combustion air is fed to the combustor at two levels. The bed material is fluidized with primary air introduced through an air distribution system at the bottom of the combustor and also by the combustion gases generated. Secondary air is added to the lower section of the combustor, above the dense phase fluidized bed, to achieve complete and staged combustion.

Bed material that is fluidized does not become molten, but rather the action of the air/flue gas bubbling through the bed allows the bed material to behave and move as though it were a fluid and allow thorough mixing of the bed material. Roughly fifty percent of the combustion air is introduced as primary or fluidizing air through the bottom air distribution system, and the balance is admitted as secondary air through multiple ports in the side walls. This staged combustion, at controlled relatively low temperatures, along with the injection of ammonia at the furnace outlets, effectively controls NO_x formation through selective non-catalytic reduction and provides conditions to most effectively capture SO_2 at low calcium to sulfur molar ratios.

The recycle cyclones/solids separator removes a major portion of the hot ash particles from the flue gas stream and re-circulates them back into the combustor, to enhance heat transfer to the combustor walls and to provide more time for complete combustion of the coal particles and calcination of the limestone particles. Ash is continuously withdrawn from the combustion chamber, cooled, and is then transferred for disposal.

Heat for steam generation is removed from the system in two ways: In the primary loop, heat is removed from the solids circulating in the CFB system by the heat absorbing surface in the water walls of the combustor and heat absorbing surface in the fluid bed heat exchangers. In the convection pass, heat is removed from the flue gas exiting the recycle cyclones/solids separator by superheater and economizer surfaces.

Relatively clean flue gases from the recycle cyclones/solids separator enter the convective pass of the steam generator where they pass over the superheater and economizer elements. After the convection pass, the flue gases are further cooled in an air heater, which utilizes the low grade heat of the flue gas to pre-heat combustion air. From the air heater, the flue gas continues to the dry scrubber for additional SO_2 removal, then to the baghouse filter for removal of residual particulate, then to the induced draft (ID) fan at the stack.

Flue gas will be exhausted from the boiler/baghouse train by an induced draft fan to a 275 foot high, 14 foot diameter steel stack. Ports will be provided to accommodate flue gas sampling equipment and the continuous emission monitoring system. Startup burners are used for preheating the CFB boiler bed up to coal ignition temperature and to provide heat input support at low loads. In-duct or above bed burners, firing #2 fuel oil, will be provided for startup and low load operating conditions.

The proposed WCFU will utilize portions of the existing Bonanza power plant facilities, including: the control room, administration building, raw water supply system, fuel oil system, plant drains, storm drains, sanitary and corrosive drain systems, ash conveyors, coal rail car receiving hopper and transfer building, demineralized water system, fire protection/service water, potable water, auxiliary steam, and the grounding and cathodic protection system.

An emergency generator will supply power to the WCFU systems in the event that normal electrical power is interrupted. The emergency generator will be a diesel-fired compression-ignition internal combustion engine, rated at 750 kilowatts and 1,005 horsepower. Deseret Power estimates that use of this generator will be less than 100 hours per year.

E. Waste Coal Characteristics

The waste coal is presently landfilled in refuse pits at the Deserado mine and will be reclaimed and/or diverted from the landfill for use in the CFB boiler. Based on core samples from the existing waste coal stockpile, the permit applicant (Deseret Power) estimates the following:

Characteristics of Waste Coal Currently Stockpiled
At Deserado Mine

Characteristic	Average	Range
Nominal heating value	4,000 Btu/lb	3,000 Btu/lb - 5,400 Btu/lb
Sulfur content (30-day average)	0.34%	0.24% - 0.71%
Ash content	50.5%	40% - 56%
Nitrogen content	0.51%	0.37% - 0.66%

Based on samples taken from conveyors currently transporting waste coal from the wash circuit at Deserado mine to the waste coal stockpile, Deseret Power estimates that sulfur content in new waste coal going to the stockpile ranges from 0.35% to 1.33%, somewhat higher than the range of sulfur content in the current stockpile. Based on core samples from the coal seam reserve at the Deserado mine, Deseret Power estimates that future waste coal material will reach 0.71% sulfur content on a 30-day average, approximately double the average sulfur content in the current waste coal stockpile.

F. Waste Coal Versus Run-of-Mine or Washed Coal as Potential Fuel.

Deseret Power has stated that it plans to use waste coal as sole fuel for the WCFU, except for emergencies that would prevent waste coal from being delivered from the Deserado mine and placed into the WCFU, as long as a supply of waste coal, as supplemented by waste coal generated from ongoing operations, remains available from the mine. For the aforementioned emergencies where waste coal is not available, Deseret Power wants the option of using run-of-mine (ROM) coal or washed coal from the Deserado mine in the WCFU. ROM coal is raw mined coal that has not been washed in the coal washing facility at the mine. Washed coal is mined coal that has been washed in the coal washing facility and is normally intended for use exclusively at the existing Bonanza Unit 1.

Deseret Power has also requested operational flexibility, in the EPA permit, to blend ROM coal in with the waste coal, at up to a 50/50 ratio by weight, as needed at any time, such as in the event of operational difficulties arising from use of waste coal as sole fuel, or in the event of unexpected difficulties in meeting BACT emission limits. The ROM coal has a heating value range of approximately 8,500 Btu/lb to 10,000 Btu/lb. A 50/50 blend would yield coal with average heating value of approximately 6500 Btu/lb.

Sulfur content of washed coal delivered to existing Bonanza Unit 1 has historically ranged from 0.30% to 0.86% on a daily basis, and up to 0.66% on a 30-day average. For 2005, the maximum 30-day average sulfur content increased to 0.74%. Sulfur content of ROM coal is believed by Deseret Power to be similar.

Although ROM or washed coal would be higher quality fuel than waste coal in terms of heat content (Btu's) per pound of coal burned, the cost of waste coal is much lower at current prices, by about $30 to $35 per ton of coal, versus ROM coal. This price differential does not include the additional cost of ROM or washed coal that accrues from the fact that use of ROM coal or washed coal at the WCFU would reduce the lifespan of the fuel supply for Unit 1, and therefore the useful lifespan of Unit 1 itself, which relies solely on the Deserado mine for fuel.

Deseret Power estimates that the WCFU can be fueled solely on waste coal from the Deserado mine for about 12 to 15 years at current mine operation levels, before other coal might have to be used to supplement the ongoing waste coal generated at the mine. This estimate is based on the following figures:

- The current waste coal stockpile is estimated at 7.9 million tons.
- New waste coal is being produced at the mine at a rate of about 0.4 to 0.6 million tons per year.
- The WCFU will use about 1.2 to 1.3 million tons per year of waste coal. This estimate is based on projected WCFU heat input rate of 1,445 MMBtu/hr, average waste coal heat content of 4,000 Btu/lb, and projected WCFU capacity factor of 80% to 85%.

Although there is a limited stockpile of waste coal as described above, the WCFU is being designed specifically to burn the waste coal. This means that equipment such as the coal handling, ash handling, limestone handling, lime supply, ammonia injection and control systems are all being designed to burn solely waste coal. If ROM coal or washed coal was to be combusted instead as primary fuel, these support systems, as well as the furnace, would be oversized, since run-of-mine coal and washed coal have two to three times as many Btu's per pound versus waste coal.

Generally, fuel quality shifts can be accommodated in the CFB combustion process, but some operating upsets would likely occur and might increase the emissions over the short term. For example, if the primary fuel shifted from the waste fuel to ROM coal or washed coal, a spike in emissions due to the change in sulfur content would most likely occur. The spike in sulfur emissions would automatically cause a spike in limestone and lime quantity flows as controls reacted to the changed condition. The spike in limestone flow would then cause an increase in NO_x emissions, which would then cause an increase in ammonia emissions. These changes in emissions would eventually settle out once the controls were adjusted to the higher quality fuel; however, a potential additional complication is that the material handling systems might be oversized to handle the run-of-mine or washed coal and would have to be modified.

Other impacts from a potential switch to ROM coal or washed coal, as fuel for the proposed WCFU, would be associated with the increased material handling requirements to inject sand into the furnace. As the heating value of the coal increases, the tonnage of coal required to maintain the same furnace temperature is reduced. If the percentage of sulfur in the coal remains relatively constant when switching to ROM or washed coal, then the uncontrolled SO_2 per ton of coal burned will be reduced, such that the boiler will require less limestone in order to control the SO_2 at the same required levels. Also, the ash content will be lower in ROM or washed coal. Proper operation of a CFB boiler requires that the inventory of solids in the furnace be maintained at a specified level. Based upon burning ROM or washed coal, having approximately the same sulfur content as the waste coal, and lower ash content, the volume of coal, ash and limestone (bed materials) will be reduced in the furnace. When this operating condition is encountered, it is necessary to inject sand into the furnace in order to maintain the proper solids volume or inventory in the furnace. This would affect the performance of the boiler.

G. Coal, Limestone and Ash Handling

1. Coal. Approximately 20 electric powered trains per month will deliver the needed waste coal to the WCFU. The railcars will discharge the coal into a track hopper and the waste coal will then be transported by conveyor to a storage pile containing 30 to 60 days of coal storage. The coal will be reclaimed from the storage pile by a dozer pushing the coal into a reclaim hopper, which feeds the coal onto a conveyor, which transports the coal to a crusher to size the coal and then to coal storage silos. The silos will be sized to store approximately 10.5 hours of fuel supply based on the maximum boiler load. The silos will discharge the coal onto gravimetric feeders controlling fuel flow rate to the boiler furnace.

2. Limestone. Limestone will be delivered by truck to the existing limestone pile at Bonanza plant. The limestone will be reclaimed with a dozer pushing the limestone into a reclaim hopper. The limestone will be transported by conveyor to a silo. The silo will be sized

to accommodate approximately 30 hours of storage (200 tons) based on full load operation. The limestone will be discharged from the silo into crusher/dryer mills where the limestone will be crushed and dried. A pneumatic system will transport the dry, sized limestone from the crusher/dryer mills to the boiler furnace to control SO_2.

3. Ash. Fly ash and bottom ash generated by the CFB combustor will be hydrated prior to transfer for disposal.

H. Proposed Emission Control Techniques

1. CFB boiler. Control of filterable PM/PM_{10} emissions will consist of a fabric filter baghouse. Control of SO_2 and H_2SO_4 emissions will consist of limestone injection into the CFB combustor unit and a dry 'polishing' scrubber (spray dry absorber) downstream. Control of NO_x emissions will consist of Selective Non-Catalytic Reduction (SNCR), via ammonia injection directly into the CFB combustor unit. Control of CO emissions will consist of a combustion control system designed and operated to ensure complete combustion. Control of condensible PM emissions will consist of a combination of limestone injection, dry scrubber and fabric filter baghouse.

2. Emergency generator. PM/PM_{10} emission control will consist of positive crankcase ventilation, good combustion practices, and use of low-sulfur diesel fuel. SO_2 and H_2SO_4 emission control will consist of use of low-sulfur diesel fuel (500 parts per million sulfur content or less). NO_x emission control will consist of combustion controls (ignition retarding and/or lean burn, to the maximum extent that the engine specifications will allow). CO emission control will consist of good combustion practices as specified in the operation and maintenance manual from the engine manufacturer. The engine to be purchased will be "Tier 2 certified," meaning that it will be designed by the manufacturer to comply with the "Tier 2" emission limits in 40 CFR 89.112, Table 1, that apply to non-road compression-ignition engines with electrical generating capacity greater than 560 kilowatts.

3. Coal, limestone and ash handling. PM/PM_{10} point source emissions from conveying systems will be controlled by use of enclosed conveyors, and by installing dust control and collection systems at all material transfer points. The dust collection systems will utilize either induced draft filter bag units (baghouses) or cartridge type (vent) filters, as follows:

Emissions	Emission Point ID	Estimated Air flow	Location
Coal dust	Baghouse OCH/DC-1	15,000 dscfm	Existing terminal building
Coal dust	Baghouse EP-W-MH-01	8,500 dscfm	Crusher building
Coal dust	Baghouse EP-W-MH-02	8,500 dscfm	Coal day silo headhouse
Limestone dust	Baghouse EP-W-MH-03	1,000 dscfm	Limestone crushers
Limestone dust	Vent filter EP-W-MH-04	1,000 dscfm	Surge bin

Limestone dust	Baghouse EP-W-MH-05	4,000 dscfm	Limestone storage silo
Ash dust	Vent filter EP-W-MH-06	1,000 dscfm	Bed ash recirculation bin
Ash dust	Vent filter EP-W-MH-07	1,000 dscfm	Bed ash disposal surge bin
Ash dust	Baghouse EP-W-MH-08	3,600 dscfm	Fly ash silo
Ash dust	Baghouse EP-W-MH-09	3,600 dscfm	Bed ash silo
Lime dust	Vent filter EP-W-MH-10	2.000 dscfm	Lime storage silo
Inert material	Vent filter EP-W-MH-11	2.000 dscfm	Inert bed day bin

Control of PM/PM_{10} non-point source (i.e., fugitive) emissions will consist of the following: Control for the coal stockpile will include compaction, water sprays and surfactant as needed. Also, the working area of the coal stockpile will be minimized. Control for the limestone stockpile will include water sprays and surfactant as needed. ("As needed" is defined in the proposed permit as any time a ten percent opacity level is exceeded.) Control for the ash/sludge pile will include compaction, water sprays, minimizing the exposed area and re-vegetation.

4. Cooling tower. For control of PM/PM_{10} emissions generated from evaporation of particulate-laden water, the cooling tower will be equipped with cellular-type mist eliminators designed to limit circulating water drift loss to 0.001 percent or less.

I. Potential to Emit

1. Controlled (with BACT applied)

Pollutant	Estimated emissions	Basis of estimate
Particulate matter (filterable) from CFB boiler	76 tons/yr	[0.012 lb/MMBtu allowed in permit] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/yr operation] x [1 ton per 2000 lbs]
Particulate matter (condensible) from CFB boiler	120 tons/yr	[0.019 lb/MMBtu EPA engineering estimate] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/yr operation] x [1 ton per 2000 lbs]
Sulfur dioxide	348 tons/yr	[0.055 lb/MMBtu allowed in permit] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/yr operation] x [1 ton per 2000 lbs]
Nitrogen oxide	557 tons/yr	[0.088 lb/MMBtu allowed in permit] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/yr operation] x [1 ton per 2000 lbs]
Carbon monoxide	949 tons/yr	[0.15 lb/MMBtu allowed in permit] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/yr operation] x [1 ton per 2000 lbs]
Sulfuric acid	22 tons/yr	[0.0035 lb/MMBtu allowed in permit] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/yr operation] x [1 ton per 2000 lbs]
Volatile organic compounds	32 tons/yr	[0.005 lb/MMBtu by boiler design] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/yr operation] x [1 ton per 2000 lbs]
Particulate matter from coal, ash and limestone handling	18 tons/yr	AP-42 emission factors for coal, ash and limestone handling, and taking into account compaction of stockpiles, watering, enclosed conveyors, baghouses, vent filters, and other emission controls proposed by Deseret Power.

2. Uncontrolled

Pollutant	Estimated emissions	Basis of estimate
Particulate matter (filterable) from CFB boiler	632,900 tons/yr	[0.66 lb total ash per lb of waste coal burned] x [0.8 lb fly ash per lb of total ash] x [projected coal consumption of 1.2 million tons/year for "average" waste coal]
Particulate matter (condensible) from CFB boiler	317 tons/yr	[0.0501 lb/MMBtu estimated by boiler supplier, based on boiler design and combustion of "average" waste coal] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/yr operation] x [1 ton per 2000 lbs]
Sulfur dioxide	10,823 tons/yr	[1.71 lb/MMBtu uncontrolled SO_2 emission potential for "average" waste coal] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/year operation] x [1 ton per 2000 lbs]
Nitrogen oxide	949 tons/yr	[0.15 lb/MMBtu estimated by boiler supplier, based on boiler design and combustion of "average" waste coal] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/year operation] x [1 ton per 2000 lbs]
Carbon monoxide	949 tons/yr	[0.15 lb/MMBtu estimated by boiler supplier, based on boiler design and combustion of "average" waste coal] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/year operation] x [1 ton per 2000 lbs]
Sulfuric acid	165 tons/yr	[1.71 lb/MMBtu uncontrolled SO_2 emission potential for "average" coal] x [1% of sulfur content emitted as H_2SO_4] x [98 lb H_2SO_4 per 64 lb SO_2] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/year operation] x [1 ton per 2000 lbs]

Volatile organic compounds	32 tons/yr	[0.005 lb/MMBtu estimated by boiler supplier, based on boiler design and combustion of "average" waste coal] x [1445 MMBtu/hr boiler heat input capacity] x [8760 hrs/year operation] x [1 ton per 2000 lbs]
Particulate matter from coal, ash and limestone handling	83 tons/yr	AP-42 emission factors

J. Proposed Emission Monitoring Techniques

1. CFB boiler: Filterable PM emissions will be monitored continuously by a particulate matter continuous emission monitoring system (PM CEMS). Condensible PM emissions will be monitored by annual EPA Method 202 or EPA Conditional Test Method 39 stack tests. H_2SO_4 emissions will be monitored by annual EPA Method 8 or NCASI Method 8A stack tests. (Note: NCASI Method 8A is not an EPA Method, but is published by the National Council on Air and Stream Improvement, Inc., December 1996 It is available on NCASI website at http://www.ncasi.org. An explanation of why EPA is allowing it as an alternative to EPA Method 8 may be found in section VI.L.7 of this Statement of Basis.)

SO_2, NO_x and CO emissions will be monitored continuously by SO_2, NO_x and CO continuous emission monitoring systems (CEMS). A diluent continuous monitoring system will be required for converting CEMS data into units of lb/MMBtu. All CEMS will be required to pass the applicable Performance Specification Tests in 40 CFR part 60, Appendix B, and comply with ongoing quality assurance requirements in 40 CFR part 60, Appendix F.

2. Emergency generator: Monitoring for nitrogen oxide, carbon monoxide and particulate emissions will consist of: (1) records demonstrating that the emergency generator engine is purchased from a manufacturer who has obtained a "certificate of conformity" from EPA, certifying that the engine is compliant with the "Tier 2" emission standards for PM_{10}, NO_x and CO in 40 CFR 89.112, Table 1, for engines with electrical generating capacity greater than 560 kilowatts, and (2) records demonstrating that the engine manufacturer's recommendations are being followed for compliance with the "Tier 2" standards. Monitoring for SO_2 emissions will consist of records verifying that only diesel fuel with sulfur content of less than 0.05 percent by weight is used.

3. Materials handling system baghouses: PM/PM_{10} emissions will be monitored by initial stack testing at the largest (15,000 dry standard cubic feet per minute, "dscfm") baghouse, one of the two 8,500 dscfm baghouses, and one of the smaller baghouses (the 4,000 dscfm baghouse). If stack test results at the first 8,500 dscfm baghouse are in excess of the allowable emission limit, then the second 8,500 dscfm baghouse will be required to be

tested. If stack test results at the 4,000 dscfm baghouse are in excess of the allowable emission limit, then the remaining 3 baghouses will be required to be tested.

After initial testing, in lieu of subsequent annual tests (if test results are in compliance), EPA proposes to require monthly opacity monitoring at each baghouse exhaust stack via EPA Method 22. If a Method 22 opacity observation detects any visible emissions, then: (1) a EPA Method 9 opacity observation will be required, to establish whether the emissions are in excess of the 10% opacity limit, and (2) the cause of the visible emissions will be required to be investigated and, if caused by a baghouse malfunction, will be required to be corrected within three working days, if the cause of the malfunction is broken bags, or within seven working days for any other cause.

4. <u>Non-point source (i.e., fugitive) PM/PM_{10} emissions</u>: Monitoring will consist of records demonstrating that water sprays and/or surfactant are applied "as warranted" for adequate dust control at the coal and limestone stockpiles. "As warranted" is defined in the permit as dust control sufficient to keep visible emissions at the stockpiles below ten percent opacity. Weekly observations for any visible emissions will be required.

V. Description of this Permitting Action

A. Purpose.

The purpose of this permit action is to approve construction of a new 110 megawatt electric utility unit at Deseret Power's existing Bonanza power plant, known as the Waste Coal Fired Unit (WCFU). Steam for generating electricity will be provided by a Circulating Fluidized Bed (CFB) boiler, rated at no more than 1,445 MMBtu/hr heat input capacity, fueled by waste coal from the nearby Deserado Mine. As explained earlier, emission controls for the CFB boiler will include a fabric filter baghouse for filterable PM/PM_{10} control, limestone injection and dry scrubber (spray dry absorber) for SO_2 and H_2SO_4 control, Selective Non-Catalytic Reduction (SNCR) for NO_x control, a combustion control system for CO control, and a combination of limestone injection, dry scrubber and fabric filter baghouse for condensible PM control.

Also permitted for construction will be coal, limestone and ash handling systems for the WCFU. Emission controls for point source PM/PM_{10} emissions from the materials handling systems will include enclosed conveyers, along with fabric filter baghouses and vent filters at material transfer points. Emission controls for non-point source (i.e., fugitive) emissions will consist of compaction of material stockpiles, minimizing the working area of the stockpile, and application of surfactant and water sprays as warranted.

B. PSD Applicability.

40 CFR 52.21(a)(2)(iii) provides: "No new major stationary source or major modification to which the requirements of paragraphs (j) through (r)(5) of this section apply shall begin actual construction without a permit that states that the major stationary source or major modification will meet those requirements. The Administrator has authority to issue any such permit." As explained in sections I and II of this Statement of Basis, EPA has determined that the WCFU project will constitute a major modification to an existing PSD major stationary source (Bonanza power plant), and therefore is subject to PSD permitting. The WCFU project will result in significant emission increases at Bonanza plant for the following PSD-listed pollutants: total PM, PM_{10}, SO_2, NO_x, H_2SO_4 and CO.

C. Application Submittals and Addendums.

The initial PSD permit application was submitted by Deseret Power via cover letter dated April 13, 2004. The application was revised and resubmitted on November 1, 2004. Further revisions were submitted via letters and e-mails on the following dates:

- March 23, 2005: Letter and attachments from Deseret Power to EPA modified the permit modeling, in response to EPA's November 22 and December 29, 2004 letters. Deseret also corrected the coordinates of the stack.

- March 23, 2005: Letter from Deseret Power to U.S. Forest Service modified the permit modeling.

- May 4, 2005: E-mail from Deseret Power to EPA agreed to installation of a dry scrubber for additional sulfur dioxide control and reduced the proposed SO_2 BACT emission limit from 0.10 lb/MMBtu to 0.055 lb/MMBtu.

- May 10, 2005: Letter from Deseret Power to EPA reduced the proposed NO_x BACT emission limit to 0.088 lb/MMBtu.

- May 10, 2005: Letter from Deseret Power to EPA proposed alternative BACT emission limits in pounds per hour for startup/shutdown periods.

- May 10, 2005: Letter from Deseret Power to EPA agreed to install a particulate matter continuous emission monitoring system (PM CEMS).

- May 10, 2005: Letter from Deseret Power to EPA committed to comply with the recently released mercury emission limits and install a mercury CEMS. (EPA later replied to Deseret on June 13, 2005 that electric utilities have been delisted from MACT rulemaking and therefore a case-specific MACT determination for mercury will not be required. Deseret Power will, however, be required to comply with mercury emission limits recently established in 40 CFR 60, subpart Da.)

- May 10, 2005: Letter from Deseret Power to EPA clarified (at EPA's request) the reference in Deseret's permit application to the NSPS emission standard for total filterable particulate matter, with regard to averaging time of the standard.

- May 10, 2005: Letter from Deseret Power to EPA provided a revised Section 7, Miscellaneous Permit Information, for the permit application. Specifically, the information pertained to potential impact of the WCFU project on endangered species.

- June 16, 2005: E-mail from Deseret Power to EPA increased the amount of anticipated ammonia slip, due to the lower NO_x and SO_2 emission limits now being proposed by Deseret Power (0.088 lb/MMBtu for NO_x and 0.055 lb/MMBtu for SO_2).

- October 17, 2005: E-mail from Deseret Power to EPA amended the BACT analysis for the Emergency Diesel Generator, contained in Sections 5.9 through 5.13 of the permit application, and provided revised predicted emissions for the Emergency Diesel Generator.

- November 11, 2005: E-mail from Deseret Power to EPA proposed BACT for PM/PM_{10} emissions at the cooling tower. Cost calculations were provided via followup e-mail to EPA on December 13, 2005.

- January 9, 2006: E-mail from Deseret Power to EPA proposed a calculated emission limit as BACT for SO_2 instead of the 0.040 lb/MMBtu limit that EPA proposed to Deseret on December 1, 2005, as the 'lower tier' limit (i.e., when uncontrolled SO_2 emission potential of the coal drops below 1.9 lb/MMBtu on a 30-day average). The calculated limit would be a weighted average between the upper and lower tiers proposed earlier by EPA (0.055 and 0.040).

- January 13, 2006: E-mail from Deseret Power to EPA, in response to verbal request from EPA, provided an expanded description of waste coal characteristics.

- January 13, 2006: E-mail from Deseret Power to EPA, in response to verbal request from EPA, suggested permit language corresponding to Deseret's weighted average SO_2 BACT proposal of January 9, 2006.

- January 30, 2006: E-mail from Deseret Power to EPA provided a revised estimate of condensible particulate matter emissions (0.033 lb/MMBtu) and proposed a revised BACT emission limit for total PM_{10} of 0.045 lb/MMBtu, rather than the 0.052 lb/MMBtu originally proposed by Deseret.

- February 2, 2006: E-mail from Deseret Power to EPA, in response to verbal request from EPA, provided a description of boiler operational changes and materials handling changes that would likely be necessary, if run-of-mine coal was to be burned as primary fuel instead of waste coal.

- February 7 and 8, 2006: E-mails from Deseret Power to EPA, in response to verbal request from EPA, provided additional information in support of Deseret's proposed BACT emission limit of 0.15 lb/MMBtu (30-day rolling average) for CO.

- February 21, 2006: E-mail from Deseret Power to EPA proposes PSD BACT emission limit of 0.0038 lb/MMBtu on a 30-day rolling average for sulfuric acid (H_2SO_4), on the basis that 0.0038 is the lowest detectable limit when using NCASI Method 8A.

- February 22, 2006: E-mail from Deseret Power to EPA provides supporting information requested by EPA for Deseret's estimate of 0.033 lb/MMBtu for condensible particulate matter emissions.

- February 23, 2006: E-mail from Deseret Power to EPA provides top-down BACT analysis requested by EPA for control options for condensible particulate matter emissions.

- April 10, 2006: E-mail from Deseret Power to EPA confirms that Deseret Power wants operational flexibility to blend run-of-mine coal with the waste coal at any time, if needed, at up to a 50/50 ratio by weight, equivalent to about 6500 Btu/lb heat content coal.

- April 25, 2006: E-mail from Deseret Power to EPA provides an estimate of potential uncontrolled fugitive particulate emissions from coal, ash and limestone handling, based on AP-42 emission factors.

- April 5, 2007: E-mail from Deseret Power to EPA, regarding Endangered Species Act section 7 consultation, requests that a prior e-mail from Deseret Power to EPA, dated December 8, 2006, be incorporated as part of the PSD permit application for the 110-MW WCFU project. The prior e-mail said:

  1. Deseret agrees that it will provide to the USFWS, on an annual basis, the amount of water withdrawn from the Green River for Deseret's 110-MW WCFU project, once the project is built and operating.

  2. Deseret agrees to notify EPA and USFWS the date when construction of the 110-MW WCFU project commences.

- April 5, 2007: E-mail from Deseret Power to EPA, regarding Endangered Species Act section 7 consultation, requests that a prior e-mail from Deseret Power to EPA, dated December 4, 2006, be incorporated as part of the PSD permit application for the 110-MW WCFU project. The Dec. 4, 2006 e-mail said Deseret will commit to paying the final 90% of the water depletion fee, for withdrawing water from the Green River for the 110-MW WCFU, when construction commences on the WCFU, rather than just prior to any water being withdrawn from the Green River. (The first 10% of the fee is due when the EPA PSD permit is issued.)

VI. **Best Available Control Technology Analysis**

A. Approach Used in BACT Analysis

Pursuant to 40 CFR 52.21(j), a new major stationary source shall apply BACT for each pollutant subject to regulation under the Clean Air Act (CAA) that it would have the potential to emit in significant amounts. A major modification shall apply BACT for each pollutant subject to regulation under the CAA for which it would result in a significant net emissions increase at the source. The requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit. The definition of BACT at §52.21(b)(12) states, in part, that BACT means:

… an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the Clean Air] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement technology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology.

The 1990 Clean Air Act amendments added "clean fuels" after "fuel cleaning or treatment" in the above definition.

On December 1, 1987, EPA issued a memorandum defining the top-down approach for determining BACT. In brief, the top-down approach provides that all available control technologies be ranked in descending order of control effectiveness. Each alternative is then evaluated, starting with the most stringent, until BACT is determined. The top-down approach consists of the following steps, for each pollutant to which BACT applies:

Step 1: Identify all control technologies.

Step 2: Evaluate technical feasibility of options from Step 1 and eliminate technically infeasible options, based on physical, chemical and engineering principles.

Step 3: Rank remaining control technologies from Step 2 by control effectiveness, in terms of emission reduction potential.

Step 4: Evaluate most effective controls from Step 3, considering economic, environmental and energy impacts of each control option. If top option is not selected, evaluate the next most effective control option.

Step 5: Select BACT (most effective option from Step 4 not rejected)

B. PSD BACT Emission Limits Apply at All Times.

EPA's interpretation of the CAA, and of the PSD rules in 40 CFR parts 51 and 52, is that PSD BACT emission limits must apply at all times. Automatic exemptions from PSD BACT emission limits cannot be allowed for periods of startup, shutdown, malfunctions, or for any other reason. The following EPA memoranda have consistently made this clear:

September 28, 1982 memorandum from Kathleen Bennett, EPA Assistant Administrator for Air, Noise and Radiation, to EPA Regional Offices, titled "Policy on Excess Emissions During Startup, Shutdown, Maintenance and Malfunctions."

February 15, 1983 memorandum from Kathleen Bennett to EPA Regional Offices, same title as above.

January 28, 1993 memorandum from John Rasnic of EPA's Office of Air Quality Planning and Standards (OAQPS) to Linda Murphy of EPA Region I.

September 20, 1999 memorandum from Steve Herman and Robert Perciasepe, EPA Assistant Administrators, to EPA Regional Offices, titled "State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown."

In particular, the 1993 memorandum states that PSD permits cannot contain automatic exemptions which allow excess emissions during startup and shutdown. The 1982 memorandum states the same for malfunctions. These memoranda are available on EPA's NSR Policy and Guidance database, at the following website:

http://www.epa.gov/region07/programs/artd/air/nsr/nsrpg.htm

C. Pollutants Subject to BACT for this Project

For major modifications to existing major stationary sources, 40 CFR 52.21(j)(3) requires that BACT be applied for each regulated NSR pollutant for which there will be a significant net emission increase at the source. The requirement applies to each proposed emitting unit at which a net emissions increase in the pollutant would occur as a result of the physical change or change in the method of operation of the unit. As detailed in Deseret Power's PSD permit application dated November 1, 2004, the WCFU project will result in significant net emission increases from the Bonanza power plant for the following regulated NSR pollutants:

- particulate matter (PM),
- particulate matter smaller than 10 microns (PM_{10}),
- sulfur dioxide (SO_2),
- nitrogen oxide (NO_x),
- sulfuric acid (H_2SO_4), and
- carbon monoxide (CO).

A BACT analysis for each of these pollutants is presented later in this Statement of Basis. Since potential uncontrolled emissions of volatile organic compounds (VOC) from the WCFU project are estimated at 32 tons per year, less than the PSD significance threshold, no BACT analysis for VOC is required.

The definition of "regulated NSR pollutant" in 40 CFR 52.21(b)(5) includes "any pollutant for which a national ambient air quality standard [NAAQS] has been promulgated." On July 18, 1997, EPA promulgated the NAAQS for particulate matter with aerodynamic diameter smaller than 2.5 microns ($PM_{2.5}$).

Consistent with the October 23, 1997 memorandum titled, "Interim Implementation of New Source Review Requirements for PM2.5," issued by John Seitz, Director of EPA's Office of Air Quality Planning & Standards (OAQPS), and consistent with the April 5, 2005 memorandum titled, "Implementation of New Source Review Requirements in PM2.5 Nonattainment Areas," issued by Stephen D. Page, Director of OAQPS, and consistent with the November 1, 2005, Federal Register notice on the proposed implementation rule for the PM2.5 NAAQS (70 FR 66044.), in which EPA recommends that PM_{10} be used as a surrogate for PM2.5, EPA considers all permit limits and analyses in this Statement of Basis that pertain to PM_{10} to also satisfy the requirements for PM2.5 at Deseret Power's proposed WCFU project.

The aforementioned memoranda are available on EPA website:

Oct. 1997 memo: http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/pm25.pdf

Apr. 2005 memo: http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/pmguid25.pdf

D. Alternative Coal (Clean Fuels) for BACT

Under the Clean Air Act definition of BACT, the permitting authority must consider "clean fuels" when making a BACT determination. From the discussion in section IV.F of this Statement of Basis, on operational changes that would be necessary at the WCFU to accommodate coal other than waste coal as primary fuel, EPA believes the WCFU could accommodate alternative coal as primary fuel without a basic redesign of the WCFU project. EPA therefore believes that consideration of alternative coal as "clean fuel" is within the scope of a BACT analysis for this project. The following analysis leads EPA to conclude that use of alternative coal (i.e., coal other than waste coal) from the Deserado mine would be economically cost-prohibitive as a BACT option, and that use of alternative coal from other mines would also be cost-prohibitive as a BACT option, in terms of economic, energy and environmental costs.

1. Alternative coal from Deserado mine. The following is an incremental cost analysis to determine if use of alternative coal from the Deserado mine, rather than waste coal, would be cost-prohibitive for BACT. All figures used below are considered conservative by EPA, yielding the lowest dollar-per-ton cost to switch to alternative coal. The alternative coal would be either ROM coal or washed coal. Since the washed coal is generated specifically for use at existing Bonanza Unit 1, and is more expensive than ROM coal because it must be processed through a wash plant, this analysis will focus on the lower-cost ROM coal as the alternative coal.

As explained earlier in this Statement of Basis, ROM coal is raw mined coal that has not been processed through the wash plant. The ROM coal characteristics discussed in this analysis are those of the coal currently being mined, not the ROM coal that might be used 12 to 16 years from now, after the waste coal stockpile is depleted. As discussed in section IV.E of this Statement of Basis, based on core samples from the coal seam reserve at the Deserado mine, future mined coal is expected by Deseret Power to have as much as double the sulfur content of currently mined coal.

The only significant physical difference between the waste coal and the currently mined ROM coal that EPA or Deseret Power is aware of, as far as the effect on emission rate in lb/MMBtu, is the difference in heating value. Deseret Power states that heating value of the current ROM coal ranges from 8,500 to 10,000 Btu/lb. For the sake of this analysis, EPA will use 9,250 Btu/lb. Deseret states that "average" waste coal stockpiled at the Deserado mine has heating value of about 4,000 Btu/lb.

Regarding cost of the coal, Deseret Power states that the waste coal is approximately $5 per ton delivered, which includes cost to reclaim the coal at the mine, transport it to the power plant, and any associated taxes. ROM coal would have to be purchased from the mine operator at $35 to $40 per ton. For the sake of this analysis, EPA will use a conservative (i.e., lower end) estimate of $35 per ton to purchase and deliver ROM coal.

Deseret Power has stated that the WCFU would use about 1.2 million tons of waste coal per year. Based on the relative heating values of ROM coal versus waste coal mentioned above, EPA calculates that about 519,000 tons of ROM coal would be need to be combusted per year, to achieve equivalent annual boiler heat output as combustion of 1.2 million tons of waste coal per year. Therefore, for sake of this analysis, EPA estimates that a switch entirely to ROM coal for the WCFU would involve the following coal purchase cost for the ROM coal:

$35/ton x 519,000 tons/year = $18,165,000/year.

The annual cost of using the waste coal would be:

$5/ton x 1,200,000 tons/year = $6,000,000/year

(Note: The draft Statement of Basis indicated $5/ton x 1,200,000 tons/year = $3,405,000. This was an inadvertent mathematical error.) The incremental cost to use entirely ROM coal rather than waste coal would therefore be the difference in cost of the two coals, which is $12,165,000/year.

Regarding potential emission reductions in lb/MMBtu that might result from a switch entirely from waste coal to ROM coal, EPA estimates the following:

NO_x: EPA is proposing 0.080 lb/MMBtu on a 30-day average as BACT for the WCFU (after a 15-month "break-in" period), based on combustion of waste coal. EPA believes the emissions might be reduced down to 0.07 lb/MMBtu on currently mined ROM coal. This estimated reduction is based on the higher heat content of ROM coal versus waste coal, and on 0.07 lb/MMBtu being the lowest BACT determination in the RACT/BACT/LAER Clearing-house database, and the lowest BACT determination EPA is aware of anywhere, for a CFB boiler project. (See NO_x BACT discussion later in this Statement of Basis.) A reduction down to 0.07 lb/MMBtu would be equivalent to a NO_x reduction of about 63 tons/yr, assuming the WCFU runs at design heat input capacity all year.

SO_2: EPA is proposing a "lower tier" emission limit of 0.040 lb/MMBtu on a 30-day average as BACT for the WCFU, based on combustion of "average" waste coal. EPA believes the emissions might be reduced down to about 0.022 lb/MMBtu on currently mined ROM coal. This estimated SO_2 reduction is based on an uncontrolled SO_2 emission potential of 0.734 lb/MMBtu for currently mined ROM coal (which takes into account the higher heat content of ROM coal versus waste coal), and on an estimated SO_2 control efficiency of 97%. (The figure of 0.022 lb/MMBtu is also the lowest BACT determination in the RACT/BACT/LAER Clearing-house database, and the lowest BACT determination EPA is aware of anywhere, for a CFB boiler project. See SO_2 BACT discussion later in this Statement of Basis.) A reduction down to 0.022 lb/MMBtu would be equivalent to a SO_2 reduction of about 114 tons/yr, assuming the WCFU runs at design heat input capacity all year.

CO: EPA is proposing 0.15 lb/MMBtu on a 30-day average as BACT for the WCFU, based on combustion of waste coal. EPA believes the emissions might be reduced down to about 0.10 lb/MMBtu on currently mined ROM coal. This estimated reduction is based on the higher heat content of ROM coal versus waste coal, and on 0.10 lb/MMBtu being the lowest BACT determination in the RACT/BACT/LAER Clearinghouse database, and the lowest BACT determination EPA is aware of anywhere, for a CFB boiler project, excluding projects that will not be constructed. (See CO BACT discussion later in this Statement of Basis.) A reduction down to 0.10 lb/MMBtu would be equivalent to a CO reduction of about 316 tons/yr, assuming the WCFU runs at design heat input capacity all year.

Sulfuric acid (H_2SO_4): EPA is proposing 0.0035 lb/MMBtu on a 3-run stack test average (equivalent to roughly a 3-hour average) as BACT for the WCFU, based on combustion of waste coal. EPA believes the emissions might be reduced down to about 0.0024 lb/MMBtu on currently mined ROM coal. This estimated reduction is based on the higher heat content of ROM coal versus waste coal, and on 0.0024 lb/MMBtu being the lowest BACT determination in the RACT/BACT/LAER Clearing-house database, and the lowest BACT determination EPA is aware of anywhere, for a CFB boiler project. (See H_2SO_4 BACT discussion later in this Statement of Basis.) A reduction down to 0.0024 lb/MMBtu would be equivalent to a reduction of about 7 tons/yr, assuming the WCFU runs at design heat input capacity all year.

Filterable particulate matter: For the filterable portion of total PM, EPA is proposing 0.012 lb/MMBtu on a 30-day average as BACT for the WCFU, based on combustion of waste coal. EPA believes the emissions might be reduced down to about 0.010 lb/MMBtu on currently mined ROM coal. This estimated reduction is based on the higher heat content of ROM coal versus waste coal, and on 0.010 lb/MMBtu being the lowest BACT determination in the RACT/BACT/LAER Clearinghouse database, and the lowest BACT determination EPA is aware of anywhere, for a CFB boiler project. (See BACT discussion for filterable PM later in this Statement of Basis.) A reduction down to 0.010 lb/MMBtu would be equivalent to a reduction of about 13 tons/yr, assuming the WCFU runs at design heat input capacity all year.

Condensible particulate matter: For the condensible portion of PM, EPA has estimated emissions of 0.019 lb/MMBtu for the WCFU, based on combustion of waste coal. (See BACT discussion for condensible PM later in this Statement of Basis.) The limits of control for condensible PM are not very well known. (See BACT discussion for condensible PM later in this Statement of Basis.) For the sake of this alternative coal analysis, EPA will assume this estimate might be reduced down to 0.005 lb/MMBtu on currently mined ROM coal., which is the condensible portion of the total PM/PM_{10} emission limit in the recent Utah permit for the Sevier Power Company CFB boiler project. A reduction down to 0.005 lb/MMBtu would be equivalent to a reduction of about 88 tons/yr, assuming the WCFU runs at design heat input capacity all year.

The estimates above lead to the following cost estimates, in dollars per ton of additional pollutant removed annually, to use ROM coal rather than waste coal as primary fuel for the WCFU.

Annualized Cost of Potential Emission Reductions If Run-Of-Mine Coal is Used Rather Than Waste Coal for Deseret Power's Proposed WCFU

Pollutant	Potential Emission Reduction (Currently Mined "Run of Mine" Coal versus Waste Coal)	Annualized Cost ($/ton)
NO_x	63 tons/yr	$ 193,095/ton
SO_2	114 tons/yr	$ 106,710/ton
CO	316 tons/yr	$ 38,496/ton
H_2SO_4	7 tons/yr	$1,737,857/ton
Filterable PM	13 tons/yr	$ 935,769/ton
Condensible PM	88 tons/yr	$ 138,238/ton
All (sum)	601 tons/yr	$ 20,241/ton

From the cost estimates above, EPA concludes that use of currently mined "run-of-mine" (ROM) coal at the Deserado mine, i.e., raw coal that has not been washed, rather than waste coal from the Deserado mine, would be cost-prohibitive as a BACT option for the proposed WCFU, even if reductions of all pollutants are summed together and then the annualized cost in dollars-per-ton for emission reduction is calculated on that basis. (As shown above, summing the pollutants yields $20,241/ton, which is a lower dollar-per-ton cost than looking at any one pollutant individually.) The same annualized dollar-per-ton costs would be incurred if there was only a partial switch to ROM coal (i.e., coal blending). This is because a partial switch yields only partial emission reductions. This option (i.e., use of alternative coal from the Deserado mine, either partially or entirely in place of waste coal) is therefore eliminated as a BACT option.

As stated earlier in this Statement of Basis, Deseret Power has requested operational flexibility, in the EPA permit, to blend ROM coal in with the waste coal, at up to a 50/50 ratio by weight, as needed at any time, such as in the event of operational difficulties arising from use of waste coal as sole fuel, or in the event of unexpected difficulties in meeting BACT emission limits. Although EPA finds that use of ROM coal in place of waste coal would be cost-prohibitive for BACT, and Deseret Power is not proposing to blend ROM coal with waste coal except for the contingency situations described immediately above, EPA believes that the BACT emission limits in the permit are sufficiently stringent to represent BACT at up to a 50/50 blend ratio.

2. Alternative coal from other mines. The following analysis supplements the analysis of alternative coals in the draft Statement of Basis, to explain more fully, in terms of cost per ton of additional pollutant removed from the atmosphere, why use of coal from any mine in the region other than the Deserado mine, rather than use of waste coal from the Deserado mine, would be cost-prohibitive as a BACT option. In presenting this analysis, EPA is not taking a position on whether the use of a coal supply other than the one proposed by the applicant must be evaluated in the BACT analysis for the WCFU or similarly situated facilities.

After EPA issued the draft permit for the WCFU, the EPA Environmental Appeals Board issued its opinion in *In re: Prairie State Generating Company*, PSD Appeal No. 05-05 (Aug. 24, 2006). This opinion established that there may be circumstances under which the permitting authority has the discretion not to list alternative coal supplies as an option at Step 1 of the BACT analysis, because such an option could fundamentally redefine the source.

However, we need not address whether this permit presents a similar circumstance, since the draft Statement of Basis included the use of a cleaner coal as an option and evaluated the economic impact of requiring the applicant to use exclusively mined coal from the Deserado mine rather than waste coal, or alternatively, exclusively mined coal from other mines rather than waste coal. (Draft Statement of Basis at pages 25-29.) Since EPA already started down this path of looking at other coal supplies for this permitted project, EPA has supplemented its analysis, in response to public comments on the draft Statement of Basis, to further illustrate why it is appropriate to eliminate this option for this permit.

Similar to the approach used above for evaluating use of alternative coal at the Deserado mine as a BACT option, the first step in evaluating use of coal from an alternative mine as a BACT option is to determine what a coal switch would cost, per ton of coal delivered. EPA asked Deseret Power to provide an estimate of what the total cost would be, per ton of coal delivered, to have coal supplied to the WCFU from mines in the region other than the Deserado mine. EPA asked that the estimate be for the least total cost scenario of the various other mines that could potentially supply coal. EPA further asked for a breakdown of mine-mouth ("Free-On-Board") cost plus transportation cost. (Ref: November 14, 2006 e-mail from Mike Owens, EPA Region 8, to Ed Thatcher, Deseret Power, included in the Administrative Record for issuance of the final Deseret WCFU permit.)

Deseret Power responded that its letter to EPA dated May 10, 2005, at page 5, provided a cost estimate for coal purchased on the open market and delivered to the WCFU unit. The estimated cost for the coal at that time was \$40 to \$45 per ton delivered, which included the estimated delivery charge of \$15 per ton. The FOB mine cost for the coal was estimated to be \$25 to \$30 per ton at that time. According to the November 13, 2006 issue of Coal Outlook (copy attached to Deseret Power's November 15, 2006 e-mail cited below), the FOB mine cost for coal in Utah has increased to \$37.75 per ton for current purchases of coal.

As mentioned in the draft Statement of Basis, the Bonanza plant is approximately 75 miles from the nearest rail transportation and approximately 100 miles by truck from the nearest alternative source of coal. The cost to construct a rail line to connect to the interstate rail system has been estimated by Deseret Power to exceed $300 million. (EPA has eliminated this option as too expensive.) The cost to truck the coal from the nearest alternative coal source (i.e., other than the Deserado mine) was estimated by Deseret Power to be at least $15/ton. (Ref: Sept. 13, 2005 letter from Deseret Power to EPA, page 3, footnote 1, included in the Administrative Record for issuance of the draft Deseret WCFU permit.)

In more recent correspondence to EPA, Deseret Power stated that it believes the delivery cost to haul the coal from the nearest alternative mines to the Bonanza plant site would still be about $15 per ton. Therefore, the current delivered cost would be $37.75 plus $15.00, or about $52.75 per ton delivered. (Ref: November 15, 2006 e-mail from Ed Thatcher, Deseret Power, to Mike Owens, EPA Region 8, included in the Administrative Record for issuance of the final Deseret WCFU permit.) Being the cost from the nearest alternative mines, this 'cheapest delivered' cost is a conservative estimate, i.e., yielding the lowest calculated BACT cost to switch to coal from a mine other than the Deserado mine.

The next step in the analysis is to determine the annual cost of switching from Deserado waste coal to alternative coal from another mine. This requires a determination of how much alternative coal is necessary to achieve the equivalent annual boiler heat output as combustion of 1.2 million tons of waste coal per year, which is Deseret Power's projected waste coal usage rate. To make this determination, it is necessary to know the estimated heat content of the alternative coal. The CFB boiler project cited by commenters, Sevier Power Company, would use coal with an estimated heat content range of 10,200 to 12,000 Btu/lb, with average heat content of 11,390 Btu/lb. (Ref: "New Source Plan Review" by Utah Division of Air Quality, dated December 23, 2003, for the Sevier Power Company project, page 13, Table I-2, available online at http://www.airquality.utah.gov/Permits/PmtPowerPlants.htm.)

Rather than rely just on the Sevier project cited by commenters for an estimate of the heat content of available coals in the region, EPA also examined a recent Utah Geological Survey (UGS) report, which lists heat content of coal at Utah mines ranging from 11,243 Btu/lb to 13,052 Btu/lb. (Ref: "Annual Review and Forecast of Utah Coal, Production and Distribution - 2005," published August 2006 by Utah Geological Survey, Open-File Report 481, Table A8: "Average Coal Quality at Utah Mines, 2005." Report available online at http://ugs.utah.gov/online/ofr.ofr-481.pdf.) For the sake of this analysis, EPA will use the upper end of this range (13,052 Btu/lb) as a conservative assumption, i.e., yielding the lowest calculated BACT cost to switch to alternative coal.

Since Deseret Power's waste coal has an average heat content of about 4,000 Btu/lb, EPA calculates that it would require about 367,760 tons per year of alternative coal rated at 13,052 Btu/lb heat content, to achieve the equivalent annual WCFU boiler heat output as combustion of 1.2 million tons per year of waste coal. The coal purchase cost of the alternative coal would therefore be:

$52.75/ton x 367,760 tons/year = $19,400,000/year.

EPA stated in the draft Statement of Basis that the cost of waste coal would be about $5 per ton delivered. The annual cost of using the waste coal would be:

$5/ton x 1,200,000 tons/year = $6,000,000/year.

The incremental cost to use entirely alternative coal from another mine in the region, rather than waste coal from the Deserado mine, would therefore be the difference in cost of the two coals, which is $13,400,000/year.

The next step in the analysis is to determine the potential annual emission reductions that could be achieved by switching from waste coal to alternative coal from another mine. In the draft Statement of Basis, EPA presented its calculation of the reductions that could be achieved for each PSD pollutant, if emissions are reduced from the proposed WCFU permit allowables down to the lowest BACT determination EPA is aware of anywhere for a CFB boiler project (including the Sevier Power Company project cited by commenters). For condensible PM, EPA has since revised its estimate of lowest achievable emission rate down to 0.005 lb/MMBtu, to correspond to the condensible portion of the BACT emission limit for total PM/PM_{10} in the Utah permit for the Sevier Power Company project.

Potential Emission Reductions Due to a Switch From Waste Coal to Alternative Coal from Another Mine For Deseret Power's Proposed WCFU

Pollutant	Proposed Emission Limit for WCFU (lb/MMBtu)	Lowest BACT Determination Anywhere for a CFB Boiler Project (lb/MMBtu)	Equivalent Annual Reduction (tons/year)
NO_x	0.080	0.07	63
SO_2	0.040	0.022	114
CO	0.15	0.10	316
H_2SO_4	0.0035	0.0024	7
Filterable PM	0.012	0.010	13
Condensible PM	0.019	0.005	88

FOOTNOTE #1: The Sevier Power Company project cited by commenters is permitted at 0.1 lb/MMBtu for NOx, 0.022 lb/MMBtu for SO2, 0.115 lb/MMBtu for CO, 0.0024 lb/MMBtu for H2SO4, and 0.015 lb/MMBtu. "Lowest BACT Determination" values listed above are at least as low.

FOOTNOTE #2: The proposed WCFU permit has no separate BACT emission limit for condensibles. The figure of 0.019 lb/MMBtu above is an estimate based on best information available to EPA and the proposed emission controls for the WCFU, as described in the draft Statement of Basis.

EPA believes it is unlikely that lower emissions than listed above could be achieved on any coal in the Region. As explained in Footnote #1 above, the figures listed as "Lowest BACT Determination Anywhere for a CFB Boiler Project" are at least as low as the BACT determination for each pollutant at the Sevier project cited by commenters. Further, based on "Average Coal Quality at Utah Mines, 2005," listed in the afore-mentioned UGS report, it appears to EPA that the proposed coal for the Sevier project is at least as clean, in terms of ash content and sulfur content, as any other coals in the region. The lowest ash content of the coals listed in Table A8 of the UGS report is 8.5%. The ash content of the proposed coal for the Sevier project is lower, at 8.3%. The lowest sulfur content of the coals listed in Table A8 of the UGS report is 0.4%. The sulfur content of the proposed coal for the Sevier project is at least as low, at 0.40%. (Ref: Table A8 of the aforementioned UGS report; Table I-2 of the aforementioned "New Source Plan Review" for the Sevier project.)

The calculated cost and corresponding emission reductions described above lead to the following cost estimates, in dollars per ton of additional pollutant removed annually, to use alternative coal from another mine in the region, rather than waste coal from the Deserado mine:

Annualized Cost of Potential Emission Reductions
Due to a Switch from Waste Coal at the Deserado Mine
to Alternative Coal from Another Mine
for Deseret Power's Proposed WCFU

Pollutant	Potential Emission Reduction (Alternative Coal versus Waste Coal)	Cost ($/ton)
NO_x	63 tons/yr	$ 212,698/ton
SO_2	114 tons/yr	$ 117,543/ton
CO	316 tons/yr	$ 42,405/ton
H_2SO_4	7 tons/yr	$1,914,285/ton
Filterable PM	13 tons/yr	$1,030,769/ton
Condensible PM	88 tons/yr	$ 152,272/ton
All (sum)	651 tons/yr	$ 20,583/ton

As mentioned in the draft Statement of Basis's discussion of alternative coal from other mines, there would also be substantial energy and environmental costs associated with obtaining coal from a mine other than the Deserado mine, due to the large number of truck trips to deliver the coal (more than 20 per day, assuming 50 tons payload per truck), at 200 miles round trip per load. The substantial energy expenditure in terms of diesel fuel, the amount of pollution from truck exhaust, and the increased traffic hazard on public highways, all make this option even more cost-prohibitive.

Based on the analysis above, EPA concludes that use of alternative coal from any other mine in the region, rather than waste coal from the Deserado mine, would be cost-prohibitive as a

BACT option for the proposed WCFU, even if reductions of all pollutants are summed together and then the annualized cost in dollars-per-ton for emission reduction is calculated on that basis. (As shown above, summing the pollutants yields $20,583/ton, which is a lower dollar-per-ton BACT cost than looking at any one pollutant individually.)

The same annualized dollar-per-ton costs would be incurred if there was only a partial switch to alternative coal from another mine (i.e., coal blending). This is because a partial switch yields only partial emission reductions.

Regarding comparison to the cost of BACT that other similar sources have to bear (which EPA believes is best evaluated in terms of dollars per ton of additional pollutant removed, not simply in terms of what other sources pay for their coal as commenters on the draft WCFU permit have suggested), EPA is not aware of any BACT determination for a CFB boiler project anywhere in the U.S. where incremental cost effectiveness as high as $20,583/ton (the EPA-calculated economic cost for using coal from an alternative mine rather than waste coal from the Deserado mine), or as high as $20,241/ton (the EPA-calculated economic cost for using ROM coal from the Deserado mine rather than waste coal from the Deserado mine) has been considered reasonable for BACT for any pollutants, regardless of the type of BACT option being considered.

Although EPA considers the economic, energy and environmental costs associated with use of alternative coal for Deseret Power's project to be clearly excessive for BACT, EPA has nevertheless looked at some recent BACT determinations by other permitting authorities for similar projects, for purposes of comparison. EPA found the following:

1) In a PSD permit action in mid 2006 for Longleaf Energy Associates LLC, Longleaf Energy Station project, Georgia indicated that incremental cost effectiveness of $8,964/ton, comparing dry scrubbing to wet scrubbing for SO_2 control at a pulverized coal fired electric utility boiler, was excessive for BACT. Incremental and average cost effectiveness of the selected BACT option (dry scrubbing) was listed as $724/ton.

(Ref: Georgia's Preliminary Determination for SIP Permit Application #15846, page 62, dated July 2006, available online at: http://www.air.dnr.state.ga.us/airpermit/psd/dockets/longleaf/permitdocs/0990030pd.pdf.

2) In a PSD permit action in early 2007 for Southern Montana Electric Generation and Transmission Cooperative's CFB boiler project (Highwood Generating Station), Montana indicated that a "cost effective value" of $27,365/ton for SO_2 control, for a control option employing a combination of limestone injection, low-sulfur coal and wet flue gas desulfurization (FGD), was excessive for BACT. Montana also indicated that a "cost effective value" of $7,939/ton for SO_2 control, for a control option employing a combination of limestone injection, low-sulfur coal and dry FGD, was excessive for BACT.

The selected BACT option for SO_2 control, with a "cost effective value" of $4,054/ton, employed a combination of limestone injection, low-sulfur coal, and hydrated ash reinjection. Montana did not indicate whether "cost effective value" means incremental cost effectiveness or total cost effectiveness.

(Ref: Montana's "Permit Analysis" for Air Quality Permit #3423-00, page 23, dated May 30, 2007, obtained from the Montana Department of Environmental Quality Air Resources Management Bureau, Helena, Montana.)

3) In a PSD permit action in early 2005 for Rocky Mountain Power Inc.'s Hardin project, Montana indicated that incremental cost effectiveness of $23,855/ton, comparing dry FGD/spray dry absorber to wet FGD for SO_2 control, at a pulverized coal fired electric utility boiler, was excessive for BACT. Average cost effectiveness of wet FGD was listed as $1,395/ton. Average cost effectiveness of the selected BACT option (dry FGD/spray dry absorber) was listed as $918/ton.

(Ref: Montana's Permit Analysis for Hardin project, Permit #3185-02, pages 15 and 17, dated May 16, 2005, obtained from Montana Air Resources Management Bureau, in the Montana Department of Environmental Quality.)

4) In a PSD permit action in late 2006 for Cargill's Blair corn milling and ethanol production plant, Nebraska indicated that incremental cost effectiveness of $5,900/ton, comparing limestone injection alone to limestone injection plus dry FGD, for SO_2 control at a CFB boiler, was excessive for BACT.

(Ref: Nebraska permit action CP06-0008, page 12 of Fact Sheet, dated September 8, 2006, available online at
http://www.epa.gov/region07/programs/artd/air/nsr/archives/2006/finalpermits/
cargill_blair_final_psd_permit.pdf.)

5) In a PSD permit action in late 2006 for ADM's Columbus corn milling and ethanol production plant, Nebraska indicated that incremental cost effectiveness of $5,600/ton for NO_x control (comparing Selective Non-Catalytic Reduction (SNCR) at 0.07 lb/MMBtu to SNCR at below 0.07), and incremental cost effectiveness of $6,700/ton for $SO_2/H_2SO_4/HF$ control (comparing limestone injection to "additional" limestone injection) at a CFB boiler, were excessive for BACT. Nebraska listed incremental cost-effectiveness of $2,174 for the selected BACT option for NO_x control (SNCR at 0.07 lb/MMBtu). Nebraska also listed average cost-effectiveness of $5,200/ton for the selected BACT option for VOC control at the CFB boiler (wet scrubbing/packed tower),

(Ref: Nebraska permit action CPM02-0006, page 14 of Appendix B of Fact Sheet; pages 8, 9, 19 and 20 of Appendix D of Fact Sheet, dated August 4.2006, available online at:
http://www.epa.gov/region07/programs/artd/air/nsr/archives/2006/finalpermits/
adm_columbus_final_psd_permit.pdf.)

6) In a PSD permit in early 2005 for Montana-Dakota Utilities/Westmoreland Power, Gascoyne Generating Station project, North Dakota indicated that incremental cost effectiveness of $14,339/ton, comparing Selective Catalytic Reduction (SCR) at 0.04 lb/MMBtu to SNCR at 0.09 lb/MMBtu, for NO_x control at a CFB boiler, was excessive for BACT. Average cost effectiveness of SCR was listed as $7,545/ton. Average and incremental cost effectiveness of the selected BACT option (SNCR) was listed as $2,926/ton.

(Ref: North Dakota's Permit Application Analysis for Gascoyne Project, pages 65 and 68, dated March 2005, obtained from the North Dakota Department of Health, Environmental Health Section, Air Quality Division, Bismarck, ND.)

7) In a PSD permit action in early 2004 for Red Trail Energy's Richardton, ND, ethanol production plant, North Dakota listed incremental cost effectiveness of $10,252/ton, comparing wet FGD plus limestone injection to dry FGD (spray dryer absorber) plus limestone injection, for SO_2 control at a CFB boiler. Average cost effectiveness of wet FGD plus limestone injection was listed as $1,041/ton. Average cost effectiveness of dry FGD plus limestone injection was listed as $527/ton. North Dakota rejected wet FGD and determined that BACT is represented by dry FGD plus limestone injection.

(Ref: North Dakota's Permit Application Analysis for Red Trail Energy project, pages 38 and 40, dated May 2004, obtained from the North Dakota Department of Health, Environmental Health Section, Air Quality Division, Bismarck, ND.)

8) In a PSD permit action in early 2005 for River Hill Power Company's CFB boiler project, Pennsylvania indicated that incremental cost effectiveness of $15,975/ton, comparing use of the waste coal proposed by the permit applicant to use of the nearest alternative source of coal with lower sulfur content, for SO_2 control at the CFB boiler, was excessive for BACT.

Pennsylvania also indicated that all SO_2 BACT options involving wet FGD systems "were economically infeasible at an incremental dollar per ton value greater than $5,000 per ton of SO_2 removed."

Pennsylvania concluded that use of a spray dryer absorber or flash dryer absorber (i.e., dry FGD) was "economically feasible for the control of SO_2 at an incremental cost of $1,511.01 per ton of SO_2 removed."

(Ref: Pennsylvania's "Plan Approval Application Review Memo, Plan Approval Application #17-00055A," pages 10-11, dated May 2, 2005, obtained from the Commonwealth of Pennsylvania, Department of Environmental Protection, Northcentral Region, Air Quality Program.)

9) In a PSD permit action in early 2005 for Wellington Development's Greene Energy Resource Recovery Project, Pennsylvania indicated that incremental cost effectiveness of at least $20,000/ton, comparing use of the waste coal proposed by the applicant to pre-combustion cleaning of the waste coal (excluding additional coal disposal costs after cleaning of the waste coal), for SO_2 control at the CFB boiler, was excessive for BACT. Pennsylvania also indicated that overall cost effectiveness of $5,764/ton, for limestone injection plus wet FGD for SO_2 control at the CFB boiler, was excessive for BACT.

(Ref: Pennsylvania's "Comment and Response Document," Air Quality File PA-30-00150A, page 6, dated June 21, 2005; Table 5-4 of PSD Permit Application, prepared by ENSR International, August 2004, page 5-29. Both documents were obtained from the Commonwealth of Pennsylvania, Department of Environmental Protection, Southwest Regional Office, Air Quality Program.)

10) In a PSD permit action in early 2004 for Intermountain Power's Unit 3 project, Utah indicated that incremental cost effectiveness of about $14,000/ton to $16,350/ton, comparing different types of baghouse fabric filter bags (Ryton-type bags versus specialty coated bags) for PM/PM_{10} control at a pulverized coal fired electric utility boiler, was excessive for BACT. Average cost effectiveness of the selected BACT option for PM_{10} control (a baghouse with Ryton-type bags) was $31/ton.

(Ref: Utah's Modified Source Plan Review for IPP3 project, pages 132-133, dated March 22, 2004, available online at:
http://www.airquality.utah.gov/Permits/PmtPowerPlants.htm.)

11) In a PSD permit action in early 2007 for Basin Electric's Dry Fork Station project (a pulverized coal-fired electric utility boiler),Wyoming indicated that incremental cost effectiveness of $23,755/ton for NO_x control (comparing Selective Catalytic Reduction (SCR) at 0.043 lb/MMBtu to SCR at 0.040 lb/MMBtu) was excessive for BACT. Average cost effectiveness for SCR at 0.040 lb/MMBtu was listed as $2,004/ton. Average cost effectiveness for SCR at 0.043 lb/MMBtu was listed at $1,751/ton.

Although Wyoming determined that incremental cost effectiveness of $10,303/ton was reasonable for SCR at 0.043 lb/MMBtu, for other reasons described by Wyoming the selected BACT option for NO_x control was SCR at 0.05 lb/MMBtu, with incremental cost effectiveness of $3,512/ton and average cost effectiveness of $1,511/ton.

Wyoming also indicated that incremental cost effectiveness of $15,299/ton for SO_2 control (comparing dry FGD/spray dry absorber at 0.073 lb/MMBtu to wet FGD at 0.054 lb/MMBtu), was excessive for BACT. Average cost effectiveness of wet FGD at 0.054 lb/MMBtu was listed as $1,595/ton.

Although Wyoming determined that incremental cost effectiveness of $9,296/ton was reasonable for a spray dry absorber at 0.043 lb/MMBtu, for other reasons described by Wyoming the selected BACT option for SO_2 control was a spray dry absorber at 0.08 lb/MMBtu, with average cost effectiveness of $1,159/ton; no incremental cost effectiveness listed by Wyoming for this BACT option..

(Ref: Wyoming's Permit Application Analysis for the Dry Fork project, NSR-AP-3546, pages 6, 7, 8, 10 and 11, dated February 5, 2007, obtained from Wyoming Air Quality Division, Cheyenne, WY.)

12) In a PSD permit action in early 2002 for Black Hills Power & Light's WYGEN2 project, Wyoming indicated that incremental cost effectiveness of $7,742/ton, comparing low-NO_x burners plus SCR at 0.06 lb/MMBtu to low-NO_x burners plus SCR at 0.08 lb/MMBtu, for NO_x control at a pulverized coal fired electric utility boiler, was reasonable for BACT. However, for other reasons described by Wyoming, the selected BACT option was low-NO_x burners plus SCR at 0.07 lb/MMBtu, with "total" (i.e., average) cost effectiveness somewhere between $4,067/ton (the average cost effectiveness to achieve 0.08 lb/MMBtu) and $4,156/ton (the average cost effectiveness to achieve 0.06 lb/MMBtu).

(Ref: Wyoming's Permit Application Analysis for the WYGEN2 project, NSR-AP-92, page 7, dated April 24, 2002, obtained from Wyoming Air Quality Division, Cheyenne, WY.)

13) In a PSD permit action in late 2006 for Black Hills Power & Light's WYGEN3 project, Wyoming indicated that incremental cost effectiveness of $14,609/ton, comparing a baghouse with fiberglass or polyphenylene sulfide filter bags (listed as capable of achieving 0.012 lb/MMBtu) to a baghouse with specialty filter bags such as Teflon (listed as capable of achieving 0.011 to 0.010 lb/MMBtu), for PM/PM_{10} control at a pulverized coal fired electric utility boiler, was excessive for BACT.

Average cost effectiveness of the selected BACT option (a baghouse with fiberglass or polyphenylene sulfide filter bags) was listed as $130/ton. Average cost effectiveness of a baghouse with specialty filter bags was listed as $134/ton.

(Ref: Wyoming's Permit Application Analysis for the WYGEN3 project, NSR-AP-3934, pages 10 and 11, dated October 9, 2006, obtained from Wyoming Air Quality Division, Cheyenne, WY.)

The pages cited above, for each of the 13 examples, are included in the Administrative Record for issuance of the final Deseret WCFU permit.

Although this information is only on comparative economic costs of BACT options, not on comparative energy and environmental costs (which were generally not quantified by the permitting authorities), the information does seem to indicate that similar sources have typically not been expected to bear BACT costs, on an incremental cost effectiveness basis, as high as the incremental cost effectiveness for using alternative sources of coal for Deseret Power's s project, in lieu of waste coal ($20,583/ton for alternative coal from another mine and $20,241/ton for alternative coal from the Deserado mine).

Regarding the Sevier Power project cited by commenters on the draft WCFU permit package, the State of Utah presented no data in its "New Source Plan Review" on cost of BACT for any PSD pollutant, and none of the BACT options considered by Utah for that project involved alternative sources of coal. Further, no information was provided on cost of coal for the Sevier project.

Alternative coal for the WCFU project is therefore eliminated as a BACT option, in terms of environmental, economic and energy costs, at Step 4 of the BACT analysis.

3. Proposed fuel restrictions at CFB boiler to reflect basis for BACT analysis. EPA proposes to include the following CFB boiler fuel restrictions in the permit, to reflect the basis for the BACT analysis:

a. Fuel during startup: The Permittee shall not combust, in the CFB boiler, any startup fuel other than diesel fuel (#2 grade fuel oil or better) or natural gas. The diesel fuel shall have a sulfur content of no more than 0.05 percent (500 parts per million) by weight.

b. Fuel during emergencies when waste coal is not available: During any emergency that prevents waste coal from being delivered from the Deserado mine and placed into the WCFU, the Permittee is permitted to combust, in the CFB boiler, any other coal originating from the Deserado mine, including run-of-mine coal or washed coal. For purposes of this permit condition, an emergency is defined as any situation arising from sudden and reasonably unforeseeable events beyond the control of the Permittee. Depletion of the waste coal stockpile at the Deserado mine is not an emergency.

c. Fuel other than during startup and emergencies: Other than during startup or emergencies as specified in this permit, the Permittee is permitted to combust, in the CFB boiler, coal from the Deserado mine consisting of either waste coal alone, or else a blend of waste coal and run-of-mine coal in any ratio yielding up to 6,500 Btu/lb heat content on a 30-day rolling average.

E. Supercritical Boiler Technology for BACT.

EPA has evaluated a supercritical CFB boiler as a BACT option and has determined that since there are no known supercritical pressure turbines available in the size needed for the WCFU project, this option should be eliminated at step two of the top-down BACT analysis as technically infeasible, because it is not available and applicable for the WCFU project.

At the first step of the top-down BACT analysis, all demonstrated and potentially applicable control technology alternatives must be identified. This must include a survey of production processes or innovative technologies that have a practical potential for application to reduce relevant emissions at the source type being evaluated. At the second step, technically infeasible options are eliminated. A technology is feasible if either it is demonstrated, i.e. installed and operated successfully at a similar facility, or it is both “available” and “applicable.” A technology is considered “available” if it can be obtained by the applicant through commercial channels. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration. If a technology is not demonstrated, or is found to be unavailable or not applicable, that technology will be eliminated from BACT consideration as technically infeasible.

As described by Babcock & Wilcox, a major boiler supplier, a supercritical boiler (regardless of combustion process, i.e. PC-fired, CFB, gas-fired, etc.) is designed to operate with the working medium, i.e. water, at a pressure above the critical point (3200 psia). At this pressure the medium cannot be separated to liquid and steam thus natural circulation is impossible, and the fluid is pumped through all heat absorbing tubes (called “Once-Through” in the boiler industry, versus natural circulation that the sub-critical pressure WCFU boiler is based on). (Ref: e-mails and attachments from Ed Thatcher, Deseret Power, to Mike Owens, EPA Region 8, November 6, 2006.)

The use of supercritical pressure in a power plant affects the design of all components within the plant cycle, boiler, turbine, pumps, etc. The steam cycle is based on available turbine designs. The boiler and other equipment are designed to meet the steam cycle defined by the turbine. This technology is being deployed currently at pulverized coal utility boilers. EPA therefore concludes that it is appropriate to consider supercritical technology, as a technology transfer control option under step one of the top-down BACT analysis.

However, according to Babcock & Wilcox and Foster-Wheeler, two major boiler suppliers, supercritical pressure steam turbines are not available in the size needed for the WCFU project. The smallest supercritical pressure turbine currently known to be available is three to four times larger than is needed for the WCFU project, which will operate at approximately 1500 psia and is thus based on a sub-critical steam cycle. (Ref: e-mails and attachments from Ed Thatcher, Deseret Power, to Mike Owens, EPA Region 8, November 6, 2006 and November 13, 2006.)

In addition, the following information was provided by Siemens Power Systems to Deseret Power (forwarded to EPA Region 8 via e-mail from Deseret Power on November 13, 2006):

> *"To our knowledge, no manufacturer offers supercritical steam turbines in 110-120 MW range. The reason is that you would be unlikely to see any significant performance improvements for units that small. Key reasons are as follows:*
>
> *1. When you go to supercritical steam conditions the specific volume of the steam is reduced because of the higher pressure. That means the blades in the HP section have to be shorter. A major source of inefficiency in steam turbines is due to "flow disruptions" at the top and bottom of the blade where the moving flow meets the stationary rotor or casing. As the blades get shorter the impact of this "end wall" condition increases which in turn increases the flow losses.*
>
> *2. The supercritical conditions require a once-through boiler which requires a more powerful feed pump drive (higher pressures). That decreases plant efficiency and if you can't make that difference up with improved cycle performance, supercritical makes no sense.*
>
> *We generally don't see units less than about 500 MW being built as supercritical because the performance improvement isn't significant and the unit is more expensive than subcritical."*

A Western Governors Association report, cited in public comments on the draft WCFU permit, states that "no supercritical CFB combustion units have been demonstrated on a commercial scale." EPA is aware of only one supercritical CFB boiler that has been proposed, designed and/or constructed anywhere in the world. As of January 11, 2006, design of that unit had not yet been completed. The unit is being designed for Poland's Poludniowy Koncern Energetyczny (PKE) for installation at its power plant at Lagisza in southern Poland. The proposed unit will have an output of 460 MW (four times larger than Deseret Power's proposed WCFU) and is being designed to fire bituminous coal. It is currently scheduled to begin operation in 2009. The unit is being designed to fire bituminous coal. (Ref: Foster-Wheeler press release, January 11, 2006.)

Supercritical CFB boilers, while potentially applicable as a BACT option, are not a "demonstrated" technology under the BACT analysis, as the only such boiler EPA is aware of (the PKE boiler planned in Poland) has not been installed and operated successfully. Further, the technology is not "available" under the BACT analysis since, as explained above, it is not commercially available for CFB boilers, and supercritical pressure steam turbines are not available in the size needed for the WCFU project. Therefore, this technology is eliminated at step two of the top-down BACT analysis because it is undemonstrated and is not available.

F. IGCC not Within Scope of BACT Analysis for this Project.

Consideration of Integrated Gasification Combined Cycle (IGCC) technology, as an alternative to a waste-coal-fired CFB boiler, has not been included in Step 1 of the BACT analyses below, since IGCC would be redefining the source. In preparing the draft permit, EPA did consider whether IGCC is a BACT option, but concluded it is not because it would fundamentally change the basic design of the proposed source. Prior to reaching this conclusion, EPA did, however, request detailed information from Deseret Power regarding whether or not IGCC would be technically feasible using waste coal from the Deserado mine. Correspondence between EPA and Deseret Power on this topic has been included in the Administrative Record for this permit action.

G. BACT for NO_x Emissions from CFB Boiler.

Emissions of NO_x from coal combustion are formed from three chemical mechanisms:

(1) fuel NO_x (resulting from oxidation of chemically bound nitrogen in the fuel),

(2) thermal NO_x (resulting from oxidation of molecular nitrogen in the combustion air), and

(3) prompt NO_x (resulting from reaction between molecular nitrogen and hydrocarbon radicals).

Most of the emissions from coal combustion are from fuel NO_x, with lesser amounts from thermal NO_x and relatively negligible amounts from prompt NO_x.

Fuel NO_x formation depends on many complex chemical characteristics in the coal and boiler. Due to the chemical complexities and large number of factors affecting fuel NO_x formation, it is difficult to accurately quantify the amount of expected fuel NO_x formation for a particular facility. The chemical reactions that take place depend on numerous factors, including fuel-bound nitrogen content, carbon to volatile matter ratio, oxygen content, calcium content, sulfur, and moisture content. While a survey of the literature does suggest that the **percentage** of fuel-bound nitrogen converted to NO_x decreases as the total nitrogen in the fuel increases (probably due to the percentage of volatile fuel-bound nitrogen in the total amount of fuel-bound nitrogen), the literature also suggests that, in general, there will be an increase in NO_x emissions with increases in fuel-bound nitrogen.

Thermal NO_x formation for coal-fired utilities is often controlled through combustion techniques. Deseret Power has proposed CFB boiler technology, which inherently reduces the amount of thermal NO_x formation through low combustion temperatures and staged combustion capabilities. Deseret Power has also proposed Selective Non-Catalytic Reduction (ammonia injection) as an add-on control.

Clean fuels (i.e., alternative coal, either from the Deserado mine or another mine) is also a possible option for BACT, but has already been eliminated as cost-prohibitive for BACT, for all pollutants at this project. This was explained earlier in this Statement of Basis.

1. Step 1: Identify Potential Control Technologies.

Control technologies with practical potential for application to coal-fired CFB boilers for NO_x emission control are listed below. This list is based on literature survey (including AP-42 and a November 1999 EPA Technical Bulletin on NO_x Control, discussed further below), as well as review of recent BACT determinations for CFB utility boilers. As a result of this review, EPA considers the following technologies to be potential control options:

a. Selective Catalytic Reduction (SCR)
b. Selective Non-Catalytic Reduction (SNCR)
c. Non-thermal Plasma Reactor
d. Carbon Injection in Combustion Chamber

Recent permit applications for other CFB boiler projects (e.g., permit application by Great Northern Power Development for the South Heart Power Project in North Dakota) identify additional NO_x control technologies as possible options. These are: staged combustion, low-NO_x burners, overfire air, and flue gas recirculation. However, EPA does not consider these to be potential control options for a CFB boiler, for the following reasons:

- Staged combustion – In staging, a portion of the total air required to complete combustion is withheld from the initial combustion stage. The balance of air required for complete combustion is mixed with the incomplete products of combustion only after the oxygen content of the first-stage air is consumed. Staged combustion design of the boiler reduces air-rich combustion and NOx formation. This is an inherent part of CFB process design, rather than a "control option."

- Low-NO_x burners (LNBs) and overfire air (OFA) – LNBs restrict NO_x formation by controlling the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. OFA involves the staged injection of air into the firing chamber. LNB and OFA are widely used in PC-fired boilers. However, CFB boilers do not use burners during normal operation, as combustion takes place within the fluidized bed. Therefore, these technologies are not applicable to a CFB boiler.

- Flue gas recirculation (FGR) – FGR is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizer or 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 adsorption of the combustion heat by the relatively inert flue gas and to reduce the O_2 concentration in the combustion zone. Because FGR reduces NO_x formation by reducing peak flame temperature, it is ineffective on combustion sources such as CFBs that operate at low combustion temperatures.

Table 1.1-2 of AP-42 (Sept. 1998 edition) lists several types of combustion modifications as potential additional NO_x control options for coal-fired boilers; however, Table 1.1-2 does not indicate that any of these options have practical potential for application to CFB boilers, nor is EPA aware of any reason why any of these options would have practical potential for application to CFB boilers. Generally, combustion design of a CFB boiler controls thermal NO_x formation to the same degree, if not to a greater degree, than combustion controls for the other types of boilers listed in Table 1.1-2 of AP-42.

Options for NO_x control at coal-fired CFB boilers are also listed in an EPA publication titled, "Technical Bulletin: Nitrogen Oxides (NO_x), Why and How They are Controlled," EPA-456/F-99-006R, November 1999. The Technical Bulletin mentions the following control techniques:

- Natural Gas Reburn
- Low Excess Air
- Reduced Air Preheat
- Reducing Residence Time
- Fuel Reburning
- Non-Thermal Plasma Reactor
- Sorbent Injection

Natural gas reburn, low excess air, reduced air preheat, reducing residence time, and fuel reburning all act on thermal NO_x. The combustion temperature of a CFB boiler, by nature of its design, is much lower than that of a pulverized coal (PC) boiler (1,500^{o}F versus 3,000^{o}F). (Ref: Western Governors Association Technology Working Group Report, undated, page 10.) This lower combustion temperature results in virtually no thermally-generated NO_x. Because of this, control techniques designed to reduce NO_x emissions by reducing the combustion temperature, and thus reducing thermal NO_x, were not considered to have practical potential for application to coal-fired CFB boilers and thus were eliminated as control options at Step 1 of the BACT analysis. This is explained in more detail below.

Two of the control techniques listed in the Technical Bulletin are already proposed to be included for the WCFU: Low Excess Air is an inherent part of the CFB boiler design, and Sorbent Injection (a.k.a. Selective Non-Catalytic Reduction, discussed further below) is the chosen BACT control option. Non-Thermal Plasma Reactor is not known to be commercially available for CFB units and is therefore not considered to be a technically feasible control option.

Below are descriptions from the Technical Bulletin of the individual control techniques, along with a more detailed discussion of each technique's potential (or lack thereof) for control of NO_x emissions at the proposed WCFU.

<u>Natural Gas Reburn</u> – This is considered by EPA to be the same method as generic "Fuel Reburning." The principles are the same whether the additional fuel reburned is natural gas, fuel oil, or coal. See "Fuel Reburning" below.

<u>Low Excess Air</u> – Excess air flow for combustion has been correlated to the amount of thermal NO_x generated. Limiting the net excess air flow to less than 2% can strongly limit NO_x content of flue gas at pulverized coal fired boilers. Although there are fuel-rich and fuel-lean zones in the combustion region, the overall net excess air is limited when using this approach.

A certain amount of excess air is required to maintain flame stability and provide satisfactory combustion. Limiting excess air to such a low level would also increase emissions of carbon monoxide (CO).

Reducing the amount of excess air may be a valid way to reduce NO_x emissions from an older CFB unit with poor combustion controls. However, the unit proposed by Deseret is a new unit with state-of-the-art combustion controls. One of the goals of those controls is to minimize excess air to maximize boiler efficiency. If one were to consider reducing excess air further than the design rate, it would result in increased CO emissions and disrupt the stable operation of the unit. Further, this control technique acts primarily on thermal NO_x and therefore, while it may have substantial effect on NO_x emissions at pulverized coal fired boilers, it has much less effect on NO_x emissions at combustion sources such as CFBs that operate at low combustion temperatures.

This control technique was addressed earlier in this discussion, through reference to Table 1.1-2 of AP-42, which indicates it is does not have practical potential for application to coal-fired CFB boilers for NO_x control. It has therefore been eliminated at Step 1 of the BACT analysis.

Reduced Air Preheat – Preheating the combustion air cools the flue gases, reduces the heat losses, and gains efficiency. However, this can raise the temperature of combustion air to a level where NO_x forms more readily. Reducing the amount of air preheat reduces the combustion temperature and NO_x formation is suppressed. However, reducing the amount by which the incoming combustion air is preheated carries a significant efficiency penalty of up to 1% per 40°F. (Ref: Technical Bulletin, page 12.) This reduction in efficiency would increase emissions of all criteria pollutants. As mentioned in the introductory discussion of thermal NO_x above, the combustion temperature of a CFB boiler, by nature of its design, is much lower than that of a pulverized coal (PC) boiler and results in virtually no thermally-generated NO_x. Therefore, reduced air preheat is not considered to be an effective NO_x control option for coal-fired CFB boilers, i.e., it does not have practical potential for application to CFB boilers for NO_x control. It has therefore been eliminated as a control option at Step 1 of the BACT analysis.

Reducing Residence Time (at peak temperature through injection of steam) – This control technique involves injection of water or steam, which causes the stoichiometry of the mixture to be changed and adds steam to dilute calories generated by combustion. Both of these actions cause combustion temperature to be lower. If temperature is sufficiently reduced, thermal NO_x will not be formed in as great a concentration.

In order to control NO_x, steam is typically injected directly into the flame to reduce the adiabatic flame temperature. In a CFB boiler, this is not physically possible, as combustion occurs throughout the fluidized bed. As with reduced air preheat, injecting steam would reduce boiler efficiency and result in increased emissions of all pollutants.

This control technique is addressed in the introductory discussion of thermal NO_x above and is not considered to be an effective control option for coal-fired CFB boilers, i.e., it does not have practical potential for application to CFB boilers. It has therefore been eliminated as a control option at Step 1 of the BACT analysis.

Fuel Reburning – This control technique consists of recirculation of cooled flue gas with added fuel, similar to Flue Gas Recirculation (FGR) discussed on page 31 of the Statement of Basis. With fuel reburn, calories are diluted and the primary combustion temperature can be lowered. In other words, the peak flame temperature can be lowered through adsorption of the combustion heat by the relatively inert flue gas. As explained in the introductory discussion of thermal NO_x above, this control technique acts on thermal NOx and is not considered to be effective on combustion sources such as CFBs that operate at low combustion temperatures. As such, it does not have practical potential for application to coal-fired CFB boilers for NO_x control. It has therefore been eliminated as a control option at Step 1 of the BACT analysis.

Non-Thermal Plasma Reactor – This control technique involves using methane and hexane as reducing agents. Non-thermal plasma has been shown to remove NO_x in a laboratory setting with a reactor duct only two feet long. The reducing agents were ionized by a transient high voltage that created a non-thermal plasma. The ionized reducing agents reacted with NO_x and achieved a 94% destruction efficiency. There are indications that even higher destruction efficiency can be achieved. A successful commercial vendor uses ammonia as a reducing agent to react with NO_x in an electron beam generated plasma. Such a short reactor can meet available space requirements for virtually any plant. The non-thermal plasma reactor could also be used without reducing agent to generate ozone and use that ozone to raise the valence of nitrogen for subsequent absorption as nitric acid.

Trinity Consultants investigated the non-thermal plasma reactor as a NO_x control option and advised Deseret Power that it is not known to be commercially available. (Ref: E-mail from Ed Thatcher, Deseret Power, to Mike Owens, EPA Region 8, November 13, 2006.) Therefore, while this control technique might be considered a technology transfer control option at Step 1 of the BACT analysis, it is eliminated at Step 2 as technically infeasible (see below) because it is not known to be commercially available for NO_x control at CFB boilers.

Sorbent Injection (in combustion chamber/duct) -- This control technique involves injection of limestone into the combustion zone. As explained further in Steps 2 through 5 of this NO_x BACT analysis, injection of ammonia (Selective Non-Catalytic Reduction) is the chosen NO_x control option for the proposed WCFU.

According to the Technical Bulletin, another version of sorbent injection "uses carbon injected into the air flow to finish the capture of NO_x. The carbon is captured in either the baghouse or the ESP just like other sorbents." (Ref: Technical Bulletin at page 19.) Although carbon injection is an emerging technology used to reduce mercury emissions, Deseret Power is not aware of it having been used anywhere to control NO_x. (Ref: E-mail dated November 13, 2006, from Ed Thatcher of Deseret Power to Mike Owens of EPA Region 8.) EPA is similarly not aware of carbon injection having been used anywhere to control NO_x. Carbon injection for NO_x control is therefore eliminated at Step 2 of the BACT analysis as technically infeasible (see below) because it is not known to be commercially available for that purpose.

2. Step 2: Eliminate Technically Infeasible Options

a. Selective Catalytic Reduction (SCR). SCR is a post-combustion technology that reduces NO_x by the injection of ammonia into the flue gas in the presence of a catalyst to reduce NO_x to nitrogen and water. SCR systems have been widely employed on pulverized coal (PC)-fired boilers in the United States and have achieved emission rates below 0.05 lb/MMBtu. To date, there are no known SCR systems operating on a CFB unit.

SCR systems operate effectively in a temperature range of 650-750 degrees F. For a CFB boiler, this temperature would exist in an area upstream of the particulate control device. Considering the high particulate loading rate and calcium oxide (CaO) concentration of the flue gas due to limestone injection in this section of a CFB boiler, and due to use of waste coal fuel in the boiler with ash content as high as 60%, an SCR system installed upstream of particulate controls would experience rapid catalyst de-activation and fouling. These technical problems would make high-dust SCR upstream of the particulate controls technically infeasible for a CFB boiler design.

Another possible approach is to install the SCR system downstream of the particulate control equipment. For Deseret's CFB boiler, the temperature downstream of the particulate control equipment (baghouse) would be in the range of 150 degrees F, which is lower than the temperature range for operating SCRs on coal-fired utilities.

Although EPA is not aware of any CFB boilers operating with SCR for NO_x control, either upstream or downstream of particulate controls, EPA asked Deseret Power to evaluate whether low-temperature SCR downstream of the particulate controls could be a feasible NO_x control option. Based on information from the National Park Service on this topic, EPA listed SCR vendors that Deseret Power could contact. Deseret Power contacted those vendors and found that the vendors only provide SCR technology for natural gas applications, not for coal-fired boilers. Based on this information, EPA does not consider low-temperature SCR a technically feasible NO_x control option for this project.

Since low-temperature SCR is not technically feasible, EPA asked Deseret Power to evaluate the possibility of reheating the flue gas downstream of the baghouse to the temperature range known to be effective for SCR use (650-750 F). Applicants and permitting authorities for other CFB projects (Gascoyne and South Heart projects in North Dakota and River Hill project in Pennsylvania) have considered flue gas reheat for SCR.

While Deseret Power informed EPA that they do not believe technology is available for flue gas reheat that warrants its consideration in the BACT analysis, Deseret Power did provide an estimate of fuel cost for raising flue gas stack temperature to the extent that SCR might be utilized. (These costs are presented in Step 4 below.) Based on review of other determinations on the technical feasibility of flue gas reheat and the potential use of SCR on a CFB unit, EPA believes SCR is a technically feasible NO_x control option for this project.

b. Selective Non-Catalytic Reduction. SNCR is another post-combustion control option where ammonia or urea is injected into the flue gas in the reaction zone to reduce NO_x to nitrogen and water. The SNCR reaction occurs at temperatures higher than with an SCR system, without the use of a catalyst. The optimum temperature range for SNCR is about 1600-1900 F. SNCR has been employed at CFB units in the United States and is considered a technically feasible NO_x control option for this project.

c. Non-thermal plasma reactor. As explained in Step 1 above, a non-thermal plasma reactor may have practical potential for application to coal-fired CFB boilers, as a technology transfer control option at Step 1 of the BACT analysis, but is not known to be commercially available for CFB boilers. Therefore, it is not considered to be technically feasible and is eliminated at this Step 2.

d. Carbon injection into the combustion chamber. As explained in Step 1 above, carbon injection into the combustion chamber may have practical potential for application to coal-fired CFB boilers, as a technology transfer control option at Step 1 of the BACT analysis, but is not known to be commercially available for CFB boilers. Therefore, it is not considered to be technically feasible and is eliminated at this Step 2.

3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness.

The two NO_x control options that are considered technically feasible for this project are SCR and SNCR. EPA believes application of SCR to a CFB boiler could achieve emission levels comparable to application of SCR at a PC-fired boiler. PC-fired boilers with SCR have been able to achieve NO_x emission rates below 0.05 lb/MMBtu on a 30-day average. For example, the BACT analysis by North Dakota for the Gascoyne CFB boiler project estimates a controlled NO_x emission rate with SCR of 0.04 lb/MMBtu on a 30-day average.

Public comments received by EPA on the draft WCFU permit cited statements from Babcock & Wilcox (a boiler manufacturer) that commercial SCR installations have shown that 90% NO_x reductions can be achieved with low ammonia slip, and that Babcock & Wilcox states that up to 95% NO_x control can be achieved with SCR. While EPA's analysis in the draft Statement of Basis was based on 0.04 lb/MMBtu potentially achievable with SCR, as a result of new information provided in public comments EPA has re-analyzed on the basis of 90% emission reduction from an uncontrolled emission rate of 0.15 lb/MMBtu, which is equivalent to a final emission rate of 0.015 lb/MMBtu potentially achievable with SCR. Therefore, for the sake of ranking in Step 3 of this BACT analysis, and for the sake of cost analysis in Step 4, EPA estimates that an emission rate of 0.015 lb/MMBtu could potentially be achieved with flue gas reheat and SCR.

EPA's review of recently issued permits, permit applications, and operating data for CFB projects utilizing SNCR (discussed further in Step 5 below) indicates that an emission rate of 0.07 lb/MMBtu could be achieved with SNCR under certain conditions, which are not present with Deseret's project. However, as explained below, EPA believes Deseret Power's WCFU project will be able to consistently achieve an emission rate of 0.080 lb/MMBtu. The two control options (SCR and SNCR) are therefore ranked by EPA as follows:

- SCR – 0.015 lb/MMBtu (30-day rolling average)
- SNCR – 0.08 lb/MMBtu (30-day rolling average)

4. Step 4: Evaluate Economic, Environmental and Energy Impacts.

a. Selective Catalytic Reduction. As noted above, for SCR to be a technically feasible NO_x control option for this project, flue gas reheating would be required downstream of the particulate controls. This would involve significant additional fuel cost. The cost and environmental impacts are discussed below. Even without flue gas reheating, an SCR system does require some additional energy in order to overcome the pressure drop over the SCR catalyst beds; however, this has not proven to be a significant energy or economic impact for employing SCR technology on coal-fired power plants.

With any SCR installation, there are some commonly noted adverse environmental impacts. These would include ammonia slip emissions, catalyst disposal, and potential ammonia handling hazards. These impacts are usually deemed to be offset by the environmental benefits of significant NO_x reduction from the SCR system. With the SCR system located downstream of the particulate and SO_2 control devices in order to deal with technical problems associated with a CFB application, there may be additional condensible particulate emissions resulting from the conversion of SO_2 to SO_3 and eventually to H_2SO_4 over the catalyst bed.

Another adverse environmental impact is the additional emissions from combustion of distillate fuel oil or propane for flue gas reheating. Deseret Power has calculated a required heat input of 99.2 MMBtu/hr to raise the temperature of the flue gas from 275 F to 480 F. The 480 F used by Deseret Power is on the low end of, or even below, where an SCR can most effectively operate. Thus, the fuel consumption values may actually be higher than calculated by Deseret.

Since there are no natural gas lines into Deseret Power's Bonanza plant, the only reheat options are distillate fuel oil or propane. EPA has calculated the emissions based on AP-42 emission factors. These emissions are presented in the table below. The calculations assume heat rating of the distillate fuel oil to be 0.14 MMBtu/gal, which equals 710 gallons per hour. For propane, the calculations assume 0.0905 MMBtu/gal, which equals 1,100 gallons per hour.

The difference in emission rates between SNCR and SCR would be 0.065 lb/MMBtu (i.e., 0.08 minus 0.015). Assuming CFB operation at 90% of capacity on an annual average, this difference would be equivalent to a NO_x reduction of 370 tons per year:

(0.08 lb/MMBtu – 0.015 lb/MMBtu) x (1,445 MMBtu/hr) x
(8,760 hr/yr) x (0.9) x (1 ton/2,000 lb) = **370 tons/year**

With distillate reheat, the net NO_x reduction would be 308 tons per year (i.e., 370 minus 62). With propane reheat, the net NO_x reduction would be 278 tons per year (i.e., 370 minus 92). These figures are shown in the table below.

Estimated Emissions From Reheating of CFB Flue Gas
To Accommodate Use of Conventional SCR
At Deseret Power's Proposed WCFU

Pollutant	Distillate Oil Emissions (tons/year)	Propane Emissions (tons/year)
PM (total)	10	3
SO_2	3	Negligible
NO_x	62	92
VOC	1	2
CO	16	15

Even without considering reheat cost, the annualized cost of SCR is several times greater than SNCR, due to higher capital and operating costs. (Example: PSD permit application dated August 2005, for South Heart CFB boiler project in North Dakota, calculates the annualized capital recovery cost for SCR to be about six times as much as for SNCR.) As explained above, SCR installed downstream of particulate controls would also involve reheat cost. Deseret Power provided cost figures for only the supplemental fuel that would be required to reheat the flue gas so that SCR could be used. No additional costs were calculated for capital, installation, or operation of the SCR system or capital, installation, and other non-fuel operational costs for the reheat system. Hence, this is a very conservative cost analysis, since as mentioned above, these additional capital, installation and operational costs for the SCR and reheat system would likely be substantial. The lowest-cost option for reheat fuel was calculated to be distillate oil at $12,411,476 per year, based on 6,205,738 gallons per year at $2.00 per gallon.

Without any add-on controls, EPA estimates that the CFB boiler should be able to achieve a NO_x emission rate of about 0.15 lb/MMBtu or lower. (Actual operational data on existing CFB boilers suggests to EPA that this value could be much lower. The 0.15 value was chosen by EPA only as a conservative estimate in doing this cost analysis.) Using this uncontrolled emission rate as a baseline, the total cost effectiveness for the SCR/reheat system only, considering the cost of reheat fuel, is calculated as follows:

Emission reduction going from baseline to SCR controlled emissions:

(0.15 lb/MMBtu – 0.015 lb/MMBtu) x (1,445 MMBtu/hr) x
(8,760 hr/yr)(0.9) (1 ton/2,000 lb) = **769 tons/year**

The average cost per ton for NO_x reductions, considering only distillate fuel costs when considering the additional NOx that would be generated by burning distillate fuel:

($12,411,476 / yr) / (769 - 62 ton/yr) = **$17,555/ton**

The incremental cost of going from SNCR to SCR, considering only the distillate fuel costs is calculated as follows:

($12,411,476 / yr) / (370 ton/yr) = **$33,545 /ton**

The incremental cost going from SNCR to SCR, considering only the distillate fuel costs, and considering the additional emissions caused by reheat for SCR, is calculated as follows:

($12,411,476 / yr) / (370 - 62 ton/yr) = **$40,297 /ton**

EPA concludes that the economic impacts associated with a cost of more than $40,000 per ton of pollutant removed justify elimination of SCR as the top control option. Both the total cost effectiveness and incremental cost effectiveness are considered by EPA as cost-prohibitive for BACT. In addition, if capital, installation, and other operational costs for both the SCR and reheat system were considered, the above cost values would increase significantly.

b. Selective Non-Catalytic Reduction. Deseret has proposed SNCR as BACT for NO_x, which is the next highest ranked control option. Since SCR has been rejected above, and since there are no significant collateral impacts for SNCR, this control option is selected as BACT.

5. Step 5: Proposed NO_x BACT for CFB Boiler.

As stated above, SNCR has been selected as NO_x BACT. An emission limit must now be established that represents the maximum degree of reduction achievable for SNCR for this project. The above discussion and analysis indicates that SNCR for the WCFU project can achieve 0.080 lb/MMBtu on a rolling 30-day average. Deseret Power has proposed an emission limit of 0.088 lb/MMBtu on a 30-day rolling average. Deseret Power searched the RACT/BACT/LAER Clearinghouse (RBLC) database and found the following determinations:

Comparison of CFB Boiler NO_X Emission Rates using SNCR:
RACT/BACT/LAER Clearinghouse Data

Facility	RBLC ID	Heat Input mmBtu/hr	NO_X Emissions Lb/mmBtu	Fuel
AES-PRCP	PR-0007	4922.7	0.1	Columbian Coal
Reliant Energy Mid-Atlantic Power	PA-0182	2532.0	0.15	Coal
Archer Daniels Midland (9&10)	IL-0060	1500.0	0.12	Coal
Choctaw Generation	MS-0036	2475.6	0.2	Lignite
Archer Daniels Midland (5&6)	IA-0046	1500.0	0.07	Coal
Archer Daniels Midland	IA-0051	1500	0.07	Bituminous Coal
Kimberly Clark	PA-0204	799	0.2	Coal
Toledo Edison	OH-0231	1764	0.2	Pet Coke
York County Energy Partners	PA-0132	2500.0	0.125	Bituminous Coal
Northampton Generating Co.	PA-0134	1146.0	0.1	Anthracite Culm
Westwood Energy	PA-0124	423	0.3	Anthracite Culm
Gilberton Power	PA-0110	520	0.3	Anthracite Culm
Archer Daniels Midland (7&8)	IL-0058	1500	0.12	Coal
Energy New Bedford Cogeneration	MA-0028	1671.0	0.15	Eastern US Coal
AES Warrior Run	MD-0022	2070.0	0.1	Eastern US Coal
Archer Daniels Midland	IA-0025	551.5	0.07	Coal
Energy New Bedford Cogeneration	MA-0009	3342.0	0.15	Eastern US Coal
Tauton Energy Center	MA-0011	1604.4	0.15	Eastern US Coal
North Branch Energy Partners	PA-0058	563.5	0.15	Waste Bit. Coal

Deseret Power proposed 0.088 lb/MMBtu on a 30-day rolling average as NO_x BACT. The following section describes EPA's basis for proposing a second limit of 0.080 lb/MMBtu on a 30-day rolling average, applicable beginning 15 months after the date of initial startup of the CFB boiler. During the first 15 months, the limit will be Deseret's requested limit of 0.088 lb/MMBtu on a 30-day rolling average, the basis for which is described later in this discussion.

EPA reviewed several recently issued permits and permit applications for CFB boiler projects fired on lower quality coal, to compare limits using SNCR. These projects are not listed in the RBLC database. Some projects are, or will be, subject to BACT limits as low as 0.07 lb/MMBtu. This information is presented in the table below.

Summary of Recent CFB Projects Permitted or Proposed:
NO_x Emission Rates using SNCR

Project / Company Name	State	Primary Coal Type	Permit Status	NO_x Emission Rate (lb/MMBtu)
Karthaus Township CFB Project / River Hill Power Company	PA	Eastern Waste	Issued 07/21/05	0.07 (30 DRA)
Highwood Generating Station / Southern Montana Electric	MT	Western Subbituminous	Application 11/30/05	0.07 (annual avg) 0.09 (24-hr avg)
Kentucky Mountain Power Project	KY	Unknown; not specified in permit	Issued 05/04/01	0.07 (30 DRA)
Beech Hollow Energy Project / Robinson Power Co. LLC	PA	Eastern Waste	Issued 04/01/05	0.08 (30 DRA)
Greene Energy Resource Recovery Project / Wellington Dvpt, LLC	PA	Eastern Waste	Issued 06/21/05	0.08 (30 DRA) 0.1 (24-hr avg)
Gascoyne Generating Station / Montana-Dakota Utilities Co.	ND	Lignite	Issued 06/02/05	0.09 (30 DRA)
South Heart Power Project / Great Northern Power Dvpt, L.P.	ND	Lignite	Application 08/18/05	0.09 (30 DRA)

30 DRA = 30-day rolling average

Deseret Power maintains that comparing its plant to eastern plants is unfair because of the higher Btu content of the eastern waste coal and the ability of some of these projects to blend higher grade bituminous coal with its waste coal to boost the heat content even higher. For the sake of comparison, EPA will compare the Deseret waste coal profile to two permitted or proposed projects with NO_x limits of 0.07 lb/MMBtu, listed in the table above. These projects are the River Hill Power Project in Pennsylvania and the Highwood Generating Station in Montana.

(Note 1: A similar proposed CFB boiler project listed in the table above, Kentucky Mountain Power Project (KMPP), also with an emission limit of 0.07 lb/MMBtu, has not been included by EPA in this analysis, because, unlike the Deseret WCFU permit, the KMPP permit says the NO_x emission limit is "waived for the specific SNCR optimization study activity as detailed in Condition 2 above not to extend more than 365 days after the initial compliance demonstration. However, the nitrogen oxide emissions rate shall never exceed 0.10 lb/MMBtu, during or after the SNCR optimization study." By contrast, the Deseret WCFU permit says the initial NO_x emission limit is 0.088 lb/MMBtu and the final NO_x emission limit (applicable starting 12 months after completion of initial performance testing) is 0.080 lb/MMBtu, with no waiver or provision for raising the limit later. Since Kentucky is willing to waive the initial NO_x emission limit for up to a year while a study is conducted, and adjust it up to as high as 0.10 lb/MMBtu after the study is conducted, EPA discounts to some degree the significance of KMPP's initial emission limit of 0.07 lb/MMBtu.)

(Note 2: Another similar proposed CFB boiler project, Estill County Energy Partners in Kentucky, has not been included by EPA in this analysis, and is furthermore not listed in the table above, because the permit application – which proposed a NO_x emission limit of 0.07 lb/MMBtu -- is no longer actively being processed. It was determined to be incomplete by Kentucky in late 2004.)

Deseret Power's "average" waste coal will have a High Heating Value (HHV) of 4,000 Btu/lb (with a range of 3,000-5,400 Btu/lb). The River Hill Project is proposing to burn eastern waste coal blended with bituminous coal, which could boost the Btu content substantially higher than Deseret's proposed waste coal. The Highwood Generating Station is proposing to burn subbituminous coal with a heating value of 8,752 Btu/lb. This is over twice the heat content of Deseret's average waste coal.

With respect to the heating value of the coal, EPA believes the River Hill and Highwood Generating Station projects mentioned above will have an inherent advantage over Deseret to meet a lower NO_x limit. Therefore, EPA is not convinced that a direct comparison can be made between the NO_x limits for these projects and Deseret's WCFU project, even if Deseret were to blend up to a 50/50 ratio of waste coal with ROM coal from the Deserado mine, when needed. A 50/50 blend would yield an average Btu content of about 6500 Btu/lb. While EPA considered these projects in establishing a NO_x limit for Deseret, EPA believes the difference in the heating value of Deseret's fuel versus the fuel for River Hill and Highwood warrants some consideration.

In addition to looking at some of the recent permitting activity, EPA attempted to review actual emissions data for CFB boilers combusting waste coal. Unfortunately, there are not any examples of waste coal CFB plants operating in the Western United States. However EPA found emissions data from several waste coal CFB units operating in Pennsylvania. These units are primarily fueled by either eastern bituminous waste coal (gob) or waste anthracite (culm).

It appears that the plants burning waste anthracite emit very low levels of NO_x emissions, even without the use of SNCR (Gilberton and Northeastern Power). However, among other differences, anthracite is known to have a lower percent volatile matter compared to bituminous coal. A lower percent volatile matter will result in less fuel-nitrogen being released as NO_x. Therefore, while these data indicate that extremely low emissions are sometimes achievable for waste coal CFBs, they are probably not the best comparison of what can be achieved for Deseret's WCFU project. Deseret will be burning waste bituminous coal, so the best comparison for currently operating plants would be to look at CFB units in Pennsylvania that are burning waste eastern bituminous coal. Below is a table summarizing monthly 2005 NO_x emissions for these plants.

As can be seen from the table below, several plants are achieving below 0.08 lb/MMBtu during the ozone season months of May through September (in bold). While these plants are all equipped with SNCR, it appears that the controls are generally only operated during the ozone season. Conversely, if the controls are being operated during the non-ozone season, they are not being utilized to the same extent, as emissions are higher during those months.

While these data do suggest that NO_x emission rates of 0.08 lb/MMBtu are being achieved in practice, they should not necessarily be interpreted as representing what Deseret's WCFU is capable of sustaining over the long term. EPA has not investigated what NO_x limits these plants are required to meet, nor has EPA investigated other specific coal characteristics that might affect NO_x (other than that these plants burn some level of bituminous waste coal), so EPA cannot say these emissions represent the best achievable NO_x emissions for these facilities. EPA can say that these data show that an emission rate 0.08 lb/MMBtu has been achieved for CFB units fired on eastern bituminous waste coal.

Actual NO_x Emissions During 2005 From
Eastern Bituminous Waste Coal Fired CFB Units

Month	Scrubgrass Generating Station Unit 1	Scrubgrass Generating Station Unit 2	Seward Unit 1	Seward Unit 2	Piney Creek Power	Cambria Cogen Unit 1	Cambria Cogen Unit 2
	NOx (lb/MMBtu)	NOx (lb/MMBtu)	NOx (lb/MMBtu)	NOx (lb/MMBtu)	NOx (lb/MMBtu)	NOx (lb/MMBtu)	NOx (lb/MMBtu)
Jan	0.154	0.145	0.230	0.230	0.205	0.295	0.301
Feb	0.174	0.169	0.230	0.230	0.199	0.294	0.298
Mar	0.154	0.133	0.390	0.230	0.175	0.287	0.297
Apr	0.157	0.134	0.230	0.230	0.179	0.291	0.300
May	**0.066**	**0.061**	**0.067**	**0.095**	**0.138**	**0.143**	**0.143**
Jun	**0.066**	**0.058**	**0.065**	**0.067**	**0.078**	**0.117**	**0.117**
Jul	**0.063**	**0.064**	**0.085**	**0.089**	**0.074**	**0.098**	**0.098**
Aug	**0.066**	**0.068**	**0.074**	**0.074**	**0.062**	**0.088**	**0.088**
Sep	**0.060**	**0.085**	**0.060**	**0.080**	**0.064**	**0.088**	**0.088**

Oct	0.116	0.135	0.094	0.093	0.170	0.292	0.290
Nov	0.115	0.136	0.085	0.108	0.163	0.288	0.287
Dec	0.121	0.145	0.087	0.083	0.191	0.284	0.292

Furthermore, these data show that of the CFB plants currently in operation, none are consistently demonstrating emission rates much lower than 0.08 lb/MMBtu, as to warrant EPA setting a lower NO_x BACT limit for Deseret's WCFU. Additionally, in presenting its position for a NO_x limit of 0.088 lb/MMBtu, Deseret Power has stated that the limestone injection rate into the boiler that will be required to meet the low SO_2 BACT emission limits proposed by EPA, will prevent the proposed WCFU from meeting a NO_x limit any lower than 0.088 lb/MMBtu. EPA agrees that increasing the limestone injection rate into the boiler may increase NO_x formation (due to the presence of excess unreacted CaO in the boiler), but finds this effect difficult to quantify, especially considering the effect the SNCR will have on actual NO_x emissions. That said, EPA is unaware of any other waste coal CFB projects currently being permitted with NO_x limits below 0.08 lb/MMBtu that also have SO_2 limits of 0.04 lb/MMBtu or below.

Considering the comparisons of recently permitted low quality coal CFB projects and the above actual emissions data for operating CFB plants burning eastern waste bituminous coal and utilizing SNCR, EPA believes a NO_x emission rate of 0.080 lb/MMBtu on a rolling 30-day average represents BACT for Deseret's WCFU project, after an initial break-in period (see further discussion below), and taking into account the operational flexibility requested by Deseret Power to blend, when needed, up to 50/50 ratio of run-of-mine coal with the waste coal.

Deseret Power maintains that in order to optimize NO_x control, a "break-in" period will be needed after initial startup of the CFB unit, to fine-tune and chemically balance the SNCR. EPA asked for further explanation. Below is Deseret's response:

> *The "Break-in Period" for a CFB unit and optimization of the unit to achieve the permitted NO_x emission limit, with the most efficient plant operation, would occur after the completion of plant commissioning and performance testing at full load operation which is expected to take 3 to 4 months after initial startup. During this initial operating period, the operation and maintenance personnel will be trained for this specific unit, plant controls would be checked out and tuned and equipment problems would be de-bugged.*
>
> *The NO_x optimization process involves making many adjustments to the unit such as combustion controls, adjustments to the SNCR ammonia system, and since the limestone injection rate affects NO_x production, adjustments will have to be made to the limestone feed system in conjunction with adjustments to the dry scrubber so the SO2 emission limit is also met. The NO_x optimization process is expected to consist of up to 3 periods each consisting of the following steps:*

a) Testing – Initial NO_x and boiler performance evaluations would be made with installed instrumentation and control room indications. Following these initial evaluations, formal tests are required to confirm the indications from the installed instruments. Data will also be collected from test connections that do not have permanent instrumentation installed. This requires testing contractors with specialized testing equipment to measure emissions at the stack, in addition to other test grids at the boiler outlet and possibly other locations in the system. The scheduling of personnel and contractors to perform testing can often require 4 – 8 weeks of pre-planning. In addition to emissions many other measurements and fuel / sorbent / ash samples will be taken simultaneously with the emissions measurements.

b) Evaluation – Follow-up fuel / sorbent / ash laboratory analyses will be conducted and a test report prepared. The lab analysis and report preparation usually requires 4 to 6 weeks. The report will then be reviewed by a team of engineers to determine whether further actions are necessary, this study will require up to 4 weeks of engineering time.

c) Adjustments – If the evaluation determines that further action is needed, the actions would be implemented. These actions may consist of making operating adjustments or installing additional test connections or making modifications to components inside the plant systems. Implementation of these actions may require anywhere from a few weeks to several months, depending on the type / scope of the action required.

d) Re-retest – Once the adjustments are implemented, formal re-testing would be conducted as explained in 'a)' above.

e) Evaluation – The re-test report would be prepared, then analyzed to determine if further action is needed. If action is needed, this process would then be repeated.

One period of the above steps would require 3 to 4 months to complete, thus 9 to 12 months of testing / evaluation would be required to go through this process 3 times plus the initial startup and commissioning period of 3 to 4 months. In addition, time needs to be allowed to schedule and conduct at least one modification outage to make modifications to systems internal to the boiler. Thus a "Break-in Period" of at least 12 to 15 months is recommended. It is possible that it may take more time to complete the optimization process depending on the problems that are encountered and the permitted NO_x emission rate. Progress reports could be submitted to EPA to keep EPA advised on the status of the work during the "Break-in Period".

Based on the above explanation from Deseret, and on the NO_x BACT analysis above, EPA proposes the following emission limits as NO_x BACT:

- **Prior to the date which is 12 months after completion of initial performance testing: 0.088 lb/MMBtu on a rolling 30-day average.**

- **Beginning on the date which is 12 months after completion of initial performance testing, and thereafter: 0.080 lb/MMBtu on a rolling 30-day average.**

As explained earlier in this Statement of Basis, Deseret Power will be permitted to use coal from the Deserado mine, consisting of either waste coal alone, or else a blend of waste coal and run-of-mine coal yielding heat content of up to 6,500 Btu/lb. For reasons explained above, EPA believes the proposed NO_x BACT emission limit of 0.080 lb/MMBtu, on a rolling 30-day average, will represent BACT up to at least a 50/50 blend.

6. Comparison to applicable NSPS emission standard.

The definition of BACT in 40 CFR 52.21(b)(12) contains the statement that, "*In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61*." The applicable NO_x emission standard, in Subpart Da of 40 CFR part 60 (New Source Performance Standards), is 1.0 pound per megawatt-hour (lb/MWh) on a rolling 30-day average.

The following equation is used by EPA to convert from lb/MWh to lb/MMBtu:

$$\mathbf{X} \text{ lb/MMBtu} * 3.412 \text{ MMBtu/MWh} * 1/\text{Efficiency} = \mathbf{Y} \text{ lb/MWh}$$

In developing Subpart Da standards in lb/MWh, EPA assumed a 36% gross efficiency for coal-fired electric utility boilers. Approximately a quarter of existing boilers presently have average efficiencies greater than 36%; however, CFB boilers tend to have lower gross efficiency values, ranging from 30% to 38%. With the relative low-quality waste coal that will be used at Deseret's proposed WCFU, EPA expects that the WCFU efficiency would be at the lower end of this efficiency range.

If 36% gross efficiency is assumed, then by the equation above, the WCFU would have to maintain NO_x emissions at 0.11 lb/MMBtu or lower, to meet the 1.0 lb/MWh standard. If the WCFU operates at a low efficiency of 30%, then it must maintain an emissions rate of 0.09 lb/MMBtu or less, to meet the 1.0 lb/MWh standard. Considering rounding (1.049 lb/MWh), a unit with a NO_x emission limit of 0.090 lb/MMBtu would only have to maintain an efficiency of 29.2% to comply with the NSPS. Approximately 90% of existing units have average efficiency values greater than this. The proposed NO_x BACT emission limits for the WCFU (0.088 lb/MMBtu initially; 0.080 lb/MMBtu after a 15-month break-in period) are lower than 0.09 lb/MMBtu and therefore are at least as stringent as the applicable NSPS emission standard of 1.0 lb/MWh.

7. Proposed compliance monitoring approach.

For compliance demonstrations, EPA proposes to require use of NO_x CEMS. EPA also proposes to allow the diluent cap approach from 40 CFR part 75 for calculating emissions in lb/MMBtu, in the event of very low boiler load, such as during startup or shutdown. This approach was developed by EPA in Part 75 to address low-load situations at electric utility boilers. Further explanation of the diluent cap approach may be found at the end of section VI.K.5 of this Statement of Basis (Step 5 of SO_2 BACT discussion).

H. BACT for PM/PM_{10} Filterable Emissions from CFB Boiler.

The composition and amount of filterable particulate matter emitted from coal fired boilers are a function of firing configuration, boiler operation, coal properties, and emission controls. Particulate matter (as total suspended particulate) will be emitted from the CFB boiler as a result of entrainment of incombustible inert matter (ash) and condensable substances. Since CFB boilers attain nearly complete combustion, very little carbon will be present.

In addition to the potential control technologies listed in Step 1 below, clean fuels (i.e., alternative coal, either from the Deserado mine or another mine) is also a possible option for BACT, but has already been eliminated as cost-prohibitive for BACT, for all pollutants at this project. This was explained earlier in this Statement of Basis.

1. Step 1: Identify Potential Control Technologies.

EPA knows of two potential technologies for the control of filterable particulate from coal fired boilers:

a. Fabric filtration
b. Electrostatic Precipitation

2. Step 2: Eliminate Technically Infeasible Options.

Both fabric filtration (FF) and electrostatic precipitation (ESP) are technically feasible. Control of PM/PM_{10} using either FF or ESP is clearly demonstrated, available, and applicable to CFB boilers. This finding is consistent with general scientific thought that FFs and ESPs represent technically feasible control options for the control of particulate and trace metals from CFB boilers. Wet control techniques do not represent a demonstrated control technique for CFB boilers and do not offer more stringent levels of control of particulate matter than fabric filters.

a. Fabric Filtration. Fabric filtration is a constant emission device. Pressure drop across the filters, inlet particulate loading, or changes in gas volumes may change the rate of filter cake buildup but will not change the final emission rate. The major particle collection mechanisms of fabric filters are inertial impaction, diffusion from Brownian motion and interception. During fabric filtration, dusty gas is drawn through the fabric by induced draft fans. The fabric is responsible for some filtration, but more significantly it acts as support for the dust layer that accumulates. The layer of dust, also known as filter cake, is a highly efficient filter, even for sub-micrometer particles.

Fabric filters possess some key advantages over other types of particle collection devices. Along with the very high collection efficiencies, for filterable particulate matter, they also have the flexibility to treat many types of dusts and a wide range of volumetric gas flows. Fabric filters can be operated with relatively low pressure drops of 4 to 8 inches water gauge, depending upon dust loading and other factors. Fabric filters also have some potential disadvantages. In general, they are limited to filtering dry streams.

b. Electrostatic Precipitation. Collection of particles by electrostatic precipitation involves the ionization of the stream passing through the ESP, the charging, migration, and collection of particles on oppositely charged surfaces, and the removal of particles from the collection surface. In dry ESPs, the particulate is removed by rappers, which vibrate the collection surface. Wet ESPs use water to rinse the particles off.

Fabric filters and ESPs are both capable of particulate matter and trace metal control levels in excess of 99%. Some literature reports that fabric filters are more effective in collecting fine particulates than ESPs. ESP vendors, however, counter that this is a misconception since it is based on general comparisons of performance of new fabric filter installations with old, undersized, ESP installations (Masteropietro, 1994). Particulate collection industry experts currently consider new ESP designs capable of levels of particulate matter control equivalent to fabric filters. Pressure drop through an ESP is generally 1-2 inches water gauge.

Effectiveness of an ESP is impacted by the resistivity of the fly ash. Presence of SO_3 improves the ash resistivity, enabling the ash to be ionized and collected in the ESP. Inherently less SO_3 is generated in the CFB combustion process, even with a medium to high sulfur coal, due to in situ sulfur capture with limestone injection. Even less SO_3 is generated in a CFB with a low sulfur coal such as with this project fuel. In order to enhance the collection efficiency of an ESP with low SO_3 levels in the flue gas, elemental sulfur would need to be converted to SO_3 and injected into the flue gas upstream of the ESP with sufficient residence time for complete mixing.

Recent studies, conducted by Sjostrom, Bustard, et al, for the EPA and Department of Energy, suggest that fabric filters achieve a much higher mercury removal when compared to ESPs. For subbituminous coal, the percentage of mercury removed was 70% by fabric filtration versus 9% by electrostatic precipitation.

3. Step 3: Rank Remaining Control Technologies by Control Effectiveness.

The control technologies not eliminated in Step 2 are ranked in order of most effective (lowest emission rate) as follows:

a. Fabric filtration
b. Electrostatic precipitation

While both technologies offer similar removal properties for particulate matter, the project is proposing fabric filters due to the higher mercury removal as evidenced by the studies conducted for EPA.

4. Step 4: Evaluate Economic, Environmental and Energy Impacts.

The proposed project will employ fabric filters (the highest ranked option) as the control device to reduce particulate matter and trace metal emissions; thus, further review of economic, environmental and energy impacts is not necessary.

5. Step 5: Proposed PM/PM_{10} Filterable BACT for CFB Boiler.

Deseret Power searched the RACT/BACT/ LAER Clearinghouse (RBLC) and the California Air Resources Board (CARB) listings for coal fired fluidized bed boilers with limits on particulate matter emissions. Below is a summary of facilities utilizing CFB boiler technology and fabric filters for PM/PM_{10} reduction.

Comparison of CFB Boiler Filterable PM/PM_{10}
Emission Rates using Fabric Filtration:
RACT/BACT/LAER Clearinghouse Data

Facility	RBLC ID	Heat Input MMBtu/hr	Filterable particulate emissions (lb/MMBtu)		Fuel
			PM	PM_{10}	
AES-PRCP	PR-0007	4922.7	-	0.015	Columbian Coal
Reliant Energy Mid-Atlantic Power	PA-0182	2532.0	-	0.01	Coal
Archer Daniels Midland (9&10)	IL-0060	1500.0	0.025	-	Coal
Choctaw Generation	MS-0036	2475.6	-	0.015	Lignite
Archer Daniels Midland (5&6)	IA-0046	1500.0	0.015	0.03	Coal
Archer Daniels Midland	IA-0051	1500	0.015	0.03	Bituminous Coal
Kimberly Clark	PA-0204	799	-	-	Coal
Toledo Edison	OH-0231	1764	0.03	-	Pet Coke
York County Energy Partners	PA-0132	2500.0	-	0.011	Bituminous Coal
Northampton Generating Co.	PA-0134	1146.0	-	0.01	Anthracite Culm
Westwood Energy	PA-0124	423	-	-	Anthracite Culm
Gilberton Power	PA-0110	520	-	-	Anthracite Culm
Archer Daniels Midland (7&8)	IL-0058	1500	0.025	-	Coal
Energy New Bedford Cogeneration	MA-0028	1671.0	-	0.018	Eastern US Coal

AES Warrior Run	MD-0022	2070.0	0.015	-	Eastern US Coal
Archer Daniels Midland	IA-0025	551.5	-	0.03	Coal
Energy New Bedford Cogeneration	MA-0009	3342.0	0.018	-	Eastern US Coal
Tauton Energy Center	MA-0011	1604.4	0.018	-	Eastern US Coal
North Branch Energy Partners	PA-0058	563.5	-	0.02	Waste Bit. Coal

In consideration of emission limits for similar facilities, EPA has concluded that an appropriate BACT emission limit for filterable particulate matter at Deseret's WCFU would be 0.012 lb/MMBtu on a 24-hour block average (midnight to midnight). EPA's reasoning for this conclusion is presented below.

With the exception of the AES-PRCP plant, all other plants operating CFB boilers with PM/PM_{10} emission limits utilized fabric filters for control of filterable PM/PM_{10} emissions. The facilities reporting the lowest filterable PM_{10} emission limits were the Reliant Energy Mid-Atlantic Power and Northampton Generating Company with an emission limit of 0.01 lb/MMBtu. York County Energy Partners reported a PM_{10} emission limit of 0.011 lb/MMBtu. Although EPA does not have data on the heat content of the coal for these three facilities, EPA expects that the heat content of these eastern coals would be substantially higher than the heat content of the waste coal for Deseret's WCFU (which is derived from western bituminous coal), and would also likely be higher than the heat content of a 50/50 blend of Deseret's waste coal and run-of-mine coal. Therefore, these facilities can reasonably be expected to achieve a lower PM/PM_{10} emission rate in lb/MMBtu than Deseret's WCFU.

Not yet listed in the Clearinghouse database (but available to the public) is a permit issued by Pennsylvania on July 21, 2005, for a CFB boiler project by River Hill Power Company LLC. The permit was revised on March 7, 2006. The revised permit (also available to the public) sets an emission limit for filterable PM_{10} of 0.010 lb/MMBtu, with compliance to be demonstrated by EPA Method 5, 201, or 201A. The choice of required test method implies an averaging time of approximately 3 hours. EPA Region 8 has been informed by EPA Region 3 that the heat content of River Hill's waste coal is expected to be in the vicinity of 6,000 Btu/lb.

While the numerical value and averaging time of the River Hill emission limit are more stringent than what EPA has selected for Deseret Power, the considerations below lead EPA to conclude that the emission limit proposed for Deseret Power constitutes BACT:

(1) Pennsylvania's "Plan Approval Application Review Memo" dated January 23, 2006, indicates the emission limit of 0.010 lb/MMBtu was calculated on the basis of fabric filter collection efficiency of 99.98%, fabric filter inlet loading of 170,996 lbs/hr, and CFB boiler heat input capacity of 2,871 MMBtu/hr. Using these figures, EPA Region 8 calculates 0.012

lb/MMBtu rather than 0.010 lb/MMBtu as the BACT determination for River Hill.

(2) Deseret Power's waste coal is lower quality than River Hill's, particularly in terms of ash content. For the proposed WCFU, the average fabric filter inlet loading has been calculated by Deseret Power as follows: At maximum boiler heat input of 1,445 MMBtu/hr, average waste coal heating value of 4,000 Btu/lb, 40% ash content, and 0.4% sulfur, the amount of fuel required would be 180 tons/hr and the amount of ash generated in the boiler furnace would be 72 tons/hr. Assuming approximately 30% of the ash leaves the furnace as bottom ash along with some of the calcium sulfate formed in the furnace, the amount of particulates entering the baghouse would be approximately 50 tons/hr, or 100,000 lbs/hr. This would require a removal efficiency of approximately 99.98% (same as River Hill), to not exceed the WCFU emission limit of 0.012 lb/MMBtu for filterable PM.

When burning 3,000 Btu/lb coal with 50% ash (the low end of Deseret Power's estimated waste coal quality range), the baghouse inlet loading would be approximately 85 tons/hr, or 170,000 lbs/hr. This would be the same inlet loading as River Hill's project (which is three times as large as Deseret's proposed WCFU, in terms of heat input capacity). This amount of inlet loading would require a removal efficiency of 99.99% at the WCFU baghouse, to comply with the WCFU emission limit of 0.012 lb/MMBtu. EPA cannot expect Deseret Power to comply with an even lower limit of 0.010 lb/MMBtu, over the entire range of expected coal quality. EPA calculates that to do so would require baghouse control efficiency of 99.992%. EPA is not aware of any BACT determinations anywhere for filterable PM from coal-fired projects that require as high as 99.992% control efficiency under any operating scenario.

(3) River Hill is only required to conduct annual stack tests to demonstrate compliance with its filterable PM_{10} limit, whereas Deseret Power will be required to continuously demonstrate compliance via PM CEMS. The River Hill permit does require a "PM-10 CEMS" to be installed, but says the CEMS shall not be used to demonstrate compliance with any emission limitations for up to 24 months from initial startup of River Hill's CFB boiler. PM_{10} CEMS are not yet commercially available and EPA has not yet developed a Performance Specification Test for PM_{10} CEMS. Performance Specification 11 (PS11), in Appendix B of 40 CFR part 60, is applicable to PM CEMS but not to PM_{10} CEMS. Paragraph 3.20 of PS11 requires that PM CEMS accuracy be challenged via EPA Method 5, 5I, or 17. None of these test methods involve size fractionation to determine the PM_{10} emissions.

(4) Pennsylvania's PSD permit for the River Hill project, dated March 7, 2006, says in section C-VII, condition #012, that the Pennsylvania Department of Environmental Protection may revise the allowable BACT emission rates in the permit, based upon demonstrated performance (CEM data, stack test results) during the first five years of operation, provided that the revised allowable BACT emission rates do not exceed "levels at which BACT was evaluated." This provision is applicable to any BACT emission limit in the permit. EPA Region 8 interprets this provision to allow for the possibility that the BACT emission limit for filterable PM_{10} of 0.010 lb/MMBtu could be revised upward later, to any value deemed appropriate by the

Pennsylvania DEP, based on the aforementioned CEM data and stack test results. For Deseret Power, however, EPA is not proposing any permit language saying the filterable PM emission limit may be revised upward later.

In the draft permit for Deseret's WCFU, EPA proposed an emission limit for filterable PM of 0.012 lb/MMBtu on a rolling 30-day average. However, EPA re-considered and determined that a 24-hour block average should be specified instead, on the basis of comparison with the applicable PM emission limit in Subpart Da of 40 CFR part 60, New Source Performance Standards. A 1986 guidance memorandum by EPA's Office of Air Quality Planning and Standards states that, "*The PSD regulations clearly require that the application of BACT conform with any applicable standard of performance under 40 CFR Part 60 at a minimum.*"

Ref: Memorandum from Gerald A. Emison, Director, Office of Air Quality Planning and Standards, US EPA, to David Kee, Director, Air Management Division, EPA Region 5, November 24, 1986, page 1, available online at:

http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/shrtterm.pdf

The applicable PM emission limit in Subpart Da is expressed on a daily average (equivalent to a 24-hour block average). To conform with Subpart Da of 40 CFR part 60, EPA considers it necessary to specify the averaging time of the BACT limit as a 24-hour block average. On the basis of comparison with other similar permitted facilities, EPA considers 0.012 lb/MMBtu on a 24-hour block average to be achievable at Deseret's WCFU.

As explained earlier in this Statement of Basis, for the proposed WCFU, Deseret Power will be permitted to use coal from the Deserado mine consisting of either waste coal alone, or else a blend of waste coal and run-of-mine coal yielding heat content of up to 6,500 Btu/lb. While this heat content is similar to River Hill's, the ash content of the blended coal would still be higher than River Hill's, and Deseret Power would still need to operate at a baghouse collection efficiency of nearly 99.98% for even this "best case" coal. As explained earlier, Deseret Power only plans to blend to the extent necessary to deal with any unexpected operational difficulties when firing waste coal alone, or to deal with any unexpected difficulties in meeting BACT emission limits.

In summary, EPA believes an emission limit for filterable PM of 0.012 lb/MMBtu on a 24-hour block average will represent BACT for coal from the Deserado mine with heat content up to at least 6,500 Btu/lb, and will ensure a continued high degree of PM emission control efficiency. EPA therefore proposes the following as a BACT emission limit for total filterable particulate matter:

0.012 lb/MMBtu on a 24-hour block average (midnight to midnight)

Since EPA expects that virtually all filterable particulate emissions will be PM_{10} size or smaller, EPA is proposing the same limit of 0.012 lb/MMBtu as BACT for filterable PM_{10}. Also, since EPA is proposing to require use of a particulate matter continuous emission monitoring system (PM CEMS) for demonstrating compliance, EPA does not consider it necessary to also propose an opacity limit as part of BACT for total filterable particulate. See further discussion below.

6. <u>Comparison to applicable NSPS emission standard</u>.

The definition of BACT in 40 CFR 52.21(b)(12) contains the statement that, "*In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61*." The applicable particulate matter emission standard in Subpart Da of 40 CFR part 60 (New Source Performance Standards) is 0.015 lb/MMBtu on a daily average. Allowed alternatives in Subpart Da are: 0.14 lb/MWh on a daily average, or 0.03 lb/MMBtu and 99.9% emission reduction on a daily average. The BACT emission limit of 0.012 lb/MMBtu on a 24-hour block average for the WCFU is at least as stringent as the NSPS limit. EPA also notes that the NSPS exemptions for startup, shutdown and malfunction will not apply to the BACT limit.

7. <u>Proposed compliance monitoring approach</u>.

For compliance demonstrations, EPA proposes to require use of a particulate matter continuous emission monitoring system (PM CEMS). EPA considers this particulate monitoring approach superior to establishment of an opacity limit and monitoring of opacity via a Continuous Opacity Monitoring System (COMS). This PM CEMS approach is consistent with 40 CFR 60, Subpart Da, under which PM CEMS is an allowed alternative to an opacity limit and COMS.

EPA further proposes to allow the diluent cap approach from 40 CFR part 75, for calculating emissions in lb/MMBtu, in the event of very low boiler load, such as during startup or shutdown. This approach was developed by EPA in Part 75 to address low-load situations at electric utility boilers. Further explanation of the diluent cap approach may be found in section VI.J.5 of this Statement of Basis, at the end of Step 5 of SO_2 BACT discussion.

EPA considered opacity monitoring and imposition of an opacity limit as a means of helping assure compliance with particulate emission limits. However, EPA believes that opacity monitoring at Deseret Power's WCFU, as an addition to requiring a PM CEMS calibrated according to 40 CFR 60, Appendix B, Performance Specification 11, would be ineffective for assuring compliance with emission limits for either filterable PM or total PM.

Opacity monitoring can be useful as a surrogate for direct measurement of particulate emissions. However, EPA does not consider it useful for assuring compliance with PM emission limits where those limits are extremely low. The emission limit for Deseret Power's WCFU for total PM/PM_{10} is 0.03 lb/MMBtu. This limit is based on a filterable PM/PM_{10} emission limit of

0.012 lb/MMBtu, added to projected emissions of no more than 0.018 lb/MMBtu for condensable PM. These emission limits are so low that EPA believes it highly improbable, if not impossible, that any form of existing opacity monitor could reliably detect opacity at levels that would correspond to these limits. Moreover, given the sensitivity of the PM CEMS, elevated emissions would be detected by PM CEMS well in advance of detection via a Continuous Opacity Monitoring System (COMS), or via a Method 9 or Method 22 visible emissions observation. Further, opacity only provides data from a subset of all particles, namely those particles whose size is roughly the same wavelength as visible light.

A status report prepared for EPA on PM CEMS, dated February 12, 1997 (available at http://www.epa.gov/ttn/emc/cem.html) in support of proposed revised regulations for hazardous waste combustors (HWC), states that opacity monitors are not effective below filterable PM concentrations of 45 mg/dscm. For coal combustion, this is equivalent to about 0.04 lb/MMBtu. (The total PM/PM_{10} emission limit for Deseret Power's WCFU, cited above, is lower than this.) The Introduction to the status report states:

> *EPA in the past has relied on opacity monitors as a form of surrogate-PM monitoring to indicate compliance with a PM standard. This approach involved a continuous opacity monitor to demonstrate compliance with a separately-enforceable opacity limit approximately aligned with, or near, the PM emission limit. However, this approach has a serious limitation relative to the proposed HWC rule, because of poor correlation between opacity and PM at low PM concentrations near the proposed PM emission limit of 69 mg/dscm (at 7 % O2).*
>
> *EPA recognizes that there are two inherent problems with the opacity/PM approach: 1) the general concern about the stability of any opacity/PM correlation, which is strongly dependent on particle size distribution and composition, and 2) the specific concern about the insensitivity of opacity monitors typically below PM levels of about 45 mg/dscm (at 7 % O2).*
>
> *Consequently, opacity monitors would not be sufficient because to maintain compliance with 69 mg/dscm, facilities would generally need to operate near 35 mg/dscm. Thus, emissions would typically be below the detection limits of opacity monitors most of the time. While normal emission levels below the detection limits of CEMS are acceptable, facilities often desire the detection limit to be one-tenth of the emission limit. This gives sufficient warning of how emissions are changing before the emission limit is approached, and allows the facility, based on CEMS readings, to change operations as necessary to be in compliance.*
>
> *If possible, EPA desires a quantitative, continuous measure of PM mass concentrations rather than opacity. Based on surveys and preliminary testing, EPA has recently determined that CEMS do exist that do this: beta gauges and light scattering based CEMS. These CEMS rely on calibration/certification of the device by manual gravmetric*

measurements. Therefore, EPA is proposing use of CEMS based on the availability of these newer technologies and a related Draft CEMS Performance Specification for monitoring PM mass concentration. EPA believes that such monitoring is feasible and that opacity monitoring has borderline sensitivity relative to the proposed PM emission limit. The newer technology PM CEMS can give a real-time quantitative measure of low PM concentrations while opacity monitors cannot.

(Ref: Status Report No. IV, Particulate Matter CEMS Demonstration, prepared by Energy and Environmental Research Corporation, EPA Contract 68-D2-0164, Work Assignment 4-02, February 12, 1997.)

This same reasoning is reflected in the recent revisions to Subpart Da of New Source Performance standards (40 CFR 60). The revised Subpart Da exempts facilities from ongoing opacity monitoring after initial performance testing, where PM CEMS is installed and used. The same reasoning is also reflected in EPA's Technical Guidance Document for Compliance Assurance Monitoring (available on EPA website at http://www.epa.gov/ttn/emc/cam.html), at Appendix A, Facility V (pages A.19b-1 through A.19b-4), in which no opacity monitoring is suggested where PM CEMS are used.

Further, the emission control technique for condensible PM at the proposed WCFU is a combination of alkali injection, dry SO_2 scrubbing and a fabric filter baghouse. Each of these control techniques will be installed and used to comply with other emission limits in the permit (alkali injection for NO_x control, dry SO_2 scrubbing for SO_2 control, and a fabric filter baghouse for filterable PM control). The permit requires compliance with these three other emission limits to be tracked continuously via CEMS. (Ref: Conditions III.I.4.a and III.I.4.c of the WCFU permit.) This continuous monitoring, in addition to annual stack tests required in the permit for condensable PM, is considered by EPA to be sufficient for ensuring good control of the both the condensable PM portion and the filterable PM portion of total PM.

I. BACT for PM/PM_{10} Condensible Emissions from CFB Boiler.

Portions of the discussion of condensible particulate matter (CPM) in Steps 1 through 4 below, including the discussion of why a wet ESP has been eliminated as a control option, come from an e-mail and attachments provided by Deseret Power to EPA on February 23, 2006. EPA has made a number of changes, including the addition of a discussion of wet SO_2 scrubbers as a potential control technology.

In addition to the potential control technologies listed in Step 1 below, clean fuels (i.e., alternative coal, either from the Deserado mine or another mine) is also a possible option for BACT, but has already been eliminated as cost-prohibitive for BACT, for all pollutants at this project. This was explained earlier in this Statement of Basis.

1. Step 1: Identify Potential Control Technologies.

The following control technologies with the potential to reduce condensable particulate matter (CPM) are known to EPA and Deseret Power.

a. Alkali (limestone) injection + fabric filter baghouse

b. Dry SO_2 scrubbing + fabric filter baghouse

c. Alkali injection + dry SO2 scrubbing + fabric filter baghouse

d. Alkali injection + wet SO2 scrubbing + fabric filter baghouse

e. Alkali injection + dry SO2 scrubbing + fabric filter baghouse + wet electrostatic precipitation (ESP)

2. Step 2: Eliminate Technically Infeasible Options.

All potential control technologies (or technology combinations) listed in Step 1 above are technically feasible; however, it must be noted that each of these technologies is only effective in reducing some of the constituents that make up condensible particulate matter (CPM). The primary CPM constituents identified by Deseret Power for the WCFU include hydrogen chloride (HCl), hydrogen fluoride (HF), sulfuric acid (H_2SO_4), ammonium sulfate ($(NH_4)_2SO_4$), ammonium bisulfate (NH_4HSO_4), dinitrogen pentoxide (N_2O_5), and volatile organic compounds (VOC). (Reference: e-mails from Deseret Power to EPA dated February 23, 2006 and March 27, 2006.) Based on EPA Region 8's research of publicly available literature, these technologies would be expected to provide significant emission control for all these CPM constituents except N_2O_5 and VOC.

a. Alkali (limestone) injection + fabric filter baghouse. Alkali injection reduces CPM emissions by removing SO_3 from the exhaust, thus preventing formation of H_2SO_4. The alkali material may be injected at various points within the process and may consist of materials such as magnesium hydroxide, sodium bisulfite, sodium bicarbonate, calcium hydroxide or calcium carbonate. Crushed limestone ($CaCO_3$) is part of the solid medium that makes up the combustion bed. Within the combustion zone, CaO is formed by calcining the limestone. SO_2 formed during the combustion process combines with the calcined lime to form solid $CaSO_3$, which is then collected downstream in the fabric filter baghouse.

As explained in more detail in the SO_2 BACT analysis in this Statement of Basis, alkali injection not only removes SO_3, but also removes SO_2 in the combustion bed. This reduces the quantity of SO_2 available for oxidation into SO_3. Excess lime in the combustion bed will also react with SO_3 to form solid $CaSO_4$, which is collected downstream in the fabric filter baghouse. Furthermore, excess CaO in the combustion bed and fabric filter cake will be available to react with SO_3 generated in the combustion bed.

Deseret Power is already planning to inject calcium carbonate into the CFB boiler and lime in the dry SO_2 scrubber, to reduce SO_2 emissions, and install a fabric filter baghouse. As a result, SO_3 formed during the combustion process will be controlled to the extent possible.

In processes that incorporate selective catalytic reduction (SCR), additional SO_2 may be oxidized to SO_3 as the exhaust passes through the catalyst bed. Those processes may benefit from alkali injection in the SCR or air heater outlet ducts; however, Deseret's proposed WCFU will not be using SCR. Because additional generation of SO_3 downstream of the boiler is not anticipated, there would be no benefit associated with injecting additional alkali elsewhere in the process. While duct injection would serve no purpose, alkali injection in the boiler is considered to be technically feasible and is proposed for the WCFU.

b. Dry SO_2 scrubbing + fabric filter baghouse. Dry SO_2 scrubbing has the potential to control CPM by the same mechanism as alkali injection. The alkali (in this case lime) is injected in slurry form, dried by the exhaust gas, combines with SO_2 and forms a solid that is collected downstream in the fabric filter baghouse. This control technology is considered technically feasible and is proposed by Deseret Power for installation at the WCFU.

c. Alkali injection + dry SO2 scrubbing + fabric filter baghouse. The combination of these controls is proposed by Deseret Power for the WCFU and is expected to achieve better control of CPM than the previous two control technology combinations (options a and b) discussed above.

d. Alkali injection + wet SO2 scrubbing + fabric filter baghouse. Although a control option that includes wet scrubbing is technically feasible, it is not considered as effective as option c above. This is explained below.

The wet scrubbing process uses an alkaline slurry made by adding lime or limestone to water. The alkaline slurry is sprayed into the absorber tower and reacts with SO_2 in the flue gas to form insoluble $CaSO_3$ and $CaSO_4$ solids. A wet FGD process must be located downstream of the fabric filter baghouse. SO_2 entering the wet scrubber will react with water and create micron sized H_2SO_4 droplets. Micron sized droplets can pass through the spray levels in the absorber tower and the most eliminator and be emitted as H_2SO_4. Although some of the H_2SO_4 droplets will react with the alkaline reactant in the wet scrubber, industry experience suggests that many of the micron-sized droplets will not come into contact with limestone. (Reference: Gooch, J.P., Dismukes, E.B., Formation of Sulfate Aerosol in an SO_2 Scrubbing System, Southern Research Institute, Birmingham, AL.) Furthermore, because of the inherently low SO_3 concentration in CFB flue gas, it is not anticipated that a wet FGD system will provide any significant reduction in overall SO_3 or H_2SO_4 emissions.

Acid gases and ammonium sulfate are water soluble and will be removed in the wet FGD control system. These compounds will also be removed in the unit's fabric filter baghouse; however, because the wet FGD would have to be located downstream of the fabric filter, it is expected that acid gas removal in the fabric filter will be less effective with the wet FGD combination. In conclusion, while it is technically feasible, a H_2SO_4 control system involving a wet FGD is expected to have lower control efficiency than option c above.

e. Addition of wet electrostatic precipitation to option c above. This discussion pertains to the technical feasibility of adding a wet electrostatic precipitator (ESP) downstream of the combination of controls listed as option c above. Wet ESPs are capable of controlling particulate matter as well as acid mists. ESPs collect particulate matter by applying a negative electrical charge to the particles as they pass through the charging zone of wires or electrodes. The negatively charged particles are then attracted to and captured by positively charged collector plates. In a dry ESP, the captured particles are periodically removed from the collector plates by rapping. In a wet ESP, the particles are either continuously or intermittently removed from the plates by wash water. It is the presence of wash water and the resulting high humidity inside a wet ESP that allows it to control mists or aerosols as well as particulate matter. A wet ESP's ability to control the CPM is somewhat dependent on the temperature of the exhaust stream as it passes through the wet ESP.

The exit temperature of the dry SO_2 scrubber, which Deseret Power plans to install at the WCFU, is expected to be about 275 degrees Fahrenheit. To avoid reaching saturation and the resulting wet plume and associated corrosion, the WCFU exhaust stack exit temperature must be maintained at or near this temperature. If a wet ESP is installed as well at the WCFU, adjustments to the exhaust system (including the scrubber) would have to be made to maintain the desired temperature profile. Although this makes feasibility of a wet ESP somewhat questionable at the WCFU, a wet ESP shall be considered technically feasible for the purposes of this analysis, and will be evaluated further in Steps 3 and 4 below.

3. Step 3: Rank Remaining Control Technologies by Control Effectiveness.

As mentioned in Step 2 above, Deseret Power proposes to install alkali injection, dry SO_2 scrubbing and a fabric filter baghouse (option c in Step 1 above). For reasons explained in Step 2 above, this proposed combination of controls is expected to be more effective than a combination involving wet scrubbing (option d in Step 1 above). The only option that might achieve greater control effectiveness than option c would be to add a wet ESP downstream. Below is a discussion of the possible additional CPM control that might be achieved by a wet ESP.

There are little data available on the H_2SO_4 reduction achievable with a wet ESP on a coal-fired boiler. In its BACT analysis for H_2SO_4 at the proposed Intermountain Power Unit 3, the Utah Division of Air Quality (UDAQ) stated that no more than 80 percent removal efficiency for H_2SO_4 might be expected, for a wet ESP at a pulverized coal-fired boiler, under optimum conditions. (Reference: "Modified Source Plan Review" by UDAQ for IPP3 project, March 22, 2004, page 109.) However, others have cited a removal efficiency equivalent to about 86 percent (SO_3 reduction from 21 to 3 ppm) in conducting economic analyses of wet ESP control for CPM. (Reference: Dombroski, K, et al, "SO_3 Mitigation Guide and Cost-Estimating Workbook," Proceedings of the 2004 Mega-Symposium, August 30 – September 2, Washington, D.C.) Due to the lack of additional data, and the desire to present a conservative analysis of the control technology, a value of 86 percent will be used in the Step 4 analysis below, for removal of H_2SO_4. It is also conservatively assumed that a wet ESP would remove equivalent amounts of other acid gases, such as HCl and HF, as well as filterable PM_{10} not captured by the proposed fabric filter.

No information regarding the potential of a wet ESP to control the other principal condensible PM_{10} constituents identified by Deseret's boiler supplier was found, and thus the removal efficiency for VOC, N_2O_5, and $(NH_4)_2SO_4$ is assumed to be zero.

4. Step 4: Evaluate Economic, Environmental and Energy Impacts.

The following analysis explains why addition of a wet ESP would be economically cost-prohibitive, for achieving additional CPM control for the WCFU project. The estimated capital cost of a wet ESP ranges from \$20 to \$40 per SCFM (standard cubic foot per minute) of gas flow handled. Reference: EPA-452/F-03-030, July 15, 2003, available at:

http://www.epa.gov/ttn/catc/dir1/fwespwpl.pdf.

Operation and maintenance (O&M) costs range from \$5 to \$40 per SCFM. The exhaust flow rate for the proposed unit is about 399,971 SCFM (based on a modeled flow rate of 565,440 actual cubic feet per minute at 275 degrees F, corrected to standard conditions). The table below presents the capital and O&M costs of a wet ESP for the proposed WCFU, based on the low, midpoint, and high end of the ranges provided in the EPA document cited above. Total annualized costs are based on a capital recovery factor of 0.10296 (15 years and 6% discount rate).

Capital and O&M Costs
For Addition of a Wet ESP
at Deseret Power's Proposed WCFU

EPA Cost Range	Capital Cost ($)	O&M Cost ($)	Total Annualized Cost ($)
Low	7,999,427	1,999.857	2,823,478
Mid-Point	11,999,140	8,999,355	10,234,786
High	15,998,853	15,998,853	17,646,095

The next table below shows the amount of CPM removed by a wet ESP, assuming 86 percent removal efficiency. The pre-wet ESP control emission rate for filterable PM is based on the proposed BACT emission limit for the WCFU of 0.012 lb/MMBtu. The pre-wet ESP control emission rate for H_2SO_4 is based on the proposed BACT emission limit for the WCFU of 0.0035 lb/MMBtu. The pre-wet ESP control emission rates for HCl and HF (0.0022 and 0.0008 lb/MMBtu, respectively) are based on emission estimates from Deseret's boiler supplier, provided to EPA by Deseret Power via e-mail of February 23, 2006. Potential emissions in tons per year are based on the maximum heat input rate of 1,445 MMBtu/hr and 8,760 hours per year of operation.

Estimated Emissions Reduction
for Addition of a Wet ESP
at Deseret Power's Proposed WCFU

Constituent	Pre-wet ESP Control Emissions		Emissions Removed (tons/year)
	Lb/MMBtu	tons/year	
HCl	0.0022	14.1	12.1
HF	0.0008	4.9	4.2
H_2SO_4	0.0035	22.2	19.1
PM_{10} (filterable)	0.012	75.9	65.3
Total	-	-	100.7

The next table below shows the cost of control for both filterable and condensable particulate matter based on the annualized costs and the emission removals shown in the two tables above.

Estimated PM_{10} Control Cost
for Addition of a Wet ESP
at Deseret Power's WCFU

EPA Cost Range	Control Cost ($/ton)
Low	26,039
Mid-Point	101,636
High	175,234

As shown in the table above, even the most conservative analysis demonstrates that addition of a wet ESP to the proposed WCFU would be economically prohibitive for BACT.

Some of the potential negative environmental impacts associated with a wet ESP include increased water usage, disposal of a wet waste stream, and the generation of ozone. In addition, due to the temperature drop across a wet ESP and the need to maintain the necessary exhaust temperature exiting the stack, the temperature of the exhaust entering the wet ESP would need to be higher. This would result in less heat being available for steam generation and have the result of reducing the overall efficiency of the proposed WCFU. For these reasons and the economic reasons discussed earlier, EPA believes a wet ESP should be eliminated as a BACT option for condensible particulate matter.

5. Step 5: Proposed PM/PM_{10} Condensible BACT for CFB Boiler.

The following analysis, for determination of a BACT emission limit, is based on the selected CPM control combination of alkali injection, dry SO_2 scrubbing and fabric filter baghouse. Consistent with the approach taken by permitting authorities for other CFB boiler projects, and consistent with dispersion modeling for the WCFU project, which used one emission rate for the total of filterable PM plus condensible PM, EPA does not propose a separate BACT emission limit specifically for condensible PM. Instead, EPA proposes an emission limit of 0.03 lb/MMBtu for total PM, which includes both condensible PM and filterable PM. EPA proposes the same emission limit of 0.03 lb/MMBtu for total PM_{10}, on the basis that EPA expects virtually all PM emitted from the WCFU, downstream of all emission controls, will be of PM_{10} size or smaller. This proposed emission limit is based on what EPA believes to be achievable control, in practice, of total PM, and is consistent with other issued permits for similar projects.

For demonstrating compliance with the total PM limit, EPA proposes to require the condensible PM portion to be measured by EPA Method 202 (or EPA Conditional Test Method 39 as an allowed alternative). As also explained below, EPA proposes to allow the emission limit for total PM to be adjusted to as high as 0.045 lb/MMBtu, pending EPA's review of actual stack testing data from the WCFU, after the WCFU begins operation.

In its permit application dated November 1, 2004, Deseret Power proposed a BACT emission limit for total PM_{10} of 0.052 lb/MMBtu. Dispersion modeling was based on this emission rate. Deseret Power stated in its application that this proposed limit is based on 0.012 lb/MMBtu for filterable PM_{10} and 0.040 lb/MMBtu for condensible PM. Deseret Power also stated that the condensibles emission factor is based on AP-42 since no vendor data are available.

EPA found that the AP-42 emission factor cited by Deseret Power is actually for spreader stoker, traveling grate overfeed stoker, and underfeed stoker boilers. There is no specific emission factor in AP-42 for condensible PM from CFB units. However, a footnote to Table 1.1-5 in AP-42 says that for CFB units, the emission factor for pulverized coal fired boilers with PM and FGD controls should be used. This value is 0.02 lb/MMBtu. Regardless of interpretation of AP-42, EPA advised Deseret Power that AP-42 is not intended by EPA to represent BACT.

To determine an appropriate estimate for condensible PM, EPA looked at other sources of information on condensible PM from CFB boilers, primarily the permit applications for three other projects, where the permit application was actively being processed or the permit had been issued: Gascoyne in North Dakota, Estill County Energy Partners in Kentucky, and River Hill Power in Pennsylvania. These applications all contained estimates of the various components of condensible PM that can be summed to give a value for total condensible PM. The components were: hydrogen chloride [HCl], hydrogen fluoride [HF], ammonium sulfate [$(NH_4)_2SO_4$], sulfuric acid [H_2SO_4], and volatile organic compounds [VOC].

EPA also looked at the estimates for some of these components of condensible PM that appeared in an appendix to Deseret Power's PSD permit application. Summing the components, EPA came up with a rough estimate of 0.011 lb/MMBtu for condensible PM and 0.023 lb/MMBtu for total PM/PM_{10}. This EPA analysis was explained in detail in a pre-draft Statement of Basis that was e-mailed to Deseret Power on December 1, 2005.

In a January 30, 2006 email, Deseret Power responded by submitting its own estimation ranges for components of condensible PM. Deseret Power proposed a total PM/PM_{10} limit of 0.045 lb/MMBtu, of which 0.033 lb/MMBtu was estimated for condensible PM. This estimate was three times as high as EPA's estimate of 0.011 lb/MMBtu, primarily due to differences in the estimates for the sulfuric acid and ammonium sulfate components, and also due to Deseret Power's inclusion of a small amount of dinitrogen pentoxide [N_2O_5]. Deseret Power stated that its condensible PM estimate assumes EPA Method 202 condenses SO_2 and SO_3 to H_2SO_4 and that all ammonia slip emitted at the boiler exhaust stack will condense as ammonium sulfate in the Method 202 impingers.

There was no discussion in Deseret Power's January 30, 2006 e-mail, nor in a subsequent e-mail from Deseret Power dated February 23, 2006, on top-down BACT analysis for condensible PM, on how Deseret Power's estimate for condensible PM compares to estimates for other proposed CFB boiler projects. There was also no discussion of why 0.033 lb/MMBtu should represent BACT based on the selected emission controls (alkali injection and dry SO_2 scrubbing). Below is EPA's own discussion and analysis.

The largest component by far in Deseret Power's condensible PM emission estimate was ammonium sulfate. Deseret's estimate for this component was about three times as much as Deseret's estimate for the next largest component (sulfuric acid), and was about half of Deseret's estimate for total condensible PM. This seemed incorrect to EPA. In other permit applications and analyses reviewed by EPA, the largest component of condensible PM was consistently sulfuric acid, not ammonium sulfate.

In light of this disparity between Deseret Power's information and the information in permit applications for other CFB boiler projects, EPA closely examined Deseret Power's emission estimate for ammonium sulfate. In a February 3, 2006 e-mail, EPA asked Deseret Power what level of ammonia slip was estimated and how that was used to calculate ammonium sulfate emissions. Deseret Power replied on February 22, 2006 that the "estimated contribution of $(NH_4)_2SO_4$ is based on an ammonia slip level of 4 ppm at the stack" and "all of the ammonia was assumed to be picked up as NH_4HSO_4 in the M202 impingers." While this provided some description of the estimation method, it did not entirely clear up why the estimate was so much higher than other permit applicants. It was also unclear to EPA whether Deseret Power was calculating ammonium sulfate or ammonium bisulfate emissions.

Consequently, EPA did a mass balance calculation that assumed all of the ammonia slip coming out of the CFB combustor unit (i.e., immediately downstream of SNCR controls) would react with sulfuric acid to form ammonium sulfate. This would occur upstream of the dry scrubber and baghouse. EPA also assumed 85% control of ammonium sulfate by the dry scrubber and baghouse. These assumptions were consistent with analyses in permit applications reviewed by EPA for other CFB boiler projects. EPA's calculation yielded an emission estimate of 0.0036 lb/MMBtu for ammonium sulfate. This was about one-fifth of Deseret Power's estimated emission range of 0.014 to 0.0209 lb/MMBtu.

EPA also did a separate mass balance calculation for sulfuric acid, since Deseret Power did not provide a calculation or other basis for its own estimated emission range. These calculations were also e-mailed to Deseret Power on March 9, 2006. In that e-mail, EPA concluded that the estimate for total condensible PM should be about 0.019 lb/MMBtu. When added to 0.012 lb/MMBtu for filterable PM, this would yield about 0.03 lb/MMBtu for total PM/PM_{10}, which EPA believes is an appropriate BACT emission limit for total PM/PM_{10}.

In a March 27, 2006 e-mail, Deseret Power responded to EPA's calculations by explaining Deseret's underlying estimates and assumptions for calculating a range of 0.014 to 0.0209 lb/MMBtu for ammonium sulfate. Some of these underlying estimates and assumptions are different than what EPA has seen in permit applications for other CFB boiler projects with similar controls. The key differences are the concentration of unreacted free ammonia slip at the final exhaust stack, and whether that free ammonia would form ammonium sulfate or ammonium bisulfate in the Method 202 impingers.

Deseret Power estimated that 10 ppm ammonia slip would exit the CFB combustor unit. Deseret Power also estimated that approximately 40-60% of that ammonia slip would be removed by the dry scrubber and baghouse downstream (presumably once the ammonia has reacted to form an ammonium salt). Permit applicants for other CFB boiler projects typically predicted 85% or greater removal of ammonia slip prior to the final exhaust stack. Also, Deseret Power assumed that 100% of the ammonia at the final exhaust stack would be measured as ammonium bisulfate in the Method 202 impingers. The dominant ammonia salt predicted by other permit applicants was ammonium sulfate.

These underlying estimates and assumptions are inherently difficult to evaluate for validity, yet greatly affect the predicted level of ammonium salt formation measured by Method 202. The estimate of how much ammonia slip would be removed by a dry scrubber and baghouse would primarily depend on whether the ammonia reacts to form an ammonium salt, prior to reaching the dry scrubber and baghouse. Predicting exactly which reactions occur, to what extent they occur, and whether they occur upstream or downstream of the control equipment, is difficult. The eventual fate of any free ammonia in the Method 202 impingers is also difficult to predict. Deseret Power's assumption that all of the free ammonia would form ammonium bisulfate would yield a higher mass emission rate than the assumption by other permit applicants that the free ammonia would form ammonium sulfate. This is due to the different molar ratio in each reaction equation.

The chemical reactions involving ammonia in the CFB boiler, upstream of the dry scrubber and baghouse, and in the Method 202 impingers, is very likely more complicated than either Deseret Power's or EPA's calculations suggest. While the calculations referenced above may provide a rough estimate of this component of condensible PM, EPA is not confident that all of the chemical reactions that would take place have been accurately accounted for and quantified. Therefore, EPA examined other CFB permit limits and stack testing data, to compare to both Deseret Power's and EPA's emission estimates for condensible PM at the WCFU, and to help determine an appropriate BACT emission limit for total PM. Information on other CFB permit limits and proposed permit limits is summarized in the table below.

Summary of Recent CFB Projects:
Permitted or Proposed Condensible PM Emission Rates
with SNCR / Dry Scrubber / Baghouse Controls

Project / Company Name	Permit Authority	Primary Coal Type	Permit Status	PM_{10} Emission Rate (lb/MMBtu)
AES Puerto Rico Cogeneration Plant	EPA Region 2	Columbian Coal	Issued 10/29/01 Revised 8/10/04 to raise the total PM_{10} limit from 0.015 to 0.03 lb/MMBtu based on stack testing	0.03 (total PM_{10}) This limit was originally 0.015 but was adjusted upward to 0.03 based on stack testing.
Karthaus Township CFB Project / River Hill Power Company	PA	Eastern Waste	Issued 7/21/05 Revised 3/7/06 to raise total PM10 limit from 0.012 to 0.05	0.05 (total PM_{10}) Limit may be revised upon review of CEM data and stack test results
Highwood Generating Station / Southern Montana Electric	MT	Western Subbitmumous	Draft Permit 3/30/06	0.026 (total PM_{10})

Beech Hollow Energy Project / Robinson Power Co. LLC	PA	Eastern Waste	Issued 4/1/05	0.012 (total PM_{10}) Limit may be revised upon review of stack test results
Greene Energy Resource Recovery Project / Wellington Dvpt, LLC	PA	Eastern Waste	Issued 6/21/05 Revised 9/1/05 Revision did not affect PM_{10} limit.	0.012 (total PM_{10}) Limit may be revised up to a maximum of 0.05 lb/MMBtu if operator can demonstrate condensible portion of PM_{10} is causing noncompliance.
Gascoyne Generating Station / Montana-Dakota Utilities Co.	ND	Lignite	Issued 6/2/05	0.0275 (total PM_{10})
South Heart Power Project / Great Northern Power Dvpt, L.P.	ND	Lignite	Application 8/18/05	0.0132 (condensable PM_{10} only) 0.0232 (total PM_{10} proposed)
East Kentucky Power Cooperative / Spurlock #4	KY	Eastern Bituminous	Supplemental Application 1/13/06 Draft Permit 2/14/06	0.012 (total particulates) Applicant counter-proposes optimization study with provision to raise limit no higher than 0.03 total PM_{10}

As can be seen from the table above, a fairly wide range of emission limits for total PM_{10} have been either proposed or permitted, from 0.012 lb/MMBtu up to 0.05 lb/MMBtu. Most of those emission limits have either been adjusted, or, according to language in the permits, have the ability to be adjusted later by the permitting agency based on stack test results.

EPA's estimate mentioned above for total PM/PM_{10} of 0.03 lb/MMBtu, which incorporates an estimate of 0.019 lb/MMBtu for condensible PM, is about in the middle of the range of permit limits listed above. It is about the same as the emission limit for the AES Puerto Rico Cogeneration Plant, after EPA Region 2 adjusted the original limit of 0.015 lb/MMBtu up to 0.03 lb/MMBtu based on stack testing results. It is also slightly higher than proposed or final emission limits for other similar CFB boiler projects in Region 8 states (Highwood, Gascoyne, and South Heart projects). The permit applications for these three projects all contain detailed engineering calculations to estimate the condensible PM emissions. All three estimates are in relatively close agreement, leading to very similar proposed or final emission limits for total PM_{10} (0.0232 to 0.0275 lb/MMBtu).

As explained above, the permit applications for these projects had drastically lower estimates for the ammonium sulfate component than Deseret Power's own estimate. EPA believes the adjusted emission limit in the AES permit of 0.03 lb/MMBtu for total PM_{10}, which is based on actual operating data, and the proposed or final emission limits for the other three CFB boiler projects in EPA Region 8 (which are based on consistent engineering calculations), are the most credible limits of those listed in the table above. Below is an explanation of why EPA Region 8 has reason to believe the emission limits on the low and high end of the spectrum of limits in the table above (0.012 lb/MMBtu and 0.05 lb/MMBtu) may not be as credible.

With regard to the Spurlock #4 project in Kentucky, as noted in the table above, the permit applicant has requested that the draft permit be revised to allow the emission limit of 0.012 lb/MMBtu for total PM_{10} to be raised to as high as 0.03 lb/MMBtu, based on results of an optimization study. The requested upper limit is the same as the final adjusted limit for the AES Puerto Rico project and is the same as EPA's estimate mentioned above for Deseret Power. Since Kentucky has not yet issued a final permit for the Spurlock #4 project, it remains to be seen whether this limit (0.012 lb/MMBtu) will stand, or if the permit will allow for upward adjustment based on stack testing.

With regard to the projects in Pennsylvania, the proposed or final permit limits for Beech Hollow and Greene Energy are 0.012 lb/MMBtu for total PM_{10}; however, as noted in the table above, Pennsylvania recently revised the emission limit for River Hill from 0.012 lb/MMBtu up to 0.05 lb/MMBtu, with a provision for revising the limit downward again, based on operating data. Overall, it appears to EPA that Pennsylvania is willing to set total PM_{10} emission limits anywhere between 0.012 and 0.05 lb/MMBtu and adjust those limits once operating emission data are obtained. Because of this wide range of limits, EPA discounts to some degree the significance of the initial emission limits in these permits.

EPA Region 3 submitted adverse comments to Pennsylvania on the State's permit action to raise the total PM_{10} limit for River Hill from 0.012 lb/MMBtu to 0.05 lb/MMBtu. EPA Region 3 discounted the purported degree of Method 202 artifact formation cited by River Hill and Pennsylvania. EPA Region 3 recommended an initial permit limit identical to the adjusted limit in the AES Puerto Rico permit (0.03 lb/MMBtu) with the ability to revise that limit upward, if stack testing shows it is not achievable.

Consistent with EPA Region 3's recommendation, EPA Region 8 does not favor selecting an upper bound initially in the permit (e.g., Deseret Power's proposal of 0.045 lb/MMBtu) and then providing for the limit to be adjusted downward based on operating emissions data. EPA believes this approach is a disincentive for the source to operate controls optimally during compliance testing, or to take steps to run the test method as accurately as possible. EPA instead favors setting an initial emission limit that EPA believes can reasonably be achieved (with appropriate margin of compliance) and provide for adjusting the limit upward in the event that stack testing demonstrates it is not achievable.

EPA Region 8 believes that allowing for adjustment based on stack testing is an appropriate approach for total PM/PM_{10} at Deseret Power because the emission limit incorporates condensible PM, for which there are limited test data for similar operating plants and significant uncertainty, explained above, as to the amount of expected emissions.

Deseret Power contends that a total PM/PM_{10} emission limit lower than 0.045 lb/MMBtu cannot be guaranteed, presumably because of vendor doubts on whether the limit is achievable. However, stack testing results at some other CFB facilities indicate that 0.03 lb/MMBtu can be achieved with a substantial margin of compliance. As mentioned before, the permit limit for AES Puerto Rico was adjusted from 0.015 lb/MMBtu up to 0.03 lb/MMBtu after stack testing revealed that 0.015 could not be achieved, but that a limit of 0.03 lb/MMBtu could be achieved. In its April 2004 Proposed Administrative Changes to the PSD permit application, AES Puerto Rico submitted stack testing results for AES's two recently-constructed CFB units. The total PM_{10} emissions from Unit 1 and Unit 2 were 0.023 lb/MMBtu and 0.019 lb/MMBtu respectively, including condensible PM measured by Method 202. (A copy of this information may be found in the Administrative Record for issuance of Deseret Power's permit.)

In addition, a December 5, 2004 emissions compliance test report for the Reliant Energy Seward facility shows emissions of 0.004 lb/MMBtu total PM from Seward's two CFB units (equipped with SNCR, baghouse and "fly dryer absorber"), including condensible PM measured by Method 202. (A copy of that report may be found in the Administrative Record for issuance of Deseret Power's permit.)

Furthermore, in a March 31, 2006 comment letter on the draft PSD permit for its Spurlock #4 unit, East Kentucky Power Cooperative cites a July 8, 2005 stack test, with emissions of 0.0136 and 0.0113 lb/MMBtu total PM_{10} from the Gilberton Unit 3 CFB unit (equipped with SNCR, baghouse, and dry scrubber) including condensible PM measured by Method 202. (A copy of the comment may be found in the Administrative Record for issuance of Deseret Power's permit.)

While we recognize this is a somewhat small set of data and these facilities burn different coal from that proposed by Deseret Power, these data do demonstrate that a limit of 0.03 lb/MMBtu can be achieved at some CFB units with a large margin of compliance (30% to 750%). Overall, EPA believes there is ample support for proposing an initial total PM/PM_{10} emission limit for Deseret Power at 0.03 lb/MMBtu on a 30-day rolling average. EPA further believes this proposal compares much more reasonably to other permit limits and stack test data than does Deseret Power's proposal of 0.045 lb/MMBtu.

In several e-mails to EPA, Deseret Power has cited numerous technical papers questioning the reliability of Method 202 and highlighting the effects of artifact formation in the impingers in skewing test results upward. In a November 23, 2005 e-mail, Deseret Power proposed to use the following test methodology for condensible PM: "EPA Method 5B (with filter at 340 ±5 °F): Filterable particulate and USEPA Method 202 (downstream of the Method

5B train) modified to exclude all inorganic compounds: Organic fraction CH2Cl2 extract and Parallel Controlled Condensation Method (CCM) with second Method 5B filter (with filter at 340 ±5 °F) upstream of the CCM train: H2SO4 (molecular weight of 98.08) average of three- 4 hour tests."

EPA Region 8 consulted with EPA's Office of Air Quality Planning and Standards (OAQPS) to evaluate this proposed test methodology. OAPQS rejected the proposal, instead maintaining that the artifact formation from Method 202 can be minimized by properly purging dissolved SO_2 from the sampling solution. In a November 30, 2006 email, Region 8 forwarded OAQPS's statement to Deseret Power. Below is the full text of that e-mail, as modified slightly by OAQPS on April 25, 2006.

We do not think that using Method 5B combined with Method 202 excluding all of the inorganic compounds and adding the sulfuric acid quantified by a controlled condensation train provides a reasonable measurement of the total particulate matter emissions to the atmosphere. We have posted our recommendations on the specific procedures and options available within Method 202 on our FAQ's page for this method. While the use of the elevated temperature of Method 5B would only serve to transfer particulate matter from the filter fraction to the impinger fraction, the additional post test heating of the filter would tend to vaporize any material that should be considered as particulate matter emissions.

It is recognized that Method 202 has a small positive bias due to the slow conversion of SO2 to SO3 and then H2SO4. Although the one hour nitrogen purge prevents much of this conversion, some small bias remains. For many sources which can collect quantifiable quantities (> 3 mg) of particulate matter in a one hour sample, we think this bias is insignificant when compared to the overall variability associated with stack sampling. However, for sources with very low concentrations of particulate matter, even this small bias may still be small compared to the variability associated with the remainder of the sampling. Ignoring the variabilities of the particulate filter matter mass, one could portray the bias as a significant percentage difference in the result.

In order to overcome the difficulties associated with the collection of sample in water, EPA developed a dilution based sampling system that replicated the particulate formation mechanisms that occur at operating emissions sources. The development of a dilution sampling method was recommended by the National Academy of Sciences in their 2000 report "Research Priorities for Airborne Particulate Matter" (see page 56 of the attached excerpt from this report). We have posted the dilution based sampling method on the Emissions Measurement Center web site as Conditional Test Method 39 (see the methods near the bottom of http://www.epa.gov/ttn/emc/ctm.html). We have performed limited comparisons of CTM39 and Method 202 and found that these methods provide comparable results.

Deseret Power responded to EPA in a December 21, 2005 email as follows.

The equipment supplier needs to know the test methodology before a total PM10 limit can be established. This is due to the substantial positive bias in using Reference Method 202 to determine condensable particulate matter. Deseret's November 23, 2005 email provided EPA with the supplier's proposed test method to compensate for the substantial positive bias associated with Reference Method 202. As recommended by EPA, Deseret has reviewed the questions and answers on EPA's website associated with Method 202. We did not find any answers on EPA's website that would change our concerns about Method 202.

EPA also recommended using CTM-039 in lieu of Method 202. However, neither Deseret nor its supplier has any experience with conditional test method 39. Therefore, we cannot base compliance with an emission limit on a test method that we do not have any experience with. We again request EPA to review the supplier's proposed test method sent to you with the November 23rd email and advise if it is acceptable. If EPA insists on using Method 202 without any modifications, then we need to discuss how to adjust the total emission limit to allow for the significant positive bias associated with using Method 202.

The EPA position presented to Deseret Power was similarly articulated in EPA Region 3's February 6, 2006 comment letter to Pennsylvania on the River Hill permit revision.

We respond to these assertions by discussing some results from EPA's research into the efficacy of EPA's Method 202. According to EPA's research, varying the concentration of sulfur dioxide in the flue gas has a limited effect on the amount of condensable particulate matter measured by Method 202. In short, we found that SO2 from flue gas dissolved in sampling water reaches a saturation point allowing no more SO2 in solution. Thus in order for the applicant's SO2 argument to hold true, additional sample water must be introduced to absorb more SO2 from the higher SO2 concentration of River Hill Power Plant's flue gas (compared to that of the Puerto Rican Power Plant).

A recent report from EPA has shown that there is a constant 20 ppm condensable particulate creation (known as artifact) in the water used in the sample train for Method 202. EPRI has also alleged a flaw with Method 202 is that dissolved SO2 cannot be sufficiently purged from the sample water to give meaningful condensable PM-10 results. EPA, however, has data from a recently conducted laboratory study showing the purge method used in Method 202 rids the system of 90 to 95 % of the dissolved SO2. EPA has also recommended an alternative sampling method using air dilution [CTM-039], which eliminates the issue of SO2 causing potentially high artificial results.

In conclusion, we feel that the applicant is correct in its statement that there is limited data available regarding condensable PM-10 from coal-fired power plants and in particular, waste coal-fired plants. We recognize that the applicant has spent a lot of time researching this issue and has committed to installing the appropriate and most up-to date control equipment for

PM-10 emissions. Based on discussions with engineers and scientists at EPA, we are convinced that Method 202 can be a valid method to use if the purging procedure is correctly performed. However, we feel that alternative testing methods should be made available if they are appropriate.

EPA recommends an alternative sampling method (known as conditional test method 39 or CTM 039) using air dilution which is suitable for determining both filterable and condensable components of PM-10, and it eliminates the issue of SO2 in flue gas causing potentially high artificial results. We have determined that SO2 from flue gas has limited effect on the measurement of condensable PM-10. In addition, actual stack testing on the AES plant in Puerto Rico shows that condensable PM-10 is emitted from the power plant in lower amounts than originally theorized. In light of these conclusions, EPA feels that a limit of 0.030 lb, PM-10 should be initially established, until data is obtained from stack testing determines the actual emission factor. The stack test data obtained should be used to establish the permanent total PM-10 limit. If the stack testing shows a higher limit than the permit contains, the PADEP will be able to revise that limit in consultation with EPA.

Clearly, EPA and Deseret Power do not agree on the effect of potential artifact formation associated with Method 202. While EPA does acknowledge a small degree of bias, EPA has found it to be insignificant. EPA Region 8 agrees with the position taken by EPA Region 3, that initially establishing a total PM_{10} limit of 0.03 lb/MMBtu represents BACT for total PM/PM_{10}. EPA Region 8 also agrees with Region 3's position that it is appropriate to allow for an upward adjustment of that limit, if stack testing shows that the initial limit is not achievable, based on contributions from the condensible PM portion.

In summary, EPA proposes the following permit language:

> **The Permittee shall not discharge or cause the discharge of total particulate matter (including condensible particulate matter) from the CFB boiler to the atmosphere in excess of 0.03 lb/MMBtu heat input, on a 24-hour block average (midnight to midnight), of which the filterable (non-condensible) portion shall not exceed 0.012 lb/MMBtu heat input on 24-hour block average. The same emission limits shall apply for PM_{10}.**
>
> **Because condensible particulate matter emissions from fluidized bed boilers have not been widely quantified, there is a possibility that the actual condensible portion of particulate matter would cause the PSD BACT emission limit in this permit of 0.03 lb/MMBtu for total PM/PM_{10} to be exceeded. In such event, EPA may adjust the emission limit to a level not to exceed 0.045 lb/MMBtu, pending EPA's review of stack test results.**

As explained above, EPA believes this adjustable limit approach is an acceptable approach, which has been supported in the past by the Environmental Appeals Board.

(Reference: *In re AES Puerto Rico L.P.* (May 27, 1999).) EPA further believes this approach should address Deseret Power's concern about meeting a guaranteed limit, since the final limit will essentially be dependent on actual stack testing data. EPA notes that 0.045 lb/MMBtu is less than the emission rate used in the air quality modeling analysis for the WCFU project.

As explained earlier in this Statement of Basis, for the proposed WCFU, Deseret Power will be permitted to use coal from the Deserado mine consisting of either waste coal alone, or else a blend of waste coal and ROM coal yielding heat content of up to 6,500 Btu/lb. For reasons explained above, EPA believes the proposed BACT emission limit of 0.03 lb/MMBtu on a rolling 30-day average, for total PM/PM_{10}, will represent BACT for coal from the Deserado mine with heat content of up to at least 6,500 Btu/lb, and will ensure a continued high degree of PM emission control efficiency.

6. Comparison to applicable NSPS emission standard.

Since 40 CFR 60, Subpart Da contains no emission standard that incorporates condensible PM, there is no comparison to make.

7. Proposed compliance monitoring.

For measuring the condensible portion of PM, EPA proposes to require annual stack tests using Method 202. In lieu of Method 202, the Permittee shall be allowed to use Conditional Test Method 39 (CTM-039). For demonstrating compliance with the BACT limit for total PM/PM_{10} (filterable plus condensible), EPA proposes to require that the emissions data from the PM CEMS, in lb/MMBtu on a 24-hour block average, be added to the results of the latest stack test for condensible emissions, also expressed in lb/MMBtu.

J. BACT for CO Emissions from CFB Boiler.

Emissions of CO result from the incomplete combustion of carbon and organic compounds. CO emissions are a function of oxygen availability (excess air), flame temperature, residence time at furnace temperature, combustor design, and turbulence.

In addition to the potential control technologies listed in Step 1 below, clean fuels (i.e., alternative coal, either from the Deserado mine or another mine) is also a possible option for BACT, but has already been eliminated as cost-prohibitive for BACT, for all pollutants at this project. This was explained earlier in this Statement of Basis.

1. Step 1: Identify Potential Control Technologies.

The only potential CO control technologies known to EPA for CFB boilers are the following:

a. Catalytic oxidation
b. Combustion controls

Catalytic oxidation consists of oxidation, in the flue gas, of any CO formed in the combustion process. Combustion controls consist of combustion modifications to minimize the formation of the pollutant.

2. Step 2: Eliminate Technically Infeasible Options.

Combustion controls are technically feasible but catalytic oxidation is not, for reasons described below.

a. Catalytic Oxidation. Catalytic oxidation is the control technology used to obtain the most stringent control level for CO from gas turbine combustion units. This technology has never been applied to a coal fired unit, however. For catalytic oxidation, a catalyst is situated in the flue gas stream, which would lower the activation energy of a series of reactions where reactant species, such as CO, are converted to carbon dioxide and water. The catalyst permits the combination of the reactant species at lower gas temperatures than would be required for uncatalyzed oxidation.

The catalyst would be located at a point where the gas temperature is within an acceptable range. The effective temperature range for CO oxidation is between 600 and 1150 F. In a CFB, this means that the catalyst grid would need to be installed at a point upstream of the particulate matter control device.

Catalyst non-selectivity is a problem for sulfur containing fuels such as coal. Catalysts promote oxidation of SO_2 to SO_3 as well as CO to CO_2. The amount of SO_2 conversion is a function of temperature and catalyst design. Under optimum conditions, formation of SO_3 can be minimized to 2% of inlet SO_2. Compared to the proposed emissions level, this level of conversion would increase H_2SO_4 emissions and would result in corrosion to the air preheater and ductwork.

Catalysts require intimate contact with the flue gas and some residence time to be effective. For best utilization, catalyst plates are closely spaced. Flue gas from a CFB firing high ash, low-grade waste coal will contain a very large amount of fly ash, which could cause high erosion of the catalyst and potential pluggage. Specially designed catalyst with wider spacing would need to be provided to accommodate the very high ash loading which would decrease its effectiveness, requiring more layers of catalyst to compensate. In the available open literature, it does not appear that this has been done on a CFB, and it is not considered technically feasible

b. Combustion Controls. The other means of controlling CO emissions is through the design and operation of the boiler in a manner so as to limit CO formation. Such controls are commonly referred to as combustion controls. In general, a combustion control system seeks to maintain the proper conditions to ensure complete combustion through one or more of the following operation design features: high excess air, staged combustion, overfire air, sufficient residence time, and good mixing. In the case of the proposed project, the boiler itself will incorporate design features, which enhance uniform fuel/air distribution and mixing, along with oxygen monitoring and adjustment of the staged air combustion to suppress CO formation.

3. Step 3: Rank Remaining Control Technologies by Control Effectiveness.

Since the only technically feasible control technology is combustion controls, no ranking is necessary.

4. Step 4: Evaluate Economic, Environmental and Energy Impacts.

Since the proposed project will implement combustion controls as the only technically feasible option to reduce CO emissions, review of economic, environmental, and energy impacts is not necessary.

5. Step 5: Proposed CO BACT for CFB Boiler.

Deseret Power searched EPA's RACT/BACT/LAER Clearinghouse database and California Air Resources Board (CARB) listings for coal fired CFB boilers, which report limits on CO emissions. The table below presents a summary of facilities utilizing CFB boiler technology and employ combustion controls for CO reduction.

Comparison of CFB Boiler CO Emission Rates using Combustion Controls: RACT/BACT/LAER Clearinghouse and CARB Data

Facility	RBLC ID	Heat Input mmBtu/hr	CO Emissions lb/mmBtu	Fuel
AES-PRCP	PR-0007	4922.7	0.10	Columbian Coal
Reliant Energy Mid-Atlantic Power	PA-0182	2532.0	0.15	Coal
Archer Daniels Midland (9&10)	IL-0060	1500.0	0.1	Coal
Choctaw Generation	MS-0036	2475.6	0.2	Lignite
Archer Daniels Midland (5&6)	IA-0046	1500.0	0.15	Coal
Archer Daniels Midland	IA-0051	1500	0.15	Bituminous Coal
Kimberly Clark	PA-0204	799	No limit	Coal
Toledo Edison	OH-0231	1764	0.13	Pet Coke
York County Energy Partners	PA-0132	2500.0	No limit	Bituminous Coal
Northampton Generating Co.	PA-0134	1146.0	0.15	Anthracite Culm
Westwood Energy	PA-0124	423	No limit	Anthracite Culm
Gilberton Power	PA-0110	520	No limit	Anthracite Culm
Archer Daniels Midland (7&8)	IL-0058	1500	0.1	Coal
Energy New Bedford Cogeneration	MA-0028	1671.0	0.14	Eastern US Coal
AES Warrior Run	MD-0022	2070.0	0.15	Eastern US Coal
Archer Daniels Midland	IA-0025	551.5	0.2	Coal
Energy New Bedford Cogeneration	MA-0009	3342.0	0.018	Eastern US Coal
Tauton Energy Center	MA-0011	1604.4	0.13	Eastern US Coal
North Branch Energy Partners	PA-0058	563.5	0.15	Waste Bit. Coal

The facility with the lowest listed CO emission limit is Energy New Bedford Cogeneration (MA-0009), at 0.018 lb/MMBtu. Another Energy New Bedford facility (MA-0028) is listed at 0.14 lb/MMBtu. Deseret Power informed EPA (via February 7, 2006 e-mail) that they asked the Massachusetts Division of Air Quality about the status of these two facilities and was told that the permits were issued in April 1993 for MA-0009 and in July 1994 for MA-0028, but neither facility was built.

Two Archer Daniels Midland facilities and the AES-PRCP facility are listed with CO emission limits of 0.10 lb/MMBtu; however, these facilities all use coal with much higher heat content than Deseret Power's coal, which means these facilities should be able to achieve a lower CO emission rate in lb/MMBtu than Deseret Power's proposed WCFU. Deseret Power has stated (via April 14, 2006 e-mail to EPA) that the ADM facilities both use a blend of Illinois coal with a heat content of 12,000 to 13,000 Btu/lb and Powder River Basin (Wyoming) coal with a heat content of approximately 8,500 Btu/lb. The ADM facilities are also permitted to utilize wood and shredded tires for up to 10% of the fuel, such that the heat content of the overall fuel averages 10,000 to 11,000 Btu/lb.

Deseret Power has also stated (via April 14 and 16, 2006 e-mails to EPA) that the AES-PRCP facility burns Columbian coal with a heat content range of 10,500 Btu/lb to 12,000 Btu/lb. Average heat content is 11,300 Btu/lb. By contrast, Deseret Power's "average" waste coal has heat content of about 4,000 Btu/lb. Blending the waste coal with run-of-mine coal from the Deserado mine at up to a 50/50 ratio (which Deseret Power has requested for operational flexibility) would yield heat content of about 6,500 Btu/lb.

Three other facilities are listed above with CO emission limits below 0.15 lb/MMBtu: Toledo Edison (OH-0231), Energy New Bedford Cogeneration (MA-0028) and Tauton Energy Center (MA-0011). Deseret Power has stated (via February 8, 2006 e-mail to EPA) that the heat content of the coal for all facilities listed above, except for Northampton, Westwood, Gilberton and North Branch (which are listed with waste coal or anthracite culm), is higher than the heat content of the waste coal for Deseret's WCFU. Again, the higher heat content means these facilities should be able to achieve a lower CO emission rate in lb/MMBtu than Deseret Power's proposed WCFU. The Northampton and North Branch facilities are listed with CO emission limits of 0.15 lb/MMBtu. No CO emission limits are listed for the Westwood and Gilberton facilities.

Besides having lower heat content than the coal for other CFB boiler projects, Deseret Power's waste coal will have higher ash content as well. Deseret Power has stated (via February 8, 2006 e-mail to EPA) that this results in higher CO emissions, due to some ash having carbon entrapped within the ash particle that is not released until the particle is above the combustion zone in the CFB boiler. Some of this carbon will form CO rather than being combusted.

Another consideration in determining the achievable CO emission rate for Deseret Power's proposed WCFU is the NO_x emission rate that must also be achieved. EPA is proposing a relatively stringent NO_x BACT emission limit of 0.080 lb/MMBtu. Since generation of NO_x and CO are inversely related to each other, achieving such a low NO_x limit makes it difficult to also achieve a low CO limit. Lower temperature and lower excess oxygen will lead to lower NO_x, but will also result in higher CO due to incomplete combustion. Facilities with higher NO_x

limits can achieve lower CO limits. The following facilities from the table above have NO_x limits that are same as proposed for Deseret Power's WCFU, or higher, and with CO emission limits of 0.15 lb/MMBtu or higher:

Reliant Energy Mid-Atlantic Power
Choctaw Generation
Northampton Generating Co.
AES Warrior Run
North Branch Energy Partners

In assessing the CO emission rates that the proposed WCFU can achieve, Deseret Power has stated (in its November 1, 2004 PSD permit application) that they have tried to optimize all relevant factors in the context of efforts to reduce NO_X emissions; however, those efforts tend to increase CO emissions. In light of the NO_X reductions discussed above, Deseret Power has stated that the lowest emission level that can be consistently achieved and guaranteed by its vendor is 0.15 lb/mmBtu, from 70 to 100% of design load. As explained above, this emission rate is at least as stringent as CO emission limits for other CFB boilers listed in the RBLC that combust either waste coal or blended coal with heat content as low as Deseret's waste coal or blended coal.

For operation at below 70% of design load, Deseret Power proposed an alternate CO BACT emission limit of 155 lb/hr. EPA cannot consider this proposal justifiable as BACT for operation below 70% of design load, because it is equivalent to 0.15 lb/MMBtu times 70% of the full load heat input capacity of the boiler (1,445 MMBtu/hr). EPA proposes the following CO emission limit, applicable at all times:

0.15 lb/MMBtu on a 30-day rolling average

As explained earlier in this Statement of Basis, Deseret Power will be permitted to use coal from the Deserado mine, consisting of either waste coal alone, or else a blend of waste coal and run-of-mine coal yielding heat content of up to 6,500 Btu/lb. For reasons explained above, EPA believes the proposed CO BACT emission limit of 0.15 lb/MMBtu on a rolling 30-day average, will represent BACT up to at least a 50/50 blend ratio.

6. Comparison to applicable NSPS emission standard.

Since 40 CFR 60, Subpart Da contains no emission standard for CO, there is no comparison to make.

7. Proposed compliance monitoring approach.

For compliance demonstrations, EPA proposes to require CO CEMS. EPA proposes to allow the diluent cap approach from 40 CFR part 75 for calculating emissions in lb/MMBtu, in the event of very low boiler load, such as during startup or shutdown. This approach was developed by EPA in Part 75 to address low-load situations at electric utility boilers. Further explanation of the diluent cap approach may be found in section VI.J.5 of this Statement of Basis, at the end of Step 5 of the SO_2 BACT discussion.

K. BACT for SO_2 Emissions from CFB Boiler

In addition to the potential control technologies listed in Step 1 below, clean fuels (i.e., alternative coal, either from the Deserado mine or another mine) is also a possible option for BACT, but has already been eliminated as cost-prohibitive for BACT, for all pollutants at this project. This was explained earlier in this Statement of Basis.

1. Step 1: Identify Potential Control Technologies.

From fossil fuel fired sources, emissions of SO_2 and other related compounds, such as total reduced sulfur and reduced sulfur compounds, are generated from the release of sulfur in the fuel. Upon combustion, approximately 98% of sulfur in solid fuels is emitted as gaseous sulfur oxides. Sulfur dioxide, related sulfur compounds, sulfuric acid mist, and hydrogen fluoride, commonly referred to as acid gases, are all controlled by the technologies listed below. All these technologies are considered by EPA to be potential control technologies for SO_2 at CFB boilers.

a. Limestone injection
b. Dry scrubbing
   (i) Spray dry absorber
   (ii) Circulating dry scrubber
   (iii) Hydrated ash reinjection
   (iv) Dry sorbent injection
c. Wet scrubbing

2. Step 2: Eliminate Technically Infeasible Options.

With the exception of dry sorbent injection and alternative coal from other mines, all technologies listed above are considered technically feasible for SO_2 control at CFB boilers. Below is a discussion of each technology.

a. Limestone injection. Limestone injection is technically feasible and is typically an inherent part of the combustor design for "second generation" CFB combustors. Crushed limestone is fed to the CFB combustor, becoming the solid medium in which coal combustion takes place. When limestone is heated to 1550 F, it releases CO_2 and forms lime (CaO), which subsequently reacts with acid gases released from the burning coal, to form calcium sulfate ($CaSO_4$). The $CaSO_4$ product is removed from the flue gas in the particulate collector or directly from the furnace.

In theory, 100% SO_2 removal could be achieved with a Ca/S ratio of 1.0. In practice, however, the desulfurization process results in less than complete utilization of the injected limestone. It has been found that only about 50% of the SO_2 is removed at a Ca/S ratio of 1. As Ca/S ratio is increased above 1, greater desulfurization can be achieved, but with diminishing return. Typically, CFB boilers are designed with a Ca/S stoichiometric ratio of 1.5, although ratios of up to 2.0 to 2.3 have been proposed by recent CFB permit applicants. In emission calculations submitted to EPA, Deseret Power has indicated that it expects limestone injection at the new WCFU to achieve SO_2 control efficiency of about 85%, for both “design” coal and “average” coal.

b. Dry scrubbing.

(i) Spray dry absorber. SDA systems are used in large utility boilers and have demonstrated 90-94% SO_2 removal efficiency in pulverized coal fired boilers. An SDA system is also used at a CFB boiler in Jacksonville, Florida. Deseret Power has stated that an SDA system could be installed at the WCFU, and has proposed to do so. Deseret Power estimates that about 98.8% control efficiency is achievable with SDA plus limestone injection at the WCFU, when firing “design” coal (3,000 Btu/lb and 0.71% sulfur content). Deseret estimates that the SDA could provide about 92.3% control efficiency for the SO_2 that remains after limestone injection controls, for the “design” coal.

The typical SDA system uses a lime and water slurry injected into the absorber tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a relatively dry by-product.

Designing an SDA for use with a CFB boiler presents significant challenges. First, the SDA must be located upstream of particulate controls, at a point where the CFB boiler flue gas is already laden with combustion ash, calcium sulfite solids, and unreacted lime from the combustion bed. An SDA will add unreacted hydrated lime to the flue gas, and increase particulate loading to the particulate control device.

(ii) Circulating dry scrubber. A Circulating Dry Scrubber (CDS) uses a circulating fluidized bed of dry hydrated lime reactant to remove SO_2. Flue gas passes through a venturi 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 similar to the SDA by-product, and is routed with the flue gas to the particulate control system.

CDS equipment vendors claim that CDS systems can achieve SO_2 removal efficiencies similar to those achieved by SDA systems. However, thus far, CDS systems have had limited application, and have not been used on large pulverized coal fired boilers or CFB boilers. The largest CDS unit, in Austria, is on a 275-megawatt oil-fired boiler burning 1.0% to 2.0% sulfur oil. Operating experience on smaller PC-fired boilers in the U.S. has shown high lime consumption rates, and significant fluctuations in lime utilization, based on inlet SO_2 loading. Furthermore, CDS 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 may become unacceptable, and electrostatic precipitators are generally used for particulate control.

(iii) Hydrated ash reinjection. Hydrated ash reinjection is a modified dry FGD process developed to increase utilization of unreacted CaO in the CFB ash and further reduce the SO_2 concentration in the flue gas. In a hydrated ash reinjection system, a portion of the unit's ash is collected, hydrated and re-introduced into a reaction vessel located ahead of the fabric filter inlet duct. In conventional boiler applications, additional lime may be added to the ash to increase the mixture alkalinity; however, for CFB applications sufficient residual CaO is available in the ash and additional lime is not required.

Two CFB units have recently been permitted with hydrated ash reinjection systems. Based on review of the technical literature, and on information provided by system vendors, it is anticipated that use of a hydrated ash reinjection system would result in a slight reduction in the CaS ratio in CFB boilers. Based on vendor information, it is estimated that the hydrated ash reinjection, downstream of a CFB boiler that utilizes limestone injection, could reduce the remaining SO_2 by about 80%.

(iv) Dry sorbent injection. Dry sorbent injection involves the injection of powdered absorbent 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 an injection device. The dry sorbent is typically injected counter-current to the gas flow. An expansion chamber is often located downstream of the injection point, to increase residence time and efficiency.

A dry sorbent injection system is not practical for use in a CFB boiler. The CFB boiler flue gas already contains excess unreacted lime and fly ash will be reinjected back into the CFB boiler combustion bed. A dry sorbent injection system would simply add additional unreacted lime to the flue gas. Furthermore, SO_2 control efficiencies for dry sorbent injection systems are typically only about 50% on units with a much higher uncontrolled SO_2 concentration in the flue gas. If used in conjunction with a CFB unit (with a relatively low SO_2 concentration in the flue gas), and especially if used at Deseret's proposed WCFU where the coal itself has relatively low sulfur content, the control efficiency would probably be substantially below 50%. While it could be argued that dry sorbent injection is technically feasible at CFB boilers, EPA believes, for the reasons just described, that dry sorbent injection should be eliminated from further consideration in this BACT analysis.

c. Wet scrubbing. Wet flue gas desulfurization (FGD) scrubbers are typically used to control SO_2 emissions from pulverized coal fired boilers. Although EPA is not aware of any CFB boilers equipped with a wet scrubbing system, EPA is also not aware of any reason why wet FGD would be technically infeasible at a CFB boiler.

Wet FGD systems use either lime or limestone slurry as the scrubbing liquid. The wet lime scrubbing process uses an alkaline slurry made by adding CaO to water. The alkaline slurry is sprayed in the absorber and reacts with SO_2 in the flue gas. Insoluble calcium sulfite and calcium sulfate solids are formed in the scrubber and are removed as a wet byproduct, which must be dewatered prior to disposal. Limestone scrubbers are very similar to lime scrubbers, except that limestone slurry is used as the scrubbing liquid rather than lime. This requires a higher liquid-to-gas ratio than lime scrubbing and therefore a larger absorbing unit.

Wet FGD systems have achieved control efficiencies of approximately 96% on large PC boilers firing high-sulfur bituminous coals. Deseret Power has estimated that a wet FGD installed downstream of the CFB combustor for the WCFU, after 85% removal by limestone injection, could remove about 94% of the remaining SO_2, for an overall SO_2 removal efficiency of about 99.1% (limestone injection + wet FGD).

3. Step 3: Rank Remaining Control Technologies by Control Effectiveness.

Since limestone injection will be an inherent part of the CFB boiler design, it is included as part of all options listed below, with assumed control efficiency of 85%. The options are ranked as follows, in terms of potential SO_2 control efficiency, from most to least efficient:

a.	Wet FGD scrubber + limestone injection	99.1%
b.	Spray dry absorber + limestone injection	98.8%
c.	Circulating dry scrubber + limestone injection	98.8%
d.	Hydrated ash reinjection + limestone injection	97.0%

4. Step 4: Evaluate Economic, Environmental and Energy Impacts.

Since wet FGD scrubber + limestone injection has been ranked higher than spray dry absorber + limestone injection, this Step 4 will compare the impacts of both, to determine if wet FGD scrubber should be eliminated and the next most effective option chosen (SDA + limestone injection).

Both wet and dry FGD control system designs are technically feasible and capable of achieving very stringent SO_2 emission rates. Deseret Power estimates that for its "design" coal scenario, an FGD system designed as a wet FGD appears capable of achieving a controlled SO_2 emission rate of 0.045 lb/MMBtu and a dry FGD control system is capable of achieving a controlled SO_2 emission rate of 0.055 lb/MMBtu (30-day rolling average). To achieve these emission rates, these control systems, coupled with the CFB boiler with limestone injection, will have to achieve an average overall control efficiency of approximately 99%. An evaluation of the economic, energy and environmental impacts of each control system is provided below.

Wet FGD systems are considered technically feasible control systems based on an engineering review of the technology, however, there are no wet FGD systems in operation with a CFB unit and there is no commercial operating history upon which to base expected SO_2 emission rates. The SO_2 emission rates used in this BACT analysis for a wet scrubber were based on the assumption that a wet FGD system could lower the controlled emission rate from 0.055

lb/MMBtu which can be achieved with a dry scrubber to 0.045 lb/MMBtu.

Economic Evaluation

Summarized in the table below are the expected controlled SO_2 emission rates, and maximum annual SO_2 emissions, associated with wet and dry FGD systems based on the design sulfur coal. Also shown are the capital costs and annual costs associated with building and operating each control system. The table also presents the average annual control efficiency for each SO_2 control system. A detailed summary of the cost estimates used in this BACT determination is attached.

A CFB boiler with limestone injection is an inherently low SO_2 emitting technology, and can be designed to remove approximately 85% of the potential SO_2 with limestone injection. The incremental cost of $10,540 per ton of removed SO_2 to install a wet scrubber rather than a dry scrubber is too high to justify the expenditure. Based on "average" coal for the proposed WCFU, the incremental cost is $28,054 per ton of additional removed SO_2 to go from dry scrubber to wet scrubber, also too expensive to justify.

**Comparison of Wet FGD to Dry FGD for WCFU,
Downstream of Limestone Injection Controls:
Costs and Emission Rates**

Parameter	Wet FGD with Limestone Injection, for "design" coal	Dry FGD with Limestone Injection, for "design" coal
Controlled SO_2 Emission Rate (lb/MMBtu)	0.045	0.055
Overall Control Efficiency	99.1%	98.8%
Maximum SO2 Emissions (tpy)	285	350
Total Capital Cost ($)	20,211,840	13,379,115
Total Capital Cost ($/kw)	202	134
Total Annual Costs ($/yr)	12,410,610	11,747,546
Annual SO_2 Removed (tpy)	26,675	26,612
Average Annual Cost per Ton ($/ton)	418	397
Incremental SO_2 Removed (tpy)	63	---
Incremental Cost per Ton ($/ton)	10,540	---

Environmental Impacts of Wet FGD

In addition to the adverse economic impacts of a wet FGD system versus a dry FGD system, there are several collateral adverse environmental impacts associated with a wet FGD system. Wet FGD systems generate a $CaSO_4$ waste by-product that must be properly managed. Solid wastes generated from wet FGD systems at the Bonanza site will have to be dewatered and disposed of in the landfill. A wet FGD system will also result in greater particulate matter emissions. Wet FGD systems must be located downstream of the unit's particulate control device, therefore, dissolved solids from the wet FGD system will be emitted with the wet FGD moisture plume. In addition, any SO_3 remaining in the flue gas could react with moisture in the wet FGD to generate H_2SO_4. H_2SO_4 is classified as a condensible particulate. Wet FGD systems also require significantly more water than the dry FGD system. This is an especially important consideration for Deseret's project, which will be located in an arid region of Utah. Also, wet FGD systems generate a wastewater stream that must be treated and discharged to evaporation ponds.

Environmental Impacts of Dry Scrubbing

Collateral environmental impacts are less significant with dry FGD than wet FGD. Using a dry FGD system in conjunction with a CFB boiler will require the facility to handle two reactants: limestone for injection in the CFB boiler and pebble lime for use in the dry scrubber. The receipt, storage, management and use of two reactants could result in a slight increase in material handling particulate matter emissions. Lime in a dry FGD is hydrated prior to use, therefore using a dry FGD system will increase the facility's overall consumption of water but much less than a wet FGD system would. Water used to hydrate the lime will be evaporated in the absorber vessel, and using a dry FGD should not result in the generation of a wastewater stream.

Summary – Elimination of Wet FGD as BACT Control Option

Limestone injection + wet FGD is eliminated as a BACT control option, based on economic impacts of wet FGD (unacceptably high incremental SO_2 removal costs) and environmental impacts of wet FGD (increased particulate matter and condensible particulate matter emissions; increased waste that is generated and has to be disposed of). Since the next most effective option is limestone injection + dry FGD, this option is selected as BACT.

5. Step 5: Proposed SO_2 BACT for CFB Boiler.

Deseret Power searched the RACT/BACT/LAER Clearinghouse and located the following SO_2 BACT determinations for CFB boilers:

Comparison of CFB Boiler SO_2 Emission Rates:
RACT/BACT/LAER Clearingthouse Data

Facility	RBLC ID	Heat Input mmBtu/hr	SO_2 Emissions lb/mmBtu	Control	Fuel
AES-PRCP	PR-0007	4922.7	0.022	Limestone and Dry Scrubber	Columbian Coal
Reliant Energy Mid-Atlantic Power	PA-0182	2532.0	0.6	Fly ash Reinjection	Coal
Archer Daniels Midland (9&10)	IL-0060	1500.0	0.7	Limestone	Coal
Choctaw Generation	MS-0036	2475.6	0.25	Lime	Lignite
Archer Daniels Midland (5&6)	IA-0046	1500.0	0.36	Limestone	Coal
Archer Daniels Midland	IA-0051	1500	0.36	Limestone	Bituminous Coal
Kimberly Clark	PA-0204	799	No limit	Not stated	Coal
Toledo Edison	OH-0231	1764	0.6	Limestone	Pet Coke
York County Energy Partners	PA-0132	2500.0	0.25	Lime	Bituminous Coal
Northampton Generating Co.	PA-0134	1146.0	0.129	Lime	Anthracite Culm
Westwood Energy	PA-0124	423	No limit	Not stated	Anthracite Culm
Gilberton Power	PA-0110	520	No limit	Not stated	Anthracite Culm
Archer Daniels Midland (7&8)	IL-0058	1500	0.7	Limestone	Coal
Energy New Bedford Cogeneration	MA-0028	1671.0	0.23	Limestone	Eastern US Coal
AES Warrior Run	MD-0022	2070.0	0.21	Limestone	Eastern US Coal
Archer Daniels Midland	IA-0025	551.5	No limit	Not stated	Coal
Energy New Bedford Cogeneration	MA-0009	3342.0	0.23	Limestone	Eastern US Coal

Tauton Energy Center	MA-0011	1604.4	0.23	Limestone	Eastern US Coal
North Branch Energy Partners	PA-0058	563.5	0.49	Limestone	Waste Bit. Coal

One CFB facility, AES-Puerto Rico, was permitted with limestone injection plus a dry scrubber and a controlled SO_2 emission rate of 0.022 lb/MMBtu. However, the AES-Puerto Rico permit also requires the facility to fire a high-heating value low-sulfur coal. Based on information in the permit application, maximum uncontrolled SO_2 emissions from the AES fuel will be approximately 1.3 lb/MMBtu, for 'worst-case' coal. Therefore, the facility will have to achieve an overall SO_2 control efficiency of approximately 98.3% to meet its permit limit when firing 'worst-case' coal.

The "design" fuel for Deseret's project has an uncontrolled SO_2 emission rate of 4.73 lb/MMBtu, more than twice the worst case SO_2 emission rate calculated for the AES-Puerto Rico facility. Therefore, in order to achieve a controlled emission rate of 0.055 lb/MMBtu on "design" coal for its proposed WCFU, Deseret will have to achieve a control efficiency of 98.8%, higher than the control efficiency proposed at AES-Puerto Rico. However, there are additional considerations when comparing Deseret's proposed WCFU to the AES-Puerto Rico project. This is discussed later in this analysis.

Utah recently permitted a new 275-megawatt CFB unit, known as Nevco Energy (a.k.a. Sevier Power Plant), for which limestone injection + dry FGD has been determined as BACT for SO_2 control. The SO_2 BACT emission limits are 0.05 lb/MMBtu (24-hour rolling average) and 0.022 lb/MMBtu (30-day rolling average). The CFB unit will be fired on western bituminous coal with an average sulfur content of 0.25% and a worst-case sulfur content of 0.9%. Based on a worst-case (i.e., lower) heating value of 10,200 Btu/lb, the uncontrolled SO_2 emission potential for Nevco will range from 0.49 lb/MMBtu (average) to 1.76 lb/MMBtu (worst-case), less than one-half the uncontrolled SO_2 emission potential of "design" coal for Deseret's WCFU project.

The Nevco plant will have to achieve a control efficiency of 95.5% to reduce the average emissions from 0.49 lb/MMBtu to 0.022 lb/MMBtu, and a control efficiency of 97.16% to reduce the worst-case emissions from 1.76 lb/MMBtu to 0.05 lb/MMBtu. As mentioned above, for its "design" coal scenario, Deseret Power calculates that the emission limit of 0.055 lb/MMBtu they have proposed as BACT would equate to 98.8% SO_2 control.

To summarize Deseret Power's BACT proposal: Deseret Power proposed 0.055 lb/MMBtu on a 30-day rolling average as SO_2 BACT, using limestone injection plus dry scrubber (spray dry absorber). This proposed emission limit is based on the "design" waste coal (3,000 Btu/lb heat content and 0.71% sulfur content). As stated above, the "design" waste coal has uncontrolled SO_2 emission potential of about 4.73 lb/MMBtu, such that to achieve an emission rate of 0.055 lb/MMBtu, SO_2 control efficiency would need to be about 98.8%. For this "design" coal scenario, Deseret Power has projected a control breakdown of about 85% control from limestone injection and about 92.3% control of the remaining SO_2 by a dry scrubber.

While EPA can agree that 0.055 lb/MMBtu is BACT for the "design" coal scenario, EPA does not consider it to be BACT when "average" or better waste coal is used, or when a blend of waste coal and ROM coal is used. Based on coal sampling data from the waste coal stockpile, and from the coal washing plant at the Deserado Mine, Deseret Power has stated that "average" waste coal for the WCFU would have about 4,000 Btu/lb heat content and about 0.34% sulfur content. The "average" coal would therefore have uncontrolled SO_2 emission potential of about 1.71 lb/MMBtu. This is only about one-third of the emission potential of the "design" coal.

Various coal scenarios for Deseret's WCFU, as well as for other CFB projects using waste coal or other similar quality coal, are presented in the table below. Expected control efficiencies at other CFB projects listed are all higher than Deseret has projected for the WCFU for "average" coal and emissions of 0.055 lb/MMBtu. As shown in the table, to achieve an emission rate of 0.055 lb/MMBtu, SO_2 control efficiency for "average" coal at the WCFU (not "design" coal) would need to be only about 96.6%. For this "average" coal scenario, Deseret Power has projected a control breakdown of about 85% SO_2 control from limestone injection and 78.5% control of the remaining SO_2 by a dry scrubber.

EPA believes a dry scrubber should be able to achieve much better control than 78.5% for this scenario. EPA believes that limestone injection plus dry scrubbing should instead be able to achieve about 98% overall control for "average" coal at the WCFU, consisting of 80-85% control by limestone injection and roughly 90% control of the remaining SO_2 by a dry scrubber. This level of control would be equivalent to an emission rate of about 0.040 lb/MMBtu.

Coal Scenarios and Sulfur Dioxide Control Efficiency Comparisons for CFB Projects: EPA Compilation

CFB Plant / Company	Source of Information	Coal Scenario	Btu/lb	Sulfur Wt %	Uncontrolled SO_2 (lb/MMBtu)	Controlled SO_2 (lb/MMBtu)	Control Efficiency
Richardton Ethanol Plant / Red Trail Energy LLC	Permit application	---	6900	1.2	3.3	0.09	97.3%
Gascoyne Gen. Stn / MDU Co.	Permit application	---	5974	0.93	2.95	0.038	98.7%
South Heart / Great North. Power Development	Permit application	Annual average	5965	1.17	3.72	0.039	98.9%
		24-hr average	5782	1.7	5.58	0.039	99.3%

Highwood Gen. Stn. / Southern MT Electric Co.	Permit application	Annual average	8752	0.62	1.42	0.038	97.3%
AES Puerto Rico	Permit 08/10/04; actual operating data	"worst case" coal	12,000	0.8	1.3	0.022 (3-hr avg)	98.3%
		"average" coal	Unk.	Unk.	0.88	0.022 (3-hr avg)	97.5%
Nevco Energy	Permit 10/12/04	"worst case" coal	10,200	0.9	1.76	0.05 (24-hr avg)	97.2%
		"average" coal	10,200	0.25	0.49	0.022 (30-day avg)	95.5%
Bonanza WCFU / Deseret Power	Letter 09/13/05, E-mail 11/09/05	"design" coal	3000	0.71	4.73	0.055 (Deseret proposal for BACT)	98.8%
	Permit application, E-mail 11/09/05	"average" coal	4000	0.34	1.71	0.055 (Deseret proposal for BACT)	96.6%
			4000	0.34	1.71	Variable limit between 0.055 and 0.040 (final EPA BACT)	97.7%
	Coal sampling data from Deseret	Permit cut-point coal (slightly worse than "average" coal)	4000	0.40	1.9 (EPA draft selection for cutpoint)	Variable limit between 0.055 and 0.040 (final EPA BACT)	97.1%
			4000	0.43	2.2 (EPA final selection for cutpoint)		97.5%

To address the large difference in uncontrolled SO_2 emission potential between "design" coal and "average" coal at the WCFU (a factor of almost three), and to resolve the issue about which scenario is more appropriate as a basis for BACT, EPA proposed in the draft WCFU permit a 'second tier' SO_2 BACT limit, applicable when coal is being fired with uncontrolled SO_2 emission potential of 1.9 lb/MMBtu or less.

A two-tier emission limit approach for SO_2 BACT has already been applied in state and Federal PSD permits for coal-fired boilers. EPA Region 7 has issued two such PSD permits. (Reference: Permits issued by Region 7 on March 1, 1990, to Archer-Daniels-Midland, for coal-fired CFB boilers at ADM plants in Des Moines and Cedar Rapids, Iowa.) More recently, a PSD permit was issued on May 5, 2005 by the State of Nevada, to Newmont-Nevada Energy Investment, specifying a two-tier limit as SO_2 BACT for a proposed 200-megawatt pulverized coal fired boiler. In the Newmont-Nevada permit, the higher tier SO_2 limit (in lb/MMBtu on a 24-hour average) applies when coal with sulfur content equal to or greater than 0.45% is being used. The lower tier SO_2 limit (also in lb/MMBtu on a 24-hour average) applies when coal with sulfur content less than 0.45% is being used. In addition to the lb/MMBtu limits, the Newmont-Nevada permit imposes two tiers of SO_2 removal efficiency, again based on sulfur content of coal.

An alternative approach for addressing a wide variety of coal quality scenarios at Deseret's WCFU would be to establish a control efficiency requirement as BACT, either in lieu of, or in addition to, a lb/MMBtu emission limit. (As explained above, the latter was done in the Newmont Nevada permit.) However, Deseret Power objected to this approach, and EPA does not consider it necessary for Deseret's project, as long as a 'second tier' emission limit in lb/MMBtu is established, to address situations where coal with substantially lower uncontrolled SO_2 emission potential than Deseret's "design" coal scenario is being used.

Deseret Power maintained that having to achieve an SO_2 emission rate lower than 0.055 lb/MMBtu could prevent them from achieving a NO_x emission rate below 0.088 lb/MMBtu. (EPA has proposed 0.080 lb/MMBtu as NO_x BACT, after an initial 15-month 'break-in' period to fine-tune the SNCR controls.) As explained in the NO_x BACT analysis portion of this Statement of Basis, EPA agrees that increasing the limestone injection rate into the boiler may increase NO_x formation (due to the presence of excess unreacted CaO in the boiler), but finds this effect difficult to quantify.

EPA at first considered setting the 'second tier' limit for the WCFU at 0.040 lb/MMBtu, on a 30-day rolling average. When the uncontrolled SO_2 emission potential of the coal, also on a 30-day rolling average, drops below 1.9 lb/MMBtu, the applicable 30-day average emission limit would change on the next boiler operating day from 0.055 to 0.040. A coal 'cutpoint' of 1.9 lb/MMBtu was originally chosen by EPA, to approximate Deseret's "average" coal, but with a slight margin (0.4% sulfur content, rather than 0.34%.) (By 'cutpoint,' EPA means the threshold, in terms of uncontrolled SO_2 emission potential of the coal, at which the applicable SO_2 emission limit changes from a higher limit to a lower limit, in this case changing from 0.055 to 0.040 lb/MMBtu.)

Deseret Power raised issues with this proposal. Deseret Power explained that if the emission limit changes overnight from 0.055 to 0.040, a slight shift of fuel sulfur content could result in the WCFU running out of compliance for many days, despite best operating practices. Deseret Power presented an example to EPA (via Excel spreadsheets submitted on January 6, 2006) where 4000 Btu/lb coal changing from 0.37% sulfur content to 0.31% sulfur content, on one day out of 60 days, could result in a shift from 0.055 to 0.040 as the applicable emission limit, and the WCFU would be running out of compliance for 16 days of the 60 day period, while

WCFU operator tries to 'catch up' with a 30-day limit which has dropped overnight from 0.055 to 0.040.

The underlying problem, according to Deseret Power, is the non-homogeneous, inherently unpredictable quality of the waste coal, which could not be easily controlled by the WCFU operator. Core samples from the waste coal stockpile have indicated sulfur content ranging from 0.34% to 0.71% and heating value ranging from 3000 Btu/lb to 5400 Btu/lb. The sulfur and heating value variations are not uniform through the waste pile. Thus at any given time, a high sulfur, low heating value fuel could be fed to the furnace, or a low sulfur, high heating value fuel, or any combination of sulfur and heating value. Deseret Power pointed out that this situation is fundamentally different than other scenarios where two-tier SO_2 BACT limits have been written into PSD permits (e.g., the Region 7 and State of Nevada permits cited above). In the other scenarios, "run-of-mine" coals would be used rather than waste coal, each with a narrow range of composition variation. In such scenarios, separate emissions limits for the different fuel types could be established and met with real time controls.

Another issue raised by Deseret Power is the delay in obtaining the coal analysis results. Deseret Power states that it will not be possible for them to determine the analysis of the fuel being fired, as it is being fired. Average samples of fuel being loaded into the silo will be taken to Deseret's laboratory for analysis. Deseret states that results will take a minimum of one day and may take up to three days.

If there will be a substantial delay in getting the results of the in-house analysis, Deseret stated that the coal may have to be sent to an outside laboratory for analysis, which may take up to five days. Results therefore might not be available until three days or more after fuel is loaded to the fuel input silo. The applicable SO_2 tier limit would not be known to the WCFU operator until the coal analysis is received. Thus the plant could be running out of compliance during the period when the samples were taken, but the WCFU operator would have no way of knowing as the fuel is being fired. Further, due to the non-uniform nature of fuel flow in silos, combined with the wide variation of fuel sulfur and heating value of the non-homogeneous Deseret waste fuel, Deseret Power expects that the sample analysis would very likely not be a precise indication of the fuel being fed to the furnace.

When the coal analysis is received, if it is determined by the WCFU operator that the WCFU is now subject to the lower tier SO_2 limit of 0.040, rather than 0.055, and is out of compliance, excess limestone might be fed to the WCFU. Feeding excess limestone might help the WCFU 'catch up' with an SO_2 limit that has dropped from 0.055 to 0.040 overnight, by quickly reducing SO_2 and achieving immediate reductions in 30-day average emissions. However, since the waste coal has high volatile matter content, Deseret Power expects that feeding excess limestone will result in higher NO_x emissions. Since EPA is proposing a very low NO_x limit as BACT (0.080 lb/MMBtu on a 30-day average), Deseret Power expressed concern that the WCFU could go out of compliance for NO_x while trying to quickly come down to the lower tier SO_2 30-day average. Deseret Power therefore does not view excess limestone feed as a viable approach for dealing with an overnight shift from 0.055 to 0.040 as the applicable SO_2 emission limit.

To address the issue of lag time in obtaining coal analysis results, EPA discussed with Deseret Power the possibility of using 'real-time' coal sampling equipment. Deseret Power acknowledged that such equipment is available for purchase, but said its personal experience with the equipment is that it is difficult to calibrate and results are unreliable. They stated that other coal-fired facilities they spoke to have had similar problems.

In summary, EPA views the concerns expressed by Deseret Power about the "two-tier" approach originally proposed by EPA as legitimate concerns, but still considers 0.040 lb/MMBtu to be achievable when "average" coal is being combusted. Therefore, EPA decided to express the 'second tier' SO_2 BACT emission limit as a calculated limit, prorated between 0.055 lb/MMBtu and 0.040 lb/MMBtu, on a 30-day rolling average, based on the uncontrolled SO_2 emission potential of the as-fired coal, also to be determined on a 30-day rolling average.

EPA does not view this prorating approach as a relaxation of the BACT determination. If the uncontrolled SO_2 emission potential of the coal remains below the 'cutpoint' for every day over a very long period of time, then the calculated emission limit will end up at 0.040 lb/MMBtu. The overall SO_2 control efficiency needed to achieve 0.040 lb/MMBtu, when uncontrolled SO_2 emission potential of the coal is below the 'cutpoint,' would be well above 97%. EPA considers this level of control efficiency to be BACT for combustion of Deseret's "average" waste coal.

<u>Revision of proposed cutpoint</u>: As stated above, in the draft WCFU permit, EPA proposed a cutpoint of 1.9 lb/MMBtu, below which the applicable SO_2 emission limit would change from a fixed limit of 0.055 lb/MMBtu to a variable limit prorated between 0.055 and 0.040 lb/MMBtu, based on the uncontrolled SO_2 emission potential of the as-fired coal. As a result of public comments on the draft WCFU permit, EPA re-evaluated the selection of the cutpoint, as compared to SO_2 emission limits and theoretical control efficiencies required for the AES-Puerto Rico project, discussed below.

The AES Puerto Rico project includes two CFB boilers burning Columbian coal that utilize limestone injection and dry scrubbers for SO_2 control, same as Deseret Power's proposed WCFU project. The SO_2 emission limit for the AES Puerto Rico project is 0.022 lb/MMBtu on a 3-hour average. (Ref: PSD permit issued by EPA Region 2 on October 29, 2001 and revised on August 10, 2004, page 4, condition VIII.4-CFB.a.). However, the AES Puerto Rico permit also says "Emissions in excess of the applicable emission limit listed under Condition VIII of this permit, during periods of startup and shutdown, shall not be considered a violation of the applicable emission limit." (Ref: permit at page 15, condition XIV.7.)

This startup/shutdown exemption language does not appear in the WCFU permit. Instead, the WCFU permit says "The PSD BACT emission limits in this permit, as well as the modeling limits, apply at all times, including periods of startup, shutdown and malfunction." (Ref: WCFU permit at condition III.I.1.) Therefore, EPA believes that making a direct comparison of the stringency of the SO_2 emission limit in the AES-Puerto Rico permit with the SO_2 emission limit in the WCFU permit is not entirely meaningful. Nevertheless, in consideration of public comments received, EPA compared the theoretical control efficiency requirements of the two permits over the respective range of coal qualities from worst-case coal to average coal, assuming steady-state operations apply and averaging times do not significantly affect those control requirements. This is explained in the step-by-step process below.

First, using mass balance, EPA calculated an uncontrolled SO_2 emission potential of the coal for the AES-Puerto Rico plant, in lb/MMBtu, based on coal quality parameters of 0.8% sulfur content and 12,000 Btu/lb heat content cited by commenters for the "worst case" coal. The result of EPA's calculation was 1.3 lb/MMBtu:

$$\frac{0.008 \text{ lb sulfur}}{\text{lb coal}} \times \frac{2 \text{ lb } SO_2}{\text{lb sulfur}} \times \frac{\text{lb coal}}{12{,}000 \text{ Btu}} \times \frac{1{,}000{,}000 \text{ Btu}}{\text{MMBtu}} = 1.3 \text{ lb } SO_2\text{/MMBtu}$$

To meet an emission limit of 0.022 lb/MMBtu, the AES-Puerto Rico plant would need to achieve about 98.3% SO_2 control efficiency.

Second, EPA obtained information on the sulfur content and heat content of coal that has been used historically at the AES Puerto Rico plant. EPA learned that the sulfur content varied from 0.49% to 0.75% during the fourth quarter of 2004 and the heat content was about 11,350 Btu/lb. From February of 2002 through June of 2003, the sulfur content varied from 0.53% to 0.85% and the heat content varied from 11,317 Btu/lb to 11,495 Btu/lb. From this information, EPA found that the uncontrolled SO_2 emission potential of the actual coal ranges from about 1.3 lb/MMBtu down to about 0.88 lb/MMBtu. At the low end of this range (which EPA will refer to in this analysis as "average" coal), the AES Puerto Rico plant would be need to achieve about 97.5% SO_2 control efficiency, to meet an emission limit of 0.022 lb/MMBtu. (Ref: Memorandum and attachments to the file by Mike Owens of EPA Region 8, dated August 8, 2007, included in the Administrative Record for the final WCFU permit action.)

Third, EPA compared the above-mentioned control efficiencies for AES-Puerto Rico to those that the WCFU would need to achieve to comply with the SO_2 emission limit in the draft WCFU permit. As noted in the table above, the WCFU would need to achieve about 98.8% control efficiency to comply with the upper emission limit of 0.055 lb/MMBtu, when burning worst-case coal, and a control efficiency of about 97.7% to comply with an emission limit of 0.040 lb/MMBtu, when burning average coal. Both of these control efficiencies are higher than the control efficiencies cited above for the range of coal at the AES-Puerto Rico plant (98.3% for worst-case coal and 97.5% for average coal).

The above-mentioned comparison is somewhat misleading, however, for average coal at the WCFU, because at the cutpoint originally proposed by EPA in the draft WCFU permit (i.e., uncontrolled SO_2 emission potential of coal of 1.9 lb/MMBtu, only slightly higher than 1.71 lb/MMBtu for average coal), the applicable emission limit would be the upper limit of 0.055 lb/MMBtu. Condition III.D.1.b.(ii)*(b)* of the draft WCFU permit states that the calculated emission limit of between 0.055 and 0.040 lb/MMBtu only applies below the "cutpoint." Therefore, the statement in the draft Statement of Basis that a control efficiency of 97.9% would need to be achieved to comply with the applicable emission limit at the "cutpoint," is incorrect, because the statement was erroneously based on complying with an emission limit of 0.040 lb/MMBtu. The correct control efficiency that would need to be achieved at the 1.9 lb/MMBtu "cutpoint" is 97.1%, based on an applicable emission limit of 0.055 lb/MMBtu. This corrected control efficiency, shown in the table above, is lower than the 97.5% control efficiency that the AES-Puerto Rico plant must achieve to meet its SO_2 emission limit of 0.022 lb/MMBtu when burning average coal.

Based on this correction, EPA re-evaluated the appropriate level to set for the "cutpoint" and determined that, to require a minimum control efficiency of 97.5% across the range of coal qualities described in the permit application for the WCFU, the "cutpoint" would need to be 2.2 lb/MMBtu, rather than 1.9 lb/MMBtu. This would correspond to a control efficiency of 97.5%, to comply with an applicable emission limit of 0.055 lb/MMBtu when burning coal with uncontrolled SO_2 emission potential of 2.2 lb/MMBtu. This is also shown in the table above.

When burning coal above the revised "cutpoint," i.e., coal with uncontrolled SO_2 emission potential greater than 2.2 lb/MMBtu, to comply with the applicable emission limit of 0.055 lb/MMBtu the WCFU would need to achieve higher SO_2 control efficiencies than 97.5%, reaching 98.8% when burning worst-case coal. Below the revised "cutpoint," a calculated SO_2 emission limit of between 0.055 and 0.040 lb/MMBtu is applicable and needed control efficiencies range from 98.1% just below the cut-point (2.14 lb/MMBtu) to 97.7% for the average coal.

EPA believes this revised "cutpoint" is an appropriate approach for ensuring that the WCFU maintains a high level of SO_2 control over the wide range of coal quality, and reflects the maximum degree of SO_2 reduction that can be achieved, commensurate with SO_2 BACT determinations for other similar facilities (listed in the two tables in Step 5 of this SO_2 BACT analysis), including Nevco and AES-Puerto Rico. Specifically, this revised "cutpoint" ensures a minimum control efficiency of at least 97.5%, over the range of worst-case coal to average coal.

EPA also reviewed 30-day average SO_2 CEMS data for the AES Puerto Rico plant, in quarterly CEMS reports from the years 2003 through 2005, and found a very low amount of excess emissions with regard to the emission limit of 0.022 lb/MMBtu on a 3-hour average. The reports seem to EPA to indicate that an emission limit of 0.022 lb/MMBtu on a 30-day rolling average (and the corresponding control efficiencies) could consistently be met by the AES Puerto Rico facility, over the range of coal quality cited above. (The CEMS reports are included in the Administrative Record for the final WCFU permit action.) Therefore, EPA concludes that the revised "cutpoint" of 2.2 lb/MMBtu for the WCFU represents an overall SO_2 BACT determination that is achievable for a CFB unit with limestone injection and a dry scrubber for SO_2 controls. The final WCFU permit specifies a "cutpoint" of 2.2 lb/MMBtu, rather than 1.9 lb/MMBtu in the draft permit, for triggering applicability of the lower-tier SO_2 BACT emission limit in the permit.

To address Deseret Power's concern about the lag time in obtaining coal analysis results, EPA proposes that the calculation of the applicable SO2 emission limit be based on coal samples obtained during a period which ends five boiler operating days prior to the day on which the emission limit will apply.

EPA proposes that the two-tier SO_2 emission limit approach go into effect 12 months after completion of initial performance testing, to provide a sufficient 'break-in' period to fine-tune and balance the emission control equipment for optimum efficiency. Prior to that point in time, Deseret's requested BACT emission limit of 0.055 lb/MMBtu would be in effect for any coal burned. The explanation of need for a break-in period may be found in the NO_x BACT discussion of this Statement of Basis. EPA considers the inter-relationship between NO_x control and SO_2 (explained in the NO_x BACT discussion) to call for a break-in period applicable to both pollutants.

In conclusion, EPA proposes the following emission limits as SO_2 BACT:

Prior to the date which is 12 months after completion of initial performance testing: 0.055 lb/MMBtu heat input, on a 30-day rolling average.

Beginning on the date which is 12 months after completion of initial performance testing, and thereafter:

(a) **0.055 lb/MMBtu heat input, on a 30-day rolling average, for any boiler operating day when the uncontrolled SO_2 emission potential of the combusted coal is 2.2 lb/MMBtu or greater, on a 30-day rolling average.**

(b) **a calculated emission limit, on a 30-day rolling average, as set forth below, for any boiler operating day when the uncontrolled SO_2 emission potential of the combusted coal is less than 2.2 lb/MMBtu, on a 30-day rolling average:**

$$\frac{0.055A + 0.040B}{30} \quad \text{lb/MMBtu heat input}$$

Where:

A = Number of BOD, during 30 successive BODs prior to the calculation, when the uncontrolled SO_2 emission potential of the combusted coal was 2.2 lb/MMBtu or greater, on a 30-day rolling average.

B = Number of BOD, during 30 successive BODs prior to the calculation, when the uncontrolled SO_2 emission potential of the combusted coal was less than 2.2 lb/MMBtu, on a 30-day rolling average.

BOD = Boiler Operating Day

For purposes of determining the applicable SO_2 emission limit in either *(a)* or *(b)* above, the uncontrolled SO_2 emission potential of the coal, on a 30-day rolling average, shall be based on coal samples obtained during a period of 30 successive BODs which ends five BODs prior to the day on which the emission limit applies

The term "30-day rolling average," as used in this permit, shall mean the average of 30 successive boiler operating days. The term "boiler operating day," as used in this permit, shall have the meaning given in the revised NSPS Subpart Da, published in the Federal Register on February 27, 2006 (71 FR 9866), as it applies to new units:

"Boiler operating day" … means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

As explained earlier in this Statement of Basis, Deseret Power will be permitted to use coal from the Deserado mine, consisting of either waste coal alone, or else a blend of waste coal and run-of-mine coal, yielding heat content of up to 6,500 Btu/lb. Based on the SO_2 BACT analysis above, EPA believes that the proposed 'second tier' SO_2 emission limit described above will represent BACT for coal from the Deserado mine with heat content up to at least 6,500 Btu/lb, and will ensure a continued high degree of SO_2 emission control efficiency.

6. Comparison to applicable NSPS emission standard.

The definition of BACT in 40 CFR 52.21(b)(12) contains the statement that, "*In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61*." The applicable SO_2 emission standard in Subpart Da of 40 CFR part 60 is 1.4 pounds per megawatt-hour (lb/MWh) on a rolling 30-day average. An allowed alternative in Subpart Da is 94% reduction on a 30-day rolling average.

The following equation is used by EPA to convert from lb/MWh to lb/MMBtu:

$$\mathbf{X}\ \text{lb/MMBtu} * 3.412\ \text{MMBtu/MWh} * 1/\text{Efficiency} = \mathbf{Y}\ \text{lb/MWh}$$

In developing Subpart Da standards in lb/MWh, EPA assumed a 36% gross efficiency for coal-fired electric utility boilers. Approximately a quarter of existing boilers presently have average efficiencies greater than 36%; however, CFB boilers tend to have lower gross efficiency values, ranging from 30% to 38%. With the relative low-quality waste coal that will be used at Deseret's proposed WCFU, EPA expects that the WCFU efficiency would be at the lower end of this efficiency range.

If 36% gross efficiency is assumed, then by the equation above, the WCFU would have to maintain SO_2 emissions at 0.147 lb/MMBtu or lower, to meet the 1.4 lb/MWh standard. If the WCFU operates at a low efficiency of 30%, then it must maintain an emissions rate of 0.123 lb/MMBtu or less, to meet the 1.4 lb/MWh standard. The proposed SO_2 BACT emission limits for the WCFU (0.055 lb/MMBtu on a rolling 30-day average, or else a prorated limit between 0.055 and 0.040 on a rolling 30-day average, depending on the uncontrolled SO_2 emission potential of the coal) are substantially lower than 0.123 lb/MMBtu and therefore are at least as stringent as the applicable NSPS emission standard of 1.4 lb/MWh.

7. Proposed compliance monitoring approach.

For compliance demonstrations, EPA proposes to require use of SO_2 CEMS. EPA also proposes to allow the diluent cap approach from 40 CFR part 75 for calculating emissions in lb/MMBtu, in the event of very low boiler load, such as during startup or shutdown. This approach was developed by EPA in Part 75 to address low-load situations at electric utility boilers, when Btu's coming from the boiler drop to zero (i.e., when the denominator in the lb/MMBtu calculation drops to zero). The diluent cap approach allows for the substitution of a constant carbon dioxide (CO_2) or oxygen (O_2) diluent value for a measured value from a CO_2 or O_2 diluent monitor. This is explained further below.

In the F factor equation of Method 19, the denominator is allowed to be expressed as either percent CO_2 or [20.9 minus the percent O_2]. If combustion ceases, the percent CO_2 would drop to zero and the percent O_2 would rise to ambient value of 20.9%. In either case, the denominator of the F factor equation would drop to zero, which means the calculated emissions in lb/MMBtu could rise to infinity, despite very little actual emissions coming from the boiler. With the diluent cap approach, if the measured CO_2 concentration in the boiler exhaust stack drops below 5%, it is allowed to be capped at a lower-end value of 5%. Similarly, if the measured O_2 concentration in the boiler exhaust stack rises above 14%, it is allowed to be capped at a higher-end value of 14%. EPA does not view the diluent cap approach as a relaxation of BACT.

Further description of the diluent cap approach may be found in the preamble to a direct final Part 75 rule, published in the Federal Register on May 17, 1995. The rule allows the approach to be used for boiler startup. In a subsequent Part 75 rulemaking, published in the Federal Register on May 21, 1998, EPA determined that it is appropriate to allow the diluent cap approach to be used anytime where there is very low boiler load, such as when the boiler is idling on standby status, not just during startup.

L. BACT for Sulfuric Acid (H_2SO_4) Emissions from CFB Boiler.

Combustion of fuel containing sulfur results in the reaction of sulfur trioxide (SO_3) with water vapor outside of the combustion section, resulting in formation of sulfuric acid mist (H_2SO_4). Since the formation of SO_3 is a function of the generation of SO_2, uncontrolled emissions of sulfuric acid mist are a function of the sulfur content of the coal. Sulfuric acid mist is controlled by the same technologies as for the H_2SO_4 component of PM/PM_{10} condensibles, described earlier in this Statement of Basis.

In addition to the potential control technologies listed in Step 1 below, clean fuels (i.e., alternative coal, either from the Deserado mine or another mine) is also a possible option for BACT, but has already been eliminated as cost-prohibitive for BACT, for all pollutants at this project. This was explained earlier in this Statement of Basis.

1. Step 1: Identify Potential Control Technologies.

The potential control technologies for H_2SO_4 control are the same as the technologies listed in Step 1 of the BACT discussion for PM/PM_{10} condensibles:

a. Alkali (limestone) injection + fabric filter baghouse

b. Dry SO_2 scrubbing + fabric filter baghouse

c. Alkali injection + dry SO2 scrubbing + fabric filter baghouse

d. Alkali injection + wet SO2 scrubbing + fabric filter baghouse

e. Alkali injection + dry SO2 scrubbing + fabric filter baghouse + wet electrostatic precipitation (ESP)

2. Step 2: Eliminate Technically Infeasible Options.

As explained in Step 2 of the BACT discussion for PM/PM_{10} condensibles, all potential control technologies (or technology combinations) listed above are technically feasible for control of H_2SO_4.

3. Step 3: Rank Remaining Control Technologies by Control Effectiveness.

As explained in Step 3 of the BACT discussion for PM/PM_{10} condensibles, Deseret Power proposes to install alkali injection, dry SO2 scrubbing and a fabric filter baghouse (option c above). The only option that might achieve greater control effectiveness for H_2SO_4 would be to add a wet ESP downstream of that combination of controls. The amount of additional control that might be possible is discussed in Step 3 of the PM/PM_{10} condensibles BACT analysis.

4. Step 4: Evaluate Economic, Environmental and Energy Impacts.

Same as discussion in Step 4 of the BACT discussion for PM/PM_{10} condensibles. For control of H_2SO_4, Deseret Power proposes to install alkali injection, dry SO_2 scrubbing and a fabric filter baghouse. As explained in the BACT discussion for PM/PM_{10} condensibles, adding a wet ESP downstream of those controls has been determined to be economically cost-prohibitive for BACT for H_2SO_4.

5. Step 5: Proposed H_2SO_4 BACT for CFB Boiler.

The following discussion, for determination of a BACT emission limit, is based on the selected combination of H_2SO_4 controls, consisting of alkali injection, dry SO_2 scrubbing and a fabric filter baghouse. Deseret Power searched the RACT/BACT/LAER Clearinghouse listings for coal fired fluidized bed boilers with limits on H_2SO_4 emissions where available. The table below presents a summary of facilities utilizing CFB boiler technology with limits on H_2SO_4.

Comparison of CFB Boiler H_2SO_4 Emission Rates:
RACT/BACT/LAER Clearinghouse Data

Facility	RBLC ID	Heat Input MMBtu/hr	H_2SO_4 Emissions Lb/MMBtu	Control	Fuel
AES-PRCP	PR-0007	4922.7	0.0024	Limestone and Dry Scrubber	Columbian Coal
AES Warrior Run	MD-0022	2070.0	0.015	Limestone	Eastern US Coal

Prior to agreeing to install a dry scrubber for SO_2 and H_2SO_4 control, Deseret Power proposed an emission limit of 0.005 lb/MMBtu as BACT for H_2SO_4. However, with the dry scrubber now proposed by Deseret Power, EPA believes it should be possible to do better. For calculating a BACT emission limit, EPA has used the following basis and calculation methodology:

Calculation of potential uncontrolled H_2SO_4:

(a) Basis of calculation:

- For purposes of this analysis, use "average" coal, as specified in proposed permit condition III.H.5 for compliance testing for H_2SO_4. This coal has uncontrolled SO_2 emission potential of 1.71 lb/MMBtu.

- 1% of uncontrolled SO_2 is converted to SO_3, as used in H_2SO_4 BACT analyses in PSD permit applications for the proposed Gascoyne and South Heart CFB boiler projects in North Dakota.

- Assume all of the SO_3 formed in the combustion process combines with water to form H_2SO_4 in a one-to-one molar ratio: $SO_3 + H_2O \Rightarrow H_2SO_4$

(b) Resulting calculation:

(1.71 lb SO_2/MMBtu) x (1 lb-mole SO_2/64 lb SO_2) x
(0.01 lb-mole SO_3/1 lb-mole SO_2) x (1 lb-mole H_2SO_4/1 lb-mole SO_3) x
(98 lb H_2SO_4/lb-mole H_2SO_4) =

0.026 lb/MMBtu H_2SO_4 (uncontrolled)

Calculation of potential controlled H_2SO_4:

(a) Basis of calculation:

- Gascoyne proposes about 90% overall control for H_2SO_4, based on 50% control in the boiler using limestone injection, followed by 80% control of the remainder with a dry SO_2 scrubber.

- South Heart proposes about 93% overall control for H_2SO_4, based on 60% control in the boiler using limestone injection, followed by 82% control of the remainder with a dry SO_2 scrubber.

- Deseret's "average" waste coal will have lower uncontrolled H_2SO_4 emission potential than the coal for the proposed Gascoyne and South Heart CFB boiler projects. (This can be seen from the table of coal comparisons in Step 5 of the SO_2 BACT analysis in this Statement of Basis. Coal that has much lower uncontrolled SO_2 emission potential than other coals can also be expected to have lower uncontrolled H_2SO_4 emission potential.) Therefore, a somewhat lower emission control efficiency than Gascoyne's 90% and South Heart's 93% would seem reasonable for Deseret. EPA estimates that about 87% control of H_2SO_4 is reasonable to expect at Deseret, considering Deseret expects 80% control of the H_2SO_4 by the SO_2 scrubber alone.

(b) Resulting calculation:

Reduce 0.026 lb/MMBtu by 87% in boiler and scrubber

= > 0.0034 lb/MMBtu H_2SO_4 at SO_2 scrubber outlet

This calculation does not necessarily represent EPA's final determination on setting a BACT limit for H_2SO_4. See further discussion below.

EPA is aware that there are some higher proposed or permitted BACT limits for other CFB boiler projects. The Gascoyne project has a permitted H_2SO_4 BACT limit of 0.0061 lb/MMBtu. The PSD permit application for the South Heart project has proposed a H_2SO_4 BACT limit of 0.0042 lb/MMBtu. However, as mentioned above, Deseret Power's waste coal has lower uncontrolled H_2SO_4 emission potential than the coal for these two projects. Therefore, EPA expects that Deseret Power should be able to do better for controlled H_2SO_4 than these two lignite projects.

Additionally, in a February 21, 2006 e-mail, Deseret Power has pointed to the higher limits in the River Hill permit of 0.006 lb/MMBtu and the East Kentucky Power Cooperative Spurlock #4 proposed limit of 0.005 lb/MMBtu. Again, these projects will be burning eastern waste and bituminous coals, which are higher in sulfur content than the waste coal proposed for Deseret Power's WCFU and would therefore have higher uncontrolled H_2SO_4 potential.

EPA is also aware there are some lower proposed or permitted BACT limits for other CFB boiler projects. The AES project in Puerto Rico has a permitted H_2SO_4 BACT limit of 0.0024 lb/MMBtu. However, as mentioned in Step 5 of the SO_2 BACT discussion in this Statement of Basis, the AES-Puerto Rico permit requires the facility to fire a high-heating value low-sulfur coal, which means lower uncontrolled H_2SO_4 emission potential than Deseret Power's waste coal. The Nevco project in Utah also has a permitted H_2SO_4 BACT limit of 0.0024 lb/MMBtu, but will also be firing low-sulfur coal with a much higher heating value than Deseret Power's waste coal. (The average heating value of both the Nevco and AES-Puerto Rico coals will be in excess of 11,000 Btu/lb, versus 4,000 Btu/lb for Deseret Power's "average" waste coal, or 6,500 Btu/lb for a 50/50 blend of Deseret Power's waste coal with run-of-mine coal.)

The PSD permit for the Robinson Power's Beech Hollow waste-coal-fired CFB boiler project in Pennsylvania has a final H_2SO_4 BACT limit of 0.003 lb/MMBtu, burning waste coal with 1.8% sulfur content and a dry scrubber for control. By comparison, Deseret Power's "design" waste coal has sulfur content of 0.71% and Deseret Power's "average" waste coal has sulfur content of 0.34%. Therefore, we would normally expect that Deseret Power could achieve a lower H_2SO_4 limit than the Robinson Power project; however, there are other factors which override this expectation. This is explained below.

According to the April 4, 2005 technical support document by Pennsylvania for the Robinson Power permit, Pennsylvania assumed only 0.7% of the SO_2 converts to SO_3 and subsequently to H_2SO_4, as opposed to 1% in EPA's calculation above for Deseret Power. In addition, Pennsylvania assumed the same level of H_2SO_4 control as they did for SO_2 control, which was 97%. Both of these assumptions would explain why the Robinson Power limit is lower than Deseret Power, even though Robinson Power will be burning much higher sulfur content coal.

Despite the aforementioned assumptions by Pennsylvania for the Robinson Power permit, EPA Region 8 does not believe the control efficiency for H_2SO_4 will be equal to that for SO_2, considering that for both Robinson Power and Deseret Power, the concentrations of H_2SO_4 will be roughly an order of magnitude lower than SO_2. As noted above, EPA has assumed the overall H_2SO_4 control for Deseret Power's project to be 87%. EPA believes this is a reasonable assumption compared to the other permit analyses EPA has reviewed, and considering the lower sulfur content of Deseret Power's coal.

EPA also notes that the Robinson Power permit allows for an adjustment to the BACT limit (upward or downward) based on stack testing for H_2SO_4. This permit language implies that Pennsylvania would be willing to raise the H_2SO_4 BACT limit later, if Robinson Power cannot control its H_2SO_4 emissions by 97% to meet 0.003 lb/MMBtu. In summary, for the reasons outlined above, we do not believe the H_2SO_4 limit in the Robinson Power permit, for a project that will have higher sulfur coal than Deseret Power, precludes EPA from setting a BACT limit for H_2SO_4 at Deseret Power that is higher than 0.003 lb/MMBtu.

In a February 21, 2006 e-mail to EPA, Deseret Power proposed a BACT limit of 0.0038 lb/MMBtu for H_2SO_4. This proposal was based primarily on Deseret Power's assertion that 0.0038 is the "minimum detectable limit," if NCASI Method 8A is used.

Deseret Power stated that since EPA has agreed to allow use of NCASI Method 8A for measurement of H_2SO_4 at the proposed WCFU, in lieu of EPA Method 8, and since NCASI Method 8A cites a "minimum detectable limit" for SO_3 which is equivalent to about 0.0038 lb/MMBtu for H_2SO_4, Deseret Power believes that BACT for H_2SO_4 cannot be lower than 0.0038. For reasons explained below, EPA does not consider Deseret Power's assertion to be valid:

(1) The regulatory definition of BACT in 40 CFR 52.21(b)(12) does not say or imply that issues about the accuracy or detection limits of a particular test method should be determinant of BACT. The definition states that the BACT determination is to be based on the degree of emission control that is achievable by available processes, methods, systems or techniques. The only mention of measurement methodology in the definition is in regard to whether technological or economic limitations on the application of that measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible.

(2) The "minimum detectable limit" cited by Deseret Power is not an absolute, but depends on how a particular test is conducted. The main factor affecting detection limit is the amount of sample collected, which is a direct function of the sampling rate and sampling time. Method 8A specifies a minimum sampling time of 30 minutes, which EPA believes was used by the authors of Method 8A to calculate the minimum detectable limit. However, EPA considers a sampling time of at least two hours to be possible under Method 8A. This would make the minimum detectable limit four times as low as what Deseret has cited. EPA also believes a somewhat

higher sampling rate is possible than what is assumed under Method 8A. This would also lower the minimum detectable limit. Overall, EPA believes the minimum detectable limit under Method 8A could be as much as six times lower than what Deseret Power has cited.

EPA also notes that the minimum detectable emissions cited under Method 8 are an order of magnitude lower than the minimum cited under Method 8A. The sampling rate for Method 8A is about one-third the maximum rate for Method 8.

In a later e-mail dated March 27, 2006, Deseret Power calculated 0.0021 lb/MMBtu of actual H_2SO_4 emissions, based on a scrubber inlet concentration of 0.0127 lb/MMBtu and 80% removal by the scrubber. (These figures would actually yield calculated emissions of 0.0025 lb/MMBtu.) In the same e-mail, Deseret Power stated that its vendor will guarantee 0.0035 lb/MMBtu.

As explained above, EPA has calculated an H_2SO_4 emission rate of 0.0034 lb/MMBtu, based on scrubber inlet concentration of 0.026 lb/MMBtu and 87% removal by the scrubber. This calculation is very close to Deseret Power's vendor guarantee of 0.0035 and, as also explained above, compares reasonably with issued permits for other similar CFB boiler projects, both with higher sulfur coal and with lower sulfur coal. Considering the uncertainties involved with the assumptions underlying EPA's H_2SO_4 calculation, EPA believes a slight adjustment from 0.0034 can be justified, to propose a BACT limit equivalent to the vendor's guarantee. EPA therefore proposes the following as BACT for H_2SO_4:

0.0035 lb/MMBtu, based on annual EPA Method 8 or NCASI Method 8A stack testing

As explained earlier in this Statement of Basis, for the proposed WCFU, Deseret Power will be permitted to use coal from the Deserado mine, consisting of either waste coal alone, or else a blend of waste coal and run-of-mine coal yielding heat content of up to 6,500 Btu/lb. Based on the H_2SO_4 BACT analysis above, EPA believes that the proposed H_2SO_4 emission limit will represent BACT for coal from the Deserado mine with heat content up to at least 6,500 Btu/lb, and will ensure a continued high degree of H_2SO_4 emission control efficiency.

6. Comparison to applicable NSPS emission standard.

Since 40 CFR 60, Subpart Da contains no emission standard for sulfuric acid, there is no comparison to make.

7. Proposed compliance monitoring approach.

For compliance demonstrations, EPA proposes to require annual EPA Method 8 stack tests. In lieu of Method 8, EPA proposes to allow use of NCASI Method 8A. Deseret Power has requested use of NCASI Method 8A due to concern about possible upward bias in Method 8 test results. The potential for bias arises if there is interference from sulfates, which are present in the particulate matter emissions, and from sulfur dioxide. NCASI Method 8A is a type of controlled condensation test method designed to eliminate this interference problem. EPA specialists in stack test methods, at EPA's Office of Air Quality Planning and Standards, have confirmed that use of NCASI Method 8A, as an alternative to EPA Method 8, would be acceptable.

M. BACT for NO_x Emissions from Emergency Generator.

In an internal combustion (IC) engine, NO_x can be formed two ways: thermal NO_x (oxidation of atmospheric nitrogen found in the combustion air), and fuel NO_x (conversion of nitrogen chemically bound in the fuel). Factors that influence NO_x emissions include engine design and operating parameters, type of fuel and ambient conditions.

Thermal NO_x forms in the combustion chamber when N_2 and O_2 molecules dissociate into free atoms at elevated temperatures and pressures encountered during combustion and then recombine to form NO. Thermal NO_x increases exponentially with increases in flame temperature and linearly with increases in resistance time. The NO further oxidizes to NO_x and other NO_x compounds downstream of the combustion chamber.

Fuel NO_x is formed when fuels containing bound nitrogen are burned. The emergency generator for the WCFU project will burn diesel fuel, which typically contains little or no fuel bound NO_x. As a result, when compared to thermal NO_x, fuel bound NO_x is not a major contributor to overall NO_x emissions from most IC engines.

1. Step 1: Identify Potential Control Technologies.

Based on review of the EPA document, Alternative Control Techniques for NO_x Emissions from Internal Combustion Engines (EPA-453/R-94-032), the following potential control technologies for controlling NO_x emissions from compression ignition, diesel fired internal combustion engines were identified:

a. Injection timing retardation
b. Lean burn combustion
c. Selective catalytic reduction (SCR)

Non-selective catalytic reduction (NSCR) is not a potential control technology for diesel-fired engines. A review of available literature from NSCR suppliers (e.g., DCL International Inc.) reveals that NSCR is effective and applied only to engines fired on natural gas, propane or gasoline.

2. Step 2: Eliminate Technically Infeasible Options.

All potential control technologies listed above are technically feasible and are described further below.

a. Injection timing retardation. The operating pressures and temperatures in the combustion chamber are affected by adjusting the ignition timing in the power cycle. Advancing the timing so that ignition occurs earlier in the power cycle results in peak combustion when the piston is near the top of the chamber (when volume of the combustion chamber is at a minimum). This timing adjustment results in maximum pressures and temperatures and has the potential to increase NO_x emissions. Conversely, retarding the ignition timing causes the combustion process to occur later in the power stroke when the piston is in the downward motion and combustion volume is increasing.

Ignition timing retardation has the potential to reduce NO_x formation 20% to 30% on average, by reducing operating pressures, temperatures, and residence time. However, the exact magnitude of reduction is engine specific. Some of the limitations associated with retarded injection timing are related to the degree of retardation specific to the engines so that the greatest NO_x reduction can be achieved without causing performance impacts such as increased exhaust temperatures, decreased power output, misfiring, and elevated opacity at startup. Hence, the degree of timing retardation should be recommended by the manufacturer based on testing of similar size and type engines.

b. Lean burn combustion. A lean burn engine has an air to fuel ratio that is fuel lean and operates with high excess air which reduces the peak temperature achieved and exhaust gas which is rich in oxygen. This inhibits the reaction responsible for thermal NO_x. Lean burn combustion engines may emit as much as 8% lower NO_X than rich burn or uncontrolled engines. Lean burn combustion is usually accomplished through special combustion features such as pr-combustion chamber and pre-stratifying the intake charge. Air/fuel ratio controllers are often used to maximize the reduction in emissions, increase engine efficiency, and maximize the power output. The only technical limitations associated with lean burn combustion are related to the optimal degree of lean combustion specific to the engines in order to achieve the greatest NO_x reduction. This should be recommended by the engine manufacturer based on testing of similar size and type of engines.

c. Selective catalytic reduction. Selective catalytic reduction (SCR) is an add-on NO_x control technology that is placed in the exhaust stream following the engine. The SCR process reduces NO_x emissions by injecting ammonia into the exhaust upstream of a catalyst bed. The ammonia reacts with NO_x in the presence of a catalyst to form water and nitrogen. The operating range for SCR catalysts is typically 550 to 750 F. Variations in exhaust gas tempera-ture of 50 F can have an impact on NO_x reduction efficiency. Also, the molar ratio of ammonia to NO_x is critical to NO_x reduction. Injection of ammonia at higher than the stoichiometric amount enhances NO_x reduction but results in higher ammonia emissions. The ammonia must be injected such that uniform distribution occurs across the catalyst bed.

It has been reported that NO_x reductions from 80-95% may be obtained through the implementation of SCR. SCR has only been installed on a very limited number of IC engines, based on data in the EPA RBLC database. None of these engines are limited duty emergency use applications such as proposed for the WCFU project.

3. <u>Step 3: Rank Remaining Control Technologies by Control Effectiveness</u>.

All potential control options discussed above are technically feasible and are ranked as follows:

a. SCR
b. Combustion controls
(lean burn combustion and ignition timing retardation)

4. <u>Step 4: Evaluate Economic, Environmental and Energy Impacts</u>.

The annualized cost to install an SCR system was evaluated. EPA's document (EPA-453/R-94-032) entitled, *Alternative Control Techniques (ACT) for NO_X Emissions from Internal Combustion Engines*, was utilized to determine SCR capital installation costs. The costs were developed for a generator with the following operating specifications:

- Rated capacity – 750 KW/1005 HP
- Exhaust Flow Rate – 7 ft^3/sec
- Exhaust Temperature – 515 C
- Uncontrolled NO_X emission rate – 3.2 lb/mmBtu
- NO_X reduction – minimum 80%
- Ammonia slip - <10 ppm

The data were obtained from AP-42 Section 3.4 and estimates from similar generators.

An economic analysis was conducted based on the following capital and annualized cost algorithms from the previously referenced document:

Capital cost = $22,800 + (56.4 x HP) per unit
Annual operating cost = $37,300 + (16.7 x HP) (for engines operating 500 hours or less).

For the proposed 1,005 HP engine the capital and annualized costs are $79,482 and $54,083 respectively. Typically, control costs are evaluated based on cost effectiveness calculated as annual cost per ton of pollutant removed. Based on 80% removal efficiency for the oxidation catalyst per the above reference document, and an uncontrolled emission rate of approximately 1 TPY, the cost effectiveness of installing an SCR system on the emergency generator is over $9 million per ton of NO_x removed. Based on this cost estimate, the use of SCR would be cost prohibitive for the emergency generator. Combustion controls (lean burn combustion and ignition timing retardation) are the proposed BACT control option for NO_x for the emergency generator.

5. Step 5: Proposed NO_x BACT for Emergency Generator.

Below is a comparison of NO_x BACT determinations for the most recent nine emergency generators listed in the RACT/BACT/LAER Clearinghouse database:

Comparison of Emergency Generator Nitrogen Oxide Emission Rates: RACT/BACT/LAER Clearinghouse Data

Facility	RBLC ID	Permit Date	Rating in kW	NO_x emissions	NO_x emissions (gm/kW-hr)
Arizona Clean Fuels Yuma	AZ-0046	04/14/05	1050	6.40 gm/kW-hr	6.40
PSI Energy Madison Station	OH-0275	08/24/04	1680	55.07 lb/hr	14.87
Duke Energy Washington County	OH-0254	08/14/03	600	12.4 lb/hr	9.37
Mid-American Energy Company	IA-0067	06/17/03	1340	1.71 lb/MMBtu	7.92
Duke Energy Stephens	OK-0090	03/21/03	560	2.16 lb/MMBtu	10.01
Cardinal FG CO/Cardinal Glass Plant	OK-0091	03/18/03	2000	2.035 lb/MMBtu	9.43
Sterne Electric Generating Facility	TX-0407	12/06/02	1005	41.9 lb/hr	18.91
Redbud Power Plant	OK-0072	05/06/02	1355	0.024 lb/bhp-hr	8.11
Greater Des Moines Energy Center	IA-0058	04/10/02	700	22.69 lb/hr	14.70

The most stringent BACT determination listed above is 6.40 gm/kW-hr. This is the same as the "Tier 2" emission limit listed in 40 CFR 89.112, Table 1, for nonroad compression ignition engine generators larger than 560 kW. (Note: The "Tier 2" limit is actually for NO_x plus nonmethane hydrocarbons, but the NMHC portion is considered by EPA to be extremely small compared to the NO_x.) The requirement for manufacturers to supply "Tier 2" certified engines does not go into effect until January 1, 2007. EPA proposes the "Tier 2" limit as the NO_x BACT limit for the emergency generator at Deseret Power's WCFU project, based on use of combustion controls (ignition retardation and/or lean burn), to the maximum extent that engine specification will allow, at a "Tier 2" certified engine:

6.40 gm/kW-hr

6. Proposed compliance monitoring approach.

For compliance demonstration, EPA proposes to require the following, in lieu of NO_x emission measurement:

(a) Maintain, for the life of the engine, a record of the engine manufacturer's "certification of conformity" from EPA that the engine complies with "Tier 2" emission limits. (40 CFR 89.105 requires the manufacturer to obtain such certification from EPA.)

(b) Install, maintain and operate the engine in accordance with the engine manufacturer's instructions and recommendations, for ensuring ongoing compliance with the "Tier 2" emission standards.

(c) Maintain, for the life of the engine, the engine manufacturer's instructions and recommendations referenced above.

(d) Maintain records of any engine maintenance.

(e) Restrict engine usage to 100 hours per rolling 12-month period (except for maintenance firings and test firings, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine).

EPA considers these requirements to be sufficient for demonstrating emission compliance, in lieu of NO_x emission measurement, for the following reasons:

(a) The engine manufacturer is required under 40 CFR 89.120 to test engines within each engine family for compliance with "Tier 2" emission limits.

(b) The engine manufacturer is required by 40 CFR 89 to apply deterioration factors when seeking certification of conformity, to account for accumulated engine usage.

(c) Deterioration of the emergency generator engine at Deseret Power is expected to be minimal, because: (i) Engine usage will be restricted to 100 hours per rolling 12-month period, and (ii) there are no add-on emission controls for NO_x.

N. BACT for PM/PM_{10} Emissions from Emergency Generator

1. Step 1: Identify Potential Control Technologies.

Potential control technologies of PM emissions from diesel fired internal combustion engines include the following, ranked in order of potential effectiveness:

a. Positive crankcase ventilation
b. Add on control (i.e. electrostatic precipitator, baghouse, scrubber)
c. Combustion of clean (low-sulfur) fuels
d. Implementation of good combustion practices

2. Step 2 - Eliminate Technically Infeasible Options.

All potential control technologies except add-on controls are considered technically feasible. Below is a detailed description of each technology.

a. Positive crankcase ventilation. The positive crankcase ventilation (PCV) system uses a hose connected between the engine and the intake manifold to draw these gases out of the engine's crankcase and back into the cylinders to burn with the regular fuel. The only problem to solve is how to keep these gases from going into the manifold and upsetting the required air fuel ratio. The solution to this problem is the PCV valve.

The PCV valve controls the release of crankcase gases and vapors to the intake manifold. The valve is kept closed by spring action when the engine is at rest. When the engine is running normally, the low vacuum it creates allows the valve to open and release crankcase vapors and gases into the intake manifold for burning. If the engine is idling or slowing down, the vacuum level rises and pulls the valve plunger into the valve opening. This partially blocks off the opening so that only a small amount of vapors and gases can be drawn into the intake manifold. The literature suggests that a PCV system can reduce crankcase PM_{10} emissions by at least 90% over an uncontrolled crankcase vent. The use of a PCV system may be technically feasible for the proposed engine.

b. Add-on controls. EPA is not aware of any available or technically feasible add-on controls. No diesel fired IC engines were identified in the permit review which utilized add-on control technology for PM/PM_{10} control.

c. Combustion of clean (low-sulfur) fuel. Fuel combustion is responsible for significant emissions of PM/PM_{10}. The type of fuel and process have a great impact on the PM emissions from combustion. The combustion of clean fuels to minimize PM/PM_{10} emissions is accomplished by burning fuels with minimal amounts of impurities in conjunction with good combustion practices. Low sulfur diesel fuel (less than 0.05% sulfur content) is available and will be used.

d. Good combustion practices. Good combustion practices refer to the operation of the engines at high combustion efficiency, which reduce the product of incomplete combustion such as PM/PM_{10}. The engines will be designed to maximize combustion efficiency. The engine manufacturer will provide operation and maintenance manuals to the Permittee, which will detail the methods to maintain a high level of combustion efficiency.

3. Step 3: Rank Remaining Control Technologies by Control Effectiveness.

Add-on controls have been eliminated in Step 2 above. The remaining control options are ranked as follows:

a. Positive crankcase ventilation
b. Good combustion practices
c. Combustion of clean (low-sulfur) fuel

4. Step 4: Evaluate Economic, Environmental and Energy Impacts.

The emergency generator will implement all of the above listed technically feasible control technologies; thus, further review of economic, environmental and energy impacts is not necessary.

5. Step 5: Proposed PM/PM_{10} BACT for Emergency Generator.

Deseret Power searched the RACT/BACT/LAER Clearinghouse for PM/PM_{10} BACT determinations for emergency generators. Below is a comparison of the most recent nine permitted emergency generators:

Comparison of Emergency Generator PM/PM_{10} Emission Rates: RACT/BACT/LAER Clearinghouse Data

Facility	RBLC ID	Permit Date	Rating in kW	PM emissions	PM emissions (gm/kW-hr)
Arizona Clean Fuels Yuma	AZ-0046	04/14/05	1050	0.020 gm/kW-hr	0.02
PSI Energy Madison Stn	OH-0275	08/24/04	1680	0.27 tons/yr	0.02
Duke Energy Washington County	OH-0254	08/14/03	600	0.72 lb/hr	0.54
Mid-American Energy Company	IA-0067	06/17/03	1340	0.14 lb/MMBtu	0.65
Duke Energy Stephens	OK-0090	03/21/03	560	0.124 lb/MMBtu	0.57

Cardinal FG CO/Cardinal Glass Plant	OK-0091	03/18/03	2000	0.0444 lb/MMBtu	0.21
Sterne Electric Gen. Fac.	TX-0407	12/06/02	1005	2.97 lb/hr	1.34
Redbud Power Plant	OK-0072	05/06/02	1355	None stated	None stated
Greater Des Moines Energy Center	IA-0058	04/10/02	700	0.95 lb/hr	0.62

The most stringent BACT determination listed above is 0.2 gm/kW-hr. This is the same as the "Tier 2" emission limit listed in 40 CFR 89.112, Table 1, for nonroad compression ignition engine generators larger than 560 kW. The requirement for manufacturers to supply "Tier 2" certified engines does not go into effect until January 1, 2007. EPA proposes the "Tier 2" limit as BACT for the emergency generator at Deseret Power's WCFU project, based on use of positive crankcase ventilation, good combustion practices, and diesel fuel with sulfur content of no more than 0.05% sulfur content, at a "Tier 2" certified engine:

0.20 gm/kW-hr

6. Proposed compliance monitoring approach.

For compliance demonstration, EPA proposes to require the following, in lieu of PM_{10} emission measurement:

(a) Restrict diesel fuel sulfur content to 0.05% or less. Records for each fuel delivery will be required to demonstrate compliance with the fuel restriction.

(b) Maintain, for the life of the engine, a record of the engine manufacturer's "certification of conformity" from EPA that the engine complies with "Tier 2" emission limits. (40 CFR 89.105 requires the manufacturer to obtain such certification from EPA.)

(c) Install, maintain and operate the engine in accordance with the engine manufacturer's instructions and recommendations, for ensuring ongoing compliance with the "Tier 2" emission standards.

(d) Maintain, for the life of the engine, the engine manufacturer's instructions and recommendations referenced above.

(e) Maintain records of any engine maintenance.

(f) Restrict engine usage to 100 hours per rolling 12-month period (except for maintenance firings and test firings, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine).

EPA considers these requirements to be sufficient for demonstrating emission compliance, in lieu of PM_{10} emission measurement, for the following reasons:

(a) The engine manufacturer is required under 40 CFR 89.120 to test engines within each engine family for compliance with "Tier 2" emission limits.

(b) The engine manufacturer is required by 40 CFR 89 to apply deterioration factors when seeking certification of conformity, to account for accumulated engine usage.

(c) Deterioration of the emergency generator engine at Deseret Power is expected to be minimal, because: (a) Engine usage will be restricted to 100 hours per rolling 12-month period, and (b) there are no add-on emission controls for PM_{10}.

O. BACT for CO Emissions from Emergency Generator.

Carbon monoxide emissions are generated from incomplete combustion of the diesel fuel. These emissions occur when there is a lack of oxygen available, if the combustion temperature is too low, or if the residence time in the cylinder is too short.

1. Step 1: Identify Potential Control Technologies

a. Oxidation Catalyst
b. Good combustion practices

2. Step 2: Eliminate Technically Infeasible Options.

Good combustion practices are considered technically feasible but oxidation catalyst is not, for reasons described below.

a. Oxidation catalyst. Oxidation catalysts, which are typically a precious metal deposited onto a solid honeycomb substrate, convert carbon monoxide to carbon dioxide in the presence of oxygen. A search of various regulatory databases did not show where this control method has been applied on similar emergency generator engines. Therefore, this technology is not considered a feasible option for CO emissions control.

b. Good combustion practices. Good combustion practices refer to the operation of engines at high combustion efficiency, thus reducing products of incomplete combustion such as CO. The engines will be designed to maximize combustion efficiency. The engine manufacturers will provide operation and maintenance manuals, which will detail the methods to maintain a high level of combustion efficiency. Good combustion practices are technically feasible to control CO emissions from the proposed emergency generator engine.

3. Step 3: Rank Remaining Control Technologies by Control Effectiveness.

Since the only technically feasible control technology is good combustion practices, ranking is not necessary.

4. Step 4: Evaluate Economic, Environmental and Energy Impacts.

Since the only technically feasible control technology is good combustion practices, and is proposed below as BACT, no review of economic, environmental and energy impacts is necessary.

5. Step 5: Proposed CO BACT for Emergency Generator.

Deseret Power searched the RACT/BACT/LAER Clearinghouse for CO BACT determinations for emergency generators. Below is a comparison of the most recent nine permitted emergency generators:

Comparison of Emergency Generator Carbon Monoxide Emission Rates: RACT/BACT/LAER Clearinghouse Data

Facility	RBLC ID	Permit Date	Rating in kW	CO emissions	CO emissions (gm/kW-hr)
Arizona Clean Fuels Yuma	AZ-0046	04/14/05	1050	3.50 gm/kW-hr	3.50
PSI Energy Madison Station	OH-0275	08/24/04	1680	14.63 lb/hr	3.95
Duke Energy Washington County	OH-0254	08/14/03	600	15.2 lb/hr	11.49
Mid-American Energy Company	IA-0067	06/17/03	1340	0.85 lb/MMBtu	3.94
Duke Energy Stephens	OK-0090	03/21/03	560	2.66 lb/hr	2.15
Cardinal FG CO/Cardinal Glass Plant	OK-0091	03/18/03	2000	0.202 lb/MMBtu	0.94
Sterne Electric Generating Facility	TX-0407	12/06/02	1005	9.02 lb/hr	4.07
Redbud Power Plant	OK-0072	05/06/02	1355	0.055 lb/bhp-hr	18.59
Greater Des Moines Energy Center	IA-0058	04/10/02	700	2.86 lb/hr	1.85

The "Tier 2" emission limit listed in 40 CFR 89.112, Table 1, for nonroad compression ignition engine generators larger than 560 kW, is 3.50 gm/kW-hr for CO. Three of the CO determinations listed above are more stringent than the "Tier 2" limit; however, the BACT determinations for NO_x for those three installations are much higher than the "Tier 2" limit for NO_x. NO_x and CO are inversely related to each other, in terms of emission rate. It is not known if there was a desire at those installations to minimize CO at the expense of NO_x. Nevertheless, it is believed that the "Tier 2" limits for NO_x and CO appropriate balance emissions of those pollutants. EPA proposes the "Tier 2" limit as BACT limit for the emergency generator at Deseret's WCFU, based on good combustion practices, and using a "Tier 2" certified engine:

3.50 gm/kW-hr

6. Proposed compliance monitoring approach.

For compliance demonstration, EPA proposes to require the following:

(a) Maintain, for the life of the engine, a record of the engine manufacturer's "certification of conformity" from EPA that the engine complies with "Tier 2" emission limits. (40 CFR 89.105 requires the manufacturer to obtain such certification from EPA.)

(b) Install, maintain and operate the engine in accordance with the engine manufacturer's instructions and recommendations, for ensuring ongoing compliance with the "Tier 2" emission standards.

(c) Maintain, for the life of the engine, the engine manufacturer's instructions and recommendations referenced above.

(d) Maintain records of any engine maintenance.

(e) Restrict engine usage to 100 hours per rolling 12-month period (except for maintenance firings and test firings, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine).

EPA considers these requirements to be sufficient for demonstrating emission compliance, in lieu of CO emission measurement, for the following reasons:

(a) The engine manufacturer is required under 40 CFR 89.120 to test engines within each engine family for compliance with "Tier 2" emission limits.

(b) The engine manufacturer is required by 40 CFR 89 to apply deterioration factors when seeking certification of conformity, to account for accumulated engine usage.

(c) Deterioration of the emergency generator engine at Deseret Power is expected to be minimal, because: (i) Engine usage will be restricted to 100 hours per rolling 12-month period, and (ii) there are no add-on emission controls for CO.

P. BACT for SO_2 Emissions from Emergency Generator.

1. Step 1: Identify Potential Control Technologies.

Sulfur dioxide emissions occur from the reaction of various elements in the diesel fuel. A search of regulatory databases revealed no evidence that add-on controls have been installed for SO_2 control from diesel internal combustion engines. Only one control option was found, which is use of low sulfur fuel. Low-sulfur diesel fuel (less than 0.05% sulfur content) is available and will be used.

2. Step 2: Eliminate Technically Infeasible Options.

Not necessary. Only one control option was found and is technically feasible.

3. Step 3: Rank Remaining Control Technologies by Control Effectiveness.

Not necessary. Only one control option was found.

4. Step 4: Evaluate Economic, Environmental and Energy Impacts.

Not necessary. Only one control option was found.

5. Step 5: Proposed SO_2 BACT for Emergency Generator.

Deseret Power searched the RACT/BACT/LAER Clearinghouse for SO_2 BACT determinations for emergency generators. Below is a comparison of the most recent nine permitted emergency generators:

Comparison of Emergency Generator Sulfur Dioxide Emission Rates: RACT/BACT/LAER Clearinghouse Data

Facility	RBLC ID	Permit Date	Rating in kW	SO_2 emissions	SO_2 emissions (gm/kW-hr)
Arizona Clean Fuels Yuma	AZ-0046	04/14/05	1050	None stated	None stated
PSI Energy Madison Stn	OH-0275	08/24/04	1680	8.61 lb/hr	2.32
Duke Energy Washington County	OH-0254	08/14/03	600	0.40 lb/hr	0.30
Mid-American Energy Company	IA-0067	06/17/03	1340	0.052 lb/MMBtu	0.24
Duke Energy Stephens	OK-0090	03/21/03	560	0.30 lb/hr	0.24
Cardinal FG CO/Cardinal Glass Plant	OK-0091	03/18/03	2000	0.05 lb/MMBtu	0.23

Sterne Electric Gen. Fac.	TX-0407	12/06/02	1005	2.77 lb/hr	1.25
Redbud Power Plant	OK-0072	05/06/02	1355	0.40 lb/bhp-hr	1.85
Greater Des Moines Energy Center	IA-0058	04/10/02	700	None stated	None stated

The most stringent BACT determination listed above is 0.23 gm/kW-hr. There is no "Tier 2" emission limit listed in 40 CFR 89.112, Table 1, for SO_2 emissions from nonroad compression ignition engine generators. However, the "Tier 2" standards in general are based on availability of diesel fuel with sulfur content of 0.05% or less. As mentioned above, there are no known add-on controls for SO_2 emissions from diesel engines. EPA therefore proposes the following BACT emission limit for the emergency generator at Deseret Power's WCFU, based on applicable AP-42 emission factor and use of diesel fuel with no more than 0.05% sulfur content, at a "Tier 2" certified engine:

0.25 gm/kW-hr.

6. Proposed compliance monitoring approach.

For compliance demonstration, in lieu of emission measurement, EPA proposes to restrict diesel fuel sulfur content to 0.05% or less by weight. Records for each fuel delivery will be required to demonstrate compliance with the fuel restriction. EPA also proposes to restrict engine usage to 100 hours per rolling 12-month period.

Q. BACT for PM/PM_{10} Point Source Emissions from Materials Handling

1. Step 1: Identify Potential Control Technologies.

This section addresses BACT for point sources of PM/PM_{10} emissions associated with materials handling for the WCFU (coal, limestone and ash). These point sources of emissions are the material transfer points (conveyor to storage, reclaim from storage to conveyor, and conveyor-to-conveyor). The available technology for dust collectors that could be used consists of enclosing the transfer points and routing fugitive emissions to fabric filters (baghouses or vent filters), or to mechanical collectors (cyclones). Alternatively, water sprays could be used for dust suppression. Below is a description of each potential option.

a. Fabric filters

(i) Baghouses. A baghouse separates dry particles from an exhaust stream by filtering the stream through a fabric filter and collecting the filtered material on the fabric. Following collection, baghouses can be cleaned using several methods, including reverse air, pulse-jet, and mechanical shakers. The particles removed from the bags are then collected in hoppers below the filter bags. Baghouse removal efficiencies are at least 99%. AP-42 Table B.2-3 lists the collection efficiency of fabric filters as 99% or 99.5%, depending on particle size.

(ii) Vent filters. Vent filters collect the particulate matter in the same manner as baghouses, except that when the vent filters become caked with particulate matter, the filters are replaced. Vent filter control efficiencies are also at least 99%.

b. Cyclones. Cyclones use funnel shape devices that remove particles by the shape of the flow stream, causing heavier particles to fall out of the air flow. The removal efficiency can range from 75% to 99%.

c. Water sprays. Water sprays wet the material and thereby suppress fugitive emissions. Emission control efficiency of water sprays at unenclosed material transfer points is estimated at 50-75%. Emission control efficiency of water sprays at enclosed material transfer points is estimated at 95%.

2. Step 2: Eliminate Technically Infeasible Options.

All technologies listed above are technically feasible.

3. Step 3: Rank Remaining Control Technologies by Control Effectiveness:

- Fabric filters – 99% to 99.5%
- Cyclones – 75% to 99%

- Water sprays at enclosed transfer points – 95%
- Water sprays at unenclosed transfer points – 50% to 75%

4. Step 4: Evaluate Economic, Environmental and Energy Impacts.

Deseret Power proposes to install baghouses or vent filters with control efficiencies of at least 99%. Since this is the highest ranked option in terms of control effectiveness, evaluation of impacts in comparison to other options is not necessary.

5. Step 5: Proposed BACT for PM/PM_{10} Point Source Emissions from Materials Handling.

As stated above, Deseret Power proposes to install baghouses or vent filters to control point source emissions from materials handling for the WCFU. Below is a list of the proposed baghouses and vent filters.

Emission Point ID	Air flow	Location
Baghouse OCH/DC-1	15,000 dscfm	existing terminal building
Baghouse EP-W-MH-01	8,500 dscfm	crusher building
Baghouse EP-W-MH-02	8,500 dscfm	coal day silo headhouse
Baghouse EP-W-MH-03	1,000 dscfm	Limestone crushers
Vent filter EP-W-MH-04	1,000 dscfm	Surge bin
Baghouse EP-W-MH-05	4,000 dscfm	Limestone storage
Vent filter EP-W-MH-06	1,000 dscfm	Bed ash recirculation bin
Vent filter EP-W-MH-07	1,000 dscfm	Bed ash disposal surge bin
Baghouse EP-W-MH-08	3,600 dscfm	Fly ash silo
Baghouse EP-W-MH-08	3,600 dscfm	Bed ash
Vent filter EP-W-MH-10	2.000 dscfm	Lime storage silo

Based on a search of the RACT/BACT/LAER Clearinghouse, Deseret Power originally proposed 0.01 grains per dry standard cubic foot (0.01 gr/dscf) as BACT for the baghouses. However, EPA found more stringent BACT determinations in issued PSD permits for coal-fired energy projects:

North Dakota – Gascoyne CFB boiler project:	0.005 gr/dscf
North Dakota – Coal Creek Coal Drying Demonstration Project:	0.004 gr/dscf
Iowa – Mid-American Energy Company:	0.005 gr/dscf
Wisconsin – Energy Services of Manitowoc:	0.004 gr/dscf

Colorado -- Lamar Light & Power:
0.005 gr/dscf for baghouses larger than 5,000 dscfm;
0.01 gr/dscf for baghouses smaller than 5,000 dscfm.

Based on the above information, Deseret Power has proposed to meet the same baghouse emission limits as in the Colorado permit for Lamar Light & Power. EPA considers that permit to be an appropriate representation of achievable baghouse performance for relatively small baghouses, as it accounts for baghouse size in assessing performance. EPA proposes these same limits as BACT for Deseret Power.

EPA has also found that a 10 percent opacity limit is typically imposed for material handling baghouses used in many industries. For example, the EPA-approved Utah PM_{10} State Implementation Plan for Salt Lake and Utah Counties imposes a countywide 10 percent opacity limit for baghouses as Reasonably Available Control Technology. A 10 percent opacity limit is also typically imposed for small baghouses in PSD permits for new coal-fired energy projects. EPA considers the opacity limit necessary and appropriate for demonstrating continued proper operation and maintenance of the baghouses.

Based on the above information, EPA proposes the following as BACT for PM/PM_{10} point source emissions from materials handling:

All fugitive PM/PM_{10} emissions generated at coal, limestone and ash conveyor transfer points, as well as at coal, limestone, ash, lime and inert material storage silos and storage bins serving the WCFU, shall be routed to fabric filter dust collectors (baghouses or vent filters).

Emissions of filterable PM/PM_{10} from the materials handling baghouses shall not exceed the following:

- **0.005 gr/dscf, expressed as the average of 3 Method 5 or 5D test runs, for baghouses OCH-DC-1, EP-W-MH-01 and EP-W-MH-02**

- **0.01 gr/dscf, expressed as the average of 3 Method 5 or 5D test runs, for baghouses EP-W-MH-03, EP-W-MH-05, EP-W-MH-08 and EP-W-MH-09.**

Visible emissions shall not exceed 10 percent opacity at any materials handling baghouse or vent filter.

Deseret Power has noted that AP-42, Table 1.1-6, states that the PM_{10} emissions from a baghouse are 92% of the total particulate matter emissions from a baghouse. Based on this information, EPA proposes that the BACT limit for total filterable particulate also serve as the BACT limit for filterable PM_{10}, and that Method 5 or 5D test results be considered sufficient for both purposes.

EPA is not proposing any BACT emission limits for the vent filters because EPA is not aware of any feasible way to measure the emissions. Instead, EPA proposes that the opacity limit serve to monitor overall performance of the PM/PM_{10} controls for materials handling.

6. Proposed compliance monitoring approach: For compliance demonstrations at the baghouses, EPA proposes to require Method 5 or 5D stack tests. Since Method 5 or 5D measures total filterable particulate, which includes filterable PM_{10}, EPA is not proposing to require separate Method 201 or 201A testing for filterable PM_{10}.

EPA considered requiring at least an initial stack test at each of the baghouses, but Deseret Power asked EPA to reconsider, on the basis that the information gained from testing would not justify the cost. Deseret Power pointed out that the baghouses will not come equipped with sampling access. Construction of sampling ports and sampling platforms would add to the cost of testing. EPA Region 8 consulted on this with specialists at the Emission Measurement Center (EMC) in EPA's Office of Air Quality Planning and Standards (OAQPS). EMC provided the following cost estimate, which should be regarded as only a very rough estimate:

Construct sampling port	$ 700
Construct sampling platform	4,000
Utilities	1,200
Total to create sampling access	$5,900

The cost of a Method 5 or 5D test is estimated by EMC at $3,000 to $5,000 (assuming less than 500 miles of travel for the stack testing firm), bringing the total to about $9,000 to $11,000 per baghouse, to create sampling access and conduct a test.

In evaluating whether or not the permit should require testing at all baghouses, EPA considered the following factors besides cost:

- the need to ensure in PSD permits that emission limits are enforceable as a practical matter,
- the likelihood of emission noncompliance, due to baghouse malfunction, baghouse bypassing, baghouse deterioriation over time, or any other reason,
- the amount of potential emissions from each baghouse,
- the feasibility of conducting three consecutive Method 5 or 5D test runs, given the expected intermittent use of some of the baghouses (e.g., silo loading or unloading) and the amount of time needed to collect a measurable sample, and
- the possibility that test results at one baghouse could be representative of other baghouses.

Key considerations were that the smaller baghouses at the proposed WCFU have very low emission potential and will only be used intermittently (because operations such as silo loading/ unloading only occur intermittently). After weighing all the considerations, EPA determined that the appropriate testing regime for the WCFU project would be to require at least an initial stack test at the three materials handling baghouses which are believed to have the largest emission potential. These are baghouses OCH-DC-1, EP-W-MH-01, and EP-W-MH-05. If tests at these baghouses are in excess of emission allowables, then tests will be required at the remaining baghouses. EPA proposes the following permit provisions:

> **Initial performance stack tests shall be completed within 60 calendar days after initial startup of baghouses OCH/DC-1, EP-W-MH-01 and EP-W-MH-05.**
>
> **If results of initial performance stack testing at EP-W-MH-01 are in excess of the applicable emission limit in this permit, then baghouse EP-W-MH-02 shall also be initially stack tested, within 90 calendar days after initial performance stack test results at EP-W-MH-01 are required to be submitted to EPA.**
>
> **If results of initial performance stack testing at EP-W-MH-05 are in excess of the applicable emission limit in this permit, then baghouses EP-W-MH-03, EP-W-MH-08 and EP-W-MH-09 shall also be initially stack tested, within 90 calendar days after initial performance stack test results at EP-W-MH-05 are required to be submitted to EPA.**
>
> **If results of any initial performance stack test are in excess of the applicable emission limit for that baghouse, the baghouse shall be retested annually. If results of a retest are not in excess of the applicable emission limit, further retests shall not be required.**

For monitoring performance of the materials handling baghouses, and to track ongoing compliance with particulate emission limits, EPA also proposes, as mentioned above, a 10 percent opacity limit and monthly opacity observations. EPA proposes the following permit provisions:

> **For demonstrating compliance with the opacity limit of ten percent at the materials handling vent filters and baghouses in this permit, the Permittee shall conduct Method 22 visible emission observations at least once per month, at each vent filter and baghouse. If any visible emissions are observed, both of the following actions shall be taken:**
>
> **a. The cause of the visible emissions shall be investigated and any baghouse or vent filter malfunction shall be corrected within three**

working days in the case of broken or damaged bags, or within seven working days for any other type of baghouse malfunction.

b. A Method 9 visible emission observation shall be conducted and recorded for that baghouse or vent filter, by an observer who is certified in the use of Method 9, within 24 hours after visible emissions are observed by Method 22.

If no visible emissions are observed in three consecutive monthly observations, frequency of observation at that baghouse or vent filter may be reduced to quarterly. If visible emissions are observed in any quarterly observation, frequency of observation shall return to monthly.

EPA proposes to allow seven working days to correct baghouse malfunctions, other than broken or damaged bags, because Deseret Power has stated that parts needed to make baghouse repairs are not always readily available and have to be special-ordered and delivered by air freight to Salt Lake City and then transported by motor carrier to the plant site, which is located in remote eastern Utah. EPA proposes three working days in the case of broken or damaged bags because EPA considers it reasonable to expect Deseret Power to keep extra bags on hand at the plant site.

EPA considered also requiring installation and use of bag leak detectors at the materials handling baghouses. These detectors are considered by EPA to be very useful and effective for early detection of bag leaks; however, cost should also be considered where small baghouses are involved. EPA Region 8 was informed by the Emission Monitoring Center at EPA-OAQPS that the capital cost of a bag leak detector might be as much as $24,000, and the annualized cost might be as much as $7,000 (including capital cost recovery). Although these estimates are considered very preliminary by the EMC, they appear to EPA Region 8 to be too high to be justified for the materials handling baghouses at this project, considering that baghouse operation is expected to be intermittent, potential emissions are expected to be low, baghouse bypassing, according to Deseret Power, by design is expected to be physically impossible, and the baghouses will be monitored for opacity compliance on an ongoing basis.

This cost analysis for bag leak detectors is only pertinent to the materials handling baghouses and should not be construed as a statement that bag leak detectors are too expensive to be justified at larger baghouses, such as at the main boiler baghouse for the WCFU. EPA is not requiring bag leak detectors at the main boiler baghouse because EPA is requiring use of PM CEMS instead. EPA considers PM CEMS a superior technique for monitoring main boiler baghouse performance and tracking compliance with the PSD BACT emission limit in this permit for filterable particulate matter emissions from the CFB boiler.

7. Comparison to applicable NSPS emission standard.

The definition of BACT in 40 CFR 52.21(b)(12) contains the statement that, "*In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61*." The applicable emission standard, in Subpart Y of 40 CFR part 60 (New Source Performance Standards), is a 20 percent opacity limit, which will be applicable to coal processing baghouses OCH/DC-1, EP-W-MH-01 and EP-W-MH-02. The proposed PSD BACT emission limit of 10 percent is more stringent.

R. BACT for PM/PM_{10} Non-Point Source Emissions from Materials Handling.

This section addresses BACT for non-point sources of PM/PM_{10} emissions associated with materials handling for the WCFU (coal, limestone and ash). Non-point emission sources include: conveyors for coal, limestone and ash, unenclosed coal and limestone stockpiles, coal stockpile loadout, and ash handling. Fugitive emissions generated at conveyor transfer points are considered by EPA to be point source emissions and are addressed in section L above.

1. Step 1: Identify Potential Control Technologies.

- Coal, ash and limestone conveyors – Eliminate exposure of material to the wind by enclosing the conveyors.

- Unenclosed coal and limestone stockpiles -- Compact the surface, seal the stockpiles with a surfactant initially, and with subsequent application of surfactant sealant and water sprays as warranted to minimize fugitive emissions. Alternatively, enclose the stockpiles.

- Coal stockpile loadout – Use a telescoping chute to enclose the free fall of material during loadout operation and limit the exposure of the material flow stream to the wind.

- Ash handling for disposal -- Hydrate the ash prior to transfer for disposal.

2. Step 2: Eliminate Technically Infeasible Options.

All potential control technologies listed above are technically feasible, with the exception of enclosing the stockpiles. Due to handling problems that would be caused when trying to reclaim coal from an enclosed stockpile, this option is not considered technically feasible.

3. Step 3: Rank Remaining Control Technologies by Control Effectiveness.

Since Deseret Power proposes to utilize all technically feasible control technologies listed above, ranking is not necessary.

4. Step 4: Evaluate Economic, Environmental and Energy Impacts.

Since Deseret Power proposes to utilize all technically feasible control technologies listed above, a comparison of the technologies in terms of impacts is not necessary.

5. Step 5: Proposed BACT for PM/PM_{10} Non-Point Source Emissions from Materials Handling.

EPA proposes the following permit conditions as BACT:

- **All coal, limestone and ash conveyors serving the WCFU shall be fully enclosed.**

- **All fugitive emissions generated at coal, limestone and ash conveyor transfer points serving the WCFU, as well as at coal, limestone, ash, lime and inert material storage silos and storage bins serving the WCFU, shall be routed to fabric filter dust collectors (baghouses or vent filters).**

- **All fugitive emissions from unenclosed coal and limestone stockpiles serving the WCFU shall be controlled by compaction of the surface and by application of water sprays and surfactant when warranted. Conditions which warrant application of surfactant or water sprays are defined in this permit as any time a ten percent opacity level is exceeded.**

- **The Permittee shall conduct weekly Method 22 observations of the coal and limestone stockpiles for visible emissions. If any visible emissions are observed, the Permittee shall conduct a Method 9 visible emission observation within 24 hours, by an observer who is certified in the use of Method 9. If opacity in excess of ten percent is observed by Method 9, the Permittee shall immediately apply dust suppression (water spray and/or surfactant).**

- **The coal stockpile loadout shall be equipped with a telescoping chute to enclose the free fall of material during loadout operation and limit the exposure of the material flow stream to the wind.**

- **All ash generated by the CFB boiler shall be hydrated, via a pugmill mixer, prior to transfer for disposal.**

6. Proposed compliance monitoring approach.

EPA proposes that compliance with the above requirements be demonstrated by keeping the necessary records.

S. BACT for PM/PM_{10} Emissions from Cooling Tower.

There will be one mechanical draft cooling tower installed as part of the project to cool the circulating water. The cooling tower will have 3 or 4 cells to provide the needed cooling. Each cell will have a large fan to move the air through the tower. Because wet cooling towers provide direct contact between the cooling water and the air passing through the tower, some of the liquid water is entrained in the air stream and can be carried out of the tower as drift droplets. As the water evaporates in the drifting cooling tower plume, the dissolved solids in the water forms particulates or PM_{10}. The magnitude of the uncontrolled drift loss is influenced by the design of the cooling tower, the fill design, the air and water flow pattern and other factors.

1. Step 1: Identify Potential Control Technologies.

The only known method of control for particulate matter from cooling towers is effective drift eliminators. Drift eliminators are incorporated into cooling tower design to remove as many water droplets as practical from the air stream before exiting the tower. The drift eliminators rely on separation caused by direction changes as the air passes through the drift eliminators.

2. Step 2: Eliminate Technically Infeasible Options.

Drift eliminators are the only technically feasible control option. Drift eliminator configurations include blades, herringbone, wave form and cellular or honeycomb designs. The cellular design is the most efficient.

3. Step 3: Rank Remaining Control Technologies by Control Effectiveness.

Deseret Power proposes to use drift eliminators with the most efficient configuration available (cellular), therefore ranking is not necessary.

4. Step 4: Evaluate Economic, Environmental and Energy Impacts.

Deseret Power proposes to use drift eliminators with the most efficient configuration available (cellular), therefore evaluation of impacts is not necessary.

5. Step 5: Proposed PM/PM_{10} BACT for Cooling Tower.

Deseret Power has stated that the proposed cooling tower will be equipped with high efficiency drift eliminators capable of removing 99.999% of the potential drift loss. This will result in a drift loss rate of 0.001% of the cooling tower circulating water flow. In an e-mail to EPA on November 11, 2005, Deseret Power proposed 0.001% drift loss as BACT. PM_{10} emission calculations of 3.0 lb/hr and 11.81 tons/year, on page A-3 of Deseret's PSD Permit Application dated November 1, 2004, are based on this rate of drift loss.

EPA found two recently issued PSD permits for coal-fired energy projects with BACT determinations of 0.0005% maximum drift loss at cooling towers:

- Intermountain Power Unit 3 project in Utah
- Excel Energy Comanche Unit 3 project in Colorado

Reducing drift loss from 0.001% to 0.0005% would reduce PM/PM_{10} emissions at Deseret Power's proposed WCFU from 11.8 tons/year to 5.9 tons/year. Deseret Power has stated that to reduce drift loss to 0.0005%, it would be necessary for the manufacturer to install additional layers of the cellular material in the cooling tower. This would make the cooling tower taller and increase the fan horsepower to force the air through the enlarged drift eliminators.

Deseret Power has provided a cost analysis indicating that reducing drift loss from 0.001% to 0.0005% would cost approximately $10,195 per ton of additional PM/PM_{10} removed. Below is a summary of that cost analysis. Calculation methods from EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual were used.

PM/PM_{10} BACT Cost Analysis for Cooling Tower:
Reducing Drift Loss from 0.001 Percent to 0.0005 Percent

Capital Costs:

• Total Direct Cost (TDC)	$140,000
• Total Indirect Cost (TIC)	41,700
• Total Direct and Indirect Costs (TDIC)	$181,700
• Contingency (0.1 x TDIC)	18,170
• Total Installed Capital Cost (TICC)	$199,870

Annualized Costs:

• Direct Annualized Costs:	
-- Total Fixed O&M Costs (TFOM)	$10,292
-- Total Variable O&M Costs (TVOM)	13,705
-- Total Direct Annualized Costs (TDAC)	$23,997
• Indirect Annualized Costs:	
-- Overhead, property tax, insurance, G&A charges	$14,170
-- Capital cost recovery	21,986
-- Total Indirect Annualized Costs (TIAC)	$36,156
• Total Annualized Costs (TAC = TDAC + TIAC)	$60,153

Total additional tons of pollutant removed per year	5.9
Cost Effectiveness ($ per ton of pollutant removed)	$10,195

EPA agrees with Deseret Power's conclusion that the cost per ton of achieving lower than 0.001 percent drift loss is not justified. EPA therefore proposes the following as BACT for PM/PM_{10} at the cooling tower:

0.001 percent maximum drift loss

Considering the high cost of stack testing ($20,000 estimated by the vendor), and the technical difficulties of such testing, and the fact that a drift eliminator is a passive control device (i.e., its effectiveness is based largely on its design, rather than on operation and maintenance practices), EPA proposes to express the BACT limit for drift loss as a design requirement, as follows:

The cooling tower shall be equipped with cellular-type mist eliminators designed to limit circulating water drift loss to 0.001 percent or less.

6. Proposed compliance monitoring approach: EPA proposes for compliance to be demonstrated by records documenting that the drift eliminator has been designed to limit drift loss to 0.001 percent or less.

VII. Applicability/Non-applicability of Other Federal Requirements

A. New Source Performance Standards.

The WCFU will be subject to the following subparts of 40 CFR part 60:

Subpart A – General Provisions

Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

Subpart Y – Standards of Performance for Coal Preparation Plants

Appendix B – Performance Specifications

Appendix F – Quality Assurance Procedures

Subpart A: Any emissions unit subject to an NSPS subpart is also subject to the general provisions in Subpart A (40 CFR 60.1 through 60.15). Key provisions of Subpart A include:

§60.7 – Notification and recordkeeping (including excess emission reporting and continuous emission monitoring system performance reporting)
§60.8 – Performance testing
§60.11 – Compliance with standards and maintenance requirements
§60.13 – Monitoring requirements

Subpart Da: NSPS Subpart Da applies to electric utility steam generating units for which construction or modification is commenced after September 18, 1978, and which are capable of combusting more than 250 MMBtu/hr heat input of fossil fuel. The following provisions will apply:

§60.40Da – Applicability and designation of affected facility
§60.41Da – Definitions
§60.42Da – Standard for particulate matter
§60.43Da – Standard for sulfur dioxide
§60.44Da – Standard for nitrogen oxides
§60.45Da – Standard for mercury
§60.48Da – Compliance provisions
§60.49Da – Emission monitoring
§60.50Da – Compliance determination procedures and methods
§60.51Da – Reporting requirements
§60.52Da – Recordkeeping requirements

Emission Limits in Amended NSPS Subpart Da, as of July 1, 2007
Applicable to Units Commencing Construction after February 28, 2005

Pollutant	NSPS Emission Limit	NSPS Citation	NSPS Required Performance Test
Particulate matter (filterable)	[0.015 lb/MMBtu heat input or 0.14 lb/MWh gross energy output] (daily average) ****OR**** [0.03 lb/MMBtu heat input and 99.9% reduction] (daily average)	§60.42Da(c) and (d)	Method 5 stack test
SO_2	1.4 lb/MWh or 94% reduction (30-day rolling average) applicable to units burning 75% or more (by heat input) coal refuse on a 12-month rolling average basis, otherwise 95% reduction applies.	§60.43Da(i)(1) and (j)(1)	CEMS
NO_x	1.0 lb/MWh (30-day rolling average)	§60.44Da(e)(1)	CEMS
Opacity	20% on a 6-minute average (except for one 6-minute period per hour not to exceed 27%)	§60.42Da(b)	Method 9 (3 hours for initial performance test); COMS thereafter unless PM CEMS is installed and used
Mercury	0.016 lb/GWh (12-month rolling average) applicable to units burning only coal refuse; otherwise for coal blends a weighted average applies	§60.45Da(a)(4) and (5)	CEMS

Footnote: MWh = megawatt-hour, GWh = gigawatt-hour.

§60.48Da(c) states that the PM, NOx and mercury emission standards apply at all times except during periods of startup, shutdown or malfunction. §60.48Da(d) contains provisions that allow an affected facility with a malfunctioning flue gas desulfurization system to operate during "emergency conditions."

In addition to amended emission limits, the following key amendments were made in 2005, applicable to units commencing construction after February 28, 2005:

- §60.41Da has been amended, to change the definition of boiler operating day to mean any 24-hour midnight-to-midnight period during which fuel is combusted in the unit. The existing definition in Subpart Da was any 24-hour period during which fuel is combusted the entire 24 hours. The existing definition will continue to apply to existing units.

- §60.48Da(i) has been added, to specify the calculation methodology for demonstrating compliance with NO_x emission limits in lb/MWh.

- §60.48Da(l) has been added, to specify the calculation methodology for demonstrating compliance with mercury emission limits in lb/MWh.

- §60.48Da(m) has been added, to specify the calculation methodology for demonstrating compliance with SO_2 emission limits in lb/MWh.

- §60.48Da(n) has been added, to specify the calculation methodology for demonstrating compliance with particulate matter emission limits in lb/MWh.

- §60.48Da(o)(1) has been added, to require the initial performance test for particulate matter to be repeated annually.

- §60.48Da(o)(2) has been added, to require that opacity monitoring be used not only to demonstrate compliance with the opacity limit in §60.42a(b), but also be used as an indicator of continuous particulate matter control device performance. For the latter purpose, a baseline opacity level must be established during the initial performance test. If subsequent measurement of hourly average opacity is more than 110% of the baseline level, a new performance test will be required within 60 days, to demonstrate emission compliance. A new baseline is established with each performance test. In no event may the baseline exceed the opacity limit in §60.42a(b). A Continuous Opacity Monitoring System (COMS) is required for tracking opacity compliance.

- §60.48Da(o)(4) has been added, to require a bag leak detection system at fabric filters (baghouses) used to comply with the particulate matter standard in Subpart Da. Specific performance requirements for the bag leak detection system are laid out in §60.48a(o)(4).

- §60.48Da(p) has been added, to allow for PM CEMS to be used as an alternative to the monitoring requirements of §60.48a(o). The PM CEMS must be certified by Performance Specification 11, as required by new section §60.49a(v). Valid hourly average emission measurements are required for 90% of all operating hours, on a 30-day rolling average.

- §60.49Da(f)(2) has been added, to require that emission data from SO_2 CEMS, NO_x CEMS, and COMS (where required) be obtained for at least 90% of all operating hours for each 30 successive boiler operating days. Existing units will remain subject to the existing CEMS availability requirement in Subpart Da (at least 18 hours in at least 22 out of 30 successive boiler operating days), specified in §60.49a(f)(1).

- §60.49Da(p) has been added, to require a mercury CEMS.

- §60.50Da(h) has been added, to specify performance test requirements for demonstrating mercury emission compliance.

Subpart Y: Since waste coal for the WCFU will be crushed at the Bonanza Power Plant at a rate exceeding 200 tons per day, the coal processing, conveying and storage system will be subject to a 20% opacity limit in 40 CFR 60.252(c). Baghouses OCH/DC-1, EP-W-MH-01 and EP-W-MH-02 will be subject to this opacity limit.

In the proposed PSD permit for construction of the WCFU, EPA does not specify the detailed requirements of NSPS, but just states that NSPS subparts A, Da and Y will apply. PSD BACT must be at least as stringent as NSPS, but PSD rules do not require that NSPS provisions be included in PSD permits. The detailed NSPS provisions will be included in the 40 CFR part 71 operating permit, to be issued after the WCFU is constructed and operating. The requirement for Deseret Power to apply for an operating permit for the WCFU is cited in section VII.C below.

Appendices B and F: Pursuant to §60.13, the WCFU will also be subject to the provisions of Appendices B and F of 40 CFR 60. Appendix B contains Performance Specifications (PS's) for continuous monitoring systems for opacity (PS1), SO_2 and NO_x (PS2), diluent (PS3), CO (PS4), and total filterable particulate matter (PS11). Appendix F contains quality assurance procedures for gaseous CEMS used for NSPS compliance determination. The gaseous CEMS for SO_2 and NO_x at the WCFU will be compliance-determining under NSPS Subpart Da.

B. Acid Rain Program.

The WCFU will be an "affected unit" as defined in 40 CFR 72.2 and will therefore be subject to applicable acid rain rules at 40 CFR parts 72 through 78. Key requirements are:

1. Permitting. At least twenty four (24) months before commencing operation of the WCFU, the Permittee must submit an application for an Acid Rain Program

permit in accordance with 40 CFR 72.

2. $\underline{SO_2 \text{ allowances}}$. The WCFU will be subject to requirements under 40 CFR 72.9(c)(1) and 40 CFR 73 for affected Acid Rain units to obtain and hold acid rain SO2 allowances in the unit's compliance subaccount (after any applicable deductions), as of the allowance transfer deadline (defined in 40 CFR 72), not less than the total annual emissions of SO_2 for the previous calendar year from the unit, and to comply with the applicable Acid Rain emission limitation for SO_2.

3. Continuous emission monitoring. The WCFU will also be subject to the continuous emission monitoring requirements in 40 CFR part 75. These include requirements for monitoring of SO_2, NO_x, CO_2 (not CO) and volumetric flow rate, and quality assurance requirements for continuous monitors.

4. $\underline{NO_x \text{ emission limits}}$. The WCFU will not be subject to any acid rain NO_x emission limits in 40 CFR part 76. This is because the unit did not combust any coal during 1990-1995, therefore is not a "coal-fired utility unit" as defined in §76.2. However, continuous monitoring of NO_x emissions will still be required under 40 CFR part 75.

C. Operating Permits Program.

Under 40 CFR part 71, the Permittee is required to submit an application for a Part 71 (Clean Air Act title V) Permit to Operate, within twelve months after commencing operation of the WCFU.

D. Case-Specific MACT Determination.

The November 1, 2004 permit application for the WCFU included a proposal for case-specific determination of Maximum Available Control Technology (MACT) under section 112(g) of the Clean Air Act. However, such determination will not be required. On March 29, 2005, EPA published a final rule, entitled:

> *Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units from the Section 112(c) List.*

In that final rule, EPA removed coal-fired and oil-fired electric utility steam generating units from the Clean Air Act section 112(c) source category list. As a result of that action, the requirements of section 112(g) no longer apply to such units and therefore section 112(g) is no longer an applicable requirement for such units, within the meaning of 40 CFR 71.2. Accordingly, the discussion of case-specific MACT in Deseret Power's PSD permit application of November 1, 2004, is no longer applicable.

In a related final rulemaking published in the Federal Register on May 18, 2005, 70 FR 28606, the EPA Administrator issued standards of performance under section 111 of the Clean Air Act ("New Source Performance Standards"), rather than section 112 MACT standards, to regulate mercury emissions from coal-fired and oil-fired electric utility steam generating units. The WCFU will be subject to those NSPS standards, found at 40 CFR 60.45Da, titled "Standards for mercury." The reference in the proposed PSD permit to NSPS subpart Da encompasses those new standards. The applicable mercury emission limit for the WCFU is listed in section VII.A above.

VIII. Air Quality Impact Analysis

A. Required analyses. The Federal PSD rules, at 40 CFR 52.21(k), require the permit applicant to demonstrate that the allowable emission increases (including secondary emissions) from the proposed source modification (in this case, addition of a coal-fired unit at Deseret's Bonanza power plant), in conjunction with all other applicable emission increases or reductions at the source, for all pollutants that would be emitted in excess of the significance thresholds at §52.21(b)(23)(i), would not cause or contribute to a violation of any National Ambient Air Quality Standard (NAAQS), nor cause or contribute to a violation of any applicable "maximum allowable increase" over the baseline concentration in any area. The PSD significance thresholds are listed in the table below.

Significant Emission Rates in Tons Per Year

Pollutant	Emission Rate
Carbon Monoxide	100
Nitrogen Oxides	40
Sulfur Dioxide	40
Particulate Matter (PM/PM_{10})	25/15
Sulfuric Acid Mist	7
Fluorides	3

Under the proposed PSD permit for the WCFU, emission increases at Bonanza plant would be allowed in excess of PSD significance thresholds for PM/PM_{10}, SO_2, NO_x, CO and H_2SO_4. Therefore, a demonstration of NAAQS and increment protection under §52.21(k) is required for these pollutants.

(Note: Fluorides will be allowed to be emitted in excess of the significance threshold of 3 tons per year, but all of these emissions will be in the form of hydrogen fluoride (HF), a hazardous air pollutant not regulated under PSD. EPA's Office of Air Quality Planning and Standards has advised that PSD requirements for ambient impact analysis and BACT are not applicable where all fluoride emissions from the proposed project are in the form of HF.)

The "maximum allowable increases," also known as PSD increments, are listed in §52.21(c). There are PSD Class I, II and III increments, applicable to areas designated Class I, II and III. Class I areas are defined in §52.21(e). Mandatory Class I areas (which may not be redesignated to Class II or III) are international parks, national wilderness areas larger than 5,000 acres, memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres. Mandatory Class I areas in Utah are listed in 40 CFR 81.430. Class II areas are defined in §52.21(g). These are defined as all areas not designated Class I, except for any areas redesignated from Class II to Class III. No areas have been redesignated to Class III that might be impacted by this project. The PSD Class I and II increments and the NAAQS are listed in the table below.

NAAQS and PSD Class I/II Increments

Pollutant	Averaging Period	NAAQS (ug/m^3)	PSD Class I Increment (ug/m^3)	PSD Class II Increment (ug/m^3)
NO_2	Annual	100	2.5	25
CO	8-hour	10,000	NA	NA
	1-hour	40,000	NA	NA
SO_2	3-Hour	1,300	25	512
	24-Hour	365	5	91
	Annual	80	2	20
PM_{10}	24-Hour	150	8	30
	Annual	50	4	17

§52.21(m) requires the PSD permit application to include an air quality impact analysis for making the demonstration required by §52.21(k). For each pollutant for which a NAAQS or PSD increment exists, §52.21(m)(1)(iv) requires the analysis to include at least one year of pre-construction ambient air quality monitoring data, unless EPA approves a shorter monitoring period (not less than four months). The analysis must be based on air quality models, data bases, and other requirements specified in 40 CFR 51, Appendix W, Guideline on Air Quality Models. §52.21(m)(2) requires post-construction ambient air quality monitoring, if EPA determines it is necessary to determine the effect that emissions from the source modification may have on air quality.

§52.21(i)(5)(i) allows exemption from the requirement for pre-construction ambient monitoring, where the net emissions increase of a pollutant from the proposed source modification would cause air quality impact less than the amount listed for that pollutant in §52.21(i)(5)(i).

§52.21(o) requires additional impact analyses, which must include an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the proposed source modification, or that would occur as a result of any commercial, residential, industrial and other growth associated with the source modification. Analysis for vegetation having no significant commercial or recreational value is not required.

For sources impacting Federal Class I areas, §52.21(p) requires EPA to consider any demonstration by the Federal Land Manager that emissions from the proposed source modification would have an adverse impact on air quality related values (AQRVs), including visibility impairment. If EPA concurs with the demonstration, the rules require that EPA shall not issue the PSD permit.

B. Modeling methodology.

1. General. Prior to conduct of modeling, a modeling protocol was submitted and methodologies were approved by the EPA and federal land managers (National Park Service). The dispersion modeling analysis for NAAQS compliance and PSD Class II increment compliance consisted of two phases: (1) a near field analysis and (2) a full impact analysis. For each pollutant, results of the near field analysis determine whether a full-impact analysis is needed for that pollutant. Near field analysis was performed to determine pollutant concentrations at the fence line and beyond for the proposed WCFU alone. Full-impact analysis was performed to determine pollutant concentrations from all sources (including Bonanza Unit 1) within and around the area of impact, and at Class I areas (far-field), for compliance with NAAQS and PSD Class I and II increments.

Additional modeling analyses were also performed as part of the far-field analysis, to ascertain the impact on regional haze, plume blight, and deposition at the Class I areas in Utah, Colorado, and Wyoming from the proposed WCFU

2. Near field modeling. Near field dispersion modeling was performed to determine the impact from proposed WCFU emissions only. This modeling addressed only the regulated NSR pollutants for which the WCFU would cause a significant net emissions increase at Bonanza plant. The pollutants with emission rates above PSD significance levels include carbon monoxide (CO), nitrogen oxides (as NO_2), sulfur dioxide (SO_2), particulate 10 microns or less (PM_{10}), sulfuric acid mist (H_2SO_4), fluorides (Fl), and beryllium (Be). The Building Profile Input Program (BPIP) was utilized to address downwash and determine Good Engineering Practice (GEP) stack height.

(Note: After the modeling protocol for the WCFU was first submitted to EPA in August of 2001, EPA removed beryllium from the list of pollutants with PSD significance thresholds in §52.21(b)(23)(i).)

3. Full-impact modeling (evaluate cumulative analysis area). The WCFU project full-impact (i.e., cumulative analysis) area was determined based on the modeled maximum pollutant concentrations from the WCFU, obtained from the near field analysis described above. The impact area is the geographical area for which the required air quality impact analyses for the NAAQS and PSD increments are carried out. Existing emissions sources within the full-impact area are included in WCFU PSD increment and NAAQS modeling to determine cumulative impacts. This area includes all locations where the significant increase in the potential emissions of a pollutant from WCFU sources only will cause a significant ambient impact (i.e., equals or exceeds the applicable significant impact level, or SIL, listed in 40 CFR 51.165). The SILs are a screening tool to determine the extent of the air quality analysis required to demonstrate compliance with the NAAQS and PSD increments. The table below presents the SILs for air quality impacts in PSD Class II areas.

Significance Levels for Air Quality Impacts in PSD Class II Areas

Pollutant	Annual	24-hour	8-hour	3-hour	1-hour
SO2	1	5	-	25	-
PM10	1	5	-	-	-
NO2	1	-	-	-	-
CO	-	-	500	-	2,000

Modeled maximum concentration results from near field modeling were above the significance levels listed above for SO_2 and PM_{10}. Based on these pollutant concentrations, the full-impact area was determined.

The full-impact area is a circular area with a radius extending from the source to the most distant point where the model (ISC3 in this case – Industrial Source Complex, version 3) predicts a significant impact will occur. The impact area used for the full impact analysis was the largest of the areas determined for each pollutant reviewed. The maximum distances determined for each pollutant above the significance levels were 16.0 kilometers for SO_2 and 3.9 kilometers for PM_{10}. A distance of 50 kilometers was added to each distance to define the scope of the full impact analysis.

A nearby source inventory was conducted for sources that fell within the impact area. Sources with SO_2 and PM_{10} emissions of 25 tons or greater were identified from emissions information obtained from the Colorado Department of Health for Rio Blancho, Moffat, and Garfield Counties in western Colorado, EPA AIRS database, and from the Utah Division of Air Quality for Uintah County. Based on this source inventory information, no sources in Colorado or Utah met the 25 ton criteria and fell within the impact area with the exception of Bonanza Unit 1.Source (stack and fugitive) emission information for Bonanza Unit 1 was obtained and added to the ISC3 model for the full impact analysis.

4. <u>Far-field modeling</u>. Far-field modeling was performed as part of the full-impact analysis, to determine the maximum ground-level pollutant concentrations at the PSD Class I and II areas from the proposed WCFU, for impact on air quality, visibility, and deposition. After consultation with the National Park Service, Bureau of Land Management (BLM), and the Forest Service Managers, Deseret Power was requested to evaluate the impacts from the proposed project at Canyonlands, Capitol Reef, and Arches National Parks in southeastern Utah, High Uintah Wilderness Area in Utah, Flat Tops and Mt. Zirkel Wilderness areas and Colorado National Monument in western Colorado, and Fitzpatrick and Bridger Wilderness areas in eastern Wyoming. For Dinosaur and Colorado National Monuments in Colorado, SO_2 concentrations were reviewed against the PSD Class I increments only. At the High Uintah Wilderness area and receptors within the Ute Tribe reservation, pollutant concentrations were compared against the PSD Class II increments.

5. Visibility modeling. Visibility impairment is defined as "...any humanly perceptible change in visibility (visual range, contrast, coloration) from that which would have existed under natural conditions." First, the pollutant loading of a section of the atmosphere can become visible, by the contrast or color difference between a layer or plume and a viewed background, such as a landscape feature or the sky. The second way that visibility can be impaired is a general alteration in the appearance of landscape features or the sky, changing the color or the contrast between landscape features or causing features of a view to disappear. The first phenomenon is referred to as plume impairment or plume blight; the second is referred to as uniform haze impairment. As plumes are transported within a stable atmospheric layer, they may become a layered haze

Visibility modeling was performed to determine the impact from the proposed WCFU plume against a background (plume impairment) and uniform haze impairment. For the uniform haze impairment, the concentrations derived from the CALPUFF model were used to calculate the extinction coefficients due to these pollutants. These values were then compared against the light extinction coefficient of the background air. CALPOST was set up to directly calculate the combined visibility effects from different visibility impairing pollutants.

Although all the Class I areas in this analysis were greater than 50 kilometers from the proposed WCFU, VISCREEN was applied to assess the visual effects at Arches, Canyonlands and Capitol Reef National Parks, and Mt. Zirkel, Fitzpatrick, Bridger, and Flat Tops Wilderness Areas. The extinction coefficients for hygroscopic species (modeled and background) were computed using the seasonal relative humidity (RH) adjustment factors for each national park and wilderness area found in the FLAG Phase I report, Table 2.B-1. Per recommendation by the National Park Service, the maximum relative humidity was set to 98% and 95% to cap the maximum f(RH) used in the averages. The 95% relative humidity cap was described by the NPS as the future procedure for calculating light extinction that will be incorporated in the next FLAG report release.

6. Deposition analysis. At the request of the BLM, a deposition analysis was performed to determine the proposed WCFU's contribution to the total sulfur and nitrogen deposition at the PSD Class I areas. The total sulfur and total nitrogen deposition was calculated for two lakes in the Flat Tops Wilderness Area, Ned Wilson Lake and Upper Ned Wilson Lake, and for three lakes in the Mt. Zirkel Wilderness Area, Lake Elbert, Seven Lakes, and Summit Lakes.

For sulfur (S) deposition, the wet and dry fluxes of SO_2 and sulfate (SO_4) were calculated and normalized by the molecular weight of sulfur (32), and expressed as total S. For nitrogen (N) deposition, IWAQM recommended that the wet and dry fluxes of nitric acid (HNO_3) and nitrate (NO_3) and the dry flux of nitrogen oxides (NO_X) be calculated, normalized by the molecular weight of N (14), and express as total N.

CALPUFF was used to output the wet and dry fluxes of SO_2, SO_4, HNO_3, and NO_3. The modeled deposition flux of each of the oxides of sulfur and nitrogen from CALPUFF was adjusted for the difference of the molecular weight of their oxides and the element, and the various forms were summed to yield a total deposition of sulfur. This was accomplished by using a multiplier in CALPOST to do the conversions. The CALPOST program calculated an average flux.

C. <u>Modeling inputs and assumptions</u>

1. <u>Description of models selected</u>.

a. <u>Near field analysis</u>. ISCST3 (Industrial Source Complex, Short-Term, version 3) was used for near field analysis. The ISC3 model is a steady-state Gaussian plume model that can be used to assess pollutant concentrations from a wide variety of sources associated with an industrial source complex. This model can account for the following: settling and dry deposition of particles; building downwash; area, line, and volume sources; plume rise as a function of downwind distance, building dimensions and stack placement with respect to a building; separation of point sources; and limited terrain adjustment. The ISC3 model assumes that:

- Pollutant concentrations from a continuously emitted plume are proportional to the emission rate,
- Ground-level concentrations are inversely proportional to the wind speed,
- The plume doesn't undergo any chemical reaction, and
- Dispersion produces a normal (Gaussian) distribution of pollutants along any cross-sectional transect.

b. <u>Far-field analysis</u>. The CALMET/CALPUFF/ CALPOST modeling system was used for far-field analysis. CALPUFF is a non-steady-state transport and dispersion model that advects "puffs" of material emitted from modeled sources, simulating dispersion and transformation processes along the way. The CALPUFF modeling system has three main components which were utilized for the far-field analyses: CALMET (a diagnostic 3-D meteoro-logical model), CALPUFF (the transport and dispersion model), and CALPOST (a post-processing package).

CALMET was utilized to develop hourly wind, temperature, and other geophysical parameter fields on a three-dimensional meteorological grid. Associated two-dimensional fields such as mixing height, surface characteristics and dispersion properties were also included in the file produced by CALMET. The CALMET output was used by CALPUFF for dispersion calculations. In addition, several other processors were used to prepare geophysical (land use and terrain) data, meteorological data (surface, upper air, precipitation, and buoy data) and utilize output from other prognostic models such as the Penn State/NCAR Mesoscale Model (MM5).

c. Visibility analysis. For visibility modeling, the VISCREEN and CALPUFF models were used to determine the impact from the proposed WCFU plume against a background (plume impairment) and uniform haze impairment, respectively.

VISCREEN is designed to determine whether a plume from a facility has the potential to be perceptible by untrained observers under worst-case conditions. Generally, VISCREEN is usually applied for sources locating less than 50 km from a Class I area. Point source emissions of NO_x, PM_{10}, and H_2SO_4 were modeled using worst-case meteorological conditions. In addition, for screening-level analyses, the Federal Land Managers Air Quality Related Values Workgroup (FLAG) recommends the use of the annual average reconstructed natural conditions, which were used in the analysis.

The FLAG report identified screening criteria for determining whether a pollutant plume can be perceived compared against natural conditions. These screening criteria are a plume contrast greater than 0.05 (absolute value) and a change in the color difference index (delta-E) greater than 2.0.

VISCREEN can be applied in two successive levels of screening (Levels 1 and 2). Level 1 screening is designed to provide a conservative estimate of plume visual impacts using worst-case meteorological conditions. Level 2 screening is identical to that of Level 1 (estimation of worst-day plume visual impacts) with the exception that more realistic data may be input to the model. The joint frequency distribution based on wind speed and stability for given wind direction was calculated for six-hour periods utilizing the on-site meteorological data.

2. Modeling domain and receptor locations. The WCFU project impact area was determined based on the modeled maximum pollutant concentrations. SO_2 and PM_{10} were the only pollutants with modeled maximum concentrations above EPA significant impact levels (SILs). The modeling domain must be large enough to encompass the cumulative analysis area discussed in B.3 above.

a. Near field analysis. An approximate 50 kilometer (km) by 50 km modeling domain was used. A discrete receptor grid, consisting of over 18,000 receptors, was utilized to insure that maximum pollutant concentrations were determined by the model. Receptors with 50 meter spacing were placed around the fence line and extended out to approximately 200 meters. From 200 meters to 1 km, receptors were placed every 100 meters. From 1 km to 5 km, receptors were placed every 200 meters. From 5 km to 25 km, 500 meter receptor spacing was used.

b. Far field analysis. The study area for the PSD Class I analyses (CALPUFF modeling domain) was rectangular shaped, approximately 512 km by 776 km region, roughly centered on the proposed WCFU stack. This domain includes a 50 km buffer zone around the Class I areas to capture recirculation effects. Puffs are tracked within this grid until they cross outside the boundary. At this point, they are dropped from the simulation.

3. Topography/terrain. The terrain elevation data used for this study were obtained from the United States Geological Survey's (USGS) Digital Elevation Model (DEM) in NAD 27 format. Terrain surrounding the proposed stack and in the modeling domain is complex. The terrain data consisted of 1 degree quadrangles with a scale of 1:250,000 and a horizontal resolution of 90-meters. The land use data used in this modeling analysis were also obtained from the USGS. These land use land cover (LULC) data consisted of 1:250,000 scale or 1:100,000 scale quadrangles with a horizontal resolution of 200 meters. The grid spacing was 4 kilometers.

4. Source inventory. For full-impact modeling, a nearby source inventory was conducted for sources that fell within the impact area. Bonanza Unit 1 was the only source, with pollutant emissions (SO_2 or PM_{10}) of 25 tons or greater, identified within the impact area. The emissions from Bonanza Unit 1, based on 2002 actual emissions, as well as the emissions from the proposed WCFU, were modeled for full-impact.

5. Ambient background concentration. Determination of ambient background concentration is necessary for the NAAQS compliance analysis. Ambient air quality data (NO_2, SO_2, and CO) from the Bonanza plant site were available for the period 1991 through 1993. Particulate data (PM_{10}) were also collected from the first quarter, 1991 through the second quarter, 1993 and were used to determine a PM_{10} background value. Based on these monitoring data and considering potential growth in the area that has occurred since 1993 (including an estimated 29% increase in SO_2 emission rate at the existing Bonanza Unit 1, as reported by Deseret Power to EPA via March 23, 2005 letter), estimates of background concentrations were determined as indicated in the table below.

Background Pollutant Concentration Values
(As Corrected by EPA for SO_2)

Pollutant	Averaging Period	Concentration (ug/m3)
SO_2	24-Hour	12.9
	3-Hour	25.8
	Annual	6.5
NO_2	Annual	5
PM_{10}	24-Hour	28
	Annual	10
CO	1-Hour	1150 (1 ppm)
	8-Hour	1150 (1 ppm)

6. <u>Meteorology</u>. ISCST3 requires hourly surface wind speed, wind direction, temperature, stability class and mixing height data. Four years (July 1986-June 1987, 1991-1993) of on-site surface meteorological data, merged with concurrent mixing height information for Grand Junction, Colorado, were utilized for input into ISCST3. Three-dimensional time-varying fields of meteorological conditions were developed using hourly surface observations obtained from the National Weather Service (NWS) Salt Lake City, Utah, Lander/Riverton, Wyoming, and Grand Junction, Colorado offices for 1992, 1996, and 1999 as well as additional surface stations that were identified within the modeling domain. For 1992, 1996, and 1999, 18, 17, and 38 additional surface stations, respectively, were utilized. These data were obtained from National Climatic Data Center (NCDC), Mesowest, and the NPS.

CALMET requires that at least one upper air station also be included in the analysis. Routinely available NWS twice-daily upper air sounding data obtained from the NCDC for Salt Lake City, Utah, Lander/Riverton, Wyoming, and Grand Junction, Colorado from 1992, 1996, and 1999 were used in this analysis. Precipitation data for stations within the modeling domain for the 1992, 1996, and 1999 were obtained from Earth Info, Inc. Ozone data, obtained from the EPA's CASTNET website, were utilized for 1992, 1996, and 1999.

The 1992 and 1996 data, supplied by the NPS and utilized by CALMET/CALPUFF, consisted of MM4 and MM5 data, respectively. The MM4 and MM5 meteorological data sets were produced using the Penn State University/NCAR Mesoscale Model (MM) Versions 4 and 5. One year of Rapid Update Cycle (RUC2) analysis converted onto a 30 km Lambert Conformal grid and written into the MM5.dat format for the period January 26, 1999 through January 26, 2000 was also input to the CALMET model. These data included 17 vertical levels of data extending to 450 millibars. Use of these data was concurred on by the NPS on November 16, 2001.

7. <u>Emission rates</u>. The point source emission rates used for modeling the WCFU and Bonanza Unit 1 are listed in the tables below. Fugitive emissions from coal, limestone and ash handling were also included in the modeling.

The proposed WCFU source parameters, including UTM coordinates and stack base elevations for each emissions point, emission rates, and source release parameters that were used in the modeling are presented in the next table below. The emission rates were based on "worst-case" (i.e., lowest) expected coal heating value of 3031 Btu/lb and the permit emission allowables requested by Deseret Power in the November 1, 2004 permit application, with the exception that for short-term (3-hour and 24-hour) SO_2 emission rates, EPA adjusted the emission rates upward by a factor of 5.93 for the 3-hour rate, and by 1.37 for the 24-hour rate, to account for periods of uncontrolled startup emissions, as reported by Deseret Power in a letter to EPA on March 23, 2005.

For SO_2 and NO_x, the emission allowables proposed by EPA for the PSD permit are substantially lower than the emission rates used for modeling. The November 1, 2004 permit application proposed emission allowables of 0.10 lb/MMBtu for SO_2 and 0.10 lb/MMBtu for NO_x, which are roughly equivalent to the emission rates in grams per second (g/sec) used by Deseret Power in modeling for 3-hour and 24-hour SO_2 impacts (18.52 g/sec) and for annual SO_2 and NO_x impacts (18.21 g/sec). As explained above, EPA later scaled up the short-term SO_2 emission rate used for modeling (18.52 g/sec) by factors of 5.93 for 3-hour SO_2 and by 1.37 for 24-hour SO_2, to account for higher startup emissions. EPA also scaled up the modeling results accordingly. The emission allowables proposed by EPA as BACT for the PSD permit, however, are 0.055 lb/MMBtu for SO_2 and 0.088 lb/MMBtu for NO_x, applicable prior to the date which is 12 months after completion of initial performance testing. Beginning on that date, and thereafter, the applicable emission allowables will be the following: 0.080 lb/MMBtu for NO_x and a 'sliding scale' value for SO_2 between 0.055 and 0.040 lb/MMBtu, when waste coal with uncontrolled SO_2 emission potential of less than ~~1.90~~ 2.2 lb/MMBtu is being burned; otherwise, 0.055 lb/MMBtu will continue to apply for SO_2. These emission allowables are substantially lower than the emission rate of 0.10 lb/MMBtu originally assumed by Deseret Power for modeling for SO_2 and NO_x.

ISC3 WCFU Stack Input Parameters Used for Modeling
As Corrected by EPA for 3-Hour and 24-Hour SO_2

ISC3 Input Parameters	Parameter Values
SO_2 Emission Rate	110.0 [1)] g/sec (872 lb/hr); 25.46 [2)] g/sec (201.9 lb/hr); 18.21 [3)] g/sec (144.4 lb/hr)
PM_{10} Emission Rate	9.47 g/sec (75.4 lb/hr)
NO_2 Emission Rate	18.21 g/sec
CO Emission Rate	27.32 [4)] g/sec
Beryllium Emission Rate	8.82 E-5 g/sec
H_2SO_4 Emission Rate	0.91 g/sec
HCl Emission Rate	2.31 g/sec
HF Emission Rate	0.61 g/sec
UTM Coordinate East	646635 m
UTM Coordinate North	4438574 m
Stack Base Elevation	5030 ft (1533.1 m)
Stack Height	275 feet (83.82 m)
Stack Gas Temperature	275 EF (135 EC)
Stack Gas Exit Velocity	71 fps (21.64 m/s)
Stack Diameter	13 feet (3.96 m)

FOOTNOTES: 1) Worst-case 3-hour emission rate
2) Worst-case 24-hour emission rate.
3) Annual emission rate.
4) Worst-case 1 and 8-hour emission rate.

The next table below presents the Bonanza Unit 1 emission rates used for full-impact modeling. These emission estimates are based on 2002 actual emissions. The 3-hour and 24-hour SO2 emission rates in the table (140 g/sec and 106 g/sec, respectively) are corrections to the November 1, 2004 permit application, which had listed an SO_2 emission rate of 56.3 g/sec for all averaging periods. The correction was reported to EPA by Deseret Power via letter of March 23, 2005.

Bonanza Unit I Stack Parameters Used for Modeling
As Corrected by EPA for 3-Hour and 24-Hour SO_2

Model Input Parameters	Parameter Values
SO_2 Emission Rate	140 g/sec (3-hr) 106 g/sec (24-hr) 56.30 g/sec (annual)
PM_{10} Emission Rate	16.50 g/sec
UTM Coordinate East	646441 m
UTM Coordinate North	4438414 m
Stack Base Elevation	5020 feet (1530.3 m)
Stack Height	600 feet (182.88 m)
Stack Gas Temperature	118 EF (47.78 EC)
Stack Gas Exit Velocity	3201 fpm (16.26 m/s)
Stack Diameter	26 feet (7.93 m)

FOOTNOTE: The higher short-term (3-hr and 24-hr) emission rates for SO_2 listed above (140 g/sec and 106 g/sec, respectively) were provided by Deseret in a March 23, 2005 letter to EPA. These higher rates have been factored into the modeling results tables below, for cumulative NAAQS and Class II increment analysis.

8. Additional data inputs for far-field analysis.

a. Precipitation data. Precipitation data for stations within the modeling domain for the 1992, 1996, and January, 1999 through January, 2000 period were obtained from Earth Info, Inc. These data consist of hourly observations and were thoroughly QA'd prior to use by CALMET.

b. Land use data. The land use data used in the far-field analysis were obtained from the USGS. These land use land cover (LULC) data consisted of 1:250,000 scale or 1:100,000 scale quadrangles with a horizontal resolution of 200 meters. The grid spacing was 4 kilometers. The CALMET preprocessor, Makegeo.exe, was used to combine the terrain and the LULC data to generate the geophysical file needed by CALPUFF. Makegeo.exe maps the original 37 USGS land uses to the 14 CALMET-default land uses, which are presented in the next table below. The default values presented in this table were used by CALPUFF.

Default CALMET Land Use Categories And Associated Geophysical Parameters Based on USGS Classification System

Land Use Type	Description	Surface Rough-ness (m)	Albedo	Bowen Ratio	Soil Heat Flux Parameter	Anthro-pogenic Heat Flux (W/m^2)	Leaf Area Index
10	Urban	1.0	0.18	1.5	0.25	0.0	0.2
20	Agricultural Land – Unirrigated	0.25	0.15	1.0	0.15	0.0	3.0
-20	Agricultural Land – Irrigated	0.25	0.15	0.5	0.15	0.0	3.0
30	Rangeland	0.05	0.25	1.0	0.15	0.0	0.5
40	Forest Land	1.0	0.10	1.0	0.15	0.0	7.0
51	Small Water Body	0.001	0.10	0.0	1.0	0.0	0.0
54	Bays and Estuaries	0.001	0.10	0.0	1.0	0.0	0.0
55	Large Water Body	0.001	0.10	0.0	1.0	0.0	0.0
60	Wetland	1.0	0.10	0.5	0.25	0.0	2.0
61	Forested Wetland	1.0	0.1	0.5	0.25	0.0	2.0
62	Non-forested Wetland	0.2	0.1	0.1	0.25	0.0	1.0
70	Barren Land	0.05	0.30	1.0	0.15	0.0	0.05
80	Tundra	0.20	0.30	0.5	0.15	0.0	0.0
90	Per. Snow or Ice	0.20	0.70	0.5	0.15	0.0	0.0

c. Ozone data. Ozone data, obtained from the EPA's CASTNET website, were utilized for 1992, 1996, and January 1999 through January 2000. The stations and data periods used are presented in the table below.

Ozone Station Data

Station Name	Latitude	Longitude	Data Period
Gothic, WY	38.9564	-106.9858	1992, 1996, Jan. 1999 – Jan. 2000
Mesa Verde, CO	37.1983	-108.4903	1996, Jan. 1999 – Jan. 2000
Canyonlands, UT	38.4583	-109.8211	1996, Jan. 1999 – Jan. 2000
Pinedale, WY	42.9288	-109.7880	1992, 1996, Jan. 1999 – Jan. 2000

D. Exemption from pre-construction ambient monitoring. Near field dispersion modeling for the WCFU was conducted, using four years (1986/1987, 1991, 1992, and 1993) of on-site meteorological data collected by Deseret Power. These near field modeled maximum concentration results are presented in the table below.

While the results of this modeling indicated that the ambient impacts from the proposed WCFU are slightly above the concentration threshold in 40 CFR 52.21(i)(5)(i) that would require pre-construction ambient monitoring for SO_2, EPA determined that pre-construction ambient monitoring need not be required, since ambient SO_2 air quality monitoring data are already available from the plant site for the period 1991-93. These data are considered representative since: (1) the data were collected on-site, (2) there were no other major sources of SO_2 in the area then, (3) no major sources have been added since that time, and (4) the data were collected in accordance with EPA's PSD monitoring guidelines. The data therefore satisfy the criteria in EPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD)," EPA-450/4-87-007 (May 1987), for pre-construction monitoring data to be considered representative of pre-construction ambient air quality for PSD purposes.

The 3-hour and 24-hour SO_2 "Modeled Maximum" values in the table below reflect a 29% scaling up by EPA, as compared to the values presented by Deseret Power in the PSD permit application of November 1, 2004, to reflect a 29% increase in existing Bonanza Unit 1 SO_2 emissions since 1991-93, as reported by Deseret Power to EPA via e-mail on November 13, 2006.

Near field WCFU Modeling Results
and Comparison to Monitoring Exemption Levels
(Modeled Maximums As Corrected by EPA for 3-Hour and 24-Hour SO_2)

Pollutant	Averaging Period	Modeled Maximum (ug/m^3)	Year Maximum Occurred	Threshold Level in 40 CFR 52.21(i)(5)(i) for Exemption	Percent of Threshold Level
SO_2	24-hour	13.3	1993	13	>100
	3-hour	60.5	1992	NA	NA
	Annual	0.66	1991	NA	NA
NO_2	Annual	0.65	1991	14	4.6
PM_{10}	24-hour	7.6	1993	10	76.0
	Annual	1.5	1992	NA	NA
CO	1-hour	185.3	1993	NA	NA
	8-hour	38.5	1991	575	6.7

E. Results and conclusions. The modeling analyses predicted no exceedances of the Class I or II increments, NAAQS, deposition action thresholds, plume blight thresholds, and light extinction thresholds. Results are described in more detail below.

1. National Ambient Air Quality Standards analysis results

a. Near field analysis results. Results of near field analysis for NAAQS compliance are presented in the next table below. The modeled highest and second-highest pollutant concentrations, the background concentrations, the NAAQS, and the percent of NAAQS for WCFU project sources are presented. The "Model-Predicted Concentration" reflects scale-up factors of 5.93 for 3-hour SO_2 and 1.37 for 24-hour SO_2 for the WCFU, as compared to the results presented in the PSD permit application of November 1, 2004, to reflect higher emission rates at the WCFU during a cold startup, as reported by Deseret Power to EPA via a March 23, 2005 letter. See section VIII.E.7 below for details. Also, the "Background Concentration" for SO_2, for all averaging periods, reflects a 29% scale-up, as compared to the "Background Concentration" presented by Deseret Power in the PSD permit application of November 1, 2004, to account for a 29% increase in existing Bonanza Unit 1 SO_2 emissions since 1991-93, as reported in an e-mail from Deseret Power to EPA on November 13, 2006.

NAAQS Compliance Demonstration for WCFU Project Sources
(Results as Corrected by EPA for SO_2)

Pollutant	Averaging Period	Model-Predicted Concentration ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Concen-tration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
SO2	3-hour (H)	324.4	25.8	350.2	1300	26.9
	3-hour (SH)	244.9	25.8	270.7	1300	20.8
	24-hour (H)	14.8	12.9	27.7	365	7.6
	24-hr (SH)	10.4	12.9	23.3	365	6.4
	Annual	0.66	6.5	7.2	80	9.0
PM_{10}	24-hour (H)	7.6	28.0	35.6	150	23.7
	24-hr (SH)	5.5	28.0	33.5	150	22.3
	Annual	1.5	10.0	11.5	50	23.0
NO_2	Annual	0.65	5.0	5.7	100	5.7
CO	1-hour (H)	185.3	1150	1335.3	40,000	3.3
	1-hour (SH)	178.9	1150	1328.9	40,000	3.3
	8-hour (H)	38.5	1150	1188.5	10,000	11.9
	8-hour (SH)	28.0	1150	1178.0	10,000	11.8

FOOTNOTES: H - Modeled maximum concentration
SH - Second highest modeled concentration

b. Full-impact analysis results. Results of full-impact analysis for NAAQS compliance are presented in the next table below. The WCFU's contribution to the "Model-Predicted Concentration" reflects scale-up factors of 5.93 for 3-hour SO_2 and 1.37 for 24-hour SO_2, as compared to modeling results presented in the PSD permit application of November 1, 2004, to reflect higher emission rates during a cold startup, reported by Deseret Power to EPA via a March 23, 2005 letter. See section VIII.E.7 below for details.

Also, Bonanza Unit 1's contribution to the "model-predicted concentration" reflects a scale-up factor of [140/56.3 = 2.5] for 3-hour SO_2, and a scale-up factor of [106/56.3 = 1.9] for 24-hour SO_2, as compared to modeling results presented in the PSD permit application of November 1, 2004, to reflect higher short-term SO_2 emission rates at Unit 1, as reported by Deseret Power to EPA via a March 23, 2005 letter. The letter indicated that Unit 1 peak SO_2 emissions are 140 g/sec on a 3-hour average and 106 g/sec on a 24-hour average. Unit 1's annual average SO_2 emission rate remains at 56.3 g/sec.

Also, the "Background Concentration" for SO_2, for all averaging periods, reflects a 29% scale-up, as compared to the "Background Concentration" presented by Deseret Power in the PSD permit application of November 1, 2004, to account for a 29% increase in existing Bonanza Unit 1 SO_2 emissions since 1991-93, as reported in an e-mail from Deseret Power to EPA on November 13, 2006.

NAAQS Compliance Demonstration for Full Impact Area Sources
(Results as Corrected by EPA for SO_2)

Pollutant	Averaging Period	Model-Predicted Concentration (ug/m^3)	Background Concentration (ug/m^3)	Total Concentration (ung/m^3)	NAAQS (ug/m^3)	Percent of NAAQS
SO_2	3-hr (H)	329.2	25.8	355.0	1300	27.3
	3-hr (SH)	245.4	25.8	271.2	1300	20.9
	24-hr (H)	14.8	12.9	27.7	365	7.6
	24-hr (SH)	12.9	12.9	25.8	365	7.1
	Annual	1.2	6.5	7.7	80	9.6
PM_{10}	24-hr (H)	16.3	28.0	44.3	150	29.5
	24-hr (SH)	9.6	28.0	37.6	150	25.1
	Annual	2.5	10.0	12.5	50	25.0

FOOTNOTES: H - Modeled maximum concentration
SH - Second highest modeled concentration

2. PSD Class II increment consumption analysis results

a. Near field analysis results. Results of near field analysis for PSD Class II increment compliance are presented in the next table below. The "Model-Predicted Concentration" reflects scale-up factors of 5.93 for 3-hour SO_2 and 1.37 for 24-hour SO_2, as compared to the results presented in the PSD permit application of November 1, 2004, to reflect higher emission rates during startup, as reported by Deseret Power to EPA via a March 23, 2005 letter. See section VIII.E.7 below for details.

PSD Class II Increment Compliance for WCFU Sources
(Near field Analysis)
(Results as Corrected by EPA for SO_2)

Pollutant	Averaging Period	Model-Predicted Concentration (ug/m^3)	PSD Class II Increment (ug/m^3)	Percent of Class II Increment
SO_2	3-hour (H)	324.4	512	63.3
	3-hour (SH)	244.9	512	47.8
	24-hour (H)	14.8	91	16.3
	24-hour (SH)	10.4	91	11.4
	Annual	0.66	20	3.3
PM_{10}	24-hour (H)	7.6	30	25.3
	24-hour (SH)	5.5	30	18.3
	Annual	1.5	17	8.8
NO_2	Annual	0.65	25	2.6

FOOTNOTES: H - Modeled maximum concentration
SH - Second highest modeled concentration

b. Full-impact analysis results. Results of full-impact analysis for PSD Class II increment compliance are presented in the next table below. The WCFU's contribution to the "model-predicted concentration" reflects scale-up factors of 5.93 for 3-hour SO_2 and 1.37 for 24-hour SO_2, as compared to modeling results presented in the PSD permit application of November 1, 2004, to reflect higher emission rates during startup, reported by Deseret Power to EPA via a March 23, 2005 letter. See section VIII.E.7 below for details.

Also, Bonanza Unit 1's contribution to the "model-predicted concentration" reflects a scale-up factor of [140/56.3 = 2.5] for 3-hour SO_2, and a scale-up factor of [106/56.3 = 1.9] for 24-hour SO_2, as compared to modeling results presented in the PSD permit application of November 1, 2004, to reflect higher short-term SO_2 emission rates at Unit 1, as reported by Deseret Power to EPA via a March 23, 2005 letter. The letter indicated that Unit 1 peak SO_2 emissions are 140 g/sec on a 3-hour average and 106 g/sec on a 24-hour average. Unit 1's annual average SO_2 emission rate remains at 56.3 g/sec.

PSD Class II Increment Compliance
for Full Impact Area Sources
(Results as Corrected by EPA for SO_2)

Pollutant	Averaging Period	Model-Predicted Concentration (ug/m^3)	PSD Class II Increment (ug/m^3)	Percent of Class II Increment
SO_2	3-hour (H)	329.2	512	64.3
	3-hour (SH)	245.4	512	47.9
	24-hour (H)	14.8	91	16.3
	24-hour (SH)	12.9	91	14.2
	Annual	1.2	20	6.0
PM_{10}	24-hour (H)	16.3	30	54.3
	24-hour (SH)	9.6	30	32.0
	Annual	2.5	17	14.7

FOOTNOTES: H - Modeled maximum concentration
SH - Second highest modeled concentration

3. <u>PSD Class I increment consumption analysis results</u>. Far-field analysis was conducted by Deseret Power for SO_2, PM_{10} and NO_x impacts on PSD Class I areas. Results for Class I increment compliance are presented in the next table below. The table is a summary of results based on various meteorological data sets (1992 MM4 data, 1996 MM5 data, and 1999 RUC2 data). Only the highest percent increment consumption of any of the data sets and for any averaging period is presented in this table. The applicable increment averaging periods are 3-hour, 24-hour and annual for SO_2, 24-hour and annual for PM_{10}, and annual for NO_x. The highest modeled percent increment consumption was 12.5% for 24-hour SO_2 at Dinosaur National Monument in Colorado. The second highest was 4.4% for 24-hour SO_2 at Colorado National Monument. Complete results may be found in the PSD permit application.

Modeled Maximum CALPUFF PSD Class I Increment
Consumption Results for WCFU Project

Class I Area	Pollutant	Averaging Period of Highest Percent Increment Consumption	Percent of Class I Increment Consumed
Arches National Park	SO_2	24-hr	2.1
	PM_{10}	24-hr	<1
	NO_2	Annual	<1
Bridger Wilderness	SO_2	3-hr	<1
	PM_{10}	24-hr	<1
	NO_x	Annual	<1

Fitzpatrick Wilderness	SO_2	3-hr	<1
	PM_{10}	24-hr	<1
	NO_2	Annual	<1
Canyonlands National Park	SO_2	24-hr	1.6
	PM_{10}	24-hr	<1
	NO_2	Annual	<1
Capitol Reef National Park	SO_2	24-hr	1.4
	PM_{10}	24-hr	<1
	NO_2	Annual	<1
Colorado National Monument (1)	SO_2	24-hr	4.4
	PM_{10}	24-hr	<1
	NO_2	Annual	<1
Dinosaur National Monument (Utah) (2)	SO_2	24-hr	1.5
	PM_{10}	24-hr	2.3
	NO_2	Annual	<1
Dinosaur National Monument (Colorado) (3)	SO_2	24-hr	12.5
	PM_{10}	24-hr	1.2
	NO_2	Annual	<1
Flat Tops Wilderness	SO_2	24-hr	2.5
	PM_{10}	24-hr	<1
	NO_2	Annual	<1
Mt. Zirkel Widerness	SO_2	24-hr	1.5
	PM_{10}	24-hr	<1
	NO_2	Annual	<1
High Uintah Wilderness	SO_2	3-hr	<1
	PM_{10}	24-hr	<1
	NO_2	Annual	<1
Ute Tribe Areas of Concern	SO_2	3-hr	<1
	PM_{10}	24-hr	<1
	NO_2	Annual	<1

FOOTNOTES:

(1) Colorado National Monument is PSD Class I for SO2 only.

(2) Portion of Dinosaur National Monument in Utah is classified as PSD Class II for all pollutants.

(3) Portion of Dinosaur National Monument in Colorado is classified as PSD Class I for SO2 only.

An e-mail from the National Park Service to EPA on June 16, 2005, stated that "…the modeling analyses for Class I and Class II PSD increments and impacts to Air Quality Related Values has been performed correctly and all issues regarding impacts to the NPS Class I and

Class II units have been addressed." This statement was noted in the draft Statement of Basis. Nevertheless, public comments received by EPA on the draft WCFU permit action raised issues with the Class I increment analysis.

The public commenters' suggested use of worst case short term emission rates ("modeling limits" in the permit), in determining impacts to Air Quality Related Values (AQRVs) or PSD Class I increments, greater than 50 kilometers from the source, is not an approach EPA would require, since the worst case emission rate is not intended to represent a routine or frequent operating condition. The low frequency of occurrence of the WCFU facility operating at the worst case emission rate (reflecting a cold startup), combining with simultaneous meteorology to transport emissions a considerable distance to the nearest Class I area, makes the likelihood of impacts on the nearest Class I areas extremely unlikely.

However, to be responsive to public commenters, EPA has supplemented the analysis results presented in the table above with a screening analysis for nearby Class I areas, using worst-case emission rates cited by public commenters. This was done by scaling Deseret Power's PSD Class I modeling analysis to the level of the worst case short term emission rates applied above to NAAQS and Class II increment modeling (872 lb/hr for 3-hour SO_2 and 202 lb/hr for 24-hour SO_2), even though this is not an approach EPA would require (as explained above).

Specifically, the 3-hour PSD increment concentrations were multiplied by 5.93 and the 24-hour PSD increment concentrations by 1.37. The adjusted modeled concentrations from the WCFU were then added to the cumulative PSD increment concentrations calculated by Intermountain Power Agency (IPA) for their Unit 3 PSD permit application to the State of Utah in May of 2003. The modeling analysis in the IPA Unit 3 application has been reviewed and approved by the Utah Division of Air Quality. The State of Utah has a SIP-approved PSD permitting program and implements the PSD program in Utah. That analysis showed that the PSD Class1 increment is not threatened in these areas. (See table below.)

Cumulative PSD Increment Consumption for Selected Utah Class 1 Areas Based on Combined Modeled Impacts from Deseret WCFU and Reported PSD Increment Modeling Results from Intermountain Power Project, Unit 3

Location	3-hour SO2	24-Hour SO2	Annual SO2	24-Hour PM10	Annual PM10
Arches NP	3.8	0.8	0.1	0.2	.02
Canyonlands NP	9.6	2.2	0.1	0.2	.02
Capitol Reef NP	4.0	0.9	0.1	0.2	0.2
PSD Class 1 Increment	25	5	2	8	4

Ref: Addendum to Final Permit Application ("Notice-Of-Intent"), Intermountain Power Project, Proposed Unit 3, June 16, 2003.

In addition, in a letter to EPA dated March 23, 2005, Deseret Power presented revised modeling results for impact on Class I SO_2 increment at Dinosaur National Monument in Colorado, based on worst-case startup emission rates for 3-hour and 24-hour SO_2 at the WCFU (872 lb/hr and 202 lb/hr, respectively, rather than 147 lb/hr used in the PSD permit application of November 1, 2004), and higher 3-hour and 24-hour SO_2 emission rates at Bonanza Unit 1 than used in the PSD permit application of November 1, 2004 (140 g/sec for 3-hour SO_2 and 106 g/sec for 24-hour SO_2, rather than 56.3 g/sec originally used in the November 1, 2004 PSD permit application). Results indicated increment will not be exceeded.

4. Visibility impact analysis results. The results of the Level 1 screening analysis, using VISCREEN, indicated that all Class 1 areas were below the Level 1 screening criteria. After CALPOST was run and B_{ext} (visibility extinction) was calculated at each receptor, the maximum B_{ext} values were reviewed and tabulated based on the maximum relative humidity cap, for 1992, 1996 and 1999 meteorological data sets. The results of the visibility modeling indicated that, at a relative humidity cap of 98%, and using 1992 meteorological data, there were 2 days at Arches and Capitol Reef National Parks which were slightly above the 5 percent maximum percentage change. However, using a relative humidity cap of 95%, no days exceeded the suggested 5 percent maximum percentage change, for any meteorological data. Complete results may be found in the PSD permit application.

5. Deposition analysis results. The highest total sulfur and nitrogen deposition results, in kilograms per hectare per year (kg/ha/yr), for each Class I area, for 1992, 1996, and 1999 datasets, were calculated. Total deposition is the sum of the wet and dry deposition components. The results were compared to the Deposition Analysis Thresholds (DAT). A DAT is the additional amount of nitrogen or sulfur within a Class I area, below which estimated impacted from a proposed new or modified source are considered insignificant. The

DATs for nitrogen (N) and sulfur (S) in western Class I parks is 0.005 kg/ha/yr. Results are shown in the next table below, in terms of percent of the DAT.

PSD Class I Total Deposition Results
For WCFU Project

Location	Year of Dataset w/Highest Result	Total Sulfur Deposition As Percent Of DAT	Total Nitrogen Deposition As Percent of DAT
Arches NP	1996	26	9
Bridger WA	1992	7	1
Fitzpatrick WA	1992	5	1
Canyonlands NP	1996	19	6
Capitol Reef NP	1992	6	1
Flat Tops NP	1992	77	24
Mt. Zirkel WA	1992	82	23

6. Lake chemistry analysis results. At the request of the Bureau of Land Management, Deseret Power calculated the total sulfur and total nitrogen deposition for two lakes in the Flat Tops Wilderness Area (Ned Wilson Lake and Upper Ned Wilson Lake), and for three lakes in the Mt. Zirkel Wilderness Area (Lake Elbert, Seven Lakes, and Summit Lakes). These deposition values were used to predict the changes to the chemistry of these sensitive lakes. The total sulfur and nitrogen deposition values for these lakes are shown in the table below. All values are below the DAT of 0.005 kilograms per hectare per year (kg/ha/yr).

Total Deposition at Sensitive Lakes of Concern

Sensitive Lake	Receptor No.	Total Sulfur (Kg/Ha/Yr)	Total Nitrogen (Kg/Ha/Yr)
1992			
Ned Wilson Lake	2429	3.29 E-03	9.61 E-04
Upper Ned Wilson Lake	2429	3.29 E-03	9.61 E-04
Lake Elbert	2619	3.67 E-03	9.92 E-04
Seven Lakes	2771	3.47 E-03	8.84 E-04
Summit Lake	2574	3.43 E-03	9.28 E-04
1996			
Ned Wilson Lake	2429	2.82 E-03	8.75 E-04
Upper Ned Wilson Lake	2429	2.82 E-03	8.75 E-04

Lake Elbert	2619	2.16 E-03	6.39 E-04
Seven Lakes	2771	1.63 E-03	4.31 E-04
Summit Lake	2574	2.19 E-03	6.61 E-04
1999			
Ned Wilson Lake	2429	1.59 E-03	4.69 E-04
Upper Ned Wilson Lake	2429	1.59 E-03	4.69 E-04
Lake Elbert	2619	1.68 E-03	4.42 E-04
Seven Lakes	2771	1.46 E-03	3.79 E-04
Summit Lake	2574	1.73 E-03	4.54 E-04

7. EPA adjustments to permit applicant's modeling analysis. In a letter to Deseret Power on December 29, 2004, EPA asked Deseret Power to provide the methodology used to estimate the "worst case" emission rates used in modeling compliance with the NAAQS and/or PSD increments for SO_2 and CO. Upon reviewing the spreadsheet in Deseret's response of March 23, 2005, which documented the calculations, EPA found that Deseret Power considered short term emission peaks of 10 start-up emission scenarios in the analysis. While Deseret Power considered that these startup emissions would occur for 120 hours per year, Deseret Power averaged these peak startup emissions over the remaining 8640 hours in the year.

What Deseret Power provided, therefore, was an estimate of annual average emissions that reflects 10 start-up cycles that may occur during the year. EPA determined that this was not responsive to EPA's December 29, 2004 request. The short-term NAAQS and PSD increments are based on the second highest short term average concentration that occurs during the year. Thus the start up peak emission scenarios must consider peak emissions rates that would occur on the worst day (or 3 or 8 hour period) during the year.

Deseret Power provided enough information in the March 23, 2005 submittal, however, that the short term emission rates during startup scenarios could be re-calculated by EPA. For SO_2, the worst case 3-hour average emission rate would increase from Deseret's estimate of 146.99 lb/hr to 872 lb/hr (5.93 times as high as Deseret's estimate), while 24-hour average emissions would increase from 146.99 lb/hr to 201.9 lb/hr (1.37 times as high as Deseret's estimate). When the higher emissions values are used as input for dispersion models (as shown in the tables of modeling results above), it still appears to EPA that the NAAQS and PSD Class I and II increments would not be exceeded.

EPA also determined that its revision to Deseret Power's SO_2 emissions estimate for the WCFU should be taken into account in estimating the significant impact area of the WCFU. In Deseret Power's original analysis, the Class II significant impact area for SO_2 was a 16-kilometer radius from the proposed WCFU. Deseret Power added 50 kilometers to the impact area radius and looked for other increment affecting sources within 66 kilometers of the proposed WCFU.

Other than Bonanza Unit 1, there were no other sources in the 66-kilometer radius impact area. The revised emission estimate for the WCFU would expand the impact area somewhat, but there are no additional large SO_2 sources near the edge of the 66-kilometer impact area. (This area is very remote.) At distances exceeding 66 kilometers, it would take a huge source to materially affect increment concentrations and there are none that large within at least 100 kilometers of the proposed WCFU.

On November 3, 2005, Deseret Power notified EPA via e-mail that Deseret Power accepts EPA's re-calculation of modeling for startup scenarios and asked that EPA consider the re-calculation to be an amendment to the PSD permit application.

8. Post-construction ambient monitoring. As mentioned earlier in this Statement of Basis, 40 CFR 52.21(m)(2) requires post-construction ambient air quality monitoring, if EPA determines it is necessary to determine the effect that emissions from the source modification may have on air quality. Since the modeled ambient air quality impacts of the WCFU project are far below the NAAQS and PSD Class I and II increments, EPA has determined that it will not be necessary to require post-construction ambient monitoring for the WCFU project.

9. Emission limits for modeling purposes. As explained in section VIII.A of this Statement of Basis, 40 CFR 52.21(k) requires the permit applicant to demonstrate that the allowable emission increases (including secondary emissions) from the proposed source modification (in this case, addition of a coal-fired unit at Deseret's Bonanza power plant), in conjunction with all other applicable emission increases or reductions at the source, for all pollutants that would be emitted in excess of the significance thresholds at §52.21(b)(23)(i), would not cause or contribute to a violation of any National Ambient Air Quality Standard (NAAQS), nor cause or contribute to a violation of any applicable "maximum allowable increase" over the baseline concentration in any area.

EPA interprets §52.21(k) to require that emission limits be included in PSD permits ('modeling limits') consistent with emission rates used in dispersion modeling for ambient impacts, unless it would be physically impossible for the proposed source modification to emit at a greater rate (i.e., maximum potential uncontrolled emissions). This requirement is in addition to the requirement under §52.21(j)(3) to establish BACT emission limits.

For the WCFU project, the WCFU exhaust stack emission rates that were used in dispersion modeling for PSD Class II increment compliance (with adjustments by EPA as described in section VIII.E.7 of this Statement of Basis) are the following:

PM_{10}	24-hr increment	75.4 lb/hr
SO_2	3-hr increment	872 lb/hr
SO_2	24-hr increment	201.9 lb/hr
NO_x	annual increment	144.4 lb/hr

These emission rates used for modeling are well below the maximum potential uncontrolled emission rates of the WCFU, listed in section IV.I.2 of this Statement of Basis. Therefore, modeling limits are needed in the permit.

EPA believes the proposed BACT limit for NO_x in the permit (0.080 lb/hr on a 30-day rolling average, equivalent to 115.6 lb/hr on a 30-day average at boiler heat input capacity) can also serve as a modeling limit for NO_x, since the BACT limit is lower than the NO_x emission rate used for modeling and is on a shorter-term average (30-day versus annual). However, the proposed BACT limits for PM_{10} and SO_2 in the permit, being on 30-day averages also, cannot serve as modeling limits because they are not consistent with the short-term averaging times used for dispersion modeling for those pollutants, i.e., the BACT limits are not on 3-hour or 24-hour averages. EPA therefore proposes the following emission limits as modeling limits in the permit:

The Permittee shall not discharge or cause the discharge of emissions from the CFB boiler to the atmosphere in excess of the following rates used in modeling ambient impacts of the WCFU:

1. **872 pounds per hour of sulfur dioxide, averaged over a 3-hour block period.**

2. **202 pounds per hour of sulfur dioxide, averaged over a 24-hour block period.**

3. **75.4 pounds per hour of total PM_{10} (filterable plus condensible), averaged over a 24-hour block period.**

For compliance demonstrations, EPA proposes to require use of PM CEMS and SO_2 CEMS in the CFB boiler exhaust stack. For SO_2, as well as for the filterable portion of PM_{10}, the CEMS output will be multiplied by the output from the in-stack continuous volumetric flow rate monitor, and appropriate conversion factors applied, to yield an output in pounds per hour. Results will then be averaged over 3-hour and 24-hour block periods for SO_2, and over 24-hour block periods for PM_{10}. For the condensible portion of PM_{10}, results of the latest required annual stack test for condensibles will be used, expressed in pounds per hour. Those results will then be added to the filterable portion, to yield total PM_{10}.

IX. Environmental Justice Assessment

This environmental justice assessment was offered by EPA as a draft for public comment in June of 2006, as part of the draft PSD permit package for the proposed WCFU project. No public comments were received on this assessment. This assessment is not in response to any allegations of environmental injustice about the proposed project. No such allegations have been made to EPA. Nothing in this assessment is meant to imply that environmental justice assessments must be done for all EPA permit actions in the absence of allegations of environmental injustice.

On February 11, 1994, President Clinton issued Executive Order 12898, entitled "Federal Actions To Address Environmental Justice in Minority Populations and Low-income Populations." The Executive Order calls on each federal agency to make environmental justice a part of its mission by "identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies and activities on minority populations and low-income populations." The broad goal of EO12898 is then tempered in subsection 6-609 of the Executive Order by the caution that "this order is intended only to improve the internal management of the executive branch and is not intended to…create any right…enforceable...against the United States."

EPA used the following step-by-step approach for determining whether or not the proposed WCFU project might result in disproportionately high and adverse human health or environmental effects on minority populations or low-income populations.

1. Determine the affected geographical area for the proposed WCFU project.

EPA has no standardized procedure for determining the "affected area" of a PSD-permitted project for environmental justice purposes. The determination is case-by-case. For the WCFU project, EPA determined the "affected area" for this environmental justice assessment by examining the dispersion modeling results and comparing them to the National Ambient Air Quality Standards (NAAQS). These are health-based standards, set at a level presumptively sufficient to protect public health with an adequate margin of safety. Based on this approach, EPA determined that the "affected area" is an area extending no more than a few miles out from the Bonanza power plant, with the portion of that area most likely to be affected being to the east of the Bonanza power plant (downwind). Below is an explanation of how EPA arrived at this determination.

As shown in the Statement of Basis, the air pollutants that are anticipated to be emitted in largest amounts from the proposed WCFU project are particulate matter, sulfur dioxide (SO_2), nitrogen dioxide (NO_2) and carbon monoxide (CO). The predicted ambient air quality impacts of the project, based on dispersion modeling, are shown in two tables in the Statement of Basis, entitled "NAAQS Compliance Demonstration for WCFU Project Sources (Results as Corrected by EPA for SO_2}" and "NAAQS Compliance Demonstration for Full Impact Sources (Results as

Corrected by EPA for SO_2}." By "ambient air quality impact," EPA means the model-predicted increase in concentration of a pollutant outside the fenceline of the Bonanza power plant.

The "WCFU Project Sources" table shows the predicted ambient air quality impact of the WCFU project alone. The "Full Impact Sources" table uses the same modeling approach as the "WCFU Project Sources" table, but shows the predicted ambient air quality impact of the WCFU project cumulative with the impact of the existing Bonanza Unit 1. (No other stationary sources of air pollution were included in the cumulative analysis because EPA is not aware of any other large stationary sources in the area whose emissions would be cumulative with the ambient impact from the proposed WCFU project. This is explained further in Step 2 below. By "large," EPA means sources with potential to emit more than 100 tons per year or more of any one pollutant.)

The "Full Impact Sources" table does not include NO_2 and CO from the "WCFU Project Sources" table because the results for those pollutants in the "WCFU Project Sources" table did not exceed EPA "significance levels" for proceeding to a cumulative analysis. Since the "significance levels" are so far below the NAAQS, EPA does not believe the screening out of NO_2 and CO from full impact analysis will have any effect on this environmental justice assessment. The "significance levels" may be found in a table in the Statement of Basis, entitled "Significance Levels for Air Quality Impacts in PSD Class II Areas."

The "WCFU Project Sources" table shows that the model-predicted ambient concentrations resulting from the WCFU project alone (including "background concentration") are below about 27% of the 3-hour NAAQS for SO_2, 24% of the 24-hour NAAQS for particulate matter, 12% of the 8-hour NAAQS for CO, and 7% of the annual NAAQS for NO_x. The "Full Impact Sources" table shows that the model-predicted ambient concentrations for cumulative impact are below 28% of the 3-hour NAAQS for SO_2 and 30% of the 24-hour NAAQS for particulate matter.

For particulate matter, NO_x and CO, both tables reveal that the "background concentration" is a substantial portion of the total ambient concentration. The "background concentration" is the concentration of an air pollutant that does not come from the Bonanza power plant itself, but is present everywhere. The "background concentration" is not an impact that is specific to the "affected area."

For 3-hour SO_2 ambient impacts, the "model-predicted concentration" is very high in terms of micrograms per cubic meter, reflecting about 25% of the 3-hour NAAQS for SO_2, because EPA corrected the modeling results to reflect a worst-case cold startup scenario for the WCFU. This is a very infrequent scenario. Outside of cold startups, the ambient impact for SO_2 would be 9% or less of the NAAQS for SO_2, for all averaging periods.

Based on the above information, EPA proposes to conclude that the "affected area" cannot be meaningfully defined for the WCFU project with respect to the gaseous pollutants

(SO_2, NO_2 and CO), because the dispersion modeling results (other than the very infrequent worst-case cold startup scenario for SO_2) are such a small percentage of the NAAQS. Further, the results represent the ambient air quality impact at the worst-case location (i.e., the location of maximum predicted concentration of each pollutant), and for the worst-case meteorological conditions. The ambient concentrations at all other locations, and for all other meteorological conditions, would be lower. EPA is not aware of any reason why adverse health effects should be suspected when results are such a low percentage of the NAAQS. Instead, EPA concluded that the "affected area" should be defined in terms of particulate matter, for which the dispersion modeling results are a higher percentage of the NAAQS (nearly 30% for cumulative impact).

Particulate matter is heavier than air and can be expected to drop out of the atmosphere within a few miles from the Bonanza power plant. Meteorological data in the PSD permit application from Deseret Power ("wind rose") suggest that the greatest ambient air quality impact would be along the prevailing wind direction, which is generally eastward from the Bonanza power plant. (The "wind rose" is data on how frequently the wind comes from each particular direction.) Therefore, EPA concluded that the "affected area" for this assessment should be considered an area extending no more than a few miles out from the Bonanza power plant, with the majority of the ambient air quality impact being in an eastward direction.

2. <u>Determine the locations and air pollutant emissions from any existing sources that may impact the affected area, cumulative with impacts from the proposed WCFU</u>.

As mentioned above, EPA is not aware of any large stationary sources other than Bonanza Unit 1 whose emissions would be cumulative with the ambient impact from the proposed WCFU project. There are several large oil and gas processing facilities in Uintah County, which emit primarily NO_2 and CO; however, none of these facilities are close to the Bonanza power plant. These facilities are listed below. EPA concluded that the emissions from these facilities would not add more than a negligible amount, if at all, to the dispersion modeling results described above for the WCFU project.

Company	Facility
Canyon Gas Resources	Mesa Tap Compressor Station
Colorado Interstate Gas	Natural Buttes Compressor Station
Kerr-McGee	Cottonwood Wash Compressor Station
Kerr-McGee	Ouray Compressor Station
Questar	Fidlar Compressor Station
Questar	Red Wash 24B Natural Gas Processing Plant
Questar	Wonsits Compressor Station
Wind River Resources	North Hill Creek Compressor Station

3. Examine demographic data to determine if there is a minority or low-income population residing within the affected area.

All census information described below is from http://factfinder.census.gov. The data are based on the 2000 census.

EPA has no census data or other information indicating that there are any full-time residents within the proposed "affected area." The closest town is Bonanza, Utah, which is approximately 5 miles from the Bonanza power plant. The only residents EPA is aware of in Bonanza, based on information obtained from Deseret Power, are a small number of employees of American Gilsonite, who are part-time residents. EPA has no information on whether any of these part-time residents would be classified as minority or low-income.

Census data indicate an average population density in Uintah County, where the Bonanza power plant is located, of about seven residents per square mile. Excluding the main population center in the county (Vernal/Naples), which is about 32 to 35 miles from the power plant and is not in the proposed "affected area," the average population density in the remainder (non-urban portion) of the county would be somewhat less. As mentioned above, EPA has no census data or other information to indicating that there are any full-time residents of Uintah County within the "affected area" for this assessment.

Based on the above information, EPA is unable to conclude that there is any population in the "affected area" for the WCFU project, whether minority, low-income, or otherwise. In offering this environmental justice assessment in draft form for public comment, EPA solicited comment relative to this matter. No such comments were received. For the sake of determining whether or not any nearby population may be minority or low-income even though outside the "affected area," EPA presents the following demographic data.

Uintah County's population is 87.7% Caucasian, 9.4% American Indian and Alaska Native, 3.5% Hispanic, and the remainder being other minorities. Utah's population is 89% Caucasian, 11% Hispanic, and the remainder being other minorities. In comparison to the reference population (i.e., the statewide average), it appears to EPA that Uintah County could be classified as a minority community.

In Utah, the median family income in 1999 dollars is $51,022. In Uintah County, the median family income is $38,877. In Utah, the percentage of individuals below the poverty level is 9.4%. In Uintah County, the percentage of individuals below the poverty level is 14.5%. In comparison to the reference population (i.e., the statewide average), it appears to EPA that Uintah County could be classified as a low-income community.

The nearest communities to the Bonanza power plant that have measurable population are the towns of Dinosaur and Rangely, Colorado. Dinosaur is about 18 to 20 miles north-northeast of the plant. Rangely is about 19 to 20 miles east-northeast of the plant. Dinosaur has a total population of 319 people, of whom 98.7% were classified by the 2000 U.S. Census as White. Minorities constitute 5.4% of the population of Dinosaur, which is under the Colorado state average of 25.5%. Rangely has a total population of 2,098 people, of whom 94.4% were classified by the 2000 U.S. Census as White. Minorities constitute 10.7% of the population of Rangely, which is under the Colorado state average of 25.5. Based on this information it appears to EPA that neither of these communities could be classified as a minority community.

In summary, EPA has no information indicating that any minority or low-income population resides within the "affected area." As mentioned above, in offering this environmental justice assessment in draft form for public comment, EPA solicited comment to aid in determining whether or not there is any population within the "affected area," as well as whether such population may be minority or low-income. No such comments were received.

4. Determine the extent and nature of adverse impact from cumulative air pollutant emissions within the affected area.

Based on the dispersion modeling results described above, in comparison to the NAAQS, EPA concluded that there will not be any adverse impact from cumulative SO_2, NO_2 or CO emissions within the "affected area" for this assessment. For particulate matter, EPA concluded that adverse impact may be somewhat more likely, since predicted ambient concentrations are a higher percentage of the NAAQS than for the gaseous pollutants (again, excluding the worst-case cold startup scenario for SO_2), and that the extent of the potential adverse impact would be within a few miles of the Bonanza power plant, generally eastward. EPA refers to this as "potential" adverse impact because EPA considers it unlikely there would be any adverse health or environmental impacts at 30% or less of the NAAQS for particulate matter.

5. Determine whether the proposed WCFU project, when added to existing sources, will have a disproportionately high and adverse impact on air quality affecting the minority or low-income population.

Based on the dispersion modeling results for the proposed WCFU project relative to the NAAQS, and based on information on locations of other large pollutant-emitting facilities, and based on available demographic information about the nearest population, EPA concluded that the proposed project, when added to existing sources, will not have a disproportionately high and adverse impact on air quality affecting any minority or low-income population. Again, in offering this environmental justice assessment in draft form for public comment, EPA solicited comment on any information relevant to this assessment. No such comments were received.