# Air Pollution Control
# 40 CFR 52.21(i)
# Prevention of Significant Deterioration Permit to Construct
# Draft Statement of Basis
# for Draft Permit No. PSD-OU-0002-04.00
June 14, 2006

## 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 draft Statement of Basis describing the proposed issuance of a Prevention of Significant Deterioration (PSD) permit to Deseret Power Electric Cooperative. This draft Statement of Basis discusses the background and analysis for the draft 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.

## Table of Contents

APPENDICES

# 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 (Amajor@ 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 this draft PSD permit has been published 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 shall extend until July 29, 2006. States, Tribes, local governmental agencies, and the public may review a copy of the permit application, analysis, draft permit prepared by EPA, and permit-related correspondence. Copies of these documents are available at:

US EPA Region 8
Air and Radiation Program Office (8P-AR)
999 18th Street, Suite 300
Denver, Colorado 80202-2466
Permit Contact: Mike Owens
email: owens.mike@EPA.gov
phone: 303-312-6440
fax: 303-312-6064

and: Uintah County Clerk's Office
147 East Main Street, Suite 2300
Vernal, Utah 84078

and: Ute Indian Tribe
Environmental Programs Office
6358 East Highway 40
Fort Duchesne, Utah 84026

All documents will be available for review at the U.S. EPA Region 8 office on Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays). A copy of the draft permit and draft Statement of Basis will also be available 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 may submit written comments on the draft permit during the public comment period and may request a public hearing. All comments and requests for public hearing should be addressed to the Permit Contact at the US EPA Region 8 address listed above.

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.

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. 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.

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 proposed permit and Statement of Basis represent a proposed 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 proposed 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° 05' 11" North and 109° 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

Ed Thatcher, Vice President and Chief Engineer
David Crabtree, Vice President and General Counsel
Deseret Power Electric Cooperative
10714 South Jordan Gateway
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Phone: (801) 619-6500

## 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 proposed 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 proposed 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 proposed 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 proposed 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 proposed 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<br>[0.8 lb fly ash per lb of total ash] x<br>[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<br>[1445 MMBtu/hr boiler heat input capacity] x<br>[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<br>[1445 MMBtu/hr boiler heat input capacity] x<br>[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<br>[1445 MMBtu/hr boiler heat input capacity] x<br>[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<br>[1445 MMBtu/hr boiler heat input capacity] x<br>[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<br>[1% of sulfur content emitted as $H_2SO_4$] x<br>[98 lb $H_2SO_4$ per 64 lb $SO_2$] x<br>[1445 MMBtu/hr boiler heat input capacity] x<br>[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<br>[1445 MMBtu/hr boiler heat input capacity] x<br>[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.K.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.

## VI. Best Available Control Technology Analysis

### A. Approach Used in BACT Analysis

Pursuant to ' 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 Atop-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, as described in the draft New Source Review Workshop Manual, published by EPA in October of 1990, 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.

## 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% |
| 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 | | 96.6% |
| | EPA approximation to "average" coal for WCFU | Permit cut-point coal | 4000 | 0.40 | 1.90 | 0.040 (EPA proposal for BACT) | 97.9% |

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 is proposing 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 maintains 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 chosen by EPA to approximate Deseret's "average" coal, but with a slight margin (0.4% sulfur content, rather than 0.34%).

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 states 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 is concerned 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 now proposes that the 'second tier' $SO_2$ BACT emission limit be expressed 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 1.9 lb/MMBtu 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 1.9 lb/MMBtu, would be about 97.9%. EPA considers this level of control efficiency to be BACT for combustion of Deseret's "average" waste coal.

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 1.9 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 1.9 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 1.9 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 1.9 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.

### K. 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.

## L. 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 reduces operating pressures, temperatures, and resistance time, which has the potential to reduce $NO_x$ formation 20 to 30% on average. 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. Step 3: Rank Remaining Control Technologies by Control Effectiveness.

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

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 $NO_x$.

## M. 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 Ecoomic, Environmental and Energy Impacts.

The emergency generator will implement all of the above listed technically feasible control techno-ogies; 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 $PM_{10}$.

### N. 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.

## O. 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.

## P. 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 as BACT.

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 (reference: EPA's draft 1990 NSR Workshop Manual, page H-6),
- 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.**

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.

## Q. 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.

## R. 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:

§60.41a – Definitions
§60.42a – Standard for particulate matter
§60.43a – Standard for sulfur dioxide
§60.44a – Standard for nitrogen oxides
§60.45a – Standard for mercury
§60.48a – Compliance provisions
§60.49a – Emission monitoring
§60.50a – Compliance determination procedures and methods
§60.51a – Reporting requirements

Footnotes: §60.46a, previously "Compliance provisions," is now "Reserved."
§60.47a, "Commercial demonstration permits," is not applicable.

In 2005, EPA promulgated amendments to Subpart Da to add mercury requirements. These amendments became effective on July 18, 2005. On February 9, 2006, EPA promulgated further amendments to Subpart Da. These amendments will become effective upon publication in the Federal Register. Under Subpart Da, as amended in 2005 and 2006, the following emission limits will apply to the WCFU:

**Emission Limits in Amended NSPS Subpart Da Applicable to Units Combusting > 75% Coal Refuse and Commencing Construction after February 28, 2005**

| Pollutant | NSPS Emission Limit | NSPS Citation | NSPS Required Performance Test |
|---|---|---|---|
| Particulate matter (filterable) | [0.015 lb/MMBtu or 0.14 lb/MWh] (daily average)<br>****OR****<br>[0.03 lb/MMBtu and 99.9% reduction] (daily average) | §60.42a(c) and (d) | Method 5 stack test |
| $SO_2$ | 1.4 lb/MWh or 94% reduction (30-day rolling average) | §60.43a(j)(1) | CEMS |
| $NO_x$ | 1.0 lb/MWh (30-day rolling average) | §60.44a(e)(1) | CEMS |
| Opacity | 20% on a 6-minute average (except for one 6-minute period per hour not to exceed 27%) | §60.42a(b) | Method 9 (3 hours for initial performance test); COMS thereafter |
| Mercury | $1.4 \times 10^{-6}$ lb/MWh (12-month rolling average) | §60.45a(a)(4) | CEMS |

Footnote: MWh = megawatt-hour.

In addition to amended emission limits, the following key amendments have also been made, applicable to units commencing construction after February 28, 2005:

- §60.41a 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.

- §60.48a(i) has been added, to specify the calculation methodology for demonstrating compliance with $NO_x$ emission limits in lb/MWh.

- §60.48a(l) has been added, to specify the calculation methodology for demonstrating compliance with mercury emission limits in lb/MWh.

- §60.48a(m) has been added, to specify the calculation methodology for demonstrating compliance with $SO_2$ emission limits in lb/MWh.

- §60.48a(n) has been added, to specify the calculation methodology for demonstrating compliance with particulate matter emission limits in lb/MWh.

- §60.48a(o)(1) has been added, to require the initial performance test for particulate matter to be repeated annually.

- §60.48a(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.

- §60.48a(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).

- §60.48a(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.

- §60.49a(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).

- §60.49a(p) has been added, to require a mercury CEMS.

- §60.50a(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. $SO_2$ 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. NO$_x$ 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 60.45a, 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 §51.165 and EPA's draft 1990 NSR Workshop Manual). 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. Far-field modeling. 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. Modeling inputs and assumptions

### 1. Description of models selected.

a. Near-field analysis. ISCST3 (Industrial Source Complex, Short-Term, version 3) was used for near-field analysis. The ISC3 model is a steady-state Gaussian plume model which 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. Far-field analysis. 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, estimates of background concentrations were determined as indicated in the table below.

**Background Pollutant Concentration Values**

| Pollutant | Averaging Period | Concentration (ug/m3) |
|---|---|---|
| $SO_2$ | 24-Hour | 10 |
| | 3-Hour | 20 |
| | Annual | 5 |
| $NO_2$ | Annual | 5 |
| $PM_{10}$ | 24-Hour | 28 |
| | Annual | 10 |
| CO | 1-Hour | 1150 (1 ppm) |
| | 8-Hour | 1150 (1 ppm) |

6. Meteorology. 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 were approved by the NPS on November 16, 2001.

7. Emission rates. 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.

For $SO_2$ and $NO_x$, the emission allowables proposed by EPA for the PSD permit are lower than the emission allowables used by Deseret Power for modeling. The permit application proposed emission allowables of 0.10 lb/MMBtu for $SO_2$ and 0.10 lb/MMBtu for $NO_x$, which are equivalent to the grams per second (g/sec) values in the table below. 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 lb/MMBtu is being burned; otherwise, 0.055 lb/MMBtu will continue to apply for $SO_2$.

### ISC3 WCFU Stack Input Parameters Used for Modeling

| ISC3 Input Parameters | Parameter Values |
|---|---|
| $SO_2$ Emission Rate | 18.52 $^{1)}$ g/sec; 18.21 $^{2)}$ g/sec |
| $PM_{10}$ Emission Rate | 9.47 g/sec |
| $NO_2$ Emission Rate | 18.21 g/sec |
| CO Emission Rate | 27.32 $^{3)}$ 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 and 24-hour emission rate.
2) Annual emission rate.
3) 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.

### Bonanza Unit I Stack Parameters
### Used for Modeling

| Model Input Parameters | Parameter Values |
|---|---|
| $SO_2$ Emission Rate | 56.30 g/sec |
| $PM_{10}$ 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) |

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 Roughness (m) | Albedo | Bowen Ratio | Soil Heat Flux Parameter | Anthropogenic 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. The results of this modeling indicated that the ambient impacts from the proposed WCFU are below the concentration thresholds in 40 CFR 52.21(i)(5)(i) that would require pre-construction ambient monitoring. These near-field modeled maximum concentration results are presented in the table below.

**Near-field WCFU Modeling Results and Comparison to Monitoring Exemption Levels**

| 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 | 10.8 | 1993 | 13 | 83.1 |
| | 3-hour | 54.7 | 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.

**NAAQS Compliance Demonstration for WCFU Project Sources**

| Pollutant | Averaging Period | Model-Predicted Concentration (μg/m$^3$) | Background Concentration (μg/m$^3$) | Total Concentration (μg/m$^3$) | NAAQS (μg/m$^3$) | Percent of NAAQS |
|---|---|---|---|---|---|---|
| SO2 | 3-hour (H) | 54.7 | 20.0 | 74.7 | 1300 | 5.7 |
| | 3-hour (SH) | 41.3 | 20.0 | 61.3 | 1300 | 4.7 |
| | 24-hour (H) | 10.8 | 10.0 | 20.8 | 365 | 5.7 |
| | 24-hour (SH) | 7.6 | 10.0 | 17.6 | 365 | 4.8 |
| | annual | 0.66 | 5.0 | 5.7 | 80 | 7.1 |
| PM$_{10}$ | 24-hour (H) | 7.6 | 28.0 | 35.6 | 150 | 23.7 |
| | 24-hour (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 analysi results. Results of full-impact analysis for NAAQS compliance are presented in the next table below.

### NAAQS Compliance Demonstration for Full Impact Area Sources

| 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) | 56.6 | 20.0 | 76.6 | 1300 | 5.9 |
| | 3-hr (SH) | 41.5 | 20.0 | 61.5 | 1300 | 4.7 |
| | 24-hr (H) | 10.8 | 10.0 | 20.8 | 365 | 5.7 |
| | 24-hr (SH) | 8.9 | 10.0 | 18.9 | 365 | 5.2 |
| | Annual | 1.2 | 5.0 | 6.2 | 80 | 7.8 |
| $PM_{10}$ | 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.

### PSD Class II Increment Compliance for WCFU Sources (Near-field Analysis)

| 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) | 54.7 | 512 | 10.7 |
| | 3-hour (SH) | 41.3 | 512 | 8.1 |
| | 24-hour (H) | 10.8 | 91 | 11.9 |
| | 24-hour (SH) | 7.6 | 91 | 8.3 |
| | 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.

**PSD Class II Increment Compliance for Full Impact Area Sources**

| 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) | 56.6 | 512 | 11.0 |
| | 3-hour (SH) | 41.5 | 512 | 8.1 |
| | 24-hour (H) | 10.8 | 91 | 11.9 |
| | 24-hour (SH) | 8.9 | 91 | 9.8 |
| | 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. PSD Class I increment consumption analysis results. Far-field analysis was conducted 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."

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 SO2 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, while 24-hour average emissions would increase from 146.99 lb/hr to 201.9 lb/hr. When the higher emissions values are used as input for dispersion models, it still appears to EPA that the NAAQS and PSD Class I and II increments would not be exceeded. 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)(2) 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 |
| SO2 | 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 draft environmental justice assessment is being offered by EPA for public comment as part of the draft PSD permit package for the proposed WCFU project. 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. If information is received by EPA during public comment period on the draft PSD permit that is relevant to this draft environmental justice assessment, EPA will re-assess.

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 proposes that the "affected area" for this environmental justice assessment be determined 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 proposes to determine 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 proposed 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, on pages 131-132 in the Statement of Basis, entitled "NAAQS Compliance Demonstration for WCFU Project Sources" and "NAAQS Compliance Demonstration for Full Impact Sources." 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 on page 122 of the Statement of Basis, titled "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 **7% of the NAAQS for $SO_2$ and $NO_2$, 12% for CO, and 24% for particulate matter**. The "Full Impact Sources" table shows that the model-predicted ambient concentrations for cumulative impact are below **8% of the NAAQS for $SO_2$ and 30% of the NAAQS for particulate matter**.

For each pollutant, 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."

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 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 proposes to conclude 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 proposes to conclude that the "affected area" is 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. Determine the locations and air pollutant emissions from any existing sources that may impact the affected area, cumulative with impacts from the proposed WCFU.

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 proposes to conclude 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 to indicate whether or not 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 or not 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 indicate whether or not there are any full-time residents of Uintah County within the proposed "affected area."

Based on the above information, EPA is unable to conclude whether there is any population in the proposed "affected area" for the WCFU project, whether minority, low-income, or otherwise. If information is received by EPA during public comment period relative to this matter, EPA will re-assess. In the meantime, for the sake of determining whether or not any nearby population may be minority or low-income even though outside the proposed "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 at this time indicating whether or not any minority or low-income population resides within the "affected area." EPA is soliciting public 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. If information relative to this matter is received by EPA during the public comment period on the draft PSD permit, EPA will re-assess.

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 proposes to conclude that there will not be any adverse impact from $SO_2$, $NO_2$ or CO emissions within the "affected area." For particulate matter, EPA proposes to conclude that adverse impact may be somewhat more likely, since predicted ambient concentrations are a higher percentage of the NAAQS than for the gaseous pollutants, 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 proposes to conclude 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, if information relevant to this draft environmental justice assessment is received by EPA during the public comment period on the draft PSD permit, EPA will re-assess.

# Appendix A
# List of Documents in the Administrative Record for Issuance of Federal PSD Permit #PSD-OU-0002-04.00

| Date | Description |
|---|---|
| 08-14-01 | Initial modeling protocol with cover lettersubmitted by Deseret Power to EPA. Entire modeling protocol was later revised and resubmitted to EPA on 12-04-01, then revised and resubmitted again on 03-09-04. Only the 03-09-04 revised protocol is included in this administrative record. |
| 10-01-01 | Letter from EPA to Deseret Power, commenting on 08-14-01 modeling protocol. |
| 10-16-01 | EPA notes by Monica Morales on initial meeting with Deseret Power on the waste coal fired project. |
| 12-04-01 | Revised modeling protocol with cover letter submitted by Deseret Power to EPA. Replaces 08-14-01 version. Entire modeling protocol was later revised again and resubmitted to EPA on 03-09-04. |
| 03-09-04 | Revised modeling protocol with cover letter submitted from Deseret Power to EPA. Replaces the 08-14-01 and 12-04-01 versions. |
| 03-17-04 | E-mail from EPA to Deseret Power asks that a copy of the modeling protocol be provided to the U.S. Forest Service. The e-mail also asks if there are any firm plans to go ahead with the waste coal fired project. |
| 04-12-04 | EPA comments to Deseret Power on 03-09-04 modeling protocol |
| 04-13-04 | Original PSD permit application with cover letter submitted by Deseret Power to EPA. Entire application was later revised and resubmitted to EPA on 11-01-04. Only the 11-01-04 revised application is included in this administrative record. |
| 04-27-04 | Agenda for April 28, 2004 meeting between Deseret Power and EPA, to discuss the April 13, 2004 PSD permit application for the waste coal fired project. |
| 04-28-04 | EPA notes by Mike Owens on action items arising from meeting that same day with Deseret Power, on the PSD permit application for the waste coal fired project. |
| 05-03-04 | E-mail from Deseret Power to EPA on projected water usage, in response to EPA phone inquiry, for Endangered Species Act analysis. |

| Date | Description |
|---|---|
| 05-17-04 | Letter from Deseret Power to EPA, responding to EPA's 04-12-04 comment letter on revised modeling protocol. |
| 06-09-04 | Letter from Deseret Power to EPA on various permit issues, in response to EPA's information requests from initial permit application meeting with Deseret Power on 04-28-04. |
| 07-29-04 | Letter from Deseret Power to EPA on revised visibility modeling. |
| 08-06-04 | E-mail from National Park Service to Deseret Power on revised visibility modeling. |
| 11-01-04 | Revised PSD permit application with cover letter submitted by Deseret Power to EPA. Replaces the entire original 04-13-04 permit application. |
| 11-18-04 | E-mail from EPA to Deseret Power on draft meeting agenda for November 23, 2004 meeting. |
| 11-22-04 | Letter from EPA to Deseret Power, responding to Deseret Power's 06-09-04 letter on PSD permit issues (IGCC, mercury limit and mercury CEMS, particulate condensibles, PM CEMS, modeling). |
| 11-26-04 | E-mail from EPA to Deseret Power on control technologies for particulate condensibles. |
| 11-29-04 | E-mail from EPA to Deseret Power on general provisions of 40 CFR part 63. |
| 12-02-04 | E-mail from National Park Service to EPA submits a compilation of information on proposed or permitted BACT emission limits for CFB boilers. |
| 12-10-04 | E-mail from U.S. Forest Service to Deseret Power and EPA, on review of modeling for impacts on Class I areas. |
| 12-10-04 | E-mail from EPA to Deseret Power on action items for PSD permit issues (modeling, BACT, Endangered Species Act). |

| Date | Description |
|---|---|
| 12-29-04 | Letter from EPA to Deseret Power on additional information needed from Deseret Power on its PSD permit application, pertaining to:<br>-- BACT for SO2, NOx, and particulate condensibles<br>-- Alternative BACT for startup/shutdown<br>-- Particulate matter CEMS<br>-- Mercury MACT and mercury CEMS<br>-- General MACT provisions<br>-- Integrated Gasification Combined Cycle (IGCC), as an alternative to a CFB boiler<br>-- Modeling<br>-- Endangered Species Act |
| 03-23-05 | Letter from Deseret Power to EPA, on modeling issues raised by EPA on 11-22-05 and 12-29-05. |
| 03-23-05 | Letter from Deseret Power to EPA, on modeling issues raised by the U.S. Forest Service on 12-10-04. |
| 04-06-05 | Reminder e-mail from EPA to Deseret Power that response is awaited to EPA's letter of 12-29-04 on PSD permit application. |
| 04-13-05 | EPA letter to Deseret Power on status of PSD permit application. |
| 05-04-05 | E-mail from Deseret Power to EPA, proposing a dry SO2 scrubber. This was in partial response to EPA's 12-29-04 letter. |
| 05-10-05 | Letter from Deseret Power to EPA, responding to EPA's 12-29-04 letter on PSD permit application issues. Includes analysis of potential impacts of the WCFU project on endangered species. |
| 05-25-05 | E-mail from EPA to Deseret Power, responding to Deseret Power's 05-04-05 e-mail and requesting further information on coal characteristics and vendors of dry SO2 scrubbers. |
| 05-26-05 | E-mail and attachments from National Park Service to EPA, regarding BACT for waste coal fired CFB boilers. (Forwarded to other EPA staff on 05-21-05.) |
| 06-13-05 | Letter from EPA to Deseret Power, saying case-specific MACT determination is no longer necessary, due to EPA's delisting of electric utilities as a MACT source category. |

| Date | Description |
|---|---|
| 06-16-05 | E-mail from National Park Service to EPA, saying the modeling for the WCFU project has been deemed complete by the NPS. ("...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.") |
| 06-16-05 | E-mail from National Park Service to EPA, discussing potential $SO_2$ and $NO_x$ BACT for Deseret Power's project, in comparison to other CFB boiler projects. |
| 06-16-05 | E-mail from Deseret Power to EPA on coal sampling, in partial response to EPA's 05-25-05 letter on SO2 BACT. |
| 06-22-05 | Letter from EPA to Deseret Power on various permit issues. This was a further response to EPA's 12-29-04 letter to Deseret on these issues. |
| 06-27-05 | E-mail from National Park Service to EPA on low-temperature SCR for $NO_x$ BACT. |
| 07-08-05 | Letter from EPA to Deseret Power on NOx BACT, responding to Deseret's 05-10-05 letter. |
| 07-21-05 | Letter from EPA to U.S. Fish & Wildlife Service, requesting review of Deseret's 05-10-05 analysis of potential impacts of the WCFU project on endangered species. |
| 07-25-05 | Letter from EPA to Deseret Power on SO2 BACT, in response to Deseret's 06-16-05 e-mail. |
| 08-22-05 | E-mail from National Park Service to EPA, requesting that 24-hour emission limits be included in the permit, for modeling purposes. |
| 09-13-05 | Letter from Deseret Power to EPA, responding to EPA letters of 06-22-05, 07-08-05 and 07-25-05. |
| 09-15-05 | Letter from Deseret Power to EPA, providing further response to EPA letter of 07-08-05. |
| 09-26-05 | E-mail from Deseret Power to EPA on statistical analysis of coal samples. |
| 09-28-05 | E-mail from National Park Service to EPA, providing updated information on other CFB boiler projects (River Hill, Greene, Robinson). |

| Date | Description |
|---|---|
| 09-28-05 | E-mail from National Park Service to EPA, providing a copy of a technical article by a consulting firm (Alstom) relating to fuel-bound nitrogen ($NO_x$ BACT issue). |
| 10-06-05 | E-mail from EPA to Deseret Power on NOx BACT. |
| 10-06-05 | E-mail inquiry from Deseret Power to EPA, and EPA's response, regarding whether PSD permit modifications are allowed, to re-evaluate BACT. |
| 10-06-05 | E-mail from EPA Region 7 to EPA Region 8, on dual (i.e., two-tier) $SO_2$ BACT limits. |
| 10-12-05 | E-mail from EPA to National Park Service, responding to NPS's 08/22/05 request for 24-hour emission limits. |
| 10-12-05 | E-mail from Deseret Power to EPA on break-in period for NOx control. |
| 10-12-05 | E-mail from EPA to Deseret Power on various WCFU topics. |
| 10-13-05 | E-mail from EPA to Deseret Power requesting information for the BACT determination for the emergency generator. |
| 10-13-05 | E-mail from Deseret Power to EPA on fuel-bound nitrogen. |
| 10-14-05 | E-mail from Deseret Power to EPA, responding to EPA's 10-13-05 inquiry on certain BACT topics for emergency generator (NSCR and natural gas). |
| 10-17-05 | E-mail from Deseret Power to EPA, responding further on BACT for the emergency generator. |
| 10-27-05 | E-mail from Deseret Power to EPA, attaching a list of documents that Deseret Power considers to be amendments to its 11-01-04 PSD permit application. |
| 11-02-05 | E-mail from EPA to Deseret Power requesting information on why a wet scrubber was rejected as SO2 BACT. |
| 11-02-05 | E-mail from EPA to Deseret Power, on documents that constitute amendments to Deseret Power's PSD permit application of 11-01-04. |
| 11-03-05 | E-mail from Deseret Power to EPA, listing EPA e-mails that Deseret acknowledges as amendments to the 11-01-04 PSD permit application. |

| Date | Description |
|---|---|
| 11-03-05 | E-mail from Deseret Power to EPA, listing all amendments to the 11-01-04 PSD permit application. |
| 11-03-05 | E-mail from Deseret Power to EPA, requesting a copy of the SO2 BACT writeups for the Gascoyne and South Heart CFB boiler projects in North Dakota. The e-mail also expresses the opinion that use of washed coal as an alternative fuel for the WCFU would be outside the scope of BACT. |
| 11-03-05 | E-mail from EPA to Deseret Power, transmitting the Gascoyne and South Heart writeups on $SO_2$ BACT. This was in response to Deseret Power's request the same day. |
| 11-04-05 | E-mail from Deseret Power to EPA on modeling limits. |
| 11-09-05 | E-mail from Deseret Power to EPA on SO2 removal versus NOx generation. |
| 11-09-05 | E-mail from Deseret Power to EPA on wet scrubber BACT. This was in response to the 11-02-05 EPA e-mail. |
| 11-09-05 | E-mail from EPA to Deseret Power on BACT for WCFU. |
| 11-11-05 | E-mail from Deseret Power to EPA on cooling tower BACT. |
| 11-15-05 | E-mail from EPA to Deseret Power, transmitting legal citiations by John Schakenbach, of EPA Headquarters' Clean Air Markets Division, on the diluent cap approach for measuring emissions during startup/shutdown episodes. The e-mail suggests that Deseret Power discuss this approach with EPA. |
| 11-16-05 | E-mail from EPA to Deseret Power on waste stockpile projections. |
| 11-17-05 | E-mail from Deseret Power to EPA on waste stockpile projections. |
| 11-22-05 | E-mail from National Park Service to EPA on modeling limits. |
| 11-22-05 | E-mail from National Park Service to EPA on BACT for CFB boiler in New Mexico permit. |

| Date | Description |
|---|---|
| 11-23-05 | E-mail from Deseret Power to EPA on material handling system BACT. |
| 11-23-05 | E-mail from EPA to Deseret Power, requesting 3-hr and 24-hr emission estimates. |
| 11-23-05 | E-mail from Deseret Power to EPA on Method 202 issues. |
| 11-28-05 | E-mail from Deseret Power to EPA on Method 202 issues. |
| 11-28-05 | E-mail from Deseret Power to EPA, asking for clarification of EPA's request with regard to 3-hr emission limits for $NO_x$ and $PM_{10}$. |
| 11-29-05 | E-mail from EPA to Deseret Power clarifying EPA's 11-23-05 request for 3-hr and 24-hr emission estimates. |
| 11-29-05 | Fax from North Dakota Dept. of Health to EPA, in response to EPA phone request, transmitting a copy of BACT determinations for materials handling baghouses |
| 11-30-05 | E-mail from EPA to Deseret Power on Method 202 issues. |
| 12-01-05 | E-mail and attachments from EPA to Deseret Power transmits a pre-draft of the PSD permit and Statement of Basis. |
| 12-13-05 | E-mail from Deseret Power to EPA, providing information requested by EPA on short-term (3-hr and 24-hr) emission estimates for the WCFU. |
| 12-13-05 | E-mail from Deseret Power to EPA, submitting cost analysis on why $PM/PM_{10}$ BACT for the cooling tower should be 0.001 percent drift loss, rather than the 0.0005 percent EPA has proposed as BACT. |
| 12-14-05 | EPA notes from conference call with Deseret Power on SO2 BACT. |
| 12-14-05 | E-mail from EPA to Deseret Power on cooling tower BACT. |
| 12-14-05 | E-mail from Deseret Power to EPA, responding to EPA's question of the same day on cooling tower BACT. |
| 12-20-05 | E-mail from Deseret Power to EPA on status of Estill County Energy Partners Project. |

| Date | Description |
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| 12-21-05 | E-mail from Deseret Power to EPA, commenting on the 12-01-05 pre-draft permit. |
| 12-22-05 | E-mail from Deseret Power to EPA, commenting on the 12-01-05 pre-draft Statement of Basis. |
| 12-22-05 | Letter from EPA to Deseret Power, asking for information from the boiler supplier on why EPA's proposed BACT emission limits for $SO_2$ and $NO_x$ can't be met, and explaining that Deseret Power may assert a claim of business confidentiality regarding this information. (NOTE: Deseret responded, but asserted a claim of confidentiality, so that response is not included in the Administrative Record for this permit action.) |
| 12-27-05 | E-mail from Deseret Power to EPA, requesting corrections to Appendix A of the pre-draft Statement of Basis. |
| 12-27-05 | E-mail from EPA to Deseret Power, responding to Deseret Power's e-mail of the same day. |
| 01-06-06 | E-mail from EPA to Deseret Power on $SO_2$ BACT, as followup to a conference call with Deseret Power the prior day. The e-mail clarifies what type of information EPA will need from Deseret, if EPA is to re-propose $SO_2$ BACT. |
| 01-09-06 | E-mail from Deseret Power to EPA, on difficulties of operating under two-tiered emission limits for $SO_2$ BACT. Includes Excel spreadsheets. Deseret proposes a calculated emission limit, instead of the 0.040 lb/MMBtu that EPA proposed on 12-01-06, as the lower tier, 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 (0.055 and 0.040). |
| 01-13-06 | E-mail from Deseret Power to EPA, in response to verbal request from EPA, provides an expanded description of waste coal characteristics. |
| 01-13-06 | E-mail from Deseret Power to EPA, in response to verbal request from EPA, suggests permit language corresponding to Deseret's weighted average $SO_2$ BACT proposal of 01-09-06. |
| 01-18-06 | E-mail from Deseret Power to EPA provides additional xls spreadsheets, to demonstrate the effect on compliance of a two-tier emission limit approach for $SO_2$ BACT. |

| Date | Description |
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| 01-30-06 | E-mail from Deseret Power to EPA provides a revised estimate of expected emissions of condensible particulate and proposes a revised BACT emission limit for total $PM_{10}$ of 0.045 lb/MMBtu, rather than the 0.052 lb/MMBtu originally proposed. |
| 02-02-06 | E-mail from Deseret Power to EPA, in response to verbal request from EPA, provides a description of boiler operational changes and materials handling changes that would be necessary, if run-of-mine coal or washed coal was to be burned instead of waste coal. |
| 02-03-06 | E-mail from EPA to Deseret Power requests additional information in support of Deseret's 01-30-06 revised estimate of condensible particulate emissions. |
| 02-06-06 | E-mail from EPA to Deseret Power responds to Deseret's 12-21-05 proposal to use a controlled condensation test method in lieu of Method 8, for demonstrating compliance with the PSD BACT limit proposed by EPA of 0.0025 lb/MMBtu for sulfuric acid. |
| 02-07-06,<br>02-08-06 | E-mails from Deseret Power to EPA, in response to verbal request from EPA, elaborate on the basis for the CO BACT limit proposed by Deseret (0.15 lb/MMBtu on a 30-day rolling average). |
| 02-10-06 | E-mail from EPA to Deseret Power says that EPA Region 8 recently became aware that there are potential control options for condensible particulate and informs Deseret that it will be necessary to address this topic via a top-down BACT discussion in the Statement of Basis. |
| 02-10-06 | E-mail and attachments from EPA to Deseret Power transmits a new pre-draft of the PSD permit and Statement of Basis. This package replaces the earlier version of 12-01-05. |
| 02-15-06 | E-mail and attachments from Deseret Power to EPA and U.S. Fish & Wildlife Service explains the conservation measures by Deseret Power to protect raptors from electrocution hazard along the electrical railroad line that transports coal from the Deserado mine to the Bonanza power plant. |
| 02-15-06 | E-mail from EPA to Deseret Power transmits a revision to the pre-draft Statement of Basis, to reflect the revised NSPS Subpart Da just promulgated. |

| Date | Description |
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| 02-16-06 | EPA letter to Ute Indian Tribe offers consultation with the Tribe on a jurisdiction issue originally raised by Deseret Power on July 5, 2000 and brought up again by Deseret Power in its November 1, 2004 PSD permit application. |
| 02-21-06 | 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 ($H_2SO_4$). |
| 02-22-06 | E-mail from EPA to Deseret Power transmits two sections of the pre-draft Statement of Basis that have been edited by EPA since 02-10-06: section IV.I on Potential-to-Emit and section VI.C on Alternative Coal. The e-mail also describes status of some unresolved issues. |
| 02-22-06 | E-mail from Deseret Power to EPA, in response to EPA's request of 02-03-06, provides additional information in support of Deseret's 01-30-06 revised estimate of condensible particulate emissions. |
| 02-23-06 | E-mail from Deseret Power to EPA, in response to EPA's request of 02-09-06, provides a top-down BACT analysis for condensible particulate. |
| 02-24-06 | E-mail from Deseret Power to EPA repeats an assertion made in Deseret's prior correspondence to EPA, that use of Method 202 for measuring condensible matter results in an upward bias. This e-mail includes a synopsis of information from technical papers on this topic, which were presented at the Air & Waste Management Association's 2004 Mega-Symposium. |
| 02-24-06 | E-mail from Deseret Power to EPA submits comments on the 02-10-06 pre-draft permit package. |
| 03-09-06 | E-mail from EPA to Deseret Power presents calculations by EPA regarding certain components of condensible particulate matter emissions (ammonium sulfate and sulfuric acid) and requests to see Deseret's own calculations for the components of condensible particulate matter. |
| 03-21-06 | E-mail from EPA to National Park Service transmits a copy of the pre-draft permit and Statement of Basis for review. |
| 03-22-06 | E-mail from EPA to USDA Forest Service transmits a copy of the pre-draft permit and Statement of Basis for review. |
| 03-23-06 | E-mail from EPA to Vernal Field Office of the Bureau of Land Management transmits a copy of the pre-draft permit and Statement of Basis for review. |

| Date | Description |
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| 03-27-06 | E-mail from Deseret Power to EPA, in response to EPA's e-mail of March 9, 2006, provides additional calculations in support of Deseret Power's emission estimate for condensible particulate matter. |
| 04-03-06 | E-mail from EPA Region 4 to EPA Region 8 transmits a copy of March 31, 2006 comments by East Kentucky Power Cooperative on the draft PSD/Title V permit for the Spurlock facility in Kentucky. The comments include results of Method 202 stack tests conducted on July 8, 2005 results for condensible particulate matter. |
| 04-05-06 | E-mail from EPA Region 3 to EPA Region 8 transmits a copy of results of stack tests conducted on December 5, 2004 at the Reliant Energy Seward facility in Pennsylvania, including filterable and condensible particulate matter. |
| 04-07-06 | E-mail from EPA to Deseret Power requests confirmation that Deseret wants operational flexibility to blend up to 50/50 ratio by weight of waste coal with run-of-mine coal from the Deserado mine. Previously Deseret had indicated the intent was to use waste coal as sole fuel for the WCFU, except for emergencies or when they start running out of waste coal someday. |
| 04-10-06 | E-mail from Deseret Power to EPA, in response to 4-3-06 e-mail from EPA, confirms that Deseret Power wants operational flexibility to blend run-of-mine coal with the waste coal at any time, up to 50/50 ratio. For this purpose, Deseret proposes to redefine waste coal as coal with heat content of 6500 Btu/lb or less. |
| 04-11-06 | E-mail from Deseret Power to EPA transmits a copy of a Endangered Species Act biological opinion memorandum dated May 13, 1981, by the U.S. Fish & Wildlife Service, on construction of the original Bonanza power plant, along with a copy of a March 5, 1985 USFWS memorandum on a followup meeting with Deseret Power on ESA conservation measures. |
| 04-12-06 | E-mail from EPA Region 3 to EPA Region 8 transmits a copy of results of stack tests conducted in April of 2004 at the AES facility in Puerto Rico for filterable and condensible particulate matter. |
| 04-13-06 | E-mail from EPA to Deseret Power transmits an excerpt from the EPA Region 2 permit for a CFB boiler project in Puerto Rico, on adjustment of the BACT emission limit for condensible particulate matter, based on stack test results. The e-mail also transmits a copy of the stack test results. |

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| 04-14-06 | E-mail from Deseret Power to EPA, in response to phone request from EPA, provides information on heating value of coals for two CFB boiler projects by ADM in Illinois and a CFB boiler project by AES in Puerto Rico. The purpose of the information is to determine if 0.15 lb/MMBtu can be justified as BACT for CO at Deseret's WCFU project, if heating value of blended coal is as high as 6500 Btu/lb. The Illinois and Puerto Rico projects were permitted at 0.10 lb/MMBtu for CO. |
| 04-18-06 | E-mail from Deseret Power to EPA provides further information on heating value of coal for the CFB boiler project by AES in Puerto Rico. (See 04-14-06 entry above.) |
| 04-20-06 | E-mail from USDA Forest Service to EPA provides comments on the pre-draft permit package sent to them for review on March 22, 2006. |
| 04-25-06 | E-mail from Deseret Power to EPA, in response to EPA request, provides an estimate of the potential uncontrolled fugitive particulate emissions for the WCFU project. |
| 05-02-06 | E-mail from EPA to Deseret Power transmits EPA's redraft of BACT write-ups for condensible particulate matter and for sulfuric acid. |
| 05-05-06 | E-mail from Deseret Power to EPA submits comments on EPA's 05-02-06 redraft of BACT writeups on condensible particulate matter and on sulfuric acid. |
| 05-05-06 | E-mail from Deseret Power to EPA, in response to a verbal request from EPA, provides information on baghouse particulate loading for the CFB boiler. |
| 05-12-06 | E-mail from EPA to National Park Service responds to NPS's 04-21-06 comments on the pre-draft permit and Statement of Basis. |
| 05-19-06 | E-mail from EPA to Deseret Power transmits a new pre-draft of the permit and Statement of Basis. |
| 05-24-06 | E-mail from Deseret Power to EPA requests a public hearing be held for the draft PSD permit. |
| 05-26-06 | E-mail from Deseret Power to EPA submits comments on the 05-19-06 pre-draft PSD permit. |

| Date | Description |
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| 05-26-06 | E-mail from Deseret Power to EPA submits comments on the 05-19-06 pre-draft Statement of Basis. Included in the e-mail is a statement that Deseret Power is withdrawing its request for a public hearing on the draft PSD permit. |
| 05-30-06 | E-mail from EPA to Deseret Power responds to a portion of the comments submitted by Deseret Power on 05-26-06. EPA asks Deseret Power to propose a rewording for the pre-draft Statement of Basis, to correspond to one of Deseret's requests for changes in the pre-draft permit. |
| 05-31-06 | E-mail from EPA to Deseret Power, as an update to EPA's 05-30-06 e-mail, says EPA cannot agree to Deseret's request that BACT emission limits not apply between the date of initial startup and the date of completion of initial performance tests. The e-mail reiterates, as explained in the pre-draft Statement of Basis, EPA's interpretation of the Clean Air Act that BACT emission limits apply at all times. |
| 05-31-06 | E-mail from EPA to Deseret Power transmits a copy of EPA's draft public notice for the WCFU project. |
| 06-06-06 | E-mail from EPA to Deseret Power transmits a copy of the latest draft of the PSD permit and Statement of Basis, dated 06-06-06, along with a public service announcement that EPA plans to provide to radio stations about the proposed permit action. |
| 06-14-06 | Draft Federal PSD permit #PSD-OU-0002-04.00 prepared for public comment. |
| 06-14-06 | Draft Statement-of-Basis for Federal PSD permit #PSD-OU-0002-04.00 prepared for public comment. |