

**RESPONSE TO PUBLIC COMMENTS**

**ON**

**Draft  
Air Pollution Control  
Prevention of Significant Deterioration (PSD)  
Permit to Construct**

**Permit No. PSD-OU-0002-04.00**

**Permittee:**

**Deseret Power Electric Cooperative  
10714 South Jordan Gateway  
South Jordan, Utah 84095**

**Permitted Facility:**

**110-Megawatt Waste Coal Fired Unit  
at Bonanza Power Plant**



**United States Environmental Protection Agency  
Region 8  
Air & Radiation Program  
Denver, Colorado  
August 30, 2007**

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## **A. INTRODUCTION**

On April 14, 2004, Deseret Power submitted a Prevention of Significant Deterioration (PSD) permit application to the United States Environmental Protection Agency, Region 8 (EPA), to approve construction of a new coal-fired electric utility unit at Deseret's existing Bonanza power plant. The application was updated and re-submitted to EPA on November 1, 2004. Several amendments to the application were submitted over the following year and a half. The application, amendments, draft PSD permit, draft Statement of Basis, and all related correspondence between EPA and Deseret Power are contained in the Administrative Record of this permit action, which was made available for 30-day public comment in late June of 2006.

The existing Bonanza power plant is located in eastern Utah, on the Uintah & Ouray Indian Reservation, and consists of a single bituminous coal fired electric utility unit ("Unit 1"), rated at 500 megawatts electrical output. The fuel for Unit 1 is supplied by the Deserado coal mine, located about 35 miles east of the plant. Unit 1 was constructed in the early 1980's and is operating under a Federal PSD permit originally issued by EPA on February 4, 1981, then updated and re-issued on February 7, 2001.

The new unit at Bonanza plant would consist of a Circulating Fluidized Bed (CFB) boiler and associated equipment, rated at 110 megawatts electrical output, and designed to be fueled with waste coal from the Deserado mine. The PSD permit for the new unit is proposed to be issued as a separate permit from the PSD permit for Unit 1.

The EPA published a public notice in the following newspapers, on the following dates, soliciting comments on its proposal to issue the permit for the new unit, in accordance with Sections 160-169 of the Clean Air Act (CAA), 40 CFR 52.21, and 40 CFR part 124:

Uintah Basin Standard (Roosevelt, UT)	June 27, 2006
Vernal Express (Vernal, UT)	June 28, 2006
Grand Junction Sentinel (Grand Junction, CO)	June 28, 2006
Rio Blanco Herald Times (Meeker/ Rangely, CO)	June 29, 2006
Salt Lake Tribune (Salt Lake City, UT)	June 29, 2006

The public comment period ended on July 29, 2006.

On June 22, 2006, the EPA mailed copies of the draft PSD permit, draft Statement of Basis, public notice, and Administrative Record for the proposed permit action, consisting of all permit-related correspondence, to the following parties:

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

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

EPA sent the documents to these locations specifically to have the documents available locally for public review, during the public comment period. As stated in the public notice, these documents were also available at the EPA office in Denver, Colorado, and on the internet through EPA's website, at:

<http://www.epa.gov/region8/air>, under the heading "Topics of Interest"

The draft PSD permit would require air pollutant emission controls and restrict emissions of the following pollutants at the CFB boiler and associated pollutant-emitting support equipment: total particulate matter, filterable particulate matter, sulfur dioxide, nitrogen oxide, carbon monoxide, and sulfuric acid.

During the public comment period, one comment letter and one comment e-mail were received by EPA that expressed concerns with the draft permit and/or Statement of Basis. The comment letter, received on July 28, 2006, was from a group of seven environmental organizations: Western Resource Advocates, Environmental Defense, Utah Chapter of the Sierra Club, Southern Utah Wilderness Alliance, Western Colorado Congress, Wasatch Clean Air Coalition, and HEAL Utah. Comments #1 through #11 below are from the letter. The comment e-mail, received on July 26, 2006, was from Kathy Van Dame, representing the Wasatch Clean Air Coalition. Comments #12 through #16 below are from the e-mail.

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

After the close of the public comment period, EPA received an e-mail dated April 24, 2007, from Katy Savage of Provo, Utah, expressing concern about pollutants that would be emitted from the WCFU project, and a letter dated April 25, 2007, from Daniel D. McArthur, Mayor of the City of St. George, Utah, expressing concern about delay in issuing the EPA permit for the WCFU project.

A detailed description of the commenters' concerns, along with EPA's responses to the significant issues raised in the comments, is contained in Section B of this document. Some of the lengthier comments have been paraphrased or generalized to allow direct responses to the concerns raised.

All references in Section B to the "Statement of Basis" mean the draft Statement of Basis dated June 14, 2006, which was made available along with the draft PSD permit for public comment in late June of 2006. All references to the "WCFU" mean Deseret

Power's proposed Waste Coal Fired Unit at Bonanza power plant, the subject of this PSD permit action. All references to "EPA" mean the EPA Region 8 office in Denver, unless otherwise indicated.

Section C of this document describes the specific provisions of the draft permit and draft Statement of Basis that have been changed in the final permit decision as a result of public comment. The final permit and final Statement of Basis include some administrative changes that may not be described in Section C, including renumbering permit conditions due to additional conditions added to the final permit, renumbering sections of the Statement of Basis due to additional explanations added to the Statement of Basis, and rewording as necessary to reflect the fact that the permit and Statement of Basis are final, not draft.

Deseret Power requested meetings with EPA, and met with EPA, on October 16, 2006 and on May 7, 2007, and submitted additional written permit-related material after the close of the public comment period. EPA is including the additional material and a summary of the October 16, 2006 and May 7, 2007 meetings in the Administrative Record for EPA's final permit decision.

Documents upon which EPA relied in reaching the final permit decision, and as referenced in EPA's response to comments, such as the Statement of Basis, the PSD permit application, and supplemental documents, are contained in the Administrative Record. Copies of EPA's response-to-comments document, final permit, and final Statement of Basis, are available on EPA's website at:

<http://www.epa.gov/region8/air>, under the heading "Topics of Interest"

The website also provides a link to the Administrative Record.

Copies of the response-to-comments document, the final permit, and the final Statement of Basis are also available for public review at the same locations where the draft permit and Statement of Basis were available for review:

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

Ute Indian Tribe  
Land Use Department  
P.O. Box 460  
6358 East Highway 40  
Fort Duchesne, Utah 84026

All documents in the Administrative Record are available at the EPA office:

US EPA Region 8  
Air & Radiation Program  
1595 Wynkoop Street  
Denver, CO 80202-1129  
Contact: Mike Owens, 303-312-6440  
[owens.mike@epa.gov](mailto:owens.mike@epa.gov)

## **B. COMMENTS AND RESPONSES**

The descriptions of public comments below are a paraphrasing of the originally submitted comments. The full text of each public comment may be found in the Administrative Record for issuance of the WCFU permit, available at the same locations as the draft permit package was available (the Uintah County Clerk's office in Vernal, Utah, the Ute Indian Tribe office in Fort Duchesne, Utah, and the EPA Region 8 office in Denver, Colorado).

### **1. CARBON DIOXIDE/GREENHOUSE GAS EMISSIONS**

#### **Comment #1:**

One group of commenters requested that EPA address carbon dioxide (CO<sub>2</sub>) and other greenhouse gas (GHG) emissions from the proposed Deseret Bonanza WCFU. The commenters stated that the Clean Air Act requires EPA to do so in two ways.

**Comment #1.a.** First, the commenters believe EPA has a legal obligation to regulate CO<sub>2</sub> and other GHGs under the Clean Air Act and thus should set CO<sub>2</sub> emission limits in this permit.

**Comment #1.b.** Second, the commenters believe that EPA should consider emissions of CO<sub>2</sub> in its BACT analyses for other pollutants at the Bonanza WCFU.

In support, the commenters cited a U.S. Supreme Court case that was pending at the time, an Environmental Appeals Board decision, a draft EPA guidance document, and an article presenting a potential legal rationale for using PSD permits to limit CO<sub>2</sub> emissions.

#### **Response #1:**

**Response #1.a.** Disagree. EPA recognizes the importance of addressing the global challenge of climate change, and in light of the Supreme Court's decision in *Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), the Agency is working diligently to develop an overall strategy for addressing the emissions of CO<sub>2</sub> and other GHGs under the Clean Air Act. However, EPA does not currently have the authority to address the challenge of global climate change by imposing limitations on emissions of CO<sub>2</sub> and other greenhouse gases in PSD permits.

It is well established that "EPA lacks the authority to impose [PSD permit] limitations or other restrictions directly on the emission of unregulated pollutants." *North County Resource Recovery Assoc.*, 2 E.A.D. 229, 230 (EAB 1986). The Clean Air Act and EPA's regulations require PSD permits to contain emissions limitations for "each pollutant subject to regulation" under the Act. CAA § 165(a)(4); 40 C.F.R. § 52.21(b)(12). In defining those PSD permit requirements, EPA has historically interpreted the term "subject to regulation under the Act" to describe pollutants that are presently subject to a statutory or regulatory provision that requires actual control of



emissions of that pollutant. *See* 43 Fed. Reg. 26388, 26397 (June 19, 1978) (describing pollutants subject to BACT requirements); 61 Fed. Reg. 38250, 38309-10 (July 23, 1996) (listing pollutants subject to PSD review). In 2002, EPA codified this approach for implementing PSD by defining the term “regulated NSR pollutant” and clarifying that Best Available Control Technology is required “for each regulated NSR pollutant that [a major source] would have the potential to emit in significant amounts.” 40 C.F.R. § 52.21(j)(2); 40 CFR 52.21(b)(50).

In defining a “regulated NSR pollutant,” EPA identified such pollutants by referencing pollutants regulated in three principal program areas -- NAAQS pollutants, pollutants subject to a section 111 NSPS, and class I or II substance under title VI of the Act-- as well as any pollutant “that otherwise is subject to regulation under the Act.” 40 CFR 52.21(b)(50)(i)-(iv). As used in this provision, EPA continues to interpret the phrase “subject to regulation under the Act” to refer to pollutants that are presently subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant. Because EPA has not established a NAAQS or NSPS for CO<sub>2</sub>, classified CO<sub>2</sub> as a title VI substance, or otherwise regulated CO<sub>2</sub> under any other provision of the Act, CO<sub>2</sub> is not currently a “regulated NSR pollutant” as defined by EPA regulations.

Although the Supreme Court decided the case cited by commenters and held that CO<sub>2</sub> and other GHGs are air pollutants under the CAA, *see Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), that decision does not require the Agency to set CO<sub>2</sub> emission limits in the PSD permit for the Deseret Bonanza WCFU. Notably, the Court did not hold that EPA was required to regulate CO<sub>2</sub> and other GHG emissions under Section 202, or any other section, of the Clean Air Act. Rather, the Court concluded that these emissions were “air pollutants” under the Act, and, therefore, EPA could regulate them under Section 202 (the provision at issue in the *Massachusetts* case), subject to certain Agency determinations pertaining to mobile sources.

EPA is currently exploring options for addressing GHG emissions in response to the Supreme Court decision. EPA is taking the first steps toward regulating GHG emissions from mobile sources, but the Agency has not yet issued regulations requiring control of CO<sub>2</sub> emissions under the Act generally or the PSD program specifically. Accordingly, EPA cannot include emissions limitations for CO<sub>2</sub> (or other GHGs that are not otherwise regulated NSR pollutants) in the Deseret PSD permit because it has long been established that “EPA lacks the authority to impose [PSD permit] limitations or other restrictions directly on the emission of unregulated pollutants.” *North County*, 2 E.A.D. at 230. At this time, we believe that any action EPA might consider taking with respect to regulation of CO<sub>2</sub> or other GHGs in PSD permits or other contexts should be addressed through notice and comment rulemaking, allowing for a process which is public and transparent and based on the best available science.

**Response #1.b:** Disagree. EPA recognizes the importance of addressing the global challenge of climate change, and in light of the Supreme Court’s decision in *Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), the Agency is working diligently to develop an overall strategy for addressing the emissions of CO<sub>2</sub> and other GHGs under the Clean Air Act. Nevertheless, with regard to the present permitting decision, the

record before the Agency does not suggest, and commenters have not provided any evidence showing, that the outcome of our BACT analysis for the regulated NSR pollutants emitted by the Deseret Bonanza WFCU would have been resulted in a different choice of control technologies had we considered the potential collateral environmental impacts of CO<sub>2</sub> emissions.

The CAA defines BACT as “an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of such pollutant.” CAA § 169(3) (emphasis added); *see also* 40 CFR 52.21(b)(12). EPA has established a five-step, top-down process for determining BACT emission limits for each PSD-regulated pollutant considered in a permitting decision: (1) identify all potentially applicable control options (2) eliminate technically infeasible control options; (3) rank remaining technologies by control effectiveness; (4) eliminate control options from the top down based on energy, environmental, and economic impacts; and (5) select the most effective option not eliminated as BACT. *See Prairie State Generating Co.*, 13 E.A.D. \_\_\_, PSD Appeal No. 05-05, slip op. at 14-18 (EAB Aug. 24, 2006) (summarizing and describing steps in the top-down BACT analysis). *Accord Three Mountain Power, L.L.C.*, 10 E.A.D. 39, 42-43 n.3 (EAB 2001); *Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 129-31 (EAB 1999); *Hawaii Electric Light Co.*, 8 E.A.D. 66, 84 (EAB 1998). Thus, EPA has traditionally considered the collateral impacts (energy, environmental, and economic) of each BACT option at Step 4 of this analysis.

The CAA does not specify how EPA should weigh these collateral impacts when determining BACT for a particular source. The Agency’s longstanding interpretation is that “the primary purpose of the collateral impacts clause is to temper the stringency of the technology requirements whenever one or more of the specified collateral impacts – energy, environmental, and economic – renders use of the most effective technique inappropriate.” *Columbia Gulf Transmission Co.*, 2 E.A.D. 824, 826 (EAB 1989). Accordingly, the environmental impacts analysis “is generally couched in terms of discussing which available technology, among several, produces less adverse collateral effects, and, if it does, whether that justifies its utilization even if the technology is otherwise less stringent.” *Old Dominion Electric Cooperative*, 3 E.A.D. 779, 792 (EAB 1992).

In this case, the commenters have not shown that consideration of the environmental impacts of CO<sub>2</sub> emissions in the collateral impacts step of the EPA’s BACT analysis for the regulated NSR pollutants would lead to a different result in our selection of BACT for the Deseret facility. The record before the Agency does not suggest that the Agency should have selected a less stringent option as BACT in order to reduce the potential collateral environmental impacts of CO<sub>2</sub> emissions. Although there may be some differences in the CO<sub>2</sub> emissions resulting from use of the technologies we evaluated at step 4 of the BACT analysis, we do not have information indicating such

differences would be significant enough to necessitate changing our selection of BACT for other pollutants. *See Hillman Power Co., L.L.C.*, PSD Appeal Nos. 02-04 (July 31, 2002) (“collateral environmental impacts analysis need only address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection or elimination of a control alternative.”). Commenters have not given EPA cause to believe that comparisons of the CO<sub>2</sub> emissions from various control technologies considered in the BACT analysis for the Deseret Bonanza WCFU would render unacceptable any of the options we have identified as BACT for this PSD permit.

Specifically, the comments did not contain any information on CO<sub>2</sub> emissions that would lead EPA to reach a different conclusion in its BACT analysis for this facility. The commenters state only that “EPA must consider emissions of CO<sub>2</sub> in its BACT analysis for the Bonanza WCFU,” but they do not address how the particular control technologies considered for the Bonanza WCFU would have resulted in substantially differing CO<sub>2</sub> emissions. Nor do they discuss how any such differences would have resulted in differing impacts that would have necessitated our selecting a different technology as BACT. Such comparisons are at the heart of the BACT analysis, and thus are required by a commenter alleging a deficiency in the analysis. *See Old Dominion*, 3 E.A.D. at 793 (finding no error based on petitioner’s lack of “specificity and clarity” because they provided “no specific comparison” of differences in the environmental impacts of the various technologies considered in the BACT analysis). *See also Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc.*, 435 U.S. 519, 553 (U.S. 1978) (explaining that comments regarding an Agency’s analysis of environmental impacts “cannot merely state that a particular mistake was made, ...[but] must show why the mistake was of possible significance in the results”). Accordingly, commenters have failed to show how consideration of CO<sub>2</sub> emissions in the BACT environmental impacts analysis would have changed the Deseret Bonanza permitting decisions.

Moreover, because EPA has historically interpreted the phrase “environmental impacts” to focus on local environmental impacts that are directly attributable to the proposed facility, the collateral impacts analysis of this BACT determination is not the appropriate mechanism for addressing the potential global impacts of CO<sub>2</sub> emissions from the Deseret Bonanza WCFU. *See Columbia Gulf*, 2 E.A.D. at 829-30 (finding that the environmental impacts analysis “focuses on local impacts that constrain the source from using the most effective technology”). Any predicted impacts in the area surrounding the Deseret facility that are potentially due to global climate change – to which the CO<sub>2</sub> and other GHG emissions from the proposed source may contribute generally – are not the type of local environmental impact that is readily traceable directly back to the particular source subject to PSD review.

EPA’s interpretation that the collateral environmental impacts analysis should focus on local impacts that are directly attributed to construction and operation of the proposed source is supported by relevant statutory language, legislative history, EAB decisions, and EPA policies and permitting decisions. Both the “case-by-case” language of the BACT definition and Congress’ stated reason for adding the collateral impacts analysis to that definition suggest that a facility-centered, locally-focused analysis is

appropriate. *See Kawaihae Cogeneration Project*, 7 E.A.D. 107, 116-17 (EAB 1997) (describing how the collateral impacts analysis considers factors unique to the specific source); Senate Comm. on Environment And Public Works, *A Legislative History of the Clean Air Act Amendments of 1977* (Comm. Print August 1978), vol. 6 at 4723-24 (explaining that the collateral impacts clause was added to provide permitting authorities with flexibility to consider the impact of a specific facility on the character of the community in which it was located). While the EAB's *North County* decision directed permitting authorities to look at the effect of emissions from non-PSD regulated hazardous air pollutants (i.e., HAPs) in the collateral impacts analysis, the Board's opinion did not specify that all emissions not directly regulated under PSD – such as CO<sub>2</sub> – had to be considered as well. *See id.*, 2 E.A.D. at 230 (stating that the “exact form” and “level” of the BACT environmental impacts analysis would depend on the facts of the individual permitting decision). In subsequent policy guidance, EPA did not interpret *North County* to call for consideration of global impacts, *see, e.g.*, Memorandum from Gerald Emison, OAQPS Director entitled *Implementation of North County PSD Remand*, pp. 3-4 (Sept. 22, 1987), and the EAB later determined that EPA did not have to consider CO<sub>2</sub> and other GHG emissions in the BACT environmental impacts analysis. *Interpower of New York*, 5 E.A.D. 130 (EAB 1994); *Kawaihae Cogeneration Project*, 7 E.A.D. 107 (EAB 1997). Consistent with these prior EAB decisions and Agency policy, EPA has not previously considered the environmental impact of CO<sub>2</sub> and other GHG emissions in setting the BACT levels for permits,<sup>1</sup> and for the reasons discussed above, we do not consider it necessary to do so in issuing the PSD permit for the Deseret Bonanza WFCU.

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<sup>1</sup> Although one draft of EPA's 1990 *NSR Workshop Manual* referenced “greenhouse gas emissions” as an example of environmental impact that a reviewing authority might consider in the BACT analysis, EPA has not done so in practice. The Agency never finalized the draft guidance cited by commenters, and other drafts of that same document do not include the phrase “greenhouse gas emissions” as an example of the type of environmental impact to be considered in the BACT analysis. *See* <http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/1990wman.pdf>, at B49. Moreover, both of these drafts of the *NSR Workshop Manual* also indicate that the BACT environmental impacts analysis should focus on “consideration of site-specific circumstances,” which contrasts with the notion that such analysis should be used to consider the source's impact on what is a global issue. *Id.* at B47.

## 2. INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

### **Comment #2:**

One group of commenters asserted that the proposed permit did not adequately evaluate IGCC as an available method to lower air emissions in the BACT analysis. The group of commenters presented four arguments:

**Comment #2.a.** First, arguing that Federal law requires a thorough evaluation of IGCC as part of the BACT analysis.

**Comment #2.b.** Second, arguing that recent state actions requiring consideration of cleaner coal technology establish irrefutable precedence for the consideration of IGCC, and validate the commenters' position on the "plain language of the definition of BACT."

**Comment #2.c.** Third, alleging EPA Region 8 previously determined it was appropriate to evaluate IGCC in the BACT analysis for a CFB coal-fired power plant. Commenters cited EPA Region 8's April 6, 2004 letter to the Utah Division of Air Quality, on Utah's proposed PSD permit for Nevco Energy's Sevier Power Company Project. Commenters also cited EPA's April 28, 2004 request to Deseret Power to provide an explanation of why Deseret ruled out IGCC for the WCFU project.

**Comment #2.d.** Fourth, pointing out the overall benefit of the alternative IGCC technology, including fewer emissions of criteria and hazardous air pollutants, the opportunity for capturing greenhouse gases, and increases in efficiency over other coal burning technologies.

### **Response #2:**

**Response #2.a.** Disagree. EPA does not agree that the Clean Air Act requires a detailed evaluation of IGCC for the proposed facility, at or beyond step 1 of the top-down BACT analysis. We evaluated whether IGCC should be listed at step 1 and considered the commenters arguments, but we have not been persuaded to change our view that this alternative process would represent a redefinition of the source proposed by the applicant and thus need not be listed as a potentially applicable control option at step 1 and evaluated further in the BACT analysis for this type of facility. We have, however, evaluated this option as a potential alternative to the proposed source under other parts of our PSD permit review; see discussion below in response #2.d.

The Administrator and EPA's Environmental Appeals Board ("EAB" or "Board") have long maintained a policy against utilizing the BACT requirement as a means to fundamentally redefine the basic design or scope of a proposed project. *See, e.g., Knauf Fiber Glass, GMBH*, 8 E.A.D. 121, 140 (EAB 1998); *Pennsauken County, New Jersey, Resource Recovery Facility*, 2 E.A.D. 667, 673 (Adm'r 1988). EPA has not required applicants proposing to construct coal-fired steam electric generating facilities to evaluate building natural gas-fired combustion turbines as part of a BACT analysis, even though a

gas turbine may be inherently less polluting. *SEI Birchwood Inc*, 5 E.A.D. 25 (1994); *Old Dominion Electric Cooperative Clover, Virginia*, 3 E.A.D. 779, 793 n. 38 (Adm'r 1992). Likewise, in *Hawaii Commercial & Sugar Co.*, the EAB found no error by the permitting authority when the petitioner argued that the BACT analysis for a coal-fired steam electric generator should include the option of constructing an oil-fired combustion turbine. 4 E.A.D. 95, 99-100 (EAB 1992).

EPA's policy reflects the Agency's longstanding judgment that limits should exist on the degree to which permitting authorities can dictate the design and scope of a proposed facility through the BACT analysis. This policy is based on a reasonable interpretation of sections 165 and 169(3) of the CAA, which recognizes that, although the permitting authority must take comment on and may consider alternatives to a proposed facility, the BACT analysis itself is conducted without changing fundamental characteristics of the proposed source.

The EAB recently reiterated and explained EPA's policy against redefining the source through the BACT analysis in *Prairie State Generating Company*, PSD Appeal No. 05-05 (Aug. 24, 2006). In the *Prairie State* case, involving a permit for an coal-fired electric generating station that was co-located and co-permitted with a new coal mine supplying fuel for the facility, the Board determined that it was consistent with EPA's historic policy and the Clean Air Act for the permitting authority in this case to decline to conduct a detailed BACT review of the option of using lower-sulfur coal from another location. Based on various provisions of the Clean Air Act, including language that requires the "proposed facility" to be "subject to" BACT, the Board concluded that "the statute contemplates that the permit issuer looks to how the permit applicant defines the proposed facility's purpose or basic design" as part of Step 1 of the top-down BACT analysis. *Prairie State*, slip. op. at 28-29. The Board further explained that "the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility." *Prairie State* slip. op. at 30. The Seventh Circuit recently affirmed the EAB's *Prairie State* decision, including the Board's interpretation of the interplay of determining what redefines a source and the required BACT analysis. *See generally Sierra Club v. EPA*, slip op. (7th Cir. Aug. 24, 2007).

As discussed by the Board in the *Prairie State* opinion, affirmed by the Seventh Circuit, and explained more fully below, EPA's policy against redefining the proposed source through the BACT analysis is supported by a permissible and reasonable interpretation of the Clean Air Act. The language in sections 165 and 169 of the CAA distinguishes between the consideration of alternatives to a proposed source on the one hand and permitting and selection of BACT for the proposed source on the other. Alternatives to a proposed source are evaluated through the CAA section 165(a)(2) public hearing process, which requires that, before a permitting authority may issue a permit, interested persons have an opportunity to "submit written or oral presentations on the air quality impact of such source, *alternatives thereto*, control technology requirements, and other appropriate considerations." 42 U.S.C. § 7475(a)(2) (emphasis added). By listing "alternatives" and "control technology requirements" separately in section 165(a)(2),

Congress distinguished “alternatives” to the proposed source that would wholly replace the proposed facility with a different type of facility from the kinds of “production processes and available methods, systems and techniques” that are potentially applicable to a particular type of facility and should be considered in the BACT review. *See* 42 U.S.C. § 7479(3).

In contrast to the requirements of section 165(a)(2), other parts of the PSD permitting process, including the requirement to apply BACT, focus on, and are generally confined by, the project as proposed by the applicant. Sections 165(a)(1) and 165(a)(4) of the CAA provide that no facility may be constructed unless “a permit has been issued for *such proposed facility* in accordance with this part” and “the *proposed facility* is *subject to* best available control technology for each pollutant subject to regulation under the Act.” 42 U.S.C. § 7475(a)(1) and (a)(4) (emphasis added). The following definition of BACT in section 169(3) of the Act also makes clear that the BACT review is based on the proposed project, as opposed to something fundamentally different:

an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a *case-by-case basis*, taking into account energy, environmental, and economic impacts and other costs determines is achievable for *such facility* through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of such pollutant.

42 U.S.C. § 7479(3) (emphasis added). The phrases “proposed facility” and “such facility” in section 165(a)(4) and 169(3) refer to the specific facility proposed by the applicant, which has certain inherent design characteristics. The Act also requires BACT to be determined “on a case-by-case basis.” The case-specific nature of the BACT analysis indicates that the particular characteristics of each facility are an important aspect of the BACT determination. Thus, the Act requires that permitting authorities determine BACT for each facility individually, considering the unique characteristics and design of each facility.

As the group of commenters has also pointed out, the statutory definition of BACT also requires permitting authorities in selecting BACT to consider “application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques.” 42 U.S.C. § 7479(3). EPA has interpreted this phrase to require that permitting authorities evaluate both add-on pollution control technologies and lower polluting process in the BACT review. *Prairie State* at 33.

Considering these provisions together, the Act requires that we conduct the BACT analysis on a “case-by-case” basis on the “proposed facility” while concurrently considering the “application of production processes and available methods, systems and

techniques” that could alter the proposed facility. The statute does not provide clear direction on how EPA is to reconcile these concepts and simultaneously consider the particulars of the facility proposed by the applicant while also assessing the use of methods or technology that could modify those particulars. Where a statute is ambiguous and Congress has not spoken to the precise issue, an administrative agency may formulate a policy to resolve the issue, provided that the policy is based on a permissible construction of the statute. *Chevron v. Natural Resources Defense Council*, 104 S.Ct. 2778, 2782 (1984). In this instance, sections 165 and 169(3) of the Clean Air Act are permissibly construed to authorize EPA and permitting authorities to establish some level of balance between the case-by-case nature of a BACT determination and the need to consider available processes, methods, systems, and techniques to reduce emissions. EPA’s policy against redefining a source as part of the BACT analysis reasonably harmonizes the competing BACT obligations by requiring the permitting authority to consider potentially applicable processes, methods, systems, or techniques that may reduce pollution from the type of source proposed, provided such processes or techniques do not fundamentally redefine the basic design or scope of the facility proposed by the permit applicant.

EPA does not read the legislative history cited by the commenter to require a detailed evaluation of the IGCC technology in the BACT analysis for every proposed facility that generates electricity from coal. That Senator Huddleston intended for the phrase “innovative fuel combustion techniques” to encompass “gasification” or “low Btu gasification” does not necessarily require EPA or other permitting authorities to identify the IGCC option as a candidate for further analysis at step 1 of a top-down BACT review. The “innovative fuel combustion techniques” phrase appears in the BACT definition among a list of examples of things included in the phrase “production processes and available methods, systems, and techniques.” Thus, the “innovative fuel combustion” language, like the phrase it modifies in the definition of BACT, is limited by other language discussed above that requires BACT to be applied to each proposed facility and determined on a case-by-case basis. Thus, even assuming that coal gasification was in all respects an innovative fuel combustion technique for producing electricity from coal, we do not interpret the Clean Air Act to require an “innovative fuel combustion technique” to be subject to a detailed BACT review when application of such a technique would redesign the proposed source to the point that it becomes an alternative type of facility, which, as discussed below, we believe would be the case if the IGCC technology were applied to Deseret’s project.

Furthermore, it is not clear from the terms of his statement that Senator Huddleston himself intended to require mandatory review of coal gasification in every case where such an option was not proposed by the permit applicant. Senator Huddleston said the purpose of the amendment was to leave no doubt that “all actions taken by the fuel user are to be taken into account.” This phrase suggests the Senator wanted to make sure that, when a fuel user was proposing an innovative fuel combustion technique, such as coal gasification, that such actions by the fuel user would be taken into account and credited in the determination of BACT for the proposed facility. Thus, the Senator’s statement could be read to express an intent similar to that expressed in a



subsequent Congress when adding the phrase “clean fuels” to the definition of BACT in the 1990 amendments of the Clean Air Act. Pub. Law No. 101-549, § 403(d), 104 Stat. at 2631 (1990). At the time “clean fuels” was added to the list that includes “innovative fuel combustion techniques,” the relevant Senate committee report stated the following in consecutive paragraphs:

The Administrator may consider the use of clean fuels to meet BACT requirements if a permit applicant proposes to meet such requirements using clean fuel. . . . In no case is the Administrator compelled to require mandatory use of clean fuels by a permit applicant.

S. Rep. 101-228, at 338 (describing section 402(d) of S. 1630). Based on this legislative history, EPA does not interpret the list of examples that appear in the BACT definition after the phrase “production processes, methods, systems, or techniques” to require mandatory evaluation of each of those options at advanced stages of the BACT analysis, regardless of the degree to which such an option would redefine the type of facility proposed by the permit applicant.

Although EPA reads the Act to preclude redefining the source and to draw a distinction between alternatives to the proposed source and lower polluting process that can be applied to the proposed source, EPA does not interpret the Clean Air Act to obligate a PSD permitting authority to accept all elements of a proposed project when determining BACT. To the contrary, EPA recognizes that the Act calls for an evaluation of the “application of production processes and available methods, systems, and techniques.” 42 U.S.C. §7479(3).

As the Board observed in *Prairie State*, EPA’s policy against redefining the source is only relevant when considering lower polluting processes and would not permit a reviewing authority to rule out “add-on controls” at Step 1 of the BACT analysis. Slip. op. at 33. Further, although EPA does not require a source to consider a totally different design, some design changes to the proposed source are within the scope of the BACT review. See *Knauf Fiber Glass*, 8 E.A.D. at 136. As the Board observed in the *Prairie State* case, the central issue in situations involving a lower polluting process concerns “the proper demarcation between those aspects of a proposed facility that are subject to modification through the application of BACT and those that are not.” Slip. Op. at 26. The Board observed that one of the permit issuer’s tasks at step 1 of the BACT analysis is to “discern which design elements are inherent to [the applicant’s] purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant’s basic business purpose for the proposed facility.” *Prairie State*, slip. op. at 30.

Since this line can be difficult to draw in each case, the Administrator and Environmental Appeals Board have generally recognized that the decision on whether to include a lower polluting process in the list of potentially-applicable control options compiled at Step 1 of the top-down BACT analysis is a matter within the discretion of the PSD permitting authority. *Knauf Fiber Glass*, 8 E.A.D. at 136; *Old Dominion*, 3 E.A.D.

at 793; *Hawaiian Commercial*, 4 E.A.D. at 100 & n.9. The Administrator and the EAB have usually respected the decisions of the permitting authority and only remanded permits in cases where it was clear that the permitting authority abused its discretion by excluding a particular option from consideration in the BACT review. *Knauf Fiber Glass*, 8 E.A.D. at 140. See, e.g., *Hibbing Taconite Company*, 2 E.A.D. 838, 843 (Adm'r 1989). The Seventh Circuit affirmed this view in upholding the EAB's *Prairie State* decision, emphasizing the discretion given the permitting authority in making the technical judgment as to "where control technology ends and a redesign of the 'proposed facility' begins." *Sierra Club v. EPA*, slip op. at 5.

In its review of this issue in *Hibbing*, the Board considered whether the option in question would "require any fundamental change to Hibbing's product, purpose, or equipment." *Hibbing* at 843 n. 12. In *Prairie State*, where the use of the alternative coal source arguably did not significantly affect the power-generating equipment to be used at the proposed source, the Board focused on the applicants "objective or purpose" to the extent that purpose was "articulated for reasons independent of air quality permitting." *Prairie State*, slip. op. at 30.

With respect to the project proposed by Deseret, our assessment is that the application of the IGCC process to the Deseret facility would fundamentally change the nature of the proposed major source. The IGCC option would both fundamentally change the basic design of the equipment that Deseret proposes to install and fundamentally alter the objective and purpose of Deseret to make productive use of a coal supply that was previously considered a waste. Thus, we consider the IGCC process to be an alternative to the proposed source that should be evaluated under section 165(a)(2) of the Clean Air Act rather than as a BACT candidate under section 165(a)(4).

From an equipment perspective, Deseret has proposed a facility that fires pulverized waste coal in a fluidized mixture with limestone and inert materials, in a boiler to generate steam to drive an electric turbine. An IGCC facility uses a chemical process to first convert coal into a synthetic gas and to fire that gas in a combined cycle turbine. "Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," EPA-430/R-06/006, July 2006. The combined cycle generation power block of an IGCC process employs the same turbine and heat recovery technology that is used to generate electricity with natural gas at other electric generation facilities. Thus, this portion of the IGCC process is very similar to existing power generation designs that EPA has agreed would redefine the basic design of the source when an applicant proposed to construct a pulverized coal-fired boiler. *SEI Birchwood Inc*, 5 E.A.D. 25 (1994); *Old Dominion Electric Cooperative Clover, Virginia*, 3 E.A.D. 779 (Adm'r 1992). Furthermore, the core process of gasification at an IGCC facility is fundamentally different than a boiler. Coal gasification is more akin to technology employed in the refinery and chemical manufacturing industries than technologies generally in use in power generation (i.e. a controlled chemical reaction versus a true combustion process). Use of coal gasification technology would necessitate different types of expertise on the part of the applicant and employees to produce the desired product (electricity). Thus, these fundamental

differences in equipment design are sufficient to conclude that the IGCC process would redefine the proposed source. Similarly, in *Sierra Club v. EPA*, slip op. at 4 (7th Cir. Aug. 24, 2007), the Court upheld the EAB's decision that use of low-sulfur coal that was available only at a distance from a proposed plant would redefine the source, because the plant was designed to use higher sulfur coal located at a nearby mine. As the Court explained, "to convert the design from that of a mine-mouth plant to one that burned coal obtained from a distance would require that the plant undergo significant modifications – concretely, the half-mile-long conveyor belt, and its interface with the mine and the plant, would be superfluous and instead there would have to be a rail spur and facilities for unloading coal from rail cars and feeding it into the plant." *Id.*

Furthermore, Deseret Power's proposal calls for extracting the remaining heating value of the waste coal that has accumulated over the past 20 years in order to conserve other natural resources. In light of the technical difficulties of using IGCC for waste coal (described in detail below), IGCC would not serve the basic purpose of the project, which is to take advantage of the current waste coal reserves and future waste coal generated from the coal washing operations that provide the existing Bonanza Unit 1 with its coal. See Letter from Ed Thatcher, Deseret Power, to Richard R. Long, EPA Region 8, May 10, 2005. Thus, in addition to fundamentally changing the basic design of the source that Deseret proposes to construct, the IGCC option would also have the effect of regulating the applicant's objective or purpose for the proposed facility by precluding the use of the waste coal resource. The record reflects that Deseret is seeking to use waste coal for reasons independent of air quality permitting. See *Prairie State*, slip. op. at 30.

We acknowledge that in the *Prairie State* case, the EAB recognized that IGCC technology could be listed as a potentially applicable option at step 1 of the BACT analysis, as Illinois EPA had elected to do in that case. However, the Board's opinion in *Prairie State* did not interpret the Clean Air Act to require IGCC to be listed as a potentially applicable control option at step 1 for every permit application involving a coal-fired steam electric generating unit. In *Prairie State*, the Board did not directly address the issue raised by the Petitioners comment on the Deseret permit because Illinois EPA chose, in an exercise of its discretion, to list the IGCC option at step 1 of the BACT analysis for the proposed facility and further analyze the option. IEPA ultimately eliminated the option at step 2. See *Prairie State*, slip. op. at 45. In *Prairie State*, the Board pointed to IEPA's consideration of the IGCC option beyond step 1 to illustrate that there was no question that IEPA had conducted a sufficiently thorough step 1 BACT analysis in that case, because IEPA had even considered an option that "would have required extensive design changes to *Prairie State*'s proposed facility." Slip. op. at 36. The Board did not conclude that IGCC, or any other option involving such extensive design changes, had to be listed as a potentially applicable option at Step 1 in each case or find that it would be an abuse of a permitting authorities discretion to decline to list IGCC at Step 1 of the BACT analysis for the type of facility proposed by Deseret. The Board continued to recognize that the decision of where to draw the line between BACT options listed at step 1 and alternatives to the proposed source is ultimately a matter within the discretion of the permitting authority. *Prairie State* slip. op. at 29 n. 22.

Moreover, even if EPA was to list IGCC as a potentially applicable option at step 1 of the BACT analysis for the facility proposed by Deseret, the IGCC option could also be eliminated at step 2 of the top-down BACT analysis for the facility proposed by Deseret. It is not technically feasible to use Deseret's waste coal in the IGCC process. Based on an analysis of samples, Deseret's waste coal has an average heating value of approximately 4,000 Btu/lb, with a range of 3,051 Btu/lb to 5,326 Btu/lb, and ash content of the waste coal is estimated by Deseret to be in excess of 50 percent by weight on a dry basis. *See* Statement of Basis at 9. As explained below, IGCC units are not designed to operate, nor have they been operated, with coal that has a heating value as low, or ash content as high, as the waste coal that will be utilized for the proposed project.

A recently issued EPA report on IGCC states that "relatively little research or commercial work has been done to investigate gasification of low rank coals, including subbituminous and lignite, for electric generation purposes. The existing IGCC plants use bituminous coal as feedstocks." *See* "Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," EPA-430/R-06/006, July 2006, page ES-1, available in the Administrative Record for this permit and through website at:

[http://www.epa.gov/air/caaac/coaltech/2007\\_01\\_epaigcc.pdf](http://www.epa.gov/air/caaac/coaltech/2007_01_epaigcc.pdf)

The report only discusses IGCC units as a possibility for use with bituminous, subbituminous and lignite coals. Deseret's waste coal is a lower rank of coal than subbituminous or lignite, having much lower heat content and much higher ash content than either subbituminous or lignite.

The above-mentioned EPA report states that there are currently two commercial-scale, coal-based IGCC plants in the U.S. and two in Europe. The U.S. projects (Wabash River Repowering Project in Indiana and Tampa Electric Polk Power Station in Florida) were both supported by the DOE's Clean Coal Technology demonstration program. Both plants have operated on bituminous coals and petroleum cokes; no use of low-rank coal at these facilities is known. EPA report at 2-6 and 2-7.

Another publication on IGCC analyzes the impact that various coal parameters have on various gasifiers, based on actual operation of the gasifiers. *See* "Coal Quality Handbook for IGCC," published by Cooperative Research Centre for Coal in Sustainable Development, Technology Assessment Report 8, April 1999, available through website at <http://www.ccsd.biz/products/qualitybook.cfm>.

Page 14 of the Handbook lists the maximum ash content of the coal that can be handled by various types of gasifiers. For a moving bed gasifier, the ash content has to be less than 15 percent; for an entrained bed gasifier, less than 25 percent; and for a fluidized bed gasifier, less than 40 percent. As mentioned above, Deseret's waste coal will have ash content in excess of 50 percent.

In addition to the Wabash River and Tampa Electric IGCC projects, the above-mentioned Handbook reviews several other IGCC demonstration or pilot projects, utilizing various gasifier designs, and the required characteristics of the coal. These projects include:

BGL IGCC Process, owned/operated by British Gas and Lurgi  
Demkolec IGCC plant, owned/operated by Shell  
Nedo facility, owned/operated by Engineering Research Associates  
Pinon Pine Power Project, owned/operated by Sierra Pacific and MK Kellogg  
Prenflow IGCC Process, owned/operated by Krupp Koppers and Siemens AG

However, all of these projects require coal with higher heat content and lower ash content than Deseret's waste coal. Of particular significance is that all of these projects (as well as the Wabash River and Tampa Electric projects) require coal with ash content less than 25 percent by weight on a dry basis. This is less than half the ash content of Deseret's waste coal. The Handbook also indicates that the above-mentioned IGCC projects generally require coal with much higher heat content than Deseret's waste coal, 8,100 to 13,760 Btu/lb, compared to Deseret's range of 3,051 to 5,326 Btu/lb, respectively. *See Handbook at 22-28.*

Inquiries with representatives of IGCC test programs confirmed that IGCC units have not been tested on coal with heat content as low as Deseret's waste coal. The U.S. Department of Energy's Power Systems Development Facility near Wilsonville, Alabama, has only utilized coal as low as 6,000 to 7,000 Btu/lb. The National Energy Technology Institute is also not aware of any IGCC unit utilizing coal with the low heating value that will be used in Deseret Power's proposed WCFU. (Ref: June 9, 2004 letter from Ed Thatcher, Deseret Power, to Richard R. Long, EPA Region 8.)

**Response #2.b:** Disagree. As was recognized by commenters in the comment letter, state decisions as to how to conduct the BACT analysis do not necessarily set the bar for EPA. As discussed above, the decision of where to draw the line between alternatives to the proposed source is a discretionary matter. The fact that some states have elected to list IGCC at step 1 of the BACT analysis for a coal-fired steam electric generating facility does not require EPA to do so if EPA's reasoned assessment is that the option would redefine the proposed source. EPA does not interpret the Clean Air Act to mandate evaluation of IGCC in a BACT analysis in cases involving proposed coal-fired steam electric generating facilities. We do not read the state examples cited by commenters to be based on a contrary interpretation of the Clean Air Act, but rather to reflect policy decisions in those states to conduct a more extensive analysis. Even if a state were to conclude that evaluation of IGCC was mandatory under its interpretation of the Clean Air Act or state law, such a decision by a state is not binding on EPA. Furthermore, because Illinois administers the Federal PSD program under a delegation agreement with EPA Region V, Illinois must act in a manner consistent with EPA's interpretation of the Clean Air Act and controlling regulations.

**Response #2.c:** Disagree. Regarding EPA's letter to Utah on Nevco, the commenters incorrectly characterized the letter as a determination on evaluating IGCC. Letters from EPA to states providing comments on proposed state PSD permits are not final EPA actions. *See Public Service Co. of Colorado v. Environmental Protection Agency*, 225 F 3d 1144 (10<sup>th</sup> Cir.2000).

Regarding EPA's request to Deseret Power to provide information regarding IGCC as an alternative to its planned CFB boiler, EPA's correspondence with Deseret merely explored IGCC as a possibility and made no final determination regarding IGCC. (Ref: Letters from Richard R. Long, EPA Region 8, to Ed Thatcher, Deseret Power, dated November 22, 2004, December 29, 2004, and June 22, 2005.)

**Response #2.d:** Partially agree. Since EPA's judgment is that use of the IGCC process would redefine the proposed source and thus need not be listed as an option at Step 1 of the BACT analysis for the Deseret facility, EPA is treating this comment as a request that EPA consider IGCC technology as an alternative to the proposed source in accordance with section 165(a)(2). EPA agrees with commenters that IGCC technology has many potential environmental benefits, but EPA is not requiring Deseret to employ this alternative technology for the reasons set forth below.

Under CAA section 165(a)(2), a PSD permit may not be issued unless, among other things, "a public hearing has been held with opportunity for interested persons ... to appear and submit written or oral presentations on the air quality impact of such source, alternative thereto, control technology requirements, and other appropriate considerations...." EPA interprets section 165(a)(2) of the CAA to require that EPA consider and provide a reasoned response to comments identifying alternatives to the proposed source. *Prairie State*, slip op. at 38-41.

As EPA has observed in other contexts, EPA considers IGCC to be one of the most promising alternative technologies in reducing the environmental consequence of generating electricity. *See* "Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," EPA-430/R-06/006, July 2006, at Forward. EPA has undertaken several initiatives to provide incentives for development and deployment of this technology. This approach is consistent with U.S. policy reflected in the Energy Policy Act of 2005, which established loan guarantees and tax incentives to encourage, but not require, development of IGCC facilities.

As a general matter, assessing whether IGCC is an appropriate alternative may entail a robust analysis of a broad range of factors. Such an analysis is not necessary in this case because there are two specific features of this plant that make IGCC a technically unfeasible option: fuel and plant size. The main fuel for this plant is waste coal, which has an ash content ranging from 40 to 56% and a heating value ranging from 3,000 to 5,400 Btu/lb. There exists no IGCC operating experience with this type of coal. An ash content as high as found in this waste coal would be a major issue for the design and operation of a gasifier (an integral part of an IGCC plant). In addition, the proposed

110 MW size for this plant is too small to be considered viable for an IGCC application. The four operating IGCC installations in the world (two of which are in the U.S.) are each greater than 250 MW in size. In general, the currently proposed IGCC plants by the U.S. power industry are larger than these operating IGCC installations. These plants are being proposed in larger size because they would be relatively less expensive per MW of electricity generation. Thus, even if it were possible to build a 110 MW IGCC plant, it would most likely be too costly to be considered economically viable.

More broadly, EPA believes the environmental and energy security goals of the United States are best served by encouraging the development of all forms of clean coal technology and the development of alternative fuels. Further, providing a reliable and secure supply of electricity to meet growing demand in the United States without adverse affects on air quality will require the use of a diverse array of power producing technologies and innovations in pollution control technology for each type of generating unit. Deseret's proposal to utilize a previously untapped reserve of waste coal with the best pollution control technology available for this type of source is consistent with these goals. In summary, comment #2 has not resulted in any changes to the permit.

### **3. SUPERCRITICAL CFB BOILER**

#### **Comment #3:**

One group of commenters asserted that EPA should have required consideration of a supercritical CFB boiler in the BACT analysis for the Bonanza WCFU. Commenters cited discussion in a Western Governors Association Technology Working Group report on advanced clean coal technologies.

#### **Response #3:**

Agree. In response to this comment, EPA has evaluated a supercritical CFB boiler as a BACT option and has determined that since there are no known supercritical pressure turbines available in the size needed for the WCFU project, this option should be eliminated at step two of the top-down BACT analysis as technically infeasible, because it is not available and applicable for the WCFU project. *See In re Prairie State Generating Co.*, PSD Appeal No. 05-05, slip op. at 14-18 (EAB Aug. 24, 2006) (summarizing and describing steps in the top-down BACT analysis). *Accord In re Three Mountain Power, L.L.C.*, 10 E.A.D. 39, 42-43 n.3 (EAB 2001); *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 129-31 (EAB 1999); *In re Hawaii Electric Light Co.*, 8 E.A.D. 66, 84 (EAB 1998).

At the first step of the top-down BACT analysis, all demonstrated and potentially applicable control technology alternatives must be identified. This must include a survey of production processes or innovative technologies that have a practical potential for application to reduce relevant emissions at the source type being evaluated. (*Prairie State*, slip op. at 17.) At the second step, "technically infeasible" options are eliminated. A technology is feasible if either it is demonstrated, i.e. installed and operated

successfully at a similar facility, or it is both “available” and “applicable.” *Id.* A technology is considered “available” if it can be obtained by the applicant through commercial channels. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration. If a technology is not demonstrated, or is found to be unavailable or not applicable, that technology will be eliminated from BACT consideration as technically infeasible. (*Three Mountain Power*, 10 E.A.D. at 42-43 n.3.)

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

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

However, according to Babcock & Wilcox and Foster-Wheeler, two major boiler suppliers, supercritical pressure steam turbines are not available in the size needed for the WCFU project. The smallest supercritical pressure turbine currently known to be available is three to four times larger than is needed for the WCFU project, which will operate at approximately 1,500 psia and is thus based on a sub-critical steam cycle. (Ref: e-mails and attachments from Ed Thatcher, Deseret Power, to Mike Owens, EPA Region 8, November 6, 2006 and November 13, 2006.)

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

*"To our knowledge, no manufacturer offers supercritical steam turbines in 110-120 MW range. The reason is that you would be unlikely to see any significant performance improvements for units that small. Key reasons are as follows:*

*1. When you go to supercritical steam conditions the specific volume of the steam is reduced because of the higher pressure. That means the blades in the HP section have to be shorter. A major source of inefficiency in steam turbines is due to "flow disruptions" at the top and bottom of the blade where the moving flow meets the stationary rotor or casing. As the blades get shorter the impact of this "end wall" condition increases which in turn increases the flow losses.*



*2. The supercritical conditions require a once-through boiler which requires a more powerful feed pump drive (higher pressures). That decreases plant efficiency and if you can't make that difference up with improved cycle performance, supercritical makes no sense.*

*We generally don't see units less than about 500 MW being built as supercritical because the performance improvement isn't significant and the unit is more expensive than subcritical."*

The Western Governors Association report (cited by commenters) states that "no supercritical CFB combustion units have been demonstrated on a commercial scale." (Ref: Western Governors Association Technology Working Group's report on advanced clean coal technologies, second page of section titled "Advanced Clean Coal Technology Descriptions." The report is included in materials provided by Deseret Power to EPA via e-mail of November 6, 2006. Those materials are included in the Administrative Record for issuance of the WCFU permit.) EPA is aware of only one supercritical CFB boiler that has been proposed, designed and/or constructed anywhere in the world. As of January 11, 2006, design of that unit had not yet been completed. The unit is being designed for Poland's Poludniowy Koncern Energetyczny (PKE) for installation at its power plant at Lagisza in southern Poland. The proposed unit will have an output of 460 MW (four times larger than Deseret Power's proposed WCFU) and is being designed to fire bituminous coal. It is currently scheduled to begin operation in 2009. (Ref: Foster-Wheeler press release, January 11, 2006. The press release is included in materials provided by Deseret Power to EPA via e-mail of November 6, 2006. Those materials are included in the Administrative Record for issuance of the WCFU permit.)

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

The Environmental Appeals Board (EAB) has considered the question of whether certain technologies are available. The EAB has stated that "[i]f the technology is not available, the permit applicant is under no duty to consider it in the BACT analysis." *In re Pennsauken County, New Jersey, Resource Recovery Facility*, 2 E.A.D. 667, 671-672 (Nov. 10, 1988). The EAB has recognized that "[t]he question of availability for purposes of BACT is a practical, fact determination, using conventional notions of whether the technology can be put into use." *Id.* See also, *In re Maui Electric*, 8 E.A.D. 1, 13-16 (Sept. 10, 1998). EPA has evaluated a supercritical CFB boiler as a BACT option for Deseret Power's WCFU project and has found that there are no supercritical pressure turbines available in the size needed for the project. Therefore, EPA has

concluded that a supercritical CFB boiler is technically infeasible for this project and has eliminated it at step two of the BACT analysis.

In summary, comment #3 has not resulted in any change to the permit; however, the Statement of Basis has been changed, to add an explanation of why a supercritical CFB boiler was eliminated as a BACT control option at step two of the BACT analysis. Since BACT determinations are case-by-case, EPA's determination regarding a supercritical CFB boiler for the WCFU project should not be construed as a statement about what the determination should be for other projects.

#### **4. PROPOSED BEST AVAILABLE CONTROL TECHNOLOGY (BACT) EMISSION LIMITS**

##### **4.a -- Cleaner coals:**

**Comment #4.a:** One group of commenters alleged that EPA's analysis of cleaner coals as a BACT option was inadequate. The commenters indicated that while EPA did provide a cost analysis of using all "run-of-mine" coal from the Deserado mine and the resultant additional pollutant reductions (draft Statement of Basis at 24-28), EPA did not provide a comparison of the cost of using "run-of-mine" coal, either in part or wholly, compared to the cost other coal-fired electric utility CFB boilers in the region are paying for coal.

Commenters further alleged that EPA did not provide any comparative cost analysis for use of coal from other mines in the region, either wholly or in part as a blend with the Deserado waste coal. Commenters argued that such analyses are necessary to give context to this evaluation (e.g., *In re Inter-Power of New York, Inc.*, PSD Appeal Nos. 92-8 and 92-9, Decided March 16, 1994), arguing that in determining whether the cost of a control technology is reasonable, the cost must be compared to what other similar sources have had to bear.

As an example, commenters argued that EPA should have provided a comparison to the recently permitted Sevier Power Company's CFB power plant to be located in Sigurd, Utah. That facility will be burning a higher quality bituminous coal than the waste coal proposed for the Bonanza WCFU, and will be subject to lower permit emission limits than the WCFU for SO<sub>2</sub>, total PM/PM<sub>10</sub>, carbon monoxide and sulfuric acid.

Commenters alleged that EPA must analyze and provide data on the cost and quality of coal that the Sevier Power Company and other recently proposed power plants in the region are required to incur before it can determine that the cost of using "run-of-mine" fuel from the Deserado mine – either wholly or in part – is unreasonable. The commenters also suggested that EPA provide a similar analysis for using other higher quality coal available in the region, either wholly or as a blend with the waste coal.

##### **Response #4.a:**

**Partially agree.** As described below, EPA has supplemented the analysis of alternative coals in the Statement of Basis, to: (1) explain more fully, in terms of cost per ton of additional pollutant removed from the atmosphere, why use of coal from any mine in the region other than the Deserado mine, rather than waste coal from the Deserado mine, would be cost-prohibitive as a BACT option, and (2) explain why the BACT option of using ROM coal from the Deserado mine, as well as the BACT option of using coal from any other mine in the region, is cost-prohibitive when compared to the cost of BACT that other similar sources have to bear.

In presenting the analysis for alternative coal from another mine in the region as a BACT option, EPA is not taking a position on whether the use of a coal supply other than the one proposed by the applicant must be evaluated in the BACT analysis for the WCFU or similarly situated facilities. After EPA issued the draft permit for the WCFU, the EPA Environmental Appeals Board issued its opinion in *In re: Prairie State Generating Company*, PSD Appeal No. 05-05 (Aug. 24, 2006). This opinion established that there may be circumstances under which the permitting authority has the discretion not to list alternative coal supplies as an option at Step 1 of the BACT analysis, because such an option could fundamentally redefine the source.

However, we need not address whether this permit presents a similar circumstance, since the draft Statement of Basis included the use of a cleaner coal as an option and evaluated the economic impact of requiring the applicant to use exclusively mined coal from the Deserado mine rather than waste coal, or alternatively, exclusively mined coal from other mines rather than waste coal. (Draft Statement of Basis at pages 25-29.) Since EPA already started down this path of looking at other coal supplies for this permitted project, EPA has supplemented its analysis to further illustrate why it is appropriate to eliminate this option for this permit. Specifically, as described below, EPA is supplementing its BACT analysis in section VI.D.2 of the Statement of Basis, “Alternative coal from other mines,” using a cost methodology in terms of dollars per ton of additional pollutant removed, similar to the cost methodology used in section VI.D.1, “Alternative coal from Deserado mine.”

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

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

As mentioned in the draft Statement of Basis, the Bonanza plant is approximately 75 miles from the nearest rail transportation and approximately 100 miles by truck from the nearest alternative source of coal. The cost to construct a rail line to connect to the interstate rail system has been estimated by Deseret Power to exceed \$300 million. (EPA has eliminated this option as too expensive.) The cost to truck the coal from the nearest

alternative coal source (i.e., other than the Deserado mine) was estimated by Deseret Power to be at least \$15/ton. (Ref: Sept. 13, 2005 letter from Deseret Power to EPA, page 3, footnote 1, included in Administrative Record for issuance of the WCFU permit.)

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

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

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

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

$$\$52.75/\text{ton} \times 367,760 \text{ tons/year} = \$19,400,000/\text{year}.$$

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

$$\$5/\text{ton} \times 1,200,000 \text{ tons/year} = \$6,000,000/\text{year}.$$

(Note: The draft Statement of Basis indicated  $\$5/\text{ton} \times 1,200,000 \text{ tons/year} = \$3,405,000$ . This was an inadvertent mathematical error.) The incremental cost to use entirely alternative coal from another mine in the region, rather than waste coal, would therefore be the difference in cost of the two coals, which is \$13,400,000/year.

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

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

<u>Pollutant</u>	<u>Proposed Emission Limit for WCFU (lb/MMBtu)</u>	<u>Lowest BACT Determination Anywhere for a CFB Boiler Project (lb/MMBtu)</u>	<u>Equivalent Annual Reduction (tons/year)</u>
NO <sub>x</sub>	0.080	0.07	63
SO <sub>2</sub>	0.040	0.022	114
CO	0.15	0.10	316
H <sub>2</sub> SO <sub>4</sub>	0.0035	0.0024	7
Filterable PM	0.012	0.010	13
Condensable PM	0.019	0.005	88

NOTE #1: The Sevier Power Company project cited by commenters is permitted at 0.1 lb/MMBtu for NO<sub>x</sub>, 0.022 lb/MMBtu for SO<sub>2</sub>, 0.115 lb/MMBtu for CO, 0.0024 lb/MMBtu for H<sub>2</sub>SO<sub>4</sub>, and 0.015 lb/MMBtu. "Lowest BACT Determination" values listed above are at least as low.

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

EPA believes it is unlikely that lower emissions than listed above could be achieved on any coal in the Region. As explained in Note #1 above, the figures listed as "Lowest BACT Determination Anywhere for a CFB Boiler Project" are at least as low as the BACT determination for each pollutant at the Sevier project cited by commenters. Further, based on "Average Coal Quality at Utah Mines, 2005," listed in the afore-

mentioned UGS report, it appears to EPA that the proposed coal for the Sevier project is at least as clean, in terms of ash content and sulfur content, as any other coals in the region. The lowest ash content of the coals listed in Table A8 of the UGS report is 8.5%. The ash content of the proposed coal for the Sevier project is lower, at 8.3%. The lowest sulfur content of the coals listed in Table A8 of the UGS report is 0.4%. The sulfur content of the proposed coal for the Sevier project is at least as low, at 0.40%. (Ref: Table A8 of the aforementioned UGS report; Table I-2 of the aforementioned “New Source Plan Review” for the Sevier project.)

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

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

<u>Pollutant</u>	<u>Potential Emission Reduction (Alternative Coal versus Waste Coal)</u>	<u>Cost (\$/ton)</u>
NO <sub>x</sub>	63 tons/yr	\$ 212,698/ton
SO <sub>2</sub>	114 tons/yr	\$ 117,543/ton
CO	316 tons/yr	\$ 42,405/ton
H <sub>2</sub> SO <sub>4</sub>	7 tons/yr	\$1,914,285/ton
Filterable PM	13 tons/yr	\$1,030,769/ton
Condensable PM	88 tons/yr	\$ 152,272/ton
All (sum)	651 tons/yr	\$ 20,583/ton

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

Based on the analysis above, EPA concludes that use of alternative coal from any other mine in the region, rather than waste coal from the Deserado mine, would be cost-prohibitive as a BACT option for the proposed WCFU, even if reductions of all pollutants are summed together and then the annualized cost in dollars-per-ton for emission reduction is calculated on that basis. (As shown above, summing the pollutants yields \$20,583/ton, which is a lower dollar-per-ton BACT cost than looking at any one pollutant individually.)

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

Regarding comparison to the cost of BACT that other similar sources have to bear (which EPA believes is best evaluated in terms of dollars per ton of additional pollutant removed, not simply in terms of what other sources pay for their coal as commenters have suggested), EPA is not aware of any BACT determination for a CFB boiler project anywhere in the U.S. where incremental cost effectiveness as high as \$20,583/ton (the EPA-calculated economic cost for using coal from an alternative mine rather than waste coal from the Deserado mine), or as high as \$20,241/ton (the EPA-calculated economic cost for using ROM coal from the Deserado mine rather than waste coal from the Deserado mine; see final Statement of Basis at page 28) has been considered reasonable for BACT for any pollutants, regardless of the type of BACT option being considered.

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

1) In a PSD permit action in mid 2006 for Lingleaf Energy Associates LLC, Lingleaf Energy Station project, Georgia indicated that incremental cost effectiveness of \$8,964/ton, comparing dry scrubbing to wet scrubbing for SO<sub>2</sub> control at a pulverized coal fired electric utility boiler, was excessive for BACT. Incremental and average cost effectiveness of the selected BACT option (dry scrubbing) was listed as \$724/ton.

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

2) In a PSD permit action in early 2005 for Rocky Mountain Power Inc.'s Hardin project, Montana indicated that incremental cost effectiveness of \$23,855/ton, comparing dry FGD/spray dry absorber to wet FGD for SO<sub>2</sub> control, at a pulverized coal fired electric utility boiler, was excessive for BACT. Average cost effectiveness of wet FGD was listed as \$1,395/ton. Average cost effectiveness of the selected BACT option (dry FGD/spray dry absorber) was listed as \$918/ton.

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



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

The selected BACT option for SO<sub>2</sub> control, with a "cost effective value" of \$4,054/ton, employed a combination of limestone injection, low-sulfur coal, and hydrated ash reinjection. Montana did not indicate whether "cost effective value" means incremental cost effectiveness or total cost effectiveness.

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

4) In a PSD permit action in late 2006 for Cargill's Blair corn milling and ethanol production plant, Nebraska indicated that incremental cost effectiveness of \$5,900/ton, comparing limestone injection alone to limestone injection plus dry FGD, for SO<sub>2</sub> control at a CFB boiler, was excessive for BACT.

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

5) In a PSD permit action in late 2006 for ADM's Columbus corn milling and ethanol production plant, Nebraska indicated that incremental cost effectiveness of \$5,600/ton for NO<sub>x</sub> control (comparing Selective Non-Catalytic Reduction (SNCR) at 0.07 lb/MMBtu to SNCR at below 0.07), and incremental cost effectiveness of \$6,700/ton for SO<sub>2</sub>/H<sub>2</sub>SO<sub>4</sub>/HF control (comparing limestone injection to "additional" limestone injection) at a CFB boiler, were excessive for BACT. Nebraska listed incremental cost-effectiveness of \$2,174 for the selected BACT option for NO<sub>x</sub> control (SNCR at 0.07 lb/MMBtu).

Nebraska also listed average cost-effectiveness of \$5,200/ton for the selected BACT option for VOC control at the CFB boiler (wet scrubbing/packed tower),

(Ref: Nebraska permit action CPM02-0006, page 14 of Appendix B of Fact Sheet; pages 8, 9, 19 and 20 of Appendix D of Fact Sheet, dated August 4, 2006, available online at: [http://www.epa.gov/region07/programs/artd/air/nsr/archives/2006/finalpermits/adm\\_columbus\\_final\\_psd\\_permit.pdf](http://www.epa.gov/region07/programs/artd/air/nsr/archives/2006/finalpermits/adm_columbus_final_psd_permit.pdf).)

6) In a PSD permit in early 2005 for Montana-Dakota Utilities/Westmoreland Power, Gascoyne Generating Station project, North Dakota indicated that incremental cost effectiveness of \$14,339/ton, comparing Selective Catalytic Reduction (SCR) at 0.04 lb/MMBtu to SNCR at 0.09 lb/MMBtu, for NO<sub>x</sub> control at a CFB boiler, was excessive for BACT. Average cost effectiveness of SCR was listed as \$7,545/ton. Average and incremental cost effectiveness of the selected BACT option (SNCR) was listed as \$2,926/ton.

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

7) In a PSD permit action in early 2004 for Red Trail Energy's Richardton, ND, ethanol production plant, North Dakota listed incremental cost effectiveness of \$10,252/ton, comparing wet FGD plus limestone injection to dry FGD (spray dryer absorber) plus limestone injection, for SO<sub>2</sub> control at a CFB boiler. Average cost effectiveness of wet FGD plus limestone injection was listed as \$1,041/ton. Average cost effectiveness of dry FGD plus limestone injection was listed as \$527/ton. North Dakota rejected wet FGD and determined that BACT is represented by dry FGD plus limestone injection.

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

8) In a PSD permit action in early 2005 for River Hill Power Company's CFB boiler project, Pennsylvania indicated that incremental cost effectiveness of \$15,975/ton, comparing use of the waste coal proposed by the permit applicant to use of the nearest alternative source of coal with lower sulfur content, for SO<sub>2</sub> control at the CFB boiler, was excessive for BACT.

Pennsylvania also indicated that all SO<sub>2</sub> BACT options involving wet FGD systems "were economically infeasible at an incremental dollar per ton value greater than \$5,000 per ton of SO<sub>2</sub> removed."

Pennsylvania concluded that use of a spray dryer absorber or flash dryer absorber (i.e., dry FGD) was "economically feasible for the control of SO<sub>2</sub> at an incremental cost of \$1,511.01 per ton of SO<sub>2</sub> removed."

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

9) In a PSD permit action in early 2005 for Wellington Development's Greene Energy Resource Recovery Project, Pennsylvania indicated that incremental cost

effectiveness of at least \$20,000/ton, comparing use of the waste coal proposed by the applicant to pre-combustion cleaning of the waste coal (excluding additional coal disposal costs after cleaning of the waste coal), for SO<sub>2</sub> control at the CFB boiler, was excessive for BACT. Pennsylvania also indicated that overall cost effectiveness of \$5,764/ton, for limestone injection plus wet FGD for SO<sub>2</sub> control at the CFB boiler, was excessive for BACT.

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

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

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

11) In a PSD permit action in early 2007 for Basin Electric's Dry Fork Station project (a pulverized coal-fired electric utility boiler), Wyoming indicated that incremental cost effectiveness of \$23,755/ton for NO<sub>x</sub> control (comparing Selective Catalytic Reduction (SCR) at 0.043 lb/MMBtu to SCR at 0.040 lb/MMBtu) was excessive for BACT. Average cost effectiveness for SCR at 0.040 lb/MMBtu was listed as \$2,004/ton. Average cost effectiveness for SCR at 0.043 lb/MMBtu was listed at \$1,751/ton.

Although Wyoming determined that incremental cost effectiveness of \$10,303/ton was reasonable for SCR at 0.043 lb/MMBtu, for other reasons described by Wyoming the selected BACT option for NO<sub>x</sub> control was SCR at 0.05 lb/MMBtu, with incremental cost effectiveness of \$3,512/ton and average cost effectiveness of \$1,511/ton.

Wyoming also indicated that incremental cost effectiveness of \$15,299/ton for SO<sub>2</sub> control (comparing dry FGD/spray dry absorber at 0.073 lb/MMBtu to wet FGD at 0.054 lb/MMBtu), was excessive for BACT. Average cost effectiveness of wet FGD at 0.054 lb/MMBtu was listed as \$1,595/ton.

Although Wyoming determined that incremental cost effectiveness of \$9,296/ton was reasonable for a spray dry absorber at 0.043 lb/MMBtu, for other reasons

described by Wyoming the selected BACT option for SO<sub>2</sub> control was a spray dry absorber at 0.08 lb/MMBtu, with average cost effectiveness of \$1,159/ton; no incremental cost effectiveness listed by Wyoming for this BACT option..

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

12) In a PSD permit action in early 2002 for Black Hills Power & Light's WYGEN2 project, Wyoming indicated that incremental cost effectiveness of \$7,742/ton, comparing low-NO<sub>x</sub> burners plus SCR at 0.06 lb/MMBtu to low-NO<sub>x</sub> burners plus SCR at 0.08 lb/MMBtu, for NO<sub>x</sub> control at a pulverized coal fired electric utility boiler, was reasonable for BACT. However, for other reasons described by Wyoming, the selected BACT option was low-NO<sub>x</sub> burners plus SCR at 0.07 lb/MMBtu, with "total" (i.e., average) cost effectiveness somewhere between \$4,067/ton (the average cost effectiveness to achieve 0.08 lb/MMBtu) and \$4,156/ton (the average cost effectiveness to achieve 0.06 lb/MMBtu).

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

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

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

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

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

Although this information is only on comparative economic costs of BACT options, not on comparative energy and environmental costs (which were generally not quantified by the permitting authorities), the information does seem to indicate that similar sources have typically not been expected to bear BACT costs, on an incremental cost effectiveness basis, as high as the incremental cost effectiveness for using alternative

sources of coal for Deseret Power's project, in lieu of waste coal (\$20,583/ton for alternative coal from another mine and \$20,241/ton for alternative coal from the Deserado mine).

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

This supplemental BACT analysis has not altered EPA's determination that use of alternative coal from the Deserado mine or from another mine, either partially or entirely in place of waste coal from the Deserado mine, should be eliminated as a BACT option, in terms of environmental, economic and energy costs, at Step 4 of the BACT analysis.

In summary, Comment #4.a has not resulted in any change to the permit; however, the Statement of Basis has been changed, to include the supplemental analysis described above.

#### **4.b -- Sulfur Dioxide (SO<sub>2</sub>):**

**Comment #4.b:** One group of commenters asserted that the BACT analysis and proposed BACT limit for SO<sub>2</sub> are flawed because they do not reflect the maximum degree of reduction that can be achieved. EPA proposed an SO<sub>2</sub> emission limit of 0.055 lb/MMBtu (30-day average) when the uncontrolled SO<sub>2</sub> emissions are 1.9 lb/MMBtu or greater. EPA also proposed a calculated 30-day average SO<sub>2</sub> limit which is based on a 0.055 lb/MMBtu emission rate for the number of days at which the potential uncontrolled SO<sub>2</sub> emissions are 1.9 lb/MMBtu or higher, and a 0.04 lb/MMBtu emission rate for the number of days at which the potential uncontrolled SO<sub>2</sub> emissions are less than 1.9 lb/MMBtu. Individual supporting arguments from commenters are described below, along with EPA's responses

**Comment #4.b.(1):** Commenters alleged that EPA's proposed variable BACT limit does not reflect the maximum degree of reduction that can be achieved at a CFB boiler. By comparison, commenters cited two different coal-fired CFB power plants (Nevco and AES-Puerto Rico), with the same proposed SO<sub>2</sub> controls as Deseret's WCFU, that are required to meet an SO<sub>2</sub> BACT limit of 0.022 lb/MMBtu. Commenters calculated that the emission limit for AES-Puerto Rico equates to a 98.6% reduction in SO<sub>2</sub> emissions, which must be met on a three-hour average, despite a potential uncontrolled SO<sub>2</sub> emission rate of 1.6 lb/MMBtu, lower than Deseret's WCFU.

**Response #4.b.(1):** Partially agree. EPA does not agree with commenters that comparison with the Nevco project should lead to reconsideration of the SO<sub>2</sub> BACT emission limit in the draft WCFU permit. EPA does, however, agree with commenters that comparison with the AES Puerto Rico project should lead to such reconsideration, at least in regard to the "cutpoint" in coal quality. (NOTE: By "cutpoint," EPA means the level of uncontrolled SO<sub>2</sub> emission potential of the coal, in lb/MMBtu, that would trigger a switch from a straight 0.055 lb/MMBtu emission limit to a calculated emission limit of between 0.055 and 0.040 lb/MMBtu. A more detailed mathematical description of the "cutpoint" approach, as well as a description of the rationale for that approach, may be found in Step 5 of the SO<sub>2</sub> BACT analysis in the Statement of Basis.)

**Comparison with Nevco:** As stated on pages 77-78 of the Statement of Basis, Nevco will only have to achieve a control efficiency of 95.5% to meet its emission limit when burning average coal, and 97.2% when burning worst-case coal. The proposed limits for Deseret would reflect higher control efficiency than Nevco. As also stated in the Statement of Basis, if "average" coal for the WCFU (i.e., coal with uncontrolled SO<sub>2</sub> emission potential of about 1.71 lb/MMBtu) is burned for an extended period of time, such as a month or more, the variable BACT limit in the draft WCFU permit would approach the lower limit of 0.04 lb/MMBtu, which corresponds to a control efficiency of 97.7%. The proposed upper emission limit of 0.055 lb/MMBtu at the WCFU would reflect 98.8% control efficiency for "worst-case" coal (i.e., coal with uncontrolled SO<sub>2</sub> emission potential of 4.73 lb/MMBtu). These are both higher control efficiencies than required at the Nevco project for its average and worst-case coals.

Therefore, EPA does not believe that comparison to Nevco should lead to re-consideration of the proposed SO<sub>2</sub> emission limit for Deseret's WCFU project.

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

This startup/shutdown exemption language does not appear in the draft WCFU permit. Instead, the draft WCFU permit says "The PSD BACT emission limits in this permit, as well as the modeling limits, apply at all times, including periods of startup, shutdown and malfunction." (Ref: draft WCFU permit at page 16, condition III.I.1.) Therefore, EPA believes that making a direct comparison of the stringency of the SO<sub>2</sub> emission limit in the AES Puerto Rico permit with the SO<sub>2</sub> emission limit in the draft WCFU permit is not entirely meaningful. Nevertheless, EPA has re-compared the theoretical control efficiency requirements of the two permits over the respective range of coal qualities, assuming steady-state operations apply and averaging times do not significantly affect those control requirements. This is explained in the step-by-step process below.

First, using mass balance, EPA calculated an uncontrolled SO<sub>2</sub> emission potential of the coal for the AES Puerto Rico facility, in lb/MMBtu, based on coal quality parameters of 0.8% sulfur content and 12,000 Btu/lb heat content cited by commenters for the 'worst case' coal. The result of EPA's calculation was 1.3 lb/MMBtu:

$$\frac{0.008 \text{ lb sulfur}}{\text{lb coal}} \times \frac{2 \text{ lb SO}_2}{\text{lb sulfur}} \times \frac{\text{lb coal}}{12,000 \text{ Btu}} \times \frac{1,000,000 \text{ Btu}}{\text{MMBtu}} = 1.3 \text{ lb SO}_2/\text{MMBtu}$$

To meet an emission limit of 0.022 lb/MMBtu, the AES Puerto Rico facility would need to achieve about 98.3% SO<sub>2</sub> control efficiency. (NOTE: These results differ from the results cited by commenters, which were 1.6 lb/MMBtu and 98.6% control. EPA therefore finds that the commenters' results were incorrect. Commenters did not provide an explanation of how they calculated 1.6 lb/MMBtu and 98.6% control, therefore EPA is unable to determine why commenters' results were incorrect. EPA finds that its own earlier results of 1.7 lb/MMBtu and 98.7% for 'worst-case' coal at AES Puerto Rico, cited on page 76 of the draft Statement of Basis, were also incorrect. This has been corrected in the final Statement of Basis.)

Second, EPA Region 8 obtained information on the sulfur content and heat content of coal that has been used historically at the AES Puerto Rico facility. EPA

Region 8 learned that the sulfur content varied from 0.49% to 0.75% during the fourth quarter of 2004 and the heat content was about 11,350 Btu/lb. From February of 2002 through June of 2003, the sulfur content varied from 0.53% to 0.85% and the heat content varied from 11,317 Btu/lb to 11,495 Btu/lb. From this information, EPA Region 8 found that the uncontrolled SO<sub>2</sub> emission potential of the actual coal ranges from about 1.3 lb/MMBtu ('worst-case' coal) down to about 0.88 lb/MMBtu ('average' coal). EPA Region 8 calculated that at the low end of this range, the AES Puerto Rico facility would need to achieve about 97.5% SO<sub>2</sub> control efficiency, to meet an emission limit of 0.022 lb/MMBtu. (Ref: Memorandum and attachments to the file by Mike Owens of EPA Region 8, dated August 8, 2007, included in the Administrative Record for issuance of the WCFU permit.)

Third, EPA Region 8 compared the above-mentioned control efficiencies for AES Puerto Rico to those that the WCFU would need to achieve to comply with the SO<sub>2</sub> emission limit in the draft WCFU permit. As noted above and on page 77 of the draft Statement of Basis, the WCFU would need to achieve about 98.8% control efficiency to comply with the upper emission limit of 0.055 lb/MMBtu, when burning 'worst-case' waste coal from the Deserado mine, and a control efficiency of about 97.7% to comply with an emission limit of 0.040 lb/MMBtu, when burning 'average' waste coal from the Deserado mine. Both of these control efficiencies are higher than the control efficiencies cited above for the range of coal at the AES Puerto Rico plant (98.3% for worst-case coal and 97.5% for average coal).

The above-mentioned comparison is somewhat misleading, however, for 'average' coal at the WCFU, because at the "cutpoint" in the draft WCFU permit (i.e., uncontrolled SO<sub>2</sub> emission potential of coal of 1.9 lb/MMBtu, only slightly higher than 1.71 lb/MMBtu for 'average' coal), the applicable emission limit would be the upper limit of 0.055 lb/MMBtu. Condition III.D.1.b.(ii)(b) of the draft WCFU permit states that the calculated emission limit of between 0.055 and 0.040 lb/MMBtu only applies below the "cutpoint." Therefore, the statement on page 81 of the draft Statement of Basis, that a control efficiency of 97.9% would need to be achieved to comply with the applicable emission limit at the "cutpoint," is incorrect, because the statement was erroneously based on complying with an emission limit of 0.040 lb/MMBtu. The correct control efficiency that would need to be achieved at the 1.9 lb/MMBtu "cutpoint" is actually 97.1%, based on an applicable emission limit of 0.055 lb/MMBtu. This corrected control efficiency is lower than the 97.5% control efficiency that the AES Puerto Rico facility must achieve to meet its SO<sub>2</sub> emission limit of 0.022 lb/MMBtu when burning 'average' coal.

Based on this correction, EPA re-evaluated the appropriate level to set for the "cutpoint" and determined that, to require a minimum control efficiency of 97.5% across the range of coal qualities described in the permit application for the WCFU, the "cutpoint" would need to be 2.2 lb/MMBtu, rather than 1.9 lb/MMBtu. This would correspond to a control efficiency of 97.5%, to comply with an applicable emission limit of 0.055 lb/MMBtu when burning coal with uncontrolled SO<sub>2</sub> emission potential of 2.2 lb/MMBtu.



When burning coal above the revised “cutpoint,” i.e., coal with uncontrolled SO<sub>2</sub> emission potential greater than 2.2 lb/MMBtu, to comply with the applicable emission limit of 0.055 lb/MMBtu the WCFU would need to achieve higher SO<sub>2</sub> control efficiencies than 97.5%, reaching 98.8% when burning worst-case coal. Below the revised “cutpoint,” a calculated SO<sub>2</sub> emission limit of between 0.055 and 0.040 lb/MMBtu is applicable and needed control efficiencies range from 98.1% just below the cut-point (2.14 lb/MMBtu) to 97.7% for the average coal.

EPA believes this revised “cutpoint” is an appropriate approach for ensuring that the WCFU maintains a high level of SO<sub>2</sub> control over the wide range of coal quality, and reflects the maximum degree of SO<sub>2</sub> reduction that can be achieved, commensurate with SO<sub>2</sub> BACT determinations for other similar facilities (listed in the two tables in Step 5 of the SO<sub>2</sub> BACT analysis in the Statement of Basis), including Nevco and AES Puerto Rico. Specifically, this revised “cutpoint” ensures a minimum control efficiency of at least 97.5%, over the range of worst-case coal to average coal.

EPA Region 8 also reviewed 30-day average SO<sub>2</sub> CEMS data for the AES Puerto Rico facility, in quarterly CEMS reports from the years 2003 through 2006, and found a very low amount of excess emissions with regard to the emission limit of 0.022 lb/MMBtu on a 3-hour average. The reports seem to EPA Region 8 to indicate that an emission limit of 0.022 lb/MMBtu on a 30-day rolling average (and the corresponding control efficiencies) could consistently be met by the AES Puerto Rico facility, over the range of coal quality cited above. Therefore, EPA concludes that the revised “cutpoint” of 2.2 lb/MMBtu for the WCFU represents an overall SO<sub>2</sub> BACT determination that is achievable for a CFB unit with limestone injection and a dry scrubber for SO<sub>2</sub> controls. (Ref: Memorandum and attachments to the file by Mike Owens of EPA Region 8, dated August 8, 2007, included in the Administrative Record for issuance of the WCFU permit.)

Comment #4.b.(1) has resulted in the following changes to the permit and Statement of Basis: The final permit specifies a “cutpoint” of 2.2 lb/MMBtu, rather than 1.9 lb/MMBtu in the draft permit, for triggering applicability of the lower-tier SO<sub>2</sub> BACT emission limit in the permit. The Statement of Basis has also been revised, to add an explanation of why EPA has chosen a “cutpoint” of 2.2 lb/MMBtu, and to correct EPA’s calculations for ‘worst-case’ coal at AES Puerto Rico, explained above, from 1.7 lb/MMBtu and 98.7% control efficiency to 1.3 lb/MMBtu and 98.3% control efficiency.

**Comment #4.b.(2):** Commenters alleged that while the draft Statement of Basis indicates a 98.8% SO<sub>2</sub> removal efficiency could be achieved with the CFB boiler and the spray dry absorber (draft Statement of Basis at pages 72-73), the proposed BACT emission limit for SO<sub>2</sub> does not reflect this level of control, because it is based on the absolute worst case uncontrolled SO<sub>2</sub> emission rate. Commenters indicated that the 0.055 lb/MMBtu limit reflects 98.8% SO<sub>2</sub> removal from the worst case design coal of 3,000 Btu/lb and 0.71% sulfur (which thus equates to an uncontrolled SO<sub>2</sub> emission rate of 4.73 lb/MMBtu). However, the expected *average* uncontrolled SO<sub>2</sub> emission rate is 1.71

(EPA's Statement of Basis at 15). Commenters concluded that, based on the average uncontrolled SO<sub>2</sub> emission rate, the 0.040 lb/MMBtu SO<sub>2</sub> limit (which would apply when the uncontrolled emission rate is lower than 1.9 lb/MMBtu) only represents a 97.7% SO<sub>2</sub> removal rate from average uncontrolled SO<sub>2</sub> emissions. Commenters argued that 97.7% is over a percentage point lower than the maximum degree of reduction that can be achieved.

**Response #4.b.(2): Disagree.** While the figures cited by commenters are correct, EPA does not agree that 97.7% control is inadequate for SO<sub>2</sub> BACT, for combustion of "average" waste coal at Deseret's WCFU. Considering that the worst-case coal for the WCFU has uncontrolled SO<sub>2</sub> emission potential two-and-a-half times higher than average coal (4.73 lb/MMBtu versus 1.71 lb/MMBtu), EPA does not believe an SO<sub>2</sub> control efficiency as high as that for worst-case coal (98.8%) can be achieved when burning average coal, which resulted in only 97.5% SO<sub>2</sub> control efficiency at AES Puerto Rico. As explained in response #4.b.(1) above, the two-tiered SO<sub>2</sub> emission limit with the revised "cutpoint" compares favorably to the two projects cited by commenters (Nevco and AES Puerto Rico), in terms of SO<sub>2</sub> control efficiencies needed to comply with applicable SO<sub>2</sub> emission limits.

Comment #4.b.(2) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.b.(3):** Commenters alleged that EPA Region 8 previously made a "similar" comment to the Montana Department of Environmental Quality regarding the proposed Roundup power plant. Specifically, commenters cited EPA as having stated, in a December 18, 2002 letter to Montana, that "[w]hile use of the worst-case coal scenario might be appropriate for establishing a short-term (3-hour or 24-hour) SO<sub>2</sub> emission limit, we consider it inappropriate for establishing a 30-day average emission limit, especially considering that coal blending can be used at minimal additional cost (and is routinely used in the power plant industry) to eliminate or reduce the effect of coal sulfur 'spikes.'"

**Response #4.b.(3): Disagree.** By describing the comment to Montana as "similar," commenters appear to be suggesting that EPA only considered the worst-case coal scenario when proposing SO<sub>2</sub> BACT emission limits for Deseret's WCFU. This is not true. The Statement of Basis has a lengthy discussion (on pages 77-81) of how EPA set up a two-tiered limit. EPA's comments on Roundup are consistent with EPA's proposed approach of setting up this two-tiered limit for Deseret's WCFU, rather than setting a single limit based on worst case coal

Comment #4.b.(3) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.b.(4):** Commenters alleged that the Bonanza WCFU has requested to be authorized to burn washed or run-of-mine coal which will have lower uncontrolled SO<sub>2</sub> emissions than the worst case waste coal and thus could be used to eliminate coal sulfur spikes. Also, commenters stated, Deseret has indicated that the Bonanza WCFU will have continuous SO<sub>2</sub> monitoring at the inlet to the dry scrubber. Thus, commenters

argue, Deseret will know on a fairly instantaneous basis when the coal sulfur content is spiking and thus could adjust the fuel accordingly. Consequently, the 30-day average BACT limit should reflect this level of control off of the average uncontrolled SO<sub>2</sub> emission rate of 1.7 lb/MMBtu, which equates to a BACT emission limit of 0.021 lb/MMBtu.

**Response #4.b.(4): Disagree.** The authorization to burn washed or run-of-mine coal is not unlimited as implied by commenters, but is restricted in the draft WCFU permit, as follows: Condition III.E.2.b. only allows Deseret Power to burn washed or run-of-mine coal, rather than waste coal, during emergencies when waste coal is not available. For situations other than startup or emergencies, condition III.E.2.c. allows use of run-of-mine coal blended with waste coal in any ratio yielding up to 6,500 Btu/lb heat content. This corresponds to roughly a 50/50 blend. As explained in the draft Statement of Basis at page 10, Deseret Power requested this authorization for operational flexibility, 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, even though the WCFU is being designed specifically to burn waste coal, and even though use of run-of-mine or washed coal on a routine basis, in lieu of waste coal, would be prohibitively expensive for BACT. EPA already presented a cost analysis in the draft Statement of Basis demonstrating that use of washed or run-of-mine coal, either partially or entirely in place of waste coal, should be eliminated as a BACT option for cost reasons. (See draft Statement of Basis at pages 25-28.)

At Step 5 of the SO<sub>2</sub> BACT analysis, EPA stated that “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<sub>2</sub> BACT analysis above, EPA believes that the proposed ‘second tier’ SO<sub>2</sub> 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<sub>2</sub> emission control efficiency.” (Draft Statement of Basis at page 82.)

EPA disagrees with commenters’ argument that SO<sub>2</sub> CEMS data could be used to adjust fuel and eliminate coal sulfur spikes. The SO<sub>2</sub> monitors at the inlet to the scrubber do not reflect the uncontrolled SO<sub>2</sub> emission rate of the raw coal, since a great deal of SO<sub>2</sub> control occurs upstream of the scrubber inlet, via limestone injection in the CFB boiler itself. EPA does not agree that Deseret has that much ability to control spikes in coal sulfur content (see detailed discussion on page 80 of the Statement of Basis) and the scrubber inlet SO<sub>2</sub> monitor does not help with this problem.

Comment #4.b.(4) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.b.(5):** Commenters stated that at worst, the 30-day average SO<sub>2</sub> emission limit should reflect the percent reduction required at the AES-Puerto Rico facility, which has a similar level of uncontrolled emissions (albeit, worst case coal at AES-Puerto Rico is similar to average coal at the Bonanza WCFU). That facility’s SO<sub>2</sub> emission limit reflects 98.6% reduction from uncontrolled emissions of 1.6 lb/MMBtu,

on a three-hour average basis. Thus, commenters concluded, the Bonanza WCFU SO<sub>2</sub> BACT limit should no higher than 0.024 lb/MMBtu, on a 30-day average to allow for the wide variability in sulfur content of the fuel.

**Response #4.b.(5): Partially agree.** As explained on pages 78-79 of the Statement of Basis, EPA does not agree that it is appropriate, considering the very high variability in coal quality expected to be encountered with Deseret's waste coal, to set a single SO<sub>2</sub> limit that applies to the entire range of possible fuel inputs at the WCFU. Also, as explained in response #4.b.(1), EPA does not agree with commenters' calculations of 1.6 lb/MMBtu and 98.6% control, for the "worst-case" coal scenario at the AES Puerto Rico plant. EPA calculates 1.3 lb/MMBtu and 98.3% control.

EPA does, however, agree that the WCFU should be expected to achieve a level of SO<sub>2</sub> reduction, which is commensurate with BACT determination at other similar facilities (listed in the two tables in Step 5 of the SO BACT analysis in the Statement of Basis), including AES Puerto Rico. Therefore, as explained in response #4.b.(1), EPA has revised the "cutpoint" that would trigger a change in the applicable emission limit for the WCFU, to ensure that the WCFU maintains a high level of SO<sub>2</sub> control over the wide range of coal quality, and to reflect the maximum degree of SO<sub>2</sub> reduction that can be achieved (97.5% or higher, over the range of worst-case coal to average coal), commensurate with SO<sub>2</sub> BACT determinations for other similar facilities including AES Puerto Rico.

Comment #4.b.(5) has resulted in the same changes to the permit and Statement of Basis that are described at the end of response #4.b.(1).

**Comment #4.b.(6):** Commenters alleged that EPA must also impose shorter term averaging time BACT limits consistent with the averaging times of the SO<sub>2</sub> NAAQS and PSD increments (i.e., 3-hour and 24-hour). Commenters cited an EPA statement, in a December 18, 2002 letter to Montana on the Roundup coal-fired electric utility project, that it is more appropriate to base shorter term average BACT limits on worst case uncontrolled emissions. (See comment #4.b.(3) above.) Thus, commenters concluded, the proposed BACT limit of 0.055 lb/MMBtu would be appropriate on a shorter term averaging time such as a three-hour average (similar to the AES-Puerto Rico permit).

**Response #4.b.(6): Disagree, for three reasons.** First, EPA set worst case modeling limits in the permit specifically to protect the short-term NAAQS and PSD increments. Second, the proposed SO<sub>2</sub> emission limits for Deseret's WCFU are two-tiered, unlike Roundup, and are not based solely on worst-case uncontrolled emissions. Third, Federal PSD rules at 40 CFR 52.21 do not require BACT limits for all averaging times of the PSD increments or NAAQS. EPA proposes modeling limits in the permit, separate from the BACT emission limits, to ensure that the assumed emission rates used for modeling PSD increment compliance and NAAQS compliance are not exceeded. See more detailed discussion at response #5.a.(1).

Comment #4.b.(6) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.b.(7):** Commenters argued that in addition, with a 30-day average SO<sub>2</sub> BACT limit based on average coal quality and a 3-hour average SO<sub>2</sub> BACT limit based on worst case coal quality, this would eliminate the need for EPA's proposed variable SO<sub>2</sub> limit, which commenters say would not result in the maximum degree of SO<sub>2</sub> emission reduction that could be achieved. Commenters stated that this is because EPA allows applicability to the variable SO<sub>2</sub> BACT limit to be based on a 30-day average of the uncontrolled SO<sub>2</sub> emission rate (Condition III.J.2. of the draft permit), which will allow the Bonanza WCFU to only have to comply with the higher SO<sub>2</sub> BACT limit with just a few days of spiked coal sulfur content over a 30-day period

**Response #4.b.(7):** Disagree. As explained on pages 78-79 of the Statement of Basis, since the quality of coal in the waste coal pile is highly variable and not entirely predictable, the two-tiered SO<sub>2</sub> limit is necessary to accommodate fuel variability while still ensuring that controls are maintained at a high level of efficiency over the entire range of predicted coal quality, in accordance with BACT. A 3-hour limit based solely on worst case coal quality would not ensure that controls are maintained at a high level of efficiency over the entire range of predicted coal quality.

Only in situations where coal quality is consistently above the cut-point level of 1.9 lb/MMBtu for uncontrolled SO<sub>2</sub> emission potential for prolonged periods (unlikely to happen frequently, considering the cut-point is 11% higher than what is predicted to be average coal quality of the waste pile) would the higher-tier emission limit of 0.055 lb/MMBtu be the actual 30-day SO<sub>2</sub> BACT limit. The 30-day limit is a weighted average, so having just a few days of high coal sulfur content over a 30-day period would not necessarily cause the applicable emission limit to revert to 0.055 lb/MMBtu. The applicable emission limit might very well remain closer to the lower limit of 0.04 lb/MMBtu. See Statement of Basis discussion on page 80.

Comment #4.b.(7) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.b.(8):** Commenters argued that the 5-day lag in comparing 30-day average uncontrolled SO<sub>2</sub> emissions to 30-day average controlled emission rates (Condition III.D.1.b.(ii)(b) of the draft permit) means that the proposed BACT emission limits would not ensure maximum SO<sub>2</sub> emission reductions on a continuous basis.

**Response #4.b.(8):** Disagree. EPA believes that the 5-day lag time, allowed under condition III.D.1.b. of the draft WCFU permit, is justified due to the SO<sub>2</sub> sampling time turnaround. EPA does not believe it is appropriate to retroactively apply a more restrictive limit upon a source once coal sampling results are obtained. As explained on page 80 of the draft Statement of Basis,

“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<sub>2</sub> tier limit would not be known to the WCFU operator until the coal analysis is received.”

Although there will be a scrubber inlet SO<sub>2</sub> monitor in addition to the daily coal sampling, the scrubber inlet monitor will not measure the true uncontrolled SO<sub>2</sub> emission potential of the coal, either in practice or in the permit, due to the SO<sub>2</sub> control that occurs in the CFB boiler via limestone injection, upstream of the scrubber and the scrubber inlet SO<sub>2</sub> monitor. Therefore, the scrubber inlet SO<sub>2</sub> monitor will not eliminate the need for daily coal sampling and the associated lag time. As explained by Deseret Power in a January 9, 2006 e-mail to EPA (included in the Administrative Record for issuance of the WCFU permit), SO<sub>2</sub> measurements at the scrubber inlet monitor “will be used to control limestone flow to the furnace to maintain a selected SO<sub>2</sub> inlet to the dry scrubber.” The scrubber inlet SO<sub>2</sub> monitor is not required by the draft WCFU permit, only a scrubber outlet SO<sub>2</sub> monitor, for demonstrating compliance with the SO<sub>2</sub> BACT emission limit.

Comment #4.b.(8) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.b.(9):** Commenters asserted that the draft permit also fails to address BACT requirements when Deseret is using “run-of-mine” coal, either in lieu of waste coal, or as a blend with waste coal, from the Deserado mine (as allowed by condition III.E.2.c. of the draft permit). Commenters stated that EPA has indicated, in correspondence to Deseret, that BACT needs to be met “for the entire range of operating conditions.” Yet, commenters argue, EPA did not provide any review of BACT or propose any emission limits to address BACT when the Bonanza WCFU is burning the much higher quality coal either wholly or in part.

**Response #4.b.(9):** Disagree. EPA’s SO<sub>2</sub> BACT analysis did address this situation. See discussion on page 82 of the draft Statement of Basis. Comment #4.b.(9) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.b.(10):** Commenters argued that to address the variation expected in uncontrolled SO<sub>2</sub> emissions at the Bonanza WCFU, EPA must include a SO<sub>2</sub> removal efficiency requirement as BACT in addition to the BACT emission limits that reflects the maximum degree of emission reduction that can be achieved given the variability in uncontrolled SO<sub>2</sub> emissions. Commenters note that EPA Region 8 recommended a similar approach in its comments on the proposed Roundup power plant in Montana. Specifically, EPA stated “[a] minimum required SO<sub>2</sub> scrubber efficiency should be included in the permit, to ensure proper operation and maintenance of the scrubber, and to ensure that SO<sub>2</sub> emissions are minimized at all times, regardless of the sulfur content in the coal.”

**Response #4.b.(10): Disagree.** The Roundup facility in Montana is a pulverized coal (PC) fired unit, not a circulating fluidized bed (CFB) unit like Deseret's proposed WCFU. A PC fired unit uses a SO<sub>2</sub> scrubber as the single stage of SO<sub>2</sub> control, hence the overall control efficiency can easily be measured via CEMS at the scrubber inlet and outlet. A CFB unit, however, uses two stages of SO<sub>2</sub> control. As explained on page 12 of the Statement of Basis, the first stage is limestone injection into the CFB combustor unit and the second stage is a dry SO<sub>2</sub> scrubber downstream. For this two-stage system of control, overall control efficiency cannot be easily measured on a real-time basis. The proposed two-tiered SO<sub>2</sub> limit for the WCFU is a means to deal with the high coal quality variability and unpredictability of the waste coal supply and maintain an emission limit that ensures SO<sub>2</sub> emissions are controlled to a BACT level at all times.

Comment #4.b.(10) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.b.(11):** Commenters asserted that, contrary to EPA's approach in the proposed limits in this permit, the percent reduction BACT requirement must be based on at least a daily average. Given the wide variability of uncontrolled SO<sub>2</sub> emissions allowed by the permit, calculating uncontrolled SO<sub>2</sub> emissions on a 30-day average would not ensure the maximum degree of SO<sub>2</sub> emissions reductions on those days when 100% "run-of-mine" coal is being burned.

**Response #4.b.(11): Disagree.** For situations other than startup or emergencies as defined in permit conditions III.E.2.a and b, permit condition III.E.2.c. allows use of run-of-mine coal blended with waste coal in any ratio yielding up to 6,500 Btu/lb heat content on a 30-day rolling average. This is roughly equivalent to a 50/50 blend, not 100% run-of-mine coal. As explained on page 82 of the Statement of Basis, EPA believes that the proposed 'second tier' SO<sub>2</sub> 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 SO<sub>2</sub> emission control efficiency. With the revised coal "cutpoint" described in response #4.b.(1) above, EPA calculates that control of at least 97.5% will be needed to meet the two-tier SO<sub>2</sub> emission limit for the WCFU, for the range of coal quality from worst-case coal to average coal. As explained in response #4.b.(1), EPA believes this level of control is commensurate with SO<sub>2</sub> BACT determinations at other similar sources cited by commenters.

Comment #4.b.(11) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.b.(12):** Commenters indicated that a 24-hour average percent SO<sub>2</sub> removal should be required as part of the BACT determination, as it would effectively cover all of the various operating scenarios at the Bonanza WCFU.

**Response #4.b.(12): Disagree.** In a sense, the two-tiered limits are daily averages, as the 30-day weighted average is determined based on each day's coal quality.

Each “daily average” limit – either 0.055 or 0.040 lb/MMBtu - is given a weight depending on the number of days that daily limit applies over a 30-day period. There is a strong incentive for Deseret to keep controls running at their maximum capacity in order to ensure they meet their two-tiered emission limit, especially given the unpredictability of their coal source. Comment #4.b.(12) has not resulted in any change to the permit or Statement of Basis.

In summary comments #4.b.(1) through (12) have resulted in the changes to the permit and Statement of Basis described at the end of response #4.b.(1).



#### **4.c -- Nitrogen Oxide (NO<sub>x</sub>):**

**Comment #4.c:** One group of commenters indicated that EPA did not adequately evaluate all of the technologies that could be employed at the Bonanza WCFU to reduce NO<sub>x</sub> emissions and thus, the NO<sub>x</sub> BACT determination does not reflect the maximum degree of NO<sub>x</sub> reduction that can be achieved at the Bonanza WCFU. Individual arguments from commenters are described below, along with EPA's responses

**Comment #4.c.(1):** Commenters asserted that EPA eliminated evaluation of several NO<sub>x</sub> control options as infeasible for a CFB boiler. Those options eliminated include flue gas recirculation and overfire air. See Statement of Basis at 30. Yet, commenters stated, a 1999 EPA guidance document identifies these two controls as options for NO<sub>x</sub> control at CFB boilers. (Ref: Technical Bulletin: Nitrogen Oxides (NO<sub>x</sub>), Why and How They Are Controlled, EPA-456/F-99-006R, November 1999.)

Commenters further stated that the Technical Bulletin identifies several other options for NO<sub>x</sub> control at fluidized bed boilers that were not evaluated in the Bonanza WCFU NO<sub>x</sub> BACT analysis, including: natural gas reburn, low excess air, reduced air preheat, reducing residence time at peak temperature through injection of steam, fuel reburning, non-thermal plasma reactor, and sorbent in combustion chamber/duct. Commenters argue that these technologies should have been evaluated by EPA, possibly in combination with SCR and SNCR, to determine the maximum degree of NO<sub>x</sub> reduction that can be achieved.

**Response #4.c.(1):** Partially agree. The draft Statement of Basis should have mentioned the Technical Bulletin and discussed the control techniques listed in it. EPA has since prepared that discussion, which is presented below and is included in the final Statement of Basis. As presented below, EPA finds that each of the above-listed control techniques should be eliminated from further discussion as a BACT control option, due to one or more of the following reasons:

- (1) ineffective or physically impossible at the WCFU,
- (2) an inherent part of Deseret's proposed CFB boiler design,
- (3) already proposed for the WCFU, or
- (4) not commercially available.

This discussion therefore does not alter EPA's NO<sub>x</sub> BACT determination for the WCFU. Findings are summarized in the table below, followed by individual explanations.

**RESULTS OF NO<sub>x</sub> CONTROL TECHNOLOGY EVALUATION  
ARISING FROM EPA TECHNICAL BULLETIN**

	Addressed in Statement of Basis	Not Effective or not Physically Possible	Already Proposed to be Included	Not Commercially Available
Natural Gas Reburn	X	X		
Low Excess Air	X		X	
Reduced Air Preheat		X		
Reducing Residence Time		X		
Fuel Reburning	X	X		
Non-Thermal Plasma Reactor				X
Sorbent Injection	X		X	

Introductory discussion of thermal NO<sub>x</sub>: The principal NO<sub>x</sub> formation mechanism, thermal NO<sub>x</sub>, arises from the thermal dissociation and subsequent reaction of nitrogen (N<sub>2</sub>) and oxygen (O<sub>2</sub>) molecules in the combustion air. Most thermal NO<sub>x</sub> forms in the highest temperature regions of the combustion chamber (i.e. the air/fuel interface). Limiting the combustion temperature below 2,800°F is sufficient to limit thermal NO<sub>x</sub>. (Ref #1: R.T. Waibel, *Ultra Low NO<sub>x</sub> Burners for Industrial Process Heaters*, Second International Conference on Combustion Technologies for a Clean Environment. Lisbon, Portugal, July 19-22, 1993. Figure 4, p. 5. Ref #2: IBO Industrial Emissions Control Technology III. Milwaukee, Wisconsin, August 1-3, 2005. p. 14.)

Most of control techniques listed in the table above act on thermal NO<sub>x</sub>. These include natural gas reburn, low excess air, reduced air preheat, reducing residence time, and fuel reburning. The combustion temperature of a CFB boiler, by nature of its design, is much lower than that of a pulverized coal (PC) boiler (1,500°F versus 3,000°F). (Ref: Western Governors Association Technology Working Group Report, undated, page 10.) This lower combustion temperature results in virtually no thermally-generated NO<sub>x</sub>. Because of this, control techniques designed to reduce NO<sub>x</sub> emissions by reducing the combustion temperature, and thus reducing thermal NO<sub>x</sub>, were not considered to have practical potential for application to coal-fired CFB boilers and thus were eliminated as control options at Step 1 of the BACT analysis. EPA explained this on page 31 of the draft Statement of Basis, in regard to Flue Gas Recirculation. Nevertheless, since the above-mentioned control techniques were listed in the EPA Technical Bulletin specifically in regard to CFB units, EPA has prepared the following explanations of why those techniques were eliminated as control options for the WCFU.

Also discussed below are two control techniques that are already proposed to be included for the WCFU, either as an inherent part of the CFB boiler design (low excess air), or as the chosen control option (sorbent injection, a.k.a. Selective Non-Catalytic Reduction). Also discussed are two control techniques that may have practical potential

for application to coal-fired CFB boilers, but are not known to be commercially available for CFB units (non-thermal plasma reactor and carbon injection into the combustion chamber). These techniques have therefore also been eliminated as control options for the proposed WCFU.

Descriptions of individual techniques below were taken from the above-mentioned EPA Technical Bulletin

Natural gas reburn – This is considered to be the same method as generic “fuel reburning,” which was identified by the commenters as a separate control technique. The principles are the same whether the additional fuel reburned is natural gas, fuel oil, or coal. See “Fuel reburning” below.

Low excess air – Excess air flow for combustion has been correlated to the amount of thermal  $\text{NO}_x$  generated. Limiting the net excess air flow to less than 2% can strongly limit  $\text{NO}_x$  content of flue gas at pulverized coal fired boilers. Although there are fuel-rich and fuel-lean zones in the combustion region, the overall net excess air is limited when using this approach.

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

Reducing the amount of excess air may be a valid way to reduce  $\text{NO}_x$  emissions from an older CFB unit with poor combustion controls. However, the unit proposed by Deseret is a new unit with state-of-the-art combustion controls. One of the goals of those controls is to minimize excess air to maximize boiler efficiency. If one were to consider reducing excess air further than the design rate, it would result in increased CO emissions and disrupt the stable operation of the unit. Further, this control technique acts primarily on thermal  $\text{NO}_x$  and therefore, while it may have substantial effect on  $\text{NO}_x$  emissions at pulverized coal fired boilers, it has much less effect on  $\text{NO}_x$  emissions at combustion sources such as CFBs that operate at low combustion temperatures.

This control technique was addressed on page 31 of the Statement of Basis, through EPA’s reference to Table 1.1-2 of AP-42, which indicates it does not have practical potential for application to coal-fired CFB boilers. It has therefore been eliminated at Step 1 of the BACT analysis.

Reduced air preheat – Preheating the combustion air cools the flue gases, reduces the heat losses, and gains efficiency. However, this can raise the temperature of combustion air to a level where  $\text{NO}_x$  forms more readily. By reducing the amount of air preheat, the combustion temperature is lowered and  $\text{NO}_x$  formation is suppressed. However, reducing the amount by which the incoming combustion air is preheated carries a significant efficiency penalty of up to 1% per 40°F. (Ref: above-mentioned EPA Technical Bulletin on  $\text{NO}_x$  control, page 12.) This reduction in efficiency would increase emissions of all criteria pollutants. As mentioned in the “Introductory

discussion of thermal NO<sub>x</sub>”above, the combustion temperature of a CFB boiler, by nature of its design, is much lower than that of a pulverized coal (PC) boiler and results in virtually no thermally-generated NO<sub>x</sub>. Therefore, reduced air preheat is not considered to be an effective NO<sub>x</sub> control option for coal-fired CFB boilers, i.e., it does not have practical potential for application to CFB boilers for NO<sub>x</sub> control. It has therefore been eliminated at Step 1 of the BACT analysis.

Reducing residence time at peak temperature through injection of steam – This control technique involves injection of water or steam, which causes the stoichiometry of the mixture to be changed and adds steam to dilute calories generated by combustion. Both of these actions cause combustion temperature to be lower. If temperature is sufficiently reduced, thermal NO<sub>x</sub> will not be formed in as great a concentration.

In order to control NO<sub>x</sub>, steam is typically injected directly into the flame to reduce the adiabatic flame temperature. In a CFB boiler, this is not physically possible, as combustion occurs throughout the fluidized bed. As with reduced air preheat, injecting steam would reduce boiler efficiency and result in increased emissions of all pollutants.

This control technique is addressed in the introductory discussion of thermal NO<sub>x</sub> above and is not considered to be an effective control option for coal-fired CFB boilers, i.e., it does not have practical potential for application to CFB boilers for NO<sub>x</sub> control. It has therefore been eliminated at Step 1 of the BACT analysis.

Fuel reburning – This control technique consists of recirculation of cooled flue gas with added fuel, similar to Flue Gas Recirculation (FGR) discussed on page 31 of the Statement of Basis. With fuel reburn, calories are diluted and the primary combustion temperature can be lowered. In other words, the peak flame temperature can be lowered through adsorption of the combustion heat by the relatively inert flue gas. As explained in the Statement of Basis, and in the introductory discussion of thermal NO<sub>x</sub> above, this control technique acts on thermal NO<sub>x</sub> and is not considered to be effective on combustion sources such as CFBs that operate at low combustion temperatures. As such, it does not have practical potential for application to CFB boilers for NO<sub>x</sub> control. It has therefore been eliminated at Step 1 of the BACT analysis.

Non-thermal plasma reactor – This control technique involves using methane and hexane as reducing agents. Non-thermal plasma has been shown to remove NO<sub>x</sub> in a laboratory setting with a reactor duct only two feet long. The reducing agents were ionized by a transient high voltage that created a non-thermal plasma. The ionized reducing agents reacted with NO<sub>x</sub> and achieved a 94% destruction efficiency. There are indications that an even higher destruction efficiency can be achieved. A successful commercial vendor uses ammonia as a reducing agent to react with NO<sub>x</sub> in an electron beam generated plasma. Such a short reactor can meet available space requirements for virtually any plant. The non-thermal plasma reactor could also be used without reducing agent to generate ozone and use that ozone to raise the valence of nitrogen for subsequent absorption as nitric acid.

Trinity Consultants investigated the non-thermal plasma reactor as a NO<sub>x</sub> control option and advised Deseret Power that it is not known to be commercially available. (Ref: E-mail from Ed Thatcher, Deseret Power, to Mike Owens, EPA Region 8, November 13, 2006.) Therefore, while this control technique might be considered a technology transfer control option at Step 1 of the BACT analysis, it is eliminated at Step 2 as technically infeasible because it is not known to be commercially available for NO<sub>x</sub> control at CFB boilers.

Sorbent in combustion chamber/duct.—This control technique involves injection of limestone into the combustion zone. Injection of ammonia (Selective Non-Catalytic Reduction) is also already included in the design of the proposed WCFU.

According to the above-mentioned EPA Technical Bulletin on NO<sub>x</sub> control, another version of sorbent injection “uses carbon injected into the air flow to finish the capture of NO<sub>x</sub>. The carbon is captured in either the baghouse or the ESP just like other sorbents.” (Ref: Bulletin at page 19.) Although carbon injection is an emerging technology used to reduce mercury emissions, Deseret Power is not aware of it having been used anywhere to control NO<sub>x</sub>. (Ref: E-mail dated November 13, 2006, from Ed Thatcher of Deseret Power to Mike Owens of EPA Region 8.) EPA is similarly not aware of carbon injection having been used anywhere to control NO<sub>x</sub>. (Ref: Memorandum from Mike Owens of EPA Region 8 to Deseret Bonanza WCFU PSD Permit file, dated August 8, 2007.) Carbon injection for NO<sub>x</sub> control is therefore eliminated at Step 2 of the BACT analysis as technically infeasible because it is not known to be commercially available for that purpose.

In summary, the evaluation and discussion above does not alter EPA’s NO<sub>x</sub> BACT determination of 0.080 lb/MMBtu for the WCFU. Comment #4.c.(1) has not resulted in any change to the permit; however, the Statement of Basis has been revised to include the discussion of potential NO<sub>x</sub> control options above.

**Comment #4.c.(2):** Commenters asserted that while EPA required evaluation of selective catalytic reduction (SCR) on the proposed CFB boiler, SCR was improperly eliminated from the BACT review. First, EPA required evaluation of low temperature SCR, but Deseret apparently found that low temperature SCR was only applied to natural gas applications.

Commenters cited a memorandum from Don Shepherd to John Notar (both in the Air Resources Division at the National Park Service) regarding the NEVCO Energy – Sevier Power – Engineering Analysis, in which Mr. Shepherd stated “[w]hen the question of application of SCR to a CFB was raised at the Pittsburgh workshop [on selective catalytic reduction and non-catalytic reduction for NO<sub>x</sub> control], one consultant stated that he knew of no reason why it could not be done. (In fact, one presenter in Pittsburgh suggested that addition of limestone, as would be inherent in a CFB, is desirable in counteracting the potential catalyst-poisoning effects of arsenic found in many coals).” Commenters argued that the question which should have been posed is whether SCR

could be applied to coal-fired CFB boilers. Commenters cited a statement in EPA's draft 1990 New Source Review Workshop Manual that opportunities for technology transfer must be identified and evaluated in the BACT analysis.

**Response #4.c.(2): Disagree.** EPA's draft Statement of Basis did, in fact, evaluate whether or not SCR could be applied to coal-fired CFB boilers.

With regard to statements from the National Park Service (NPS) about application of SCR to CFBs, the draft Statement of Basis (at page 32) explained that EPA asked Deseret Power to contact SCR vendors, based on NPS information about low-temperature SCR as a possible option. Specifically, Deseret Power was requested to find out if low-temperature SCR is commercially available. The answer was no. The vendors cited by the NPS as possible suppliers of low-temperature SCR informed Deseret Power that they actually provide SCR technology only for natural gas applications, not for coal-fired boilers. EPA concluded that low-temperature SCR is not a technically feasible NO<sub>x</sub> control option for the WCFU, as it is not commercially available to be applied to this project. (Draft Statement of Basis at page 32.)

With regard to step 2 (technical feasibility) of the top-down BACT analysis, two key concepts are important in determining whether an undemonstrated technology is feasible – “availability” and “applicability.” See *Prairie State*, slip op, at 17; *Three Mountain Power*, 10 E.A.D. at 42-43 n.3. A technology is considered “available” if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

The draft Statement of Basis explained that EPA did identify SCR (excluding low-temperature SCR) as a technically feasible control option, and asked Deseret Power to evaluate the possibility of reheating the flue gas downstream of the baghouse to the temperature range known to be effective for SCR use. This evaluation included a detailed cost estimate described in the Statement of Basis. EPA concluded that the economic impacts of reheat, without even considering the higher capital cost of SCR versus SNCR, justified elimination of SCR as a BACT control option. (Draft Statement of Basis, pages 32-35.)

Comment #4.c.(2) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.c.(3):** In a second argument regarding SCR, commenters asserted, “while EPA did require the evaluation of whether the flue gas downstream of the baghouse could be reheated to the temperature range known to be effective for SCR use (650-750 F) (Statement of Basis at 32), EPA should also have required evaluation of reheating the gas stream to the temperature range at which low temperature SCR could be used.” Commenters argued that, according to the Institute of Clean Air Companies, low temperature catalysts can work in the range of 350 – 550 F. (Commenters cited the

ICAC website at <http://www.icac.com/i4a/pages/index.cfm?pageid=3399>, under NO<sub>x</sub> Control Technologies.) Thus, commenters argued, EPA should have required Deseret Power to evaluate heating the gas stream up to 350 F and using low temperature SCR, which would use considerably less fuel than needed to reheat the gas stream to 650 F.

**Response #4.c.(3):** Disagree, for three reasons:

First, EPA explained in the draft Statement of Basis (at page 32), that low-temperature SCR was eliminated as technically infeasible because it is not commercially available to be applied to this project.

Second, EPA's cost analysis for reheat (on pages 34-35 of the draft Statement of Basis) was based on raising the stack temperature to 480F – as supplied by Deseret. This is within the range of 350-550F, as described by the ICAC noted above. Based on the ICAC website cited by commenters, "(i)n clean, low temperature (350-550F) applications, catalysts containing precious metals such as platinum and palladium are useful." EPA described the high cost results for reheat in the draft Statement of Basis (pages 34-35). The high cost results were only for reheat and did not include any of the substantially higher installation costs for SCR versus SNCR. This additional cost would undoubtedly negate any reduction in cost achieved by lowering the temperature threshold from 480 to 350F.

Third, commenters have not come up with any new evidence that low-temperature SCR could work.

Comment #4.c.(3) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.c.(4):** In a third argument regarding SCR, commenters asserted that the presumed emission limit that could be met with SCR should have been lower than 0.04 lb/MMBtu used in the draft Statement of Basis at 33. Commenters stated that EPA did not provide any rationale for this presumed NO<sub>x</sub> emission rate with SCR, except to cite to the level assumed by North Dakota in its BACT analysis for Gascoyne. Commenters argued that EPA should have instead evaluated a NO<sub>x</sub> emission limit based on the maximum degree of emission reduction that can be achieved with SCR. Commenters stated that, according to Babcock & Wilcox, commercial SCR installations have shown that 90% NO<sub>x</sub> reductions can be achieved with low ammonia slip, and that Babcock & Wilcox states that up to 95% NO<sub>x</sub> control can be achieved with SCR. Thus, commenters concluded, considering the NO<sub>x</sub> emission rate without SCR of 0.15 lb/MMBtu, which EPA indicated was an overestimate of NO<sub>x</sub> emissions expected from the Bonanza WCFU (Statement of Basis at 34-35), the appropriate NO<sub>x</sub> emission rate with SCR to evaluate would be at most 0.015 lb/MMBtu rather than the assumed 0.04 lb/MMBtu.

**Response #4.c.(4):** Partially agree. EPA has no definitive evidence that 0.015 lb/MMBtu could be achieved with SCR at the proposed Deseret WCFU. Further, EPA

does not agree that 0.04 lb/MMBtu is not a reasonable presumption for lowest emission rate that could be met with SCR at the Deseret WCFU. Nevertheless, EPA does agree it is conceivable a lower emission rate than 0.04 lb/MMBtu could be met with SCR. Since 90% NO<sub>x</sub> removal from SCR is believed to be achieved at some facilities, and since Deseret Power has not provided more case-specific information for SCR capabilities for its WCFU project, EPA has revised its cost analysis, based on the Babcock & Wilcox information cited by commenters. The revised analysis reflects the possibility that a lower NO<sub>x</sub> emissions rate than 0.04 lb/MMBtu could be achieved with SCR, as detailed in response #4.c.(5) below.

Comment #4.c.(4) has not resulted in any change to the permit; however, the Statement of Basis has been changed, to reflect this revised analysis of SCR described in response #4.c.(5) below.

**Comment #4.c.(5):** Based on the rationale in comments #4.c.(2) through (4) above, commenters asserted that the analysis for SCR must be re-evaluated to consider whether low temperature SCR could work on the Bonanza CFB boiler, either with or without flue gas reheating, and considering a NO<sub>x</sub> emission rate that reflects the maximum degree of emission reduction that can be achieved.

**Response #4.c.(5):** Partially agree. EPA does not agree that the analysis for SCR must be re-evaluated to consider whether low temperature SCR could work. As explained in the Statement of Basis, and as explained in responses #4.c.(2) and (3) above, EPA concluded that low-temperature SCR is not a technically feasible NO<sub>x</sub> control option for the WCFU, as it is not commercially available to be applied to this project.

EPA does agree, however, that the analysis for SCR with flue gas reheating should be revised to reflect a lower NO<sub>x</sub> emissions rate achievable with SCR than 0.04 lb/MMBtu. The revised analysis is below. Most of the text is the same as in the draft Statement of Basis, but with revised cost calculations.

In order to be responsive to the commenters' assertion that 90% NO<sub>x</sub> reduction could be achieved by installation of SCR on the Deseret WCFU, EPA has re-evaluated the cost-effectiveness of reheating the flue gas, in terms of the possibility of achieving a final NO<sub>x</sub> rate of 0.015 lb/MMBtu rather than 0.04 lb/MMBtu. Note that this does not include the other capital and operating costs associated with purchasing, installing, operating, and maintaining the SCR system, so this analysis substantially underestimates the true cost per ton of NO<sub>x</sub> reductions that would be incurred by Deseret, if SCR were applied to this project. The SCR analysis below is a modification to the draft Statement of Basis to reflect the final emission rate of 0.015 lb/MMBtu cited by commenters. In addition, consideration was given to the additional NO<sub>x</sub> emissions generated by distillate fuel combustion when calculating total cost effectiveness, which should have been done in the draft Statement of Basis analysis.

a. **Selective Catalytic Reduction.** As noted above, for SCR to be a technically feasible NO<sub>x</sub> control option for this project, flue gas reheating would be



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

With any SCR installation, there are some commonly noted adverse environmental impacts. These would include ammonia slip emissions, catalyst disposal, and potential ammonia handling hazards. These impacts are usually deemed to be offset by the environmental benefits of significant NO<sub>x</sub> reduction from the SCR system. For example, with the SCR system located downstream of the particulate and SO<sub>2</sub> control devices in order to deal with technical problems associated with a CFB application, there may be additional condensible particulate emissions resulting from the conversion of SO<sub>2</sub> to SO<sub>3</sub> and eventually to H<sub>2</sub>SO<sub>4</sub> over the catalyst bed.

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

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

The difference in emission rates between SNCR and SCR would be 0.065 lb/MMBtu (i.e., 0.08 minus 0.015). Assuming CFB operation at 90% of capacity on an annual average, this difference would be equivalent to a NO<sub>x</sub> reduction of 370 tons per year:

$$(0.08 \text{ lb/MMBtu} - 0.015 \text{ lb/MMBtu}) \times (1,445 \text{ MMBtu/hr}) \times (8,760 \text{ hr/yr}) \times (0.9) \times (1 \text{ ton}/2,000 \text{ lb}) = 370 \text{ tons/year}$$

With distillate reheat, the net NO<sub>x</sub> reduction would be 308 tons per year (i.e., 370 minus 62). With propane reheat, the net NO<sub>x</sub> reduction would be 278 tons per year (i.e., 370 minus 92). These figures are shown in the table below.

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

Pollutant	Distillate Oil Emissions (tons/year)	Propane Emissions (tons/year)
PM (total)	10	3
SO <sub>2</sub>	3	Negligible
NO <sub>x</sub>	62	92
VOC	1	2
CO	16	15

Even without considering reheat cost, the annualized cost of SCR is several times greater than SNCR, due to higher capital and operating costs. (Example: PSD permit application dated August 2005, for South Heart CFB boiler project in North Dakota, calculates the annualized capital recovery cost for SCR to be about six times as much as for SNCR. Ref: Page 4-16 of the permit application, included in the Administrative Record for issuance of the WCFU permit.) As explained above, SCR installed downstream of particulate controls would also involve reheat cost. Deseret Power provided cost figures for only the supplemental fuel that would be required to reheat the flue gas so that SCR could be used. No additional costs were calculated for capital, installation, or operation of the SCR system or capital, installation, and other non-fuel operational costs for the reheat system. Hence, this is a very conservative cost analysis, since as mentioned above, these additional capital, installation and operational costs for the SCR and reheat system would likely be substantial. The lowest-cost option for reheat fuel was calculated to be distillate oil at \$12,411,476 per year, based on 6,205,738 gallons per year at \$2.00 per gallon.

Without any add-on controls, EPA estimates that the CFB boiler should be able to achieve a NO<sub>x</sub> emission rate of about 0.15 lb/MMBtu or lower. (Actual operational data on existing CFB boilers suggests to EPA that this value could be much lower. The 0.15 value was chosen by EPA only as a conservative estimate in doing this cost analysis.) Using this uncontrolled emission rate as a baseline, the total cost effectiveness for the SCR/reheat system only, considering the cost of reheat fuel, is calculated as follows:

Emission reduction going from baseline to SCR controlled emissions:

$$(0.15 \text{ lb/MMBtu} - 0.015 \text{ lb/MMBtu}) \times (1,445 \text{ MMBtu/hr}) \times (8,760 \text{ hr/yr})(0.9) (1 \text{ ton}/2,000 \text{ lb}) = \mathbf{769 \text{ tons/year}}$$

The average cost per ton for NO<sub>x</sub> reductions, considering only distillate fuel costs when considering the additional NO<sub>x</sub> that would be generated by burning distillate fuel:

$$(\$12,411,476 / \text{yr}) / (769 - 62 \text{ ton/yr}) = \mathbf{\$17,555/\text{ton}}$$

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

$$(\$12,411,476 / \text{yr}) / (370 \text{ ton/yr}) = \$33,545 / \text{ton}$$

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

$$(\$12,411,476 / \text{yr}) / (370 - 62 \text{ ton/yr}) = \$40,297 / \text{ton}$$

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

In summary, comment #4.c.(5) has not resulted in any change to the permit, since SCR has still been eliminated for cost reasons; however, the Statement of Basis has been changed to reflect the revised NO<sub>x</sub> analysis for SCR described above.

**Comment #4.c.(6):** Further, commenters asserted, in determining whether the costs for SCR are reasonable, the costs must be compared to the costs other coal-fired electric utility boilers have had to bear for NO<sub>x</sub> control under BACT determinations. Commenters argued that it is not appropriate to compare SCR to the cost of SNCR, which is less effective than SCR in reducing NO<sub>x</sub>.

**Response #4.c.(6): Disagree.** Commenters do not cite specific coal-fired electric utility boilers the Deseret Power WCFU should be compared to, as far as the costs of NO<sub>x</sub> BACT; however, EPA assumes the commenters mean those facilities that have had to bear the costs of installing SCR. To EPA's knowledge, the only coal-fired electric utility boilers that have installed, or will be installing, SCR based on a BACT determination are for pulverized-coal units. Presently, EPA does not know of any CFB boilers that have installed SCR, or that have been required to install SCR, based on a BACT determination, nor have commenters provided any such information.

Determination of whether a control alternative can be eliminated in step four of the top-down BACT analysis involves a demonstration that "circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously." *In re Maui Electric Co.*, 8 E.A.D. 1, 6 (EAB 1998) (internal quotations omitted). Clearly, the fact that Deseret Power's WCFU is a CFB boiler, fired on high-ash waste coal, is a distinguishing feature that creates far different flue gas characteristics and unacceptably high particulate loading to an SCR system that would be installed upstream of the particulate control device, compared to those pulverized coal boilers that have installed SCR systems, or are required to install SCR systems based on a

BACT determination. These differences were explained on page 32 of the draft Statement of Basis.

EPA also disagrees with the commenters' claim that EPA inappropriately compared the cost effectiveness of SCR to SNCR. In step one of the top-down BACT analysis, both the average cost effectiveness of a control option and the incremental cost effectiveness between dominant control options can be calculated. *In re General Motors Inc.*, PSD Appeal No. 01-30, slip op. at 26 (EAB March 6, 2002). While EPA believes it is appropriate to calculate the incremental cost effectiveness of SCR, EPA did not rely on this cost alone. EPA also calculated the average cost effectiveness and found that cost was also high.

In summary, comment #4.c.(6) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.c.(7):** Commenters asserted that if EPA determines that SCR can be eliminated, after revising the BACT review in light of comments above, then its evaluation of SNCR and the associated NO<sub>x</sub> emission limit must be based on the maximum degree of emission reduction achievable with SNCR. Commenters asserted that SNCR should be able to reduce NO<sub>x</sub> emissions by at least 50%, while EPA's proposed 0.080 lb/MMBtu NO<sub>x</sub> emission limit for SNCR reflects a 47% NO<sub>x</sub> reduction. Commenters concluded that a 50% NO<sub>x</sub> reduction with SCNR would equate to an emission limit of 0.075 lb/MMBtu, or even lower, considering that EPA believes the 0.15 lb/MMBtu uncontrolled NO<sub>x</sub> emission rate is an overestimate. (Commenters cited the draft Statement of Basis at 34-35.)

**Response #4.c.(7):** Disagree. EPA believes going from 0.075 to 0.08 is justified in order to provide a margin of compliance, and it is consistent with the BACT limits for other sources listed on page 37 of the draft Statement of Basis. The margin of compliance includes a reasonable safety factor that would permit Deseret to achieve compliance on a consistent basis.

The Environmental Appeals Board has recognized that permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis. (See *In re Three Mountain Power*, 10 E.A.D. 39, 53 (EAB, May 30, 2001) and *In re Masonite Corp.*, 5 E.A.D. 551, 560-61 (EAB 1994). See also *In re Knauf Fiber Glass, GmbH*, 9 E.A.D. 1, 15 (EAB, Mar. 14, 2000). ("There is nothing inherently wrong with setting an emission limitation that takes into account a reasonable safety factor. ...The inclusion of a reasonable safety factor in the emission limitation calculation is a legitimate method of deriving a specific emission limitation that may not be exceeded."))

Comment #4.c.(7) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.c.(8):** Commenters stated that EPA pointed out to Deseret in its July 8, 2005 letter that there are several other proposed CFB boilers using SNCR with proposed NO<sub>x</sub> emission limits of 0.07 lb/MMBtu, including the Estill County Energy Partners Project in Kentucky, the Kentucky Mountain Power Project in Kentucky and the River Hill project in Pennsylvania. As EPA commented to Deseret, the Estill County project is most similar to Bonanza in size and coal quality, and thus Deseret should be able to meet a similar limit at the Bonanza WCFU. Although Deseret later pointed out that no PSD permit had been issued for the Estill County project yet, that does not negate the point that the owners/operators proposed a 0.07 lb/MMBtu NO<sub>x</sub> limit for their facility. Thus the NO<sub>x</sub> BACT analysis for SNCR should be evaluated using a lower NO<sub>x</sub> limit, in the range of 0.07 to 0.075 lb/MMBtu to ensure that the limit reflects the maximum degree of NO<sub>x</sub> reduction that can be achieved.

**Response #4.c.(8):** Disagree. See discussion on page 38 of the draft Statement of Basis for our analysis and consideration of permits with limits of 0.07 lb/MMBtu. The Estill County project was eliminated from consideration because the permit application is no longer being actively processed. No draft permit was issued for the Estill County project and no BACT determination for NO<sub>x</sub> was proposed by the permitting agency.

EPA inadvertently omitted the Kentucky Mountain Power Project (KMPP) from the table on page 37 of the draft Statement of Basis (“Summary of Recent CFB Projects Permitted or Proposed: NO<sub>x</sub> Emission Rates Using SNCR”). EPA has added KMPP in the final Statement of Basis.

The KMPP permit, issued on May 4, 2001, specifies a NO<sub>x</sub> emission limit of 0.07 lb/MMBtu; however, unlike the permit for Deseret’s WCFU, the KMPP permit says, at Section D, Condition 3, “The NO<sub>x</sub> emission limit of 0.07 lb/MMBTU is waived for the specific SNCR optimization study activity as detailed in Condition 2 above not to extend more than 365 days after the initial compliance demonstration. However, the nitrogen oxide emissions rate shall never exceed 0.10 lb/MMBTU, during or after the SNCR optimization study.” (Ref: Page 26 of KMPP permit, available on website at:

<http://www.air.ky.gov/NR/rdonlyres/696A8A04-2F29-4338-AD6A-7F6B29252676/0/Final.pdf>)

By contrast, the permit for Deseret’s WCFU says the final limit is 0.080 lb/MMBtu, with no waiver or provision for raising the limit later. Since Kentucky is willing to waive the initial NO<sub>x</sub> emission limit for up to a year while a study is conducted, and adjust it up to as high as 0.10 lb/MMBtu after the study is conducted, EPA discounts to some degree the significance of KMPP’s initial emission limit of 0.07 lb/MMBtu.

Comment #4.c.(8) has not resulted in any change to the permit; however, the KMPP permit has been added to the above-mentioned table in the Statement of Basis, along with the explanation above on why EPA discounts to some degree the significance of KMPP’s initial emission limit of 0.07 lb/MMBtu.

**Comment #4.c.(9):** Commenters asserted that the draft permit fails to address BACT requirements for NO<sub>x</sub> when Deseret is using “run-of-mine” coal either in lieu of waste coal, or as a blend with waste coal, from the Deserado mine. (Commenters cited condition III.E.2.c. of the draft permit.) As indicated by EPA in correspondence to Deseret Power, BACT needs to be met “for the entire range of operating conditions.” Yet, commenters argued, EPA did not provide any review of BACT or propose any emission limits to address BACT when the Bonanza WCFU is burning the much higher quality coal either wholly or in part. As discussed above, commenters argued, such a BACT limit must be imposed on a 24-hour average basis to ensure the maximum degree of NO<sub>x</sub> emission reduction is required when 100% “run-of-mine” coal is being burned.

**Response #4.c.(9): Disagree.** The authorization to burn run-of-mine coal is not unlimited as implied by commenters, but is restricted in the draft WCFU permit, as follows: Condition III.E.2.b. only allows Deseret Power to burn washed or run-of-mine coal during emergencies when waste coal is not available. For situations other than startup or emergencies, condition III.E.2.c. allows use of run-of-mine coal blended with waste coal in any ratio yielding up to 6,500 Btu/lb heat content. This corresponds to roughly a 50/50 blend. Use of run-of-mine coal for the WCFU, either in lieu of waste coal, or as a blend with waste coal, was evaluated in detail on pages 25-29 of the draft Statement of Basis. The proposed BACT determination for NO<sub>x</sub>, as well as for other pollutants, is based on the proposed fuel restrictions in the draft PSD permit, also laid out on page 29 of the draft Statement of Basis.

In summary, comments #4.c.(1) through (9) have not resulted in any changes to the permit. However, the Statement of Basis has been changed as follows:

(1) Added a list of additional NO<sub>x</sub> control options from the Nov. 1999 EPA Technical Bulletin that were not already addressed in the draft Statement of Basis, along with an explanation of why each option was eliminated in the top-down BACT evaluation for Deseret’s WCFU,

(2) Revised the cost analysis for SCR, to reflect a lower NO<sub>x</sub> emissions rate achievable with SCR than 0.04 lb/MMBtu, and

(3) Added the Kentucky Mountain Power Project to the list of CFB projects with permitted NO<sub>x</sub> emission rates of 0.07 lb/MMBtu, along with an explanation of why EPA discounts to some degree the significance of KMPP’s initial emission limit of 0.07 lb/MMBtu.

#### **4.d -- Total PM/PM<sub>10</sub>:**

**Comment #4.d.(1):** One group of commenters asserted that EPA's proposed emission limit for total PM/PM<sub>10</sub> does not reflect BACT. Commenters noted that EPA has proposed a limit for total PM/PM<sub>10</sub> of 0.03 lb/MMBtu, on a 30-day rolling average. However, commenters argued, as shown in the data provided by EPA in its Statement of Basis, this limit does not reflect the maximum degree of reduction that can be achieved.

Specifically, commenters noted, EPA identifies several other CFB boilers with similar pollution controls as proposed for the Bonanza WCFU with lower total PM/PM<sub>10</sub> limits. (draft Statement of Basis at 57.) Six of the eight CFB boiler permits reviewed by EPA had lower total PM limits than the proposed 0.03 lb/MMBtu. Three of the eight permits reviewed had limits on total PM of 0.012 lb/MMBtu. Commenters argued that EPA readily discounted these emission limits, but without any review of the specific details behind these emission limits (such as how the sources calculated these emission limits). (draft Statement of Basis at 58.)

Commenters further stated that while EPA did not discount the total PM emission limits of the three proposed facilities in Region 8 (Highwood, Gascoyne, and South Heart), which ranged from 0.0232 lb/MMBtu – 0.026 lb/MMBtu, EPA did not ultimately find that the methodology consistently used by these three facilities for calculating condensible PM emissions was appropriate for the Bonanza WCFU and instead allowed Bonanza's overestimate of ammonium sulfate to dictate the level of the total PM BACT limit. (draft Statement of Basis at 55-56.)

**Response #4.d.(1): Disagree.** EPA's calculated estimate is consistent with other projects cited in the draft Statement of Basis, not with Deseret's original calculation. As explained in the draft Statement of Basis, EPA found that Deseret's calculations of condensible emissions were not consistent with other permit applicants. "Consequently, EPA did a mass balance calculation that assumed all of the ammonia slip coming out of the CFB combustor unit (i.e., immediately downstream of SNCR controls) would react with sulfuric acid to form ammonium sulfate. This would occur upstream of the dry scrubber and baghouse. EPA also assumed 85% control of ammonium sulfate by the dry scrubber and baghouse. *These assumptions were consistent with analyses in permit applications reviewed by EPA for other CFB boiler projects.* EPA's calculation yielded an emission estimate of 0.0036 lb/MMBtu for ammonium sulfate. This was about one-fifth of Deseret Power's estimated emission range of 0.014 to 0.0209 lb/MMBtu." (emphasis added) (draft Statement of Basis at 56)

Federal PSD rules at 40 CFR 52.21 pertaining to BACT determination do not require EPA to review the specific details of how emission limits were calculated at other facilities. The other facilities (listed on pages 57-58 of the draft Statement of Basis) are only somewhat similar to the proposed WCFU. As explained in the Statement of Basis, in selecting an initial limit of 0.03 lb/MMBtu for total PM/PM<sub>10</sub> at the WCFU (including condensible PM), EPA relied to a large extent on its own emission calculations specific to the WCFU, for individual components of condensible PM.

Comment #4.d.(1) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.d.(2):** Commenters further alleged that the actual stack test data for similar sources are lower than EPA's proposed total PM BACT limit, with results ranging from 0.004 lb/MMBtu to 0.023 lb/MMBtu using EPA Method 202. (draft Statement of Basis at 59.) Thus, commenters argued, the majority of the data provided by EPA in its draft Statement of Basis indicate that its proposed total PM/PM<sub>10</sub> BACT limit does not reflect the maximum degree of emission reduction that can be achieved as required by the definition of BACT. While EPA's proposed 0.03 lb/MMBtu emission limit incorporates a "margin of safety," the margin of safety is too lenient.

**Response #4.d.(2): Disagree.** The draft Statement of Basis (at page 59) actually refers to 0.03 lb/MMBtu as "an initial emission limit that EPA believes can reasonably be achieved (with appropriate margin of compliance)..." EPA does not consider the margin in this case to be too lenient. EPA's rationale for proposing an initial permit limit of 0.03 lb/MMBtu is explained in great detail on pages 54-64 of the draft Statement of Basis.

As explained in the draft Statement of Basis, EPA did evaluate stack testing data from other facilities, but there are minimal data on condensible PM emissions from CFB units, and no data for CFBs burning bituminous waste coal. The proposed permit limit of 0.03 lb/MMBtu is largely based on emission calculations that are specific to Deseret Power's proposed WCFU, as described on page 56 of the draft Statement of Basis. No numerical margin of compliance was incorporated into the calculation of 0.03 lb/MMBtu as an initial limit. Rather, EPA considers the "margin of compliance" to be the ability to revise the limit upward, to no more than 0.045 lb/MMBtu, if stack testing results show that a limit of 0.03 lb/MMBtu is not achievable.

Although EPA is establishing a total PM/PM<sub>10</sub> emissions limit in the final WCFU permit that includes condensible PM consistent with the draft permit, we must note that EPA has recently acknowledged the concerns regarding the availability and implementation of test methods for condensible PM. As a result of these concerns, EPA's recent PM<sub>2.5</sub> implementation rule for State Implementation Plans has adopted a transition period during which EPA will assess possible revisions to available test methods and allow time for States to update emissions inventories. 72 Fed. Reg. 20586, 20650 (Apr. 25, 2007). EPA is currently considering whether it should also establish a similar transition period in its forthcoming PM<sub>2.5</sub> implementation rule for the New Source Review permitting program. Notwithstanding this ongoing assessment, EPA has decided to retain the proposed total PM/PM<sub>10</sub> emissions limit to accommodate the request of the permit applicant that we not allow that rulemaking action to delay the completion of this permit.

Comment #4.d.(2) has not resulted in any change to the permit or Statement of Basis.



**Comment #4.d.(3):** In addition, commenters asserted, due to the deficiencies in EPA's 0.03 lb/MMBtu BACT determination for total PM/PM<sub>10</sub>, the permit must not allow for an even further relaxation of this limit up to 0.045 lb/MMBtu. Commenters said this upper bound limit is unjustified as BACT.

**Response #4.d.(3):** Disagree. As explained on pages 58-64 of the draft Statement of Basis, due to the inherent uncertainty with setting a limit for total PM/PM<sub>10</sub> that includes condensible PM at a CFB unit burning bituminous waste coal, EPA believes that 0.045 lb/MMBtu is an appropriate upper bound for possible adjustment of the limit. In describing its engineering calculation to estimate the amount of condensible PM that would be emitted from the WCFU, EPA pointed out the uncertainties in the calculation, due to the complexities in the chemical reactions taking place from fuel combustion. (draft Statement of Basis at 57.) As also explained in the draft Statement of Basis, there are only minimal stack test data for somewhat similar projects.

EPA believes the provision to adjust the limit upward later, to no more than 0.045 lb/MMBtu, pending EPA review of stack test results, is warranted and consistent with EPA's approach in other similar situations (e.g., AES Puerto Rico, cited on page 63 of the draft Statement of Basis and cited again below).

Comment #4.d.(3) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.d.(4):** Commenters asserted that if Deseret Power obtains stack test data indicating that the total PM/PM<sub>10</sub> BACT limit cannot reasonably be complied with, EPA can propose a revised total PM<sub>10</sub> limit at a later time. Such a revised limit must be subject to public review and opportunity for comment.

**Response #4.d.(4):** Disagree. As explained on pages 54-64 of the draft Statement of Basis, EPA proposed an initial emission limit for total PM/PM<sub>10</sub> of 0.03 lb/MMBtu, including condensible PM, based on EPA emission calculations specific to the proposed WCFU, as well as based on limited stack testing data for somewhat similar facilities. As mentioned in response #4.d.(3) above, EPA explained in the draft Statement of Basis the inherent uncertainty with setting a limit for total PM/PM<sub>10</sub> that includes condensible PM at a CFB unit burning bituminous waste coal, due to the complexities in the chemical reactions taking place from fuel combustion. (draft Statement of Basis at 57.)

The Environmental Appeals Board (EAB) has recognized that "use of an adjustable limit, constrained by certain parameters, and backed by a worst case air quality analysis, is a reasonable approach." *In re AES Puerto Rico*, 8 EAD 324, 349 (1999).

As explained on page 63 of the draft Statement of Basis, EPA proposed to allow in the permit that the limit could be adjusted upward, to no more than 0.045 lb/MMBtu, pending EPA review of stack test results at the WCFU. This sets an upper bound on the possible adjustment. EPA stated in the draft permit itself that "[b]ecause condensible

particulate matter emissions from CFB boilers have not been widely quantified, there is a possibility that the actual condensible portion of particulate matter would cause the emission limit of total PM/PM<sub>10</sub> to be exceeded. In the event the Permittee cannot meet that limit because of condensible particulate matter, EPA may adjust the emission limit to a level not to exceed 0.045 lb/MMBtu, pending EPA's review of stack test results at the CFB boiler." (draft WCFU permit at page 7.) The range of possible emission limits is therefore constrained between 0.03 lb/MMBtu and 0.045 lb/MMBtu, and was subject to public review and comment.

As listed on page 128 of the draft Statement of Basis, the WCFU emission rate of total PM/PM<sub>10</sub> used for modeling of ambient air quality impact was 9.47 grams per second. This rate is equivalent to 0.052 lb/MMBtu multiplied by the WCFU maximum design heat input capacity of 1,445 MMBtu/hr. Even if the BACT limit of 0.03 lb/MMBtu is adjusted to the upper bound in the draft permit of 0.045 lb/MMBtu, the limit is still lower than the emission rate used for modeling. Therefore, the range of 0.03 to 0.045 lb/MMBtu is backed by a worst case air quality analysis, and at the upper bound of 0.045 lb/MMBtu, the NAAQS and PSD increment will still be protected.

In summary, EPA believes that the possible future adjustment of the total PM/PM<sub>10</sub> emission limit, within the parameters specified in the permit, is a "reasonable approach" as recognized by the EAB. The range of possible adjustment was subject to public review and opportunity for comment, therefore does not require additional public review and opportunity for comment later. Comment #4.d.(4) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.d.(5):** Commenters concluded that until such time as the limit is revised, the evidence provided by EPA indicates that the proposed total PM/PM<sub>10</sub> BACT limit is too high.

**Response #4.d.(5):** Disagree, as explained on pages 54-64 of the draft Statement of Basis, and as explained in responses #4.d.(1) through #4.d.(3) above. Comment #4.d.(5) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.d.(6):** Commenters further stated that the draft WCFU permit also fails to address BACT requirements when Deseret **Power** is using "run-of-mine" coal either in lieu of waste coal, or as a blend with waste coal, from the Deserado mine (as allowed by Condition III.E.2.c. of the draft permit). As indicated by EPA in correspondence to Deseret Power, BACT needs to be met "for the entire range of operating conditions." (Ref: April 7, 2006 e-mail from Mike Owens, EPA Region 8, to Ed Thatcher, Deseret Power.) Yet, commenters said, EPA did not provide any review of BACT or propose any emission limits to address BACT when the Bonanza WCFU is burning the much higher quality coal either wholly or in part. Commenters argued that, as discussed above, such a BACT limit must be imposed on a 24-hour average basis to ensure the maximum degree of PM emission reduction is required when 100% "run-of-mine" coal is being burned.

**Response #4.d.(6): Disagree.** See draft Statement of Basis at page 64: “As explained earlier in this Statement of Basis, for the proposed WCFU, Deseret Power will be permitted to use coal from their Deserado mine, consisting of either waste coal alone, or else a blend of waste coal and ROM coal yielding heat content of up to 6,500 Btu/lb. For reasons explained above, EPA believes the proposed BACT emission limit of 0.03 lb/MMBtu on a rolling 30-day average, for total PM/PM<sub>10</sub>, will represent BACT for coal from the Deserado mine with heat content of up to at least 6,500 Btu/lb, and will ensure a continued high degree of PM emission control efficiency.” Comment #4.d.(6) has not resulted in any change to the permit or Statement of Basis.

In summary, comments #4.d.(1) through (6) have not resulted in any changes to the permit or Statement of Basis.

#### **4.e -- Visible Emissions:**

**Comment #4.e:** A group of commenters asserted that EPA failed to evaluate and impose a BACT limit for visible emissions (VE), and that the BACT analysis for the Bonanza WCFU must include a visible emission limit reflective of BACT for the source.

Commenters argued that the definition of BACT at 40 CFR 52.21(b)(12) specifically indicates that BACT includes a “visible emission limitation.” Commenters noted that in the draft Statement of Basis, EPA indicated that, because EPA is proposing use of a PM continuous emission monitoring system (CEMS), “EPA does not consider it necessary to also propose an opacity limit as part of BACT for total filterable particulate.” (draft Statement of Basis at 47.) Commenters argued that EPA’s reasoning is flawed for several reasons, described in comments #4.e.(1) through (5) below:

**Comment #4.e.(1):** Commenters argued that the definition of BACT in the Clean Air Act and associated federal regulations specifically mandate that BACT include a visible emission (or opacity) limitation. There are no exemptions provided for in the statutory or regulatory definition. Thus, commenters concluded, EPA is without legal authority to decide not to impose an opacity limit because it is requiring PM CEMS for the PM limit.

**Response #4.e.(1): Disagree.** EPA does not view the phrase “visible emission standard,” in the BACT definition at 40 CFR 52.21(b)(12), as an emission limit that all PSD permittees must meet, nor as implying that a visible emission (VE) and/or opacity limit must be included in all PSD permits. However, while these limits are not required under BACT, permitting authorities have the discretion to include them in PSD permits in order to ensure compliance with BACT emission limitations.

In fact, the Circuit Court of Appeals for the District of Columbia (DC Circuit) found that visible emission limitations were properly included in PSD permits as “one such means of measuring and limiting emissions” under BACT, but stated that “EPA’s inclusion of visible emission standards (among others) to be used to determine compliance with BACT sets no single standard that all PSD permittees must meet.” *Alabama Power v. Costle*, 636 F.2d 323, 408 (D.C. Cir. 1979) (emphasis added). Instead, the DC Circuit found that permitting authorities “may exercise reasonable discretion” to include opacity/VE limits in BACT for a particular facility. *Id.* at 409. The Environmental Appeals Board has also found that such limits are not a requirement of PSD program permitting. *See Knauf Fiber Glass*, 8 E.A.D. 121, 172 (1999) (finding that opacity limits are “not a requirement of the federal PSD program”).

Accordingly, in order to avoid confusion regarding the opacity limit contained in the “PSD BACT Emission Limits” section of the permit, EPA notes that the opacity limit is included for demonstrating continued proper operation and maintenance of the materials handling baghouses, not because it is required under BACT. The permit title section III.D has been amended to indicate the section includes limits in addition to BACT.

Comment #4.e.(1) has not resulted in any substantive change to the permit or Statement of Basis.

**Comment #4.e.(2):** Commenters argued that the Particulate Matter Continuous Emission Monitoring System (PM CEMS), required by the draft permit, will only measure filterable particulate matter, while opacity measures all particulate matter that may block the transmission of light exiting the stack including condensible particulate matter. While compliance with the total particulate matter limit must be demonstrated on a rolling 30-day average basis at the Bonanza WCFU (Condition III.D.1.a. of the draft permit), this compliance determination will be based on a once-per-year stack test of the total PM emission rate (Condition III.I.4.b of the draft permit). Commenters concluded that an opacity limit that can be continuously monitored will provide a much needed additional assurance that the total particulate matter emission limits are being complied with continuously.

**Response #4.e.(2): Disagree.** While it is true that PM CEMS only measures filterable particulate matter, EPA believes that opacity monitoring at Deseret Power's WCFU, as an addition to requiring a PM CEMS calibrated according to 40 CFR 60, Appendix B, Performance Specification 11, would be ineffective for assuring compliance with emission limits for either filterable PM or total PM.

Opacity monitoring can be useful as a surrogate for direct measurement of particulate emissions. However, EPA does not consider it useful for assuring compliance with PM emission limits where those limits are extremely low. The proposed emission limit for Deseret Power's WCFU for total PM/PM<sub>10</sub> is 0.03 lb/MMBtu. This limit is based on a filterable PM/PM<sub>10</sub> emission limit of 0.012 lb/MMBtu, added to projected emissions of no more than 0.018 lb/MMBtu for condensable PM. These emission limits are so low that EPA believes it highly improbable, if not impossible, that any form of existing opacity monitor could reliably detect opacity at levels that would correspond to these limits. Moreover, given the sensitivity of the PM CEMS, elevated emissions would be detected by PM CEMS well in advance of detection via a Continuous Opacity Monitoring System (COMS), or via a Method 9 or Method 22 visible emissions observation. Further, opacity only provides data from a subset of all particles, namely those particles whose size is roughly the same wavelength as visible light.

A status report prepared for EPA on PM CEMS, dated February 12, 1997 (available at <http://www.epa.gov/ttn/emc/cem.html>, labeled on website as "PM CEMS Demo. Test, Status Report 4 (Adobe format)," with website posting date of 7/31/97) in support of proposed revised regulations for hazardous waste combustors (HWC), states (in the Introduction, as quoted below) that opacity monitors are insensitive at filterable PM concentrations below 45 mg/dscm. For coal combustion, this is equivalent to about 0.04 lb/MMBtu. (The proposed total PM/PM<sub>10</sub> emission limit for Deseret Power's WCFU, cited above, is lower than this.) The Introduction states:

*EPA in the past has relied on opacity monitors as a form of surrogate-PM monitoring to indicate compliance with a PM standard. This approach involved a continuous opacity monitor to demonstrate compliance with a separately-enforceable opacity limit approximately aligned with, or near, the PM emission limit. However, this approach has a serious limitation relative to the proposed HWC rule, because of poor correlation between opacity and PM at low PM concentrations near the proposed PM emission limit of 69 mg/dscm (at 7 % O<sub>2</sub>).*

*EPA recognizes that there are two inherent problems with the opacity/PM approach: 1) the general concern about the stability of any opacity/PM correlation, which is strongly dependent on particle size distribution and composition, and 2) the specific concern about the insensitivity of opacity monitors typically below PM levels of about 45 mg/dscm (at 7 % O<sub>2</sub>).*

*Consequently, opacity monitors would not be sufficient because to maintain compliance with 69 mg/dscm, facilities would generally need to operate near 35 mg/dscm. Thus, emissions would typically be below the detection limits of opacity monitors most of the time. While normal emission levels below the detection limits of CEMS are acceptable, facilities often desire the detection limit to be one-tenth of the emission limit. This gives sufficient warning of how emissions are changing before the emission limit is approached, and allows the facility, based on CEMS readings, to change operations as necessary to be in compliance.*

*If possible, EPA desires a quantitative, continuous measure of PM mass concentrations rather than opacity. Based on surveys and preliminary testing, EPA has recently determined that CEMS do exist that do this: beta gauges and light scattering based CEMS. These CEMS rely on calibration/certification of the device by manual gravimetric measurements. Therefore, EPA is proposing use of CEMS based on the availability of these newer technologies and a related Draft CEMS Performance Specification for monitoring PM mass concentration. EPA believes that such monitoring is feasible and that opacity monitoring has borderline sensitivity relative to the proposed PM emission limit. The newer technology PM CEMS can give a real-time quantitative measure of low PM concentrations while opacity monitors cannot.*

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

This same reasoning is reflected in the recent revisions to Subpart Da of New Source Performance standards (40 CFR 60). The revised Subpart Da exempts facilities from ongoing opacity monitoring where PM CEMS is installed and used.

Further, the proposed emission control technique for condensable PM at Deseret Power's WCFU is a combination of alkali injection, dry SO<sub>2</sub> scrubbing and a fabric filter baghouse. (Draft Statement of Basis at 50.) Each of these control techniques will be

installed and used to comply with other emission limits in the permit (alkali injection for NO<sub>x</sub> control, dry SO<sub>2</sub> scrubbing for SO<sub>2</sub> control, and a fabric filter baghouse for filterable PM control). The permit requires compliance with these three other emission limits to be tracked continuously via CEMS. (Draft WCFU permit at pages 16-17, conditions III.I.4.a and III.I.4.c.) This continuous monitoring, in addition to annual stack tests required in the permit for condensable PM, is considered by EPA to be sufficient for ensuring good control of the both the condensable PM portion and the filterable PM portion of total PM. EPA does not agree with commenters that opacity monitoring “will provide a much needed additional assurance that the total particulate matter emission limits are being complied with continuously.”

In summary, comment #4.e.(2) has not resulted in any change to the permit. However, the Statement of Basis has been revised to include the expanded explanation above on why EPA does not consider an opacity limit or opacity monitoring to be necessary at the WCFU.

**Comment #4.e.(3):** Commenters argued that a limitation on visible emissions serves as an indicator of proper operation and maintenance (O&M) of all pollution control equipment.

**Response #4.e.(3):** Disagree. EPA recognizes that opacity monitoring can be useful as an indicator of proper baghouse O&M; however, as explained in response #4.e.(2), the proposed emission control technique for condensable PM at Deseret Power’s WCFU is a combination of alkali injection, dry SO<sub>2</sub> scrubbing and a fabric filter baghouse, not just a baghouse. EPA considers CEMS for NO<sub>x</sub>, SO<sub>2</sub> and PM to be far more useful than opacity monitoring for ensuring good control of condensable PM at Deseret Power’s WCFU. Further, the fact that opacity monitoring can be useful as an indicator of proper baghouse O&M does not mean it is necessarily useful for ensuring compliance with PM emission limits. As explained in response #4.e.(2), in this case EPA does not believe it is useful. Comment #4.e.(3) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.e.(4):** Commenters argued that compliance with both the filterable and total PM/PM<sub>10</sub> limits is based on a rolling 30-day average basis, whereas compliance with opacity BACT limits are based on a six-minute averaging time. Thus, commenters concluded, the 30-day rolling average filterable PM limit measured with PM CEMS is not an adequate replacement for a six-minute average opacity BACT limit.

**Response #4.e.(4):** Disagree. See responses #4.e.(2) and #4.e.(3).

**Comment #4.e.(5):** Commenters argued that with a fabric filter baghouse for PM<sub>10</sub> control, an opacity BACT limit should be “at least 10%.” Commenters noted that the recently permitted Sevier CFB power plant in Utah is subject to a 10% visible emissions limit. The River Hill Power Company proposed CFB power plant in Pennsylvania is also subject to a 10% opacity limit. Similarly, the Gascoyne CFB facility in North Dakota will also be subject to a 10% opacity BACT limit. Commenters also

noted that the permit for the Longview power plant in West Virginia, which will utilize a pulverized coal boiler, requires PM CEMS and imposes a 10% opacity BACT limit.

**Response #4.e.(5):** Disagree. Commenters have not presented any evidence that a 10% opacity limit would have any correlation with the proposed total PM/M<sub>10</sub> emission limit of 0.03 lb/MMBtu for Deseret Power's WCFU. Further, as explained in response #4.e.(2), EPA believes it highly improbable, if not impossible, that any form of existing opacity monitor could reliably detect opacity at levels that would correspond to PM emission rates as low as 0.03 lb/MMBtu. EPA has also found there is poor correlation between opacity and PM at such low PM concentrations. Comment #4.e.(5) has not resulted in any change to the permit or Statement of Basis.

**Comment #4.e.(6):** Commenters concluded that EPA must include an evaluation of opacity BACT in its Statement of Basis and must impose a visible emission limit on the Bonanza WCFU that reflects the maximum degree of reduction achievable. Further, to ensure compliance on a continuous basis, commenters concluded that a continuous opacity monitoring system (COMS) must be required.

**Response #4.e.(6):** Disagree. See responses #4.e.(1) through (5) above.

In summary, comments #4.e.(1) through (6) have not resulted in any change to the permit. However, the Statement of Basis has been revised, to include the expanded explanation provided in response #4.e.(2), on why EPA does not consider it necessary to impose an opacity limit or opacity monitoring at the WCFU.



## **5. MEETING BACT LIMITS ON A CONTINUOUS BASIS AND MEETING ENFORCEABILITY CRITERIA**

### **Comment #5:**

One group of commenters stated that all BACT limits must be met on a continuous basis and must meet enforceability criteria, but that the draft Bonanza WCFU permit does not adequately address EPA requirements for including such provisions.

### **5.a – Meeting BACT Limits on a Continuous Basis:**

**Comment #5.a.(1):** Commenters cited from the draft 1990 NSR Workshop Manual that "BACT emission limits or conditions must be met on a continual basis at all levels of operation (e.g., limits written in lb/MMBtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds per hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements)." (NSR Workshop Manual at B.56). Commenters argued that EPA did not propose BACT limits consistent with these criteria.

Specifically, commenters argued, with respect to all of the emission limits, there must be pound per hour emission caps established, in addition to lb/MMBtu limits, that must be reflective of BACT and consistent with what is modeled to show compliance with the NAAQS, PSD increments, and air quality related values. Commenters stated the NSR Workshop Manual indicates that it is best to express emission limits in two different ways, "with one value serving as an emissions cap (e.g., lb/hr) and the other ensuring continuous compliance at any operating capacity (e.g., lb/MMBtu)." (NSR Workshop Manual at H.5. See also *In re Steel Dynamics, Inc.*, PSD Appeal Nos. 99-4 & 99-5, Decided June 22, 2000, at 220-225.)

Commenters noted that EPA only proposed BACT limits in terms of lb/MMBtu, and EPA did not evaluate or propose BACT limits in terms of lb/hr. While EPA did propose lb/hr "modeling limits" for SO<sub>2</sub> and total PM<sub>10</sub> (Section G. of the draft permit), commenters stated that these modeling limits are not reflective of BACT for the Bonanza WCFU. Commenters argued that at full heat input capacity, the 3-hour average 872 lb/hr SO<sub>2</sub> modeling limit is equivalent to 0.6 lb/MMBtu, which would be only 87% SO<sub>2</sub> removal from worst case uncontrolled SO<sub>2</sub> emissions. The 24-hour total PM<sub>10</sub> modeling limit of 75.4 lb/hr is equivalent to 0.052 lb/MMBtu at full heat input capacity – which, commenters noted, is greater than the maximum level EPA has proposed the total PM<sub>10</sub> limit could be raised to. Commenters concluded that these modeling limits clearly do not reflect BACT for these pollutants. Commenters also asserted that EPA failed to propose BACT limits in terms of lb/hr for NO<sub>x</sub>, CO, or H<sub>2</sub>SO<sub>4</sub>.

Further, commenters argued, the averaging time of the BACT emission limits must be "of a short-term nature" and must be consistent with the averaging time of the short term NAAQS and PSD increments, including a 24-hour averaging time for PM<sub>10</sub>

limits, an 8-hour averaging time for CO limits, and an 8-hour averaging time for VOC limits, as well as the 24-hour averaging time for the pollutants modeled in the visibility modeling. (NSR Workshop Manual at H.5.) Yet, commenters stated, EPA's proposed lb/MMBtu BACT limits for SO<sub>2</sub>, NO<sub>x</sub>, CO, and PM<sub>10</sub> for the Bonanza WCFU are all based on rolling 30-day averages. Commenters concluded that, while EPA has proposed short term average emission limits for SO<sub>2</sub> and PM<sub>10</sub> as modeling limits, these limits are not reflective of BACT for these pollutants.

**Response #5.a.(1): Partially disagree.** EPA agrees that a shorter-term limit than rolling 30-day should be specified for filterable PM. As discussed below, EPA has changed the averaging time to daily in the final permit.

EPA does not agree, however, that emission limitations for purposes of PSD increment protection and NAAQS protection (such as the lb/hr limits that EPA included in the draft permit, labeled "modeling limits") have to reflect BACT, nor that BACT limits must always include lb/hr limits and correspond to all averaging times of the PSD increments and NAAQS. As explained below in response #5.a.(2), EPA included Federally enforceable "modeling limits" in the draft permit specifically for ensuring compliance with the NAAQS and increments under 40 CFR 52.21(k). The rolling 30-day emission limits in lb/MMBtu in the draft permit reflect BACT, pursuant to 40 CFR 52.21(j)(3). As explained in detail on pages 30 through 90 of the draft Statement of Basis, for each pollutant for which a BACT determination is required by PSD rules, the BACT emission limit in lb/MMBtu for the WCFU was set at a level sufficiently stringent to reflect optimal emission control performance on a continual basis.

The "modeling limits" for the WCFU were established under different provisions of PSD rules than the BACT limits. As explained on page 138 of the draft Statement of Basis, "EPA interprets the PSD rules at 40 CFR 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 or 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." [emphasis added; citation in the draft Statement of Basis should have been to §52.21(j)(3); this typographical error was corrected in the final Statement of Basis.]

EPA has proposed modeling limits in lb/hr corresponding to the emission rates assumed in dispersion modeling for cumulative ambient impacts of the proposed WCFU and all existing emitting units in the vicinity of the project. (The only exception is NO<sub>x</sub>, for which, as explained in the draft Statement of Basis, EPA determined that the BACT limit could also serve as a modeling limit, without need to propose a separate modeling limit for NO<sub>x</sub> in lb/hr.)

These modeling limits are enforceable emission limits in the permit, and were established based on worst-case operating scenarios used for dispersion modeling. For example, the modeling limits for 3-hour and 24-hour SO<sub>2</sub> are based on a cold startup,

which is the worst-case SO<sub>2</sub> emission scenario that might be expected, not optimal emission control performance on a continual basis. This worst-case scenario is described on page 138 of the draft Statement of Basis and was the scenario used for dispersion modeling for demonstrating PSD increment protection and NAAQS protection.

Although the permit does not list any lb/hr emission limits as BACT limits, the lb/MMBtu BACT limits in the permit, when multiplied by the maximum heat input capacity of the CFB boiler, are mathematically equivalent to lb/hr values. The draft WCFU permit says, on page 5, that the “Approved Installation” includes “One circulating fluidized bed boiler, *maximum heat input capacity not to exceed 1,445 MMBtu/hr*, designed for firing on waste coal.” [emphasis added] As stated above, the lb/MMBtu limits in the permit were set at a level sufficiently stringent to reflect optimal emission control performance on a continual basis.

Furthermore, during periods of low boiler load, lb/hr emission caps would not necessarily reflect BACT. In a letter to Deseret Power dated June 22, 2005 (included in the Administrative Record for issuance of the WCFU permit), EPA questioned whether the lb/hr emission caps proposed by Deseret Power for startup/shutdown (i.e., during periods of low boiler load) could be justified as BACT, in terms of optimal use of the emission control equipment. The emission cap approach was ultimately not used in the permit for startup/shutdown periods. Instead, the permit states, at condition III.I.1, that the BACT emission limits (all expressed in lb/MMBtu) apply at all times, including periods of startup/shutdown.

Contrary to the conclusion implied by commenters, the Steel Dynamics EAB decision does not say PSD permits must include both emission caps (e.g., lb/hr limits) and production-based limits (e.g., lb/MMBtu). Instead, the EAB decision says, on page 225, that the Indiana Department of Environmental Management (IDEM) “...is ordered to explain why the limits it imposed are in lbs/hr (rather than in lbs/hr *and* lbs/ton, or lbs/ton alone), in particular explaining in detail the specific differences (if any) between SDI’s proposed mill and the fifteen polled mills that would justify exclusive lbs/hr limits for CO and NO<sub>x</sub>.” The EAB decision does not preclude the possibility that production-based limits alone, absent lb/hr limits, could constitute BACT.

The Steel Dynamics decision involves considerations specific to the batch-type nature of the steelmaking process, which, as explained in the decision, could warrant lb/hr limits as BACT in some cases. Deseret Power’s proposed WCFU is an electric utility generating unit designed to run continuously, not a batch-type operation. PSD rules define BACT as a case-by-case determination. The considerations in the BACT determination for the WCFU are different than for a batch-type steelmaking process, and affect whether or not lb/hr limits are warranted as part of BACT.

EPA Region 8’s comments on state permit actions are consistent with the statements above that modeling limits in lb/hr don’t necessarily have to reflect BACT, nor that BACT limits must always include lb/hr limits and correspond to all averaging

times of the PSD increments and NAAQS. In commenting to Montana on the draft PSD permit for the Roundup coal-fired electric utility project, EPA Region 8 wrote:

*Currently the draft permit only contains SO<sub>2</sub> emission limitations on a 30-day rolling average. This approach may be acceptable only if modeling for protection of the short-term NAAQS and PSD increments was based on worst-case hourly SO<sub>2</sub> emissions, rather than on the 30-day emission limitations in the draft permit. At a minimum, we believe the permit action should either establish short-term emission limits in the permit itself, or justify that worst-case hourly SO<sub>2</sub> emission limits have been modeled for protection of short-term NAAQS and PSD increments.*

(Ref: Letter from Richard R. Long, EPA Region 8, to Steve Welch, Montana Department of Environmental Quality, December 18, 2002, page 6; emphasis added.)

The letter on Roundup does not say or imply that short-term emission limitations must reflect BACT, but only that short-term limits must be imposed as necessary in the permit to validate the assumptions used in dispersion modeling.

Similarly, in an EPA guideline document, on SO<sub>2</sub> emission limitations in State Implementation Plans (SIPs), the stated purpose of short-term emission limitations is the protection of ambient standards. The document does not say or imply that short-term emission limitations must also reflect BACT:

*The EPA policy regarding averaging periods for SO<sub>2</sub> SIP emission limitations is to require enforceable limits that protect the short-term (3-hour and 24-hour) NAAQS as well as the annual NAAQS. These emission limitations must be protective with maximum emission scenarios and worst-case meteorological conditions. ... The EPA will not approve an SO<sub>2</sub> SIP with emission limitations based on 30-day averaging, unless the SIP also contains short-term limits established by an approved dispersion modeling analysis. This point is especially important for SO<sub>2</sub> sources that are complying with an NSPS (e.g., subpart Da). Although subpart Da allows 30-day averaging, parameters for evaluating the control system on a short-term basis must also be established for compliance with the NAAQS and PSD increments.*

(Ref: "SO<sub>2</sub> Guideline Document," EPA-452/R-94-008, February 1994, page 6-14, available online at: <http://nepis.epa.gov/pubtitleOAR.htm>.)

Similarly, a 1986 letter signed by EPA's Assistant Administrator for Air and Radiation, regarding SO<sub>2</sub> SIPs, states the same purpose for short-term emission limitations:

*EPA has had a long standing policy to require emission limitations to be enforceable on a short-term basis to protect the short-term standard.*

(Ref: Letter from J. Craig Potter, Assistant Administrator for Air and Radiation, US EPA, to Nancy Maloley, Commissioner, Indiana Department of Environmental Management, May 23, 1986, page 1, included in the Administrative Record for issuance of the WCFU permit.)

Again, there is no statement that such limitations must also reflect BACT.

Similarly, a 1986 EPA memorandum states the following:

*The PSD regulations clearly require that the application of BACT conform with any applicable standard of performance under 40 CFR Part 60 at a minimum. However, this should not be taken to supercede any additional limitations as needed to enable the source to demonstrate compliance with the NAAQS and PSD increments. In the case of sulfur dioxide (SO<sub>2</sub>), source compliance with the 30-day rolling average emission limit under subpart D(a) does not adequately demonstrate compliance with the short-term NAAQS and PSD increments.*

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

<http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/shrterm.pdf>

Again, the stated purpose of the short-term emission limitations is the protection of short-term ambient standards. There is no statement that such limitations must also reflect BACT.

With regard to the statement in the 1986 EPA memorandum that “the application of BACT conform with any applicable standard of performance under 40 CFR part 60 at a minimum,” EPA notes that the averaging times of the proposed BACT emission limits for the WCFU conform with those in 40 CFR 60, subpart Da, with the exception of filterable PM/PM<sub>10</sub>, for which the draft WCFU permit specifies a 30-day rolling average, whereas Subpart Da specifies a daily average. To conform with 40 CFR part 60, subpart Da, EPA believes it is necessary to change the averaging time of the BACT limit to daily.

In summary, EPA believes the draft permit for the WCFU includes all short-term (lb/hr) emission limitations that are necessary to protect ambient standards, to the extent required by Federal rules at 40 CFR 52.21(k). EPA also believes the draft permit contains all emission limits necessary to satisfy BACT, as required by Federal rules at 40 CFR 52.21(j)(3), with the exception that EPA believes the averaging time of the BACT limit for filterable PM/PM<sub>10</sub> should be changed from 30-day rolling to daily, to conform with 40 CFR 60 subpart Da. Therefore, to the extent that commenters suggest shorter-term limits are needed than those in the draft permit, EPA agrees with commenters with regard to PM/PM<sub>10</sub>.

The final permit reflects this change. Instead of 0.012 lb/MMBtu on a 30-day rolling average, the limit in the final permit is 0.012 lb/MMBtu on a daily average. Monitoring, reporting and recordkeeping requirements in the permit have been changed accordingly. Since this limit is no more stringent than filterable PM/PM<sub>10</sub> limits at some other new coal-fired projects (e.g., Utah permit (“Approval Order”) dated October 15, 2004, for construction of Intermountain Power Unit 3, included in the Administrative Record for issuance of the WCFU permit), EPA believes it is achievable by Deseret Power. The Statement of Basis has been revised accordingly, to reflect a daily average (i.e., a 24-hour block average from midnight to midnight) rather than a 30-day rolling average. Comment #5.a.(1) has resulted in these changes to the permit and Statement of Basis.

**Comment #5.a.(2):** Commenters noted that EPA’s Statement of Basis explains that the lb/hr emission rates used in the modeling analyses reflect short term emission peaks from startups. (draft Statement of Basis at 135.) Commenters asserted that EPA “admitted” that the proposed BACT limits for SO<sub>2</sub> and PM<sub>10</sub> do not adequately limit short term emissions for compliance with the NAAQS and PSD increments because the BACT limits are based on 30-day rolling averages. (draft Statement of Basis at 136.) Yet, commenters stated, “as acknowledged by EPA in the Statement of Basis,” BACT emission limits must be met on a continuous basis, and there are to be no exemptions for startup and shutdown. (draft Statement of Basis at 23.)

In particular, commenters stated, EPA noted in its draft Statement of Basis that the NSR Workshop Manual states (at page B.56) “BACT emission limits or conditions must be met on a continual basis *at all levels of operation.*” [emphasis added by commenters] Yet, commenters argued, EPA’s proposed BACT limits violate these principles and essentially provide for startup and shutdown exemptions from BACT by providing such long averaging times for the BACT emission limits.

**Response #5.a.(2):** Disagree. First, EPA included “modeling limits” in the permit, as a separate set of limits from the BACT emission limits, specifically for ensuring compliance with the NAAQS and PSD increments. (draft Statement of Basis at 138-139). Second, the draft permit does not allow any exemptions from either the BACT limits or the modeling limits for startup/shutdown periods. Section III.I.1 of the draft permit states that “The PSD BACT emission limits in this permit, as well as the modeling limits, *apply at all times, including periods of startup, shutdown and malfunction.*” [emphasis added] Moreover, the requirements in the permit for continuous monitoring of emissions of particulate matter, SO<sub>2</sub>, NO<sub>x</sub> and CO, and accompanying averaging times, are consistent with the concept of continuous compliance identified by the commenters.

As demonstrated by the detailed discussion in the draft Statement of Basis of the BACT determination for each pollutant, the 30-day limits have been set at levels sufficiently stringent as to not allow under-utilization of control equipment. Setting a stringent 30-day limit that applies at all times creates an incentive for the source to limit its duration of startup, shutdown, and malfunction periods in order to preserve any margin of compliance the source might be operating under.

In summary, EPA believes the proposed 30-day average BACT limits (and the limit for filterable PM/PM<sub>10</sub>, on a daily average in the final permit), in conjunction with continuous emission monitoring, are consistent with the EPA policy that BACT applies at all times and must be met at all levels of operation. EPA also believes that inclusion of modeling limits in the draft permit adequately addresses the commenters' concern about NAAQS and PSD increment protection. Comment #5.a.(2) has not resulted in any change to the permit or Statement of Basis.

**Comment #5.a.(3):** Commenters further argued that EPA's failure to propose shorter averaging time emission limits reflective of BACT is inconsistent with recently issued permits for coal-fired power plants. Commenters cited the Roundup power plant permit issued by the state of Montana as requiring 24-hour average BACT limits for NO<sub>x</sub> and SO<sub>2</sub>, and also a 1-hour BACT limit for SO<sub>2</sub>. Commenters also cited the Sevier power plant permit issued by the state of Utah as including rolling 24-hour average BACT limits for SO<sub>2</sub>, NO<sub>x</sub>, PM<sub>10</sub>, and H<sub>2</sub>SO<sub>4</sub>. Commenters also cited the Longview power plant permit issued by the state of West Virginia as including a 3-hour average SO<sub>2</sub> BACT limit, 24-hour average NO<sub>x</sub> and SO<sub>2</sub> BACT limits, a 6-hour average PM<sub>10</sub> BACT limit and a 3-hour average H<sub>2</sub>SO<sub>4</sub> BACT limit.

Commenters concluded that for all of the above reasons, EPA must revise its proposed BACT limits for the Bonanza WCFU to require shorter averaging times consistent with the NAAQS, PSD increments, and air quality related values standards and to also set lb/hr emission limits reflective of BACT, with compliance being monitored by continuous emission monitoring systems as proposed by EPA for SO<sub>2</sub>, NO<sub>x</sub>, and PM.

**Response #5.a.(3): Disagree.** Commenters appear to be suggesting that EPA is bound by state permitting decisions; however, as EPA stated in response #2.b above, state PSD permit actions are not binding on EPA and do not establish irrefutable precedence for EPA PSD permit actions. Further, by rule, BACT is a case-by-case determination. There may be case-specific reasons why certain permits contain different averaging times for their BACT limits. Although EPA has changed the filterable PM/PM<sub>10</sub> limit from 30-day rolling average to daily average in the final permit, EPA has done so to conform with 40 CFR 60, subpart Da, not on the basis that EPA is bound by the averaging times in state permits.

As explained in response #5.a.(1), EPA's December 18, 2002 comment letter on the draft Roundup permit did not say the permit must include BACT limits corresponding to all averaging times of the PSD increments and NAAQS. Instead, the letter said only that there should either be short-term emission limits in the permit itself, or else the State should justify that worst-case hourly SO<sub>2</sub> emission limits have been modeled for protection of short-term NAAQS and PSD increments. In the case of the WCFU permit, EPA has chosen to establish modeling limits to reflect the worst-case short-term emission rates assumed in dispersion modeling, for demonstration of short-term NAAQS and PSD increment protection.

EPA also disagrees with the comment that there should be a short-term emission limitation for VOC. Estimated potential emissions of VOC from the proposed project are 32 tons per year, below the PSD significance threshold. (draft Statement of Basis at 14.) A demonstration of NAAQS protection is not required where the estimated potential emissions of a pollutant (or precursor, in this case, VOC as a precursor of ozone) are below significance threshold. (draft Statement of Basis at 119) A BACT analysis is also not required. (draft Statement of Basis at 24)

EPA also disagrees with the comment that there should be a short-term emission limitation for CO. Since short-term emission limitations are generally used to protect PSD increments and NAAQS, and since there are no Class I or II increments for CO in PSD rules, the only applicable ambient standard that must be considered in response to comment #5.a.(3) is the CO NAAQS. While estimated potential emissions of CO from the proposed project are above the PSD significance threshold, the modeling results for ambient impacts from the proposed project were only 3.3% of the one-hour NAAQS for CO, and only 11.9% of the eight-hour NAAQS for CO. Because of these very low results in comparison to the NAAQS, and because modeling was based on “worst-case” startup emissions, EPA did not consider it necessary to include a lb/hr emission limit for CO in the permit. Since there is no Class I or II increment for CO in PSD rules, the only applicable ambient standard is the NAAQS.

Comment #5.a.(3) has not resulted in any change in the permit or Statement of Basis.



## **5.b – Meeting Enforceability Criteria:**

**Comment #5.b.(1):** Commenters asserted that the permit must also specify appropriate compliance methods and recordkeeping requirements to show compliance with the short-term emission limits in comment 5.a. above. As discussed in the NSR Workshop Manual, "the construction permit should state how compliance with each limitation will be determined." (NSR Workshop Manual at H.6.). Commenters stated that the test methods must provide for continuous compliance where feasible. Commenters argued that when compliance with BACT emission limits is determined over a 30-day averaging period – even if monitored with continuous emission monitoring systems (CEMS), this does not ensure continuous compliance.

**Response #5.b.(1): Disagree.** Commenters have presented no basis for the implied claim that the permit fails to specify continuous compliance test methods where feasible. Continuous Emission Monitoring Systems (CEMSs) have been specified in the permit, at the CFB boiler stack, for every PSD pollutant where feasible. This includes CEMSs for particulate matter, SO<sub>2</sub>, NO<sub>x</sub> and CO. Commenters also have presented no basis for the claim that use of CEMS does not ensure continuous compliance with 30-day average limits. The draft permit contains detailed requirements for testing of the accuracy of the CEMS for each pollutant, as well as quality assurance requirements, recordkeeping requirements, and reporting requirements. This includes quarterly reporting on the performance of the CEMSs. (Draft permit at pages 21-27.)

Comment #5.b.(1) has not resulted in any change to the permit or Statement of Basis.

**Comment #5.b.(2):** Commenters also alleged that the draft permit for the Bonanza WCFU lacks proper recordkeeping for some of the conditions of the permit:

First, EPA must require Deseret to maintain records of all weekly Method 22 visible emissions (VE) evaluations of the unenclosed coal and limestone stockpiles required by Condition III.F.3. of the draft permit, in addition to maintaining records of all Method 9 opacity observations (per Condition III.I.8.c. of the draft permit).

Second, regarding the monitoring of coal quality and sulfur content, EPA must require that heat content and sulfur content be tested and recorded on a daily basis for all coal used (i.e., washed or "run-of-mine" coal used during "emergencies" or in whole or blended in part during other times). This is necessary for comparison to a percent SO<sub>2</sub> removal requirement, which commenters contend is necessary to ensure BACT is met over the wide variety of coal quality and sulfur content that will be used in the Bonanza WCFU.

**Response #5.b.(2): Partially agree.** Commenters appear to be suggesting that the permit fails to require the above-mentioned recordkeeping. EPA finds that commenters are correct on the first point (Method 22 VE evaluations), but not on the second point (heat content and sulfur content of coal).

Regarding the first point, EPA agrees with commenters that language should be added to permit condition III.I.8.c, to require that records be kept of the weekly Method 22 visible emission evaluations required by condition III.F.3. EPA acknowledges that without recordkeeping, the requirement to conduct weekly Method 22 evaluations would not be enforceable as a practical matter. EPA added this recordkeeping requirement to condition III.I.8.c. in the final permit.

Regarding the second point, EPA disagrees with commenters' apparent assertion that the draft permit fails to require daily records of heat content and sulfur content of coal, for all coal used. To the contrary, permit condition III.K.6 requires that records be kept of "all measurements of coal sulfur content and heat content required by this permit." Permit condition III.J.2 states that "The as-fired coal shall be tested each boiler operating day for sulfur content and heat content." The term "boiler operating day" is defined in permit condition III.D to mean "a 24-hour period between 12 midnight and the following midnight period during which any fuel is combusted at any time in the steam generating unit" (i.e., the CFB boiler). Therefore, contrary to commenters' apparent assertion, the permit does, in fact, require that heat content and sulfur content of the coal be tested and recorded on a daily basis for all coal used.

Comment #5.b.(2) has resulted in the addition of a requirement to permit condition III.I.8.c, that records be kept of the weekly Method 22 visible emission evaluations required by condition III.F.3.

## **6. EPA ADJUSTMENTS TO DESERET'S MODELING ANALYSIS**

### **Comment #6:**

One group of commenters argued that EPA must present its adjustments to Deseret's modeling analysis and provide opportunity to comment on the results. Commenters noted that in its draft Statement of Basis, EPA indicated that Deseret Power improperly determined the maximum short term SO<sub>2</sub> emission rates expected from the Bonanza WCFU that were used in the modeling analyses. (draft Statement of Basis at 135.) EPA re-calculated worst case short term SO<sub>2</sub> emission rates based on data provided by Deseret, and found "[w]hen 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." However, commenters asserted, EPA did not provide the results of its dispersion modeling analysis with the higher worst case short term SO<sub>2</sub> emission limits to the public for review and comment.

Commenters further stated that EPA's revised 3-hour average SO<sub>2</sub> emission rate is almost six times greater than the 3-hour SO<sub>2</sub> emission rate modeled in Deseret's analyses, and the 24-hour average SO<sub>2</sub> emissions rate is close to 40% higher than what Deseret modeled. Commenters noted that Deseret accepted EPA's revised short term SO<sub>2</sub> emission rates as an amendment to its PSD permit application. Commenters argued that these increased emission rates should have been taken into account in estimating the significant impact area of the Bonanza WCFU (which, in turn, would be used to determine which sources should have been included in cumulative NAAQS and increment analyses), and also in determining whether preconstruction monitoring and/or cumulative PSD increment analyses should have been done.

Commenters further alleged that it is not clear whether EPA determined that, cumulatively with other sources in the region, the NAAQS and PSD Class I and II increments would not be exceeded with EPA's recalculated worst case SO<sub>2</sub> emission rates. Thus, commenters argued, EPA must present its revised modeling so the public can understand the true scope of short term average SO<sub>2</sub> impacts from the Bonanza WCFU and so that the public can ensure all CAA requirements will be complied with.

### **Response #6:**

Partially agree. EPA does not agree that revised modeling must be done. No new modeling runs are necessary to account for EPA's adjustments to the modeling inputs for 3-hour and 24-hour SO<sub>2</sub>. Emissions and concentrations are directly proportional in this type of model, so EPA simply scaled up the modeling results generated by Deseret's consultants to estimate local-scale impacts if worst case short term emission limits (i.e., the "Modeling Limits" in the permit) are ever reached.

As explained on pages 137-138 of the draft Statement of Basis ("EPA adjustments to permit applicant's modeling analysis"), EPA found that Deseret Power's assumed worst-case 3-hour average emission rate for SO<sub>2</sub>, for modeling purposes, should have

been 872 lb/hr rather than 147 lb/hr, to account for a cold startup. EPA similarly found that Deseret Power's assumed worst-case 24-hour average emission rate for SO<sub>2</sub>, for modeling purposes, should have been 202 lb/hr rather than 147 lb/hr. In evaluating the effect of these worst case emissions for modeling, EPA multiplied the WCFU's contribution to the modeling results shown on pages 130-134 of the draft Statement of Basis by a factor of  $[872/147 = 5.93]$  for 3 hour SO<sub>2</sub>, and by a factor of  $[202/147 = 1.37]$  for 24 hour average SO<sub>2</sub>. The corrected worst-case SO<sub>2</sub> emission rates for the WCFU (872 lb/hr on a 3-hour average and 202 lb/hr on a 24-hour average) are included as "Modeling Limits" in the draft WCFU permit. Modeling results still show compliance with the NAAQS and PSD increments for SO<sub>2</sub>.

EPA does agree, however, that it should be made clear in the Statement of Basis how the corrected 3-hour and 24-hour WCFU emission rates are reflected in the modeling results. EPA has therefore scaled up the WCFU's contribution to the 3-hour and 24-hour SO<sub>2</sub> modeling results, in the following tables, on pages 161 through 164 of the Statement of Basis:

"NAAQS Compliance Demonstration for WCFU Project Sources"  
"NAAQS Compliance Demonstration for Full Impact Area Sources"  
"PSD Class II Increment Compliance for WCFU Sources (Near-field Analysis)"  
"PSD Class II Increment Compliance for Full Impact Area Sources"

By "scale up," EPA means the modeling results in micrograms per cubic meter (ug/m<sup>3</sup>) for the WCFU are multiplied by the factors mentioned above, which are 5.93 for 3-hour SO<sub>2</sub> and 1.37 for 24-hour SO<sub>2</sub>, to reflect the worst-case short-term SO<sub>2</sub> emission scenario at the WCFU. Explanations have also been included in the Statement of Basis as to why these changes to the modeling results tables have been made.

EPA has also corrected the WCFU emission rates for 3-hour and 24-hour SO<sub>2</sub> in the Statement of Basis table titled, "ISC3 WCFU Stack Input Parameters Used for Modeling." EPA has also included the corrected WCFU emission rates in a PSD Class I increment compliance screening analysis, described in Response #9 below and added to the Statement of Basis.

EPA also agrees that its revision to Deseret's SO<sub>2</sub> emissions estimate for the WCFU should be taken into account in estimating the significant impact area of the WCFU. In Deseret's original analysis, the Class II significant impact area for SO<sub>2</sub> was a 16-kilometer radius from the proposed WCFU. Deseret added 50 kilometers to the impact area radius and looked for other increment affecting sources within 66 kilometers of the proposed WCFU. Other than Bonanza Unit 1, there were no other sources in the 66-kilometer radius impact area. The revised emission estimate for the WCFU would expand the impact area somewhat, but there are no additional large SO<sub>2</sub> sources near the edge of the 66-kilometer impact area. (This area is very remote.) At distances exceeding 66 kilometers, it would take a huge source to materially affect increment concentrations and there are none that large within at least 100 kilometers of the proposed WCFU. This additional explanation will be added to the final Statement-of-Basis.

In summary, Comment #6 has not resulted in any change to the permit; however, the changes described above have been made to the WCFU stack parameter table and to the modeling results tables in the Statement of Basis. Additional changes to the modeling results tables, to account for higher 3-hour and 24-hour SO<sub>2</sub> emission rates at Bonanza Unit 1 (140 g/sec and 106 g/sec, respectively), and to account for a 29% increase in SO<sub>2</sub> emissions at Unit 1 since 1991-93, are described in Responses #7 and #8.b. below, respectively.

## **7. CUMULATIVE NAAQS/INCREMENT ANALYSIS FOR SULFUR DIOXIDE**

### **Comment #7:**

One group of commenters asserted that Deseret's cumulative SO<sub>2</sub> NAAQS and Class II PSD increment analysis is flawed because the 2002 SO<sub>2</sub> emission rate modeled for Bonanza Unit 1 is much lower than the peak short term SO<sub>2</sub> emission rate for this unit in 2002. Specifically, commenters stated, Deseret assumed an SO<sub>2</sub> emission rate, purportedly based on 2002 actual emissions, of 56.30 grams per second (g/s). However, commenters stated, a review of the 2002 SO<sub>2</sub> emission data for Bonanza Unit 1 on EPA's Clean Air Markets Database indicates that the maximum three-hour average SO<sub>2</sub> emission rate was 126 g/s (1000 lb/hr) and the maximum 24-hour average SO<sub>2</sub> emission rate was 115.9 g/s (920 lb/hr).

Thus, commenters argued, Deseret Power underestimated Bonanza Unit 1's impacts on the short term average SO<sub>2</sub> NAAQS and increment. Commenters concluded that the NAAQS and increment analyses must be revised to model the highest 3-hour and 24-hour average emission rate of Bonanza Unit 1, as well as to model the EPA adjusted worst case 3-hour and 24-hour average SO<sub>2</sub> emission rates expected from the Bonanza WCFU. Commenters also asserted that the peak 3-hour and 24-hour SO<sub>2</sub> emission rates of Bonanza Unit 1 must be used in the cumulative Class I SO<sub>2</sub> increment modeling that is required. (See related comment #9 below.)

### **Response #7:**

Partially agree. EPA does not agree that the modeling is flawed. Deseret Power conducted additional PSD increment analysis, in response to EPA comments that Bonanza Unit 1 SO<sub>2</sub> emission rates appeared to be too low for use in modeling PSD short term increments. (Ref: EPA letters to Deseret dated November 22 and 29, 2004, and Deseret's response letter to EPA dated March 23, 2005, all included in the Administrative Record for issuance of the WCFU permit.)

Specifically, Deseret Power re-modeled for PSD Class I SO<sub>2</sub> increment consumption at the nearest state-classified Class I area (Dinosaur National Monument in Colorado) using the maximum actual emission rates for Bonanza Unit 1 from the 2001-2002 period (140 g/sec for 3-hour increment and 106 g/sec for 24-hour increment). (Note: Dinosaur is not a mandatory Federal Class I area, but is classified as Class I by the State of Colorado.) The results are summarized in Deseret Power's March 23, 2005 letter to EPA. As explained in Response #9 below, EPA has conducted a separate screening analysis for impact on mandatory Federal Class I areas, which are somewhat more distant (Arches, Canyonlands and Capitol Reef National Parks).

The results of these analyses show that cumulative impacts of the proposed WCFU and existing Bonanza Unit 1 do not threaten the PSD Class I increment at Dinosaur and the impacts are expected to be even smaller at other more distant Class I areas. Deseret Power stated that no continuous emission monitoring system (CEMS) data

for startup/shutdown/ malfunction were excluded in determining the corrected maximum 3-hour and 24-hour emission rates from Bonanza Unit 1 used as inputs for the revised modeling. (Ref: E-mail dated November 13, 2006, from Ed Thatcher of Deseret Power to Mike Owens of EPA Region 8.)

EPA does agree, however, that the corrected 3-hour and 24-hour peak emission rates for Bonanza Unit 1 and the revised modeling analysis, as reported by Deseret Power to EPA on March 23, 2005, as well as revised modeling results to account for worst-case 3-hour and 24-hour SO<sub>2</sub> emission rates at the WCFU, should be reflected in the modeling results tables in the Statement of Basis. Revisions to those tables to account for the worst-case 3-hour and 24-hour emission rates at the WCFU are described in Response #6 above. Additional revisions, to account for the higher 3-hour and 24-hour emission rates at Unit 1, have been made to the following modeling results tables, on pages 162 and 164 of the Statement of Basis:

“NAAQS Compliance Demonstration for Full Impact Area Sources”  
“PSD Class II Increment Compliance for Full Impact Area Sources”

In addition, the 3-hour and 24-hour SO<sub>2</sub> emission rates for Bonanza Unit 1 have been revised in the table titled, “Bonanza Unit 1 Stack Parameters Used for Modeling.” Further, a reference to Deseret Power’s March 23, 2005 Class I increment analysis for Dinosaur National Monument has been added to the Statement of Basis.

In summary, Comment #7 has not resulted in any change to the permit; however, the changes described above have been made to the Statement of Basis.

Additional changes to the modeling results tables in the Statement of Basis, to account for worst-case 3-hour and 24-hour SO<sub>2</sub> emission rates at the WCFU, and to account for a 29% increase in SO<sub>2</sub> emissions at Unit 1 since 1991-93, are described in Responses #6 and #8.b, respectively.

## 8. PRE-APPLICATION AMBIENT MONITORING FOR SULFUR DIOXIDE

### **Comment #8:**

**Comment #8.a:** One group of commenters stated that it appears that Deseret should not have been exempted from one year of pre-construction ambient monitoring for SO<sub>2</sub>. Commenters asserted that although the PSD permit application shows that the SO<sub>2</sub> impacts from the Bonanza WCFU would be less than the monitoring significance levels, this modeling was based on Deseret's flawed approach of estimating worst case short term emission rates.

Commenters noted that Deseret Power's worst case SO<sub>2</sub> emission rate modeled was 146.99 lb/hr. (draft Statement of Basis at 135.) EPA's recalculated worst case 24-hour average SO<sub>2</sub> emission rate was 201.9 lb/hr. Multiplying Deseret Power's original 24-hour maximum near field modeling result of 10.8 ug/m<sup>3</sup> for SO<sub>2</sub> (as provided in the Statement of Basis at 128) by the ratio of the revised worst case short term emission rate to the originally modeled worst case SO<sub>2</sub> emission rate, results in a maximum 24-hour average SO<sub>2</sub> ambient concentration of 14.8 ug/m<sup>3</sup>. This exceeds the 24-hour SO<sub>2</sub> monitoring significance level of 13 ug/m<sup>3</sup>. Thus, commenters argue, it appears that Deseret should have conducted one year of pre-application ambient monitoring for SO<sub>2</sub>. Consequently, commenters asserted, EPA must delay issuing the permit until this data is collected.

**Response #8.a:** Disagree. There is no reason to require one year of pre-construction ambient SO<sub>2</sub> monitoring, if representative ambient SO<sub>2</sub> concentration data are already available. Ambient SO<sub>2</sub> air quality monitoring data are available from the plant site for the period 1991-1993. These data are considered by EPA to be representative, since the data were collected on site, and there were no other major sources of SO<sub>2</sub> in the area then, and none have been added since that time. The data were collected in accordance with EPA's PSD monitoring guidelines

EPA's ambient monitoring guidelines for PSD list the following three criteria that must be met, for pre-construction monitoring data to be considered representative of pre-construction ambient air quality for PSD purposes

- Section 2.4.1 - Monitor location;
- Section 2.4.2 - Data Quality [the guideline says the data should be of similar quality as would be obtained if the applicant monitored according to the PSD requirements]; and
- Section 2.4.3 - Currentness of the data [the guideline says the data should be current, which generally means, for the pre-construction phase, the data must have been collected in the 3-year period preceding the permit application, provided the data are still representative of current conditions].



(Ref: Pages 6 through 9 of EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87- 007 (May 1987), available through website at: <http://www.epa.gov/ttnamti1/files/ambient/criteria/reldocs/4-87-007.pdf> )

The Environmental Appeals Board (EAB) has also recognized that the permitting authority may allow for representative data gathered from other time periods. (*See In re Encogen Cogeneration Facility*, 8 EAD 244, 255-257 (1999); *In re Hawaii Electric Light Co.*, 8 EAD 66, 97 (1998); *In re Kawaihae Cogeneration Project*, 7 EAD 107, 128 (1997).)

The first criterion above was met because the 1991-93 ambient data were collected on-site (Ref: November 1, 2004 PSD permit application, volume titled "Dispersion Modeling, Deposition and Visibility Analyses," page 3-3, included in the Administrative Record for issuance of the WCFU permit.)

The second criterion above was met because all of the data were collected in compliance with the quality assurance provisions in EPA's above-mentioned ambient monitoring guidelines. (Ref: E-mail from Ed Thatcher, Deseret Power, to Mike Owens, EPA Region 8, dated November 9, 2006, included in the Administrative Record for issuance of the WCFU permit.)

The third criterion above was met because, although the data were not collected within a three-year period preceding the PSD permit application, the data are considered representative because there have been no substantive emission changes in the vicinity of the proposed project since the 1991-93 period. Emission changes at Bonanza Unit 1 since 1991-93 have been accounted for as described in the remainder of this response.

In summary, comment #8.a has not resulted in any change in the permit; however, an expanded explanation has been included in the Statement of Basis, on why Deseret Power is exempt from pre-construction ambient monitoring for SO<sub>2</sub>.

**Comment #8.b:** As mentioned in comment #6 above, EPA re-calculated maximum short term SO<sub>2</sub> emission rates but, according to commenters, did not present the results of its revised modeling analyses. Commenters noted that, considering the emissions rate is all that would be changed in the revised modeling, one can simply adjust the results proportionately based on the EPA's revised emission rate as compared to Deseret's modeled SO<sub>2</sub> emission rate.

**Response #8.b:** Agree. EPA inadvertently failed to revise the modeling results tables in the draft Statement of Basis to account for EPA's re-calculation of maximum (worst case) short term SO<sub>2</sub> emission rates at the WCFU. The tables have been revised in the Statement of Basis.

When re-evaluating the modeling in response to comments, EPA found, however, that Deseret used ambient air quality data from the Bonanza site for 1991-1993 for determining ambient background concentrations, but failed to consider the effect of

potential growth in Bonanza Unit 1 emissions since that time. (Ref: November 13, 2006 e-mail from Deseret Power to EPA, included in the Administrative Record for issuance of the WCFU permit.)

To consider the effect of Unit 1 emission changes, EPA's AirData base was reviewed by Deseret Power and emissions, in tons per year for Uintah County, for SO<sub>2</sub>, NO<sub>x</sub>, CO, PM<sub>10</sub>, and VOC were obtained for 1990 and 2001. These data are presented below. Based on Table 1, emissions of CO, NO<sub>x</sub>, and VOC have decreased; SO<sub>2</sub> and PM<sub>10</sub> emissions have increased by 27.3 and 7.6%, respectively.

**Table 1. Criteria Pollutant Emissions for Uintah County for 1990 and 2001**

<b>Pollutant</b>	<b>1990 (tons)</b>	<b>2001 (tons)</b>	<b>Change (tons)</b>
CO	33,530	28,597	- 4,933
NO <sub>x</sub>	10,110	8,991	- 1,119
SO <sub>2</sub>	1,029	1,416	+ 389
VOC	5,818	2,952	- 2,866
PM <sub>10</sub>	8,958	9,690	+ 732

Ref: November 1, 2006 e-mail from Deseret Power to EPA.

As noted above, the background values used did not account for the relatively small increase in Bonanza Unit I SO<sub>2</sub> emissions since 1993. The background concentrations used to determine National Ambient Air Quality Standards (NAAQS) compliance in Deseret Power's PSD permit application are listed in Table 2.

**Table 2. Background Concentration Values**

<b>Pollutant</b>	<b>Averaging Period</b>	<b>Concentration (µg/m<sup>3</sup>)</b>
SO <sub>2</sub>	3-hour	20
SO <sub>2</sub>	24-hour	10
SO <sub>2</sub>	Annual	5
NO <sub>2</sub>	Annual	5
PM <sub>10</sub>	24-hour	10
PM <sub>10</sub>	Annual	28
CO	1-hour	1 ppm
CO	8-hour	1 ppm

SO<sub>2</sub> emissions from Bonanza Unit 1 from 1991 through 1993, and 1994 through 2005, were reviewed to determine the percent increase over the period. The average SO<sub>2</sub> emissions from Unit 1, in tons, from 1991 – 1993 was 774; the average SO<sub>2</sub> emissions from Unit 1 from 1994 – 2005 was 1000.7. This represents a 29% emission increase from 1991 to 2005. (Ref: November 1, 2006 e-mail from Deseret Power to EPA.)

If we assume a 29% increase in the measured ambient SO<sub>2</sub> data collected at the Bonanza Power Plant from 1991 – 1993 (to account for the 29% emissions increase) and scale up the background concentrations used for the NAAQS compliance demonstration

by 29%, the resultant three-hour, 24-hour, and annual SO<sub>2</sub> background concentrations would be 25.8 µg/m<sup>3</sup>, 12.9 µg/m<sup>3</sup>, and 6.5 µg/m<sup>3</sup>, respectively. Adding to this the highest modeled maximum SO<sub>2</sub> concentrations, from both the proposed WCFU and Bonanza Unit 1, based on 1993 meteorological data, the predicted ambient concentrations for the 3-hour, 24-hour, and annual averaging periods are 27.3%, 7.6% and 9.6% of the NAAQS, respectively.

In summary, comment #8 has not resulted in any change to the permit; however, the following modeling results tables, on pages 161 and 163 of the Statement of Basis, have been changed, to reflect the revised results for background concentrations, accounting for a 29% increase in Bonanza Unit 1 SO<sub>2</sub> emissions since 1991-93:

“NAAQS Compliance Demonstration for WCFU Project Sources”

“NAAQS Compliance Demonstration for Full Impact Area Sources”

Additional changes to the modeling results tables, to account for account for worst-case 3-hour and 24-hour SO<sub>2</sub> emission rates at the WCFU, and to account for higher 3-hour and 24-hour emission rates at Bonanza Unit 1, are described in Responses #6 and #7 above, respectively.

## **9. CUMULATIVE PSD INCREMENT ANALYSIS FOR CLASS I AREAS (AND FOR COLORADO CLASS I AREAS)**

### **Comment #9:**

One group of commenters asserted that Deseret Power failed to provide any cumulative PSD increment analysis for any affected Class I area in its permit application for the Bonanza WCFU, and that neither Deseret Power's PSD permit application, nor EPA's draft Statement of Basis, explains why cumulative increment analyses were not completed for Class I areas. Commenters asserted that PSD permitting regulations indicate that no PSD permit can be issued unless the source demonstrates that it will not cause *or contribute to* a violation of any PSD increment. 40 CFR 52.21(k)(2). Commenters argued that since Deseret has not made that demonstration, EPA cannot issue the permit.

Commenters postulated that one possible reason Deseret did not perform any cumulative Class I PSD increment analyses might be because Deseret considers the impacts of the Bonanza WCFU to be less than significance levels. (Commenters cited the Class I area impact tables on pages 4-21 through 4-28 of the dispersion modeling portion of Deseret's November 2004 PSD permit application, which identify the Bonanza WCFU's impact at each Class I area in terms of "Percent of EPA Class I Significance Levels.") However, commenters stated, there are no Class I area significance levels authorized in any federal regulation. While EPA proposed use of such Class I significant impact levels in July of 1996, EPA never finalized promulgation of those significant impact levels. Thus, commenters concluded, until EPA adopts significant impact levels for Class I increments, *any* impact must warrant a cumulative analysis.

Moreover, commenters argued, even if use of proposed but never finalized significant impact levels were appropriate to exempt the Bonanza WCFU from a cumulative increment analysis in affected Class I areas, cumulative SO<sub>2</sub> increment analyses would be required because the SO<sub>2</sub> impacts of the Bonanza WCFU would be greater than the proposed Class I significant impact levels for SO<sub>2</sub> in several Class I areas as follows:

Commenters argued that Deseret Power's modeling showed that its impact on the Colorado portion of Dinosaur National Monument would be greater than the SO<sub>2</sub> 3-hour and 24-hour average proposed significant impact levels and greater than the 24-hour average Class I proposed significant impact level in Colorado National Monument. (Commenters cited pages 4-23, 4-24 and 4-30 of the dispersion modeling portion of the PSD permit application.) Colorado's regulations mandate that Dinosaur National Monument and Colorado National Monument, although Class II areas, will be subject to the more stringent Class I increments for SO<sub>2</sub>. (Colorado Regulation 3, Part B, Section VIII.B.1.b.). Thus, commenters concluded, Deseret Power should have been required to perform a cumulative increment analysis for Dinosaur National Monument and Colorado National Monument.

Further, commenters asserted, Deseret Power's analysis of the Bonanza WCFU's impacts on short term average SO<sub>2</sub> concentrations in Class I areas was flawed because, as noted by EPA, Deseret underestimated worst case short term SO<sub>2</sub> emission rates from the Bonanza WCFU. (draft Statement of Basis at 135.) Commenters noted that, as discussed in the above comment regarding the monitoring significance threshold, the predicted SO<sub>2</sub> impacts on the Class I areas can be proportionately adjusted based on the EPA's revised SO<sub>2</sub> emission rates as compared to Deseret's modeled SO<sub>2</sub> emission rate.

Commenters further noted that EPA re-calculated Bonanza's WCFU worst case 3-hour average SO<sub>2</sub> emission rate to be 872 lb/hr, which is almost six times as high as the 146.99 lb/hr SO<sub>2</sub> emission rate modeled by Deseret. Commenters concluded that proportionately adjusting the 3-hour average SO<sub>2</sub> impacts of the Bonanza WCFU using EPA's revised worst case 3-hour average emission rate shows that the Bonanza WCFU would have an impact greater than the 3-hour average proposed significant impact level for SO<sub>2</sub> for most of the Class I areas in the region.

Commenters created and submitted a table to EPA, showing the revised Class I area 3-hour average SO<sub>2</sub> impacts based on EPA's revised worst case emission rates for those Class I areas where the Bonanza WCFU would exceed the proposed Class I significant impact levels. Based on that table, commenters argued that even if it were appropriate to exempt a facility from a cumulative Class I increment analysis based on its impacts being less than the proposed significant impact levels, the Bonanza WCFU would not be exempt from performing cumulative analyses of impacts on the 3-hour average SO<sub>2</sub> increment at Arches National Park, Canyonlands National Park, Capitol Reef National Park, Colorado National Monument, the Colorado portion of Dinosaur National Monument, the Flat Tops Wilderness area, and the Mt. Zirkel Wilderness Area.

Thus, commenters argued, Deseret Power must be required to conduct cumulative Class I increment analyses for the nearby Class I areas. EPA must not issue a PSD permit for the Bonanza WCFU without ensuring that the facility will not cause *or contribute* to a violation of any PSD increment.

Further, commenters argued, the cumulative Class I increment analyses must include the PSD increment consuming emissions of all other sources that could be affecting air quality in those Class I areas. This would include all large sources of air pollution within 200 kilometers of each Class I area, such as nearby coal-fired power plants (e.g., the Bonanza Unit 1, Hunter, Huntington, and Intermountain power plants in Utah, and the Craig, Hayden and Nucla power plants in Colorado).

In addition, commenters argued, Deseret Power must be required to model those facilities that have submitted complete PSD permit applications, and/or that have received air quality permits, but that have not yet constructed. This would include NEVCO's Sevier Power plant, Unit 3 of the Intermountain Power Plant, and Unit 4 of the Hunter Power plant, all to be located in Utah. Commenters further argued that Deseret Power must also include the existing and proposed oil and gas development occurring near the Class I areas that Bonanza will affect. Commenters concluded that until

complete and thorough Class I increment modeling analyses are completed, EPA cannot issue the permit because EPA will not know whether the facility will cause or contribute to a Class I increment violation.

Although commenters did not say their comment pertains only to SO<sub>2</sub>, EPA interprets this to be the case, since the only pollutant mentioned in the comment was SO<sub>2</sub>. Therefore, EPA's response below pertains only to SO<sub>2</sub>.

**Response #9:**

Disagree. Given the modeling results from Deseret Power's PSD permit application of November 1, 2004 that indicate very small or no impacts on any Class I areas, EPA concluded that a cumulative PSD increment analysis for nearby Class I areas would not be necessary or required for the WCFU project. Further, an e-mail from the National Park Service to EPA on June 16, 2005, regarding Deseret's November 1, 2004 PSD permit application for the WCFU project, stated that "the modeling analyses for Class I and 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."

The commenters' suggested use of worst case short term SO<sub>2</sub> emission rates ("modeling limits" in the permit), in determining impacts to Air Quality Related Values (AQRVs) or PSD increments, greater than 50 kilometers from the source, is not an approach EPA would require, since the worst case emission rate is not intended to represent a routine or frequent operating condition. The low frequency of occurrence of the WCFU facility operating at the worst case emission rate (reflecting a cold startup), combining with simultaneous meteorology to transport emissions a considerable distance to the nearest Class I area, makes the likelihood of impacts on the nearest Class I areas extremely unlikely.

Nevertheless, to be responsive to commenters, EPA conducted a screening analysis for cumulative impact on nearby mandatory Federal Class I areas (except Dinosaur National Monument, which is not mandatory Federal Class I and is addressed separately in response #7 above), using worst-case emission rates cited by public commenters. This was done by scaling Deseret Power's PSD Class I modeling analysis to the level of the worst case short term emission rates (as noted in response #6 above), even though this is not an approach EPA would require (as explained above).

Specifically, the 3-hour PSD increment concentrations were multiplied by 5.93 and the 24-hour PSD increment concentrations by 1.37. The adjusted modeled concentrations from the WCFU were then added to the cumulative PSD increment concentrations calculated by Intermountain Power Agency (IPA) for their Unit 3 PSD permit application in May of 2003. The modeling analysis in the IPA Unit 3 application has been reviewed and approved by the Utah Division of Air Quality. The State of Utah has a SIP-approved PSD permitting program and implements the PSD program in Utah.

That analysis showed that the PSD Class1 increment is not threatened in these areas. (See Table 3 below.)

**Table 3**  
**Cumulative PSD Increments Consumption for Selected Utah Class 1 Areas**  
**Based on Combined Modeled Impacts from Deseret WCFU**  
**and Reported PSD Increment Modeling Results**  
**from Intermountain Power Project, Unit 3**

Location	3-hour SO <sub>2</sub>	24-Hour SO <sub>2</sub>	Annual SO <sub>2</sub>	24-Hour PM <sub>10</sub>	Annual PM <sub>10</sub>
Arches NP	3.8	0.8	0.1	0.2	.02
Canyonlands NP	9.6	2.2	0.1	0.2	.02
Capitol Reef NP	4.0	0.9	0.1	0.2	0.2
PSD Class 1 Increment	25	5	2	8	4

Ref: Addendum to Final Permit Application (“Notice-Of-Intent”), Intermountain Power Project, Proposed Unit 3, June 16, 2003.

In summary, Comment #9 has not resulted in any change to the permit; however, the Class I increment screening analysis described above has been added to the Statement of Basis. A separate analysis by Deseret Power, for impact on PSD Class I SO<sub>2</sub> increment at Dinosaur National Monument (a Colorado Class I area, not mandatory Federal Class I) is described in Response #7 above.

## **10. PSD INCREMENT CONCERNS AT CAPITOL REEF NATIONAL PARK**

### **Comment #10:**

One group of commenters asserted that EPA must not issue the PSD permit for the Bonanza WCFU in light of the PSD SO<sub>2</sub> increment violations that commenters asserted are occurring at Capitol Reef National Park. Commenters cited a March 25, 2004 letter from the National Park Service to the Utah Division of Air Quality, submitted during the permit review and proceedings for the proposed Unit 3 of the Intermountain Power Plant located in Delta, Utah. Commenters asserted that the letter expressed the concern that there are increment violations in Capitol Reef National Park.

On the basis of the NPS letter, commenters asserted that the Bonanza WCFU will contribute to existing SO<sub>2</sub> increment violations at Capitol Reef National Park, at a level greater than the proposed Class I significance level for 3-hour SO<sub>2</sub>, and that EPA should not issue the PSD permit for the Bonanza WCFU until the increment violations are addressed.

### **Response #10:**

Disagree. Neither EPA nor the State of Utah, the two agencies with authority to do so under the Federal Clean Air Act, has determined there is an increment violation at Capitol Reef National Park. The State of Utah has an EPA-approved PSD permitting program. In issuing the PSD permit for construction of Unit 3 at Intermountain Power Plant, the State of Utah concluded that the PSD increments are not threatened. In addition, in response to comment #9 above, EPA added the impact of Deseret Power's WCFU to the Intermountain Power Unit 3 PSD cumulative increment analysis results for Capitol Reef National Park and found no PSD increment violations.

Moreover, any concern for the potential of increment violations at Capitol Reef National Park should be further minimized by the fact that PacifiCorp recently applied for permits from the State of Utah for installation of additional controls at the Hunter and Huntington plants in Delta, Utah, both of which are closer to Capitol Reef National Park than Deseret Power's proposed WCFU at Bonanza, Utah. These additional controls are projected by PacifiCorp and the State of Utah to yield a total of 21,560 tons per year of SO<sub>2</sub> emission reductions.

The permit ("Approval Order" in Utah's terminology) for additional emission controls at the Huntington plant was issued by the State of Utah on April 6, 2005, and cites expected emission reductions of 17,479 tons per year of SO<sub>2</sub>, 2,781 tons per year of NO<sub>x</sub>, and 1.432 tons per year of PM<sub>10</sub>. (Ref: Approval Order dated April 6, 2005, included in the Administrative Record for issuance of the WCFU permit.)

The permit for additional emission controls at the Hunter plant was proposed by the State of Utah on March 2, 2007 ("Intent-To-Approve" in Utah's terminology), but is not yet finalized, as of early August 2007. The ITA cites expected emission reductions of



4,081 tons per year of SO<sub>2</sub>, 8,754 tons per year of NO<sub>x</sub>, and 1,441 tons per year of PM<sub>10</sub>. (Ref: Intent-To-Approve dated March 2, 2007, included in the Administrative Record for issuance of the WCFU permit.)

These additional controls at the Huntington and Hunter plants are expected by EPA to further reduce the level of PSD increment consumption from those shown in Table 3 above. The potential controlled SO<sub>2</sub> emissions from the WCFU project are only 348 tons per year based on the proposed upper-tier emission allowable of 0.055 lb/MMBtu, or only 253 tons per year based on the proposed lower-tier emission allowable of 0.040 lb/MMBtu.

In summary Comment #10 has not resulted in any change to the permit or Statement of Basis.

## 11. VISIBILITY MODELING

### **Comment #11:**

One group of commenters asserted that Deseret Power's visibility modeling analysis of the Bonanza WCFU is flawed because Deseret Power failed to model maximum 24-hour average emissions of SO<sub>2</sub> and because Deseret Power failed to properly document why it was necessary or appropriate to rollback the relative humidity in the regional haze modeling to 95%. Consequently, commenters argued, the modeling likely underestimated the impacts of the Bonanza WCFU on visibility in nearby Class I areas.

**Comment #11.a:** Commenters noted that, as discussed above, EPA adjusted the worst case 24-hour SO<sub>2</sub> emission rate based on data from Deseret Power because Deseret Power's estimate of worst case SO<sub>2</sub> emissions did not properly include emissions from start-ups. (draft Statement of Basis at 135.) With EPA's adjustment, the worst case 24-hour average SO<sub>2</sub> emission rate is 37% higher than the emission rate that was modeled in Deseret's visibility analysis. Thus, commenters argued, Deseret's visibility analysis underestimated visibility impacts in all affected Class I areas. Commenters asserted that Deseret must be required to re-model visibility impacts using the adjusted worst case 24-hour average SO<sub>2</sub> emission rate of 201.9 lb/hr and such modeling must be provided to the Federal Land Managers for review.

**Response #11.a:** Disagree. As noted in response #9 above, the National Park Service stated on June 16, 2005, in regard to the PSD permit application for the WCFU, that "the modeling analyses for Class I and 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."

Also, it appears that commenters may have used a scaling technique to determine that the Bonanza WCFU would have an adverse visibility impact at some nearby Class I areas. Scaling the Calpuff model is not appropriate when reviewing visibility and deposition results. Calpuff converts a portion of the SO<sub>2</sub> emissions to sulfate particulate and a portion of the NO<sub>x</sub> emissions to nitrate particulate as the plume is transported. Thus, visibility and deposition values are not linear to the emission rate. Comment #11.a has not resulted in any change to the permit or Statement of Basis.

**Comment #11.b:** Commenters also argued that Deseret estimated visibility impacts using both a maximum relative humidity of 98%, consistent with the Federal Land Managers' guidance, and rolling back relative humidity to 95%. (Commenters cited page 4-49 of the modeling portion of Deseret Power's PSD permit application.) However, commenters argued, the National Park Service has indicated that any analysis rolling back relative humidity to 95% would have to be "well documented as to why it is appropriate to . . . roll back relative humidity to 95% . . ." (Commenters cited an August 6, 2004 e-mail from John Notar, National Park Service, to Ed Thatcher of Deseret Power and Kevin Golden of EPA Region 8.) Commenters asserted that Deseret Power did not

provide any such documentation, therefore the results of its visibility analysis capping relative humidity at 95% cannot be relied upon.

**Response #11.b:** Disagree. With regard to the maximum relative humidity assumption, the Federal Land Managers (FLMs) have reviewed the draft permit package for this project and had no comment. It is EPA's understanding that in recent permit applications, the FLMs have broadly accepted the use of the 95 percent humidity threshold. The Draft Calpuff Reviewer's Guide, dated September 2005, prepared for the USDA Forest Service and the National Park Service (and included in the Administrative Record for issuance of the WCFU permit), indicates the general consensus among FLMs is that use of a maximum relative humidity value of 95% is appropriate for visibility modeling. (Ref: Page 6-1 of the Guide: "The CALPOST default value for RHMAX is 98, but the general consensus among FLMs is that RHMAX = 95 is appropriate.") Comment #11.b has not resulted in any change to the permit or Statement of Basis.

**Comment #11.c:** Commenters further argued that, based on the visibility modeling done by Deseret that is consistent with current guidance of the Federal Land Managers (i.e., capping relative humidity at 98%), the Bonanza WCFU will have an adverse impact on visibility (greater than a 5% change) at Arches and Capitol Reef National Parks. (Commenters cited page 4-51 of the modeling portion of Deseret's PSD permit application.) This analysis, commenters stated, must be redone with the EPA's worst case 24-hour average SO<sub>2</sub> emission rate and the results transmitted to the appropriate Federal Land Managers.

**Response #11.c:** Disagree. EPA does not agree that 98% relative humidity should have been used to model visibility impacts. See response #11.b above. Comment #11.c has not resulted in any change to the permit or Statement of Basis.

**Comment #11.d:** Commenters also asserted that, because the impacts on visibility will be greater using the higher SO<sub>2</sub> worst case 24-hour average emission rate, it appears the Bonanza WCFU will have an adverse visibility impact at some nearby Class I areas. Commenters concluded that EPA Region 8 must ensure that, in issuing a permit for the Bonanza WCFU, its actions are consistent with the intent of the PSD requirements of the Clean Air Act – specifically, whether its actions will preserve, protect, and enhance the air quality in nearby national parks and wilderness areas (i.e., pursuant to §160(1) of the Clean Air Act), and whether its actions will ensure that emissions from the Bonanza WCFU will not interfere with portions of State Implementation Plans aimed at preventing significant deterioration of air quality including preventing future visibility impairment (i.e., pursuant to §160(4) and 169(a)(1) of the Clean Air Act).

**Response #11.d:** Disagree. As explained in responses #11.a, 11.b and 11.c above, EPA's analysis and determinations have followed applicable rules and guidance, and the FLMs have no issue with the analysis and determinations. Comment #11.d has not resulted in any change to the permit or Statement of Basis.

In summary, Comments #11.a, b c and d have not resulted in any change to the permit or Statement of Basis.

## 12. MERCURY SIGNIFICANCE THRESHOLD

### **Comment #12:**

One commenter asserted that an estimate of potential-to-emit for mercury should have been presented in the draft permit, and that a determination of whether the expected mercury emissions from the proposed WCFU will exceed PSD significance threshold should have been presented in the Statement of Basis. The commenter asserted the significance threshold of 0.1 tons per year (tpy) appears in the Federal PSD rules at 40 CFR 52.21(b)(23)(i). The commenter also remarked that coal-fired electric generating units are known to represent one of the largest sectors for mercury emissions, and that the issue of mercury significance should be explicitly discussed.

### **Response #12:**

Disagree, for two reasons. First, the commenter's assertion is incorrect. The current Federal PSD rules at 40 CFR 52.21(b)(23)(i) have no significance threshold for mercury. On December 31, 2002, EPA revised the PSD rules to remove the significance threshold for mercury from §52.21(b)(23)(i). (Ref: 67 Fed. Reg. 80186, 80239-80240 (December 31, 2002)) Second, as discussed in detail in the final preamble to the December 31, 2002 rulemaking, EPA took final action to promulgate the proposed revisions and indicated that the "1990 Amendments to the CAA at section 112(b)(6) exempted HAP listed under section 112(b)(1) from the PSD requirements in part C." *Id.* EPA went on to indicate that the HAPs listed in section 112(b)(1) of the Clean Air Act, including mercury, are excluded from the PSD provisions of part C.

Comment #12 has not resulted in any change to the permit or Statement of Basis.

### **13. COMPLIANCE WITH NEW SOURCE PERFORMANCE STANDARD FOR MERCURY**

#### **Comment #13:**

One commenter asserted that section III.I of the proposed permit for the WCFU should contain a provision to demonstrate compliance with 40 CFR 60.45Da, Standard for mercury. The commenter also asserted that the Statement of Basis should contain a discussion of the rank(s) of coal the CFB will burn and which standard within §60.45Da is applicable.

#### **Response #13:**

Disagree. Federal PSD rules at 40 CFR 52.21 do not require PSD permits to include emission standards from 40 CFR part 60, for mercury or any other pollutant. Also, the commenter's assertion that the draft Statement of Basis fails to cite the applicable mercury standard and coal category is incorrect. The applicable mercury standard from 40 CFR 60.45Da(a)(4) was shown in a table on page 115 of the draft Statement of Basis. The table may be found on page 143 of the final Statement of Basis, and is titled "Emission Limits in Amended NSPS Subpart Da as of July 1, 2007, Applicable to Units Commencing Construction after February 28, 2005."

Comment #13 has not resulted in any change to the permit or Statement of Basis.

#### **14. COMPLIANCE DEMONSTRATIONS FOR OPACITY AT MATERIALS HANDLING VENT FILTERS AND BAGHOUSES**

##### **Comment #14:**

One commenter noted that draft permit condition III.I.6, “Compliance demonstrations for opacity” at the materials handling vent filters and baghouses, states that “If no visible emissions are observed in three consecutive monthly observations, frequency of observations at that baghouse or vent filter may be reduced to quarterly.” The commenter asked EPA, “If the opacity observations have been reduced to quarterly, and an observation finds visible emissions, do the observations remain at quarterly, or return to monthly?”

##### **Response #14:**

Agree. The commenter appears to be suggesting that the permit should clarify whether the required frequency of visible emission observations reverts back to monthly from quarterly, in the event that visible emissions are observed. EPA agrees that the permit should be clear on this. Since conditions at a materials handling vent filter or baghouse can vary over time, it is EPA’s intent that frequency of observations revert back to the original frequency (i.e., monthly), if visible emissions are observed. Relaxation of observation frequency should serve as an ongoing incentive (not just a one-time-only incentive) to maintain good particulate control.

Comment #14 has resulted in the above-mentioned clarification in the final permit and Statement of Basis.

## **15. REFERENCES IN STATEMENT-OF-BASIS TO INTERMOUNTAIN POWER UNIT 3 PROJECT**

### **Comment #15:**

One commenter noted that the draft Statement of Basis, at page 51, references the Utah Division of Air Quality's "Modified Source Plan Review" for the Intermountain Power Unit 3 (IPP3) project. The commenter stated that the IPP3 permit action is under challenge by the Sierra Club and Grand Canyon Trust, therefore "possibly it is unwise to add into the record an analysis that may be overturned."

### **Response #15:**

Disagree, for two reasons. First, since the IPP3 permit has not been overturned, EPA sees no reason to delete references to Utah's "Modified Source Plan Review" for that permit action. Second, EPA does not believe its reference to Utah's "Modified Source Plan Review" is connected to the "challenge" cited by the commenter. EPA's draft Statement of Basis referenced the "Modified Source Plan Review" only in regard to a statement by the Utah Division of Air Quality (DAQ) that no more than 80 percent removal efficiency might be expected for sulfuric acid, for a wet electrostatic precipitator (ESP) at a pulverized coal-fired boiler, under optimum conditions. EPA's draft Statement of Basis also cited other sources of information on sulfuric acid removal efficiency where a wet ESP is used, and concluded that an estimate of 86% should be used for EPA's analysis, not 80%. EPA presented the Utah DAQ's estimate only to show that estimates vary.

While EPA is not certain what the commenter means by a "challenge" to the IPP3 permit, EPA presumes that the "challenge" arose from a comment letter dated May 20, 2004, on the draft PSD permit for the Intermountain Power Unit 3 project. The letter was submitted to the Utah DAQ by the Sierra Club, Grand Canyon Trust, and several other environmental organizations. Page 31 of the comment letter notes the Utah DAQ's estimate of 80% removal efficiency for sulfuric acid. The comment letter does not question that estimate. Rather, the comment letter states that Utah DAQ and Intermountain Power did not properly follow EPA's cost effectiveness formulas, and thus these calculations cannot be relied on to eliminate a wet ESP from review. (A copy of the May 20, 2004 comment letter is included in the Administrative Record for issuance of the WCFU permit.)

In summary, EPA does not consider the challenge to the Intermountain Power Unit 3 permit to be a reason to remove from its own Statement of Basis the reference to the Utah DAQ's "Modified Source Plan Review." Comment #15 has not resulted in any change to the permit or Statement of Basis.



## **16. TYPOGRAPHICAL ERROR IN PERMIT**

**Comment #16:** One commenter stated that permit condition III.H.1.a has a typographical error. It should cross-reference permit condition III.E.3 rather than III.E.4.

**Response #16:** Agree. The correction will be made in the final permit.

## **C. CHANGES TO THE PERMIT AND STATEMENT OF BASIS IN RESPONSE TO PUBLIC COMMENT**

### **Permit:**

From response #4.b.(1): Revised the “cutpoint” in permit conditions III.D.1.b.(ii)(a) and (b) from 1.9 lb/MMBtu to 2.2 lb/MMBtu.

From response #5.a.(1):

- Changed the averaging time of the emission limits at the CFB boiler stack in permit condition III.D.1.a, for total particulate matter and for filterable particulate matter, from 30-day rolling average to 24-hour block average.
- Changed permit condition III.I.4.d, to delete “total particulate matter including condensibles” and “total filterable particulate matter” from the first sentence on 30-day rolling averages.
- Added a paragraph to permit condition III.I.4.d, to say that emissions of “total particulate matter” and “total filterable particulate matter” shall be calculated on a 24-hour block average basis (midnight to midnight).
- Changed permit condition III.J.1.f, to add the phrase “and 24-hour block average emission rates” to the second sentence.
- Changed permit condition III.L.2.a, to add “24-hour block averages” to the title line. Made corresponding change in the Table of Contents. Changed the language in the condition to say that for SO<sub>2</sub>, NO<sub>x</sub> and CO, reports of 30-day rolling average emissions are required, but that for total particulate and total filterable particulate matter, reports of 24-hour block average emissions are required.
- Changed permit condition III.L.2.a.(iii), to say that the language about 30 successive boiler operating days pertains only to SO<sub>2</sub>, NO<sub>x</sub> and CO, not to total particulate matter or total filterable particulate matter.
- Added a new permit condition III.L.2.a.(iv), to say that for total particulate matter and for total filterable particulate matter, the average emission rate in lb/MMBtu for each boiler operating day shall be reported. (“Boiler operating day” is defined at the beginning of permit condition III.D and means a period from midnight to midnight, which corresponds to a 24-hour block average.)
- Moved the language about reporting for periods of non-compliance, startups, shutdowns and malfunctions from permit condition III.L.2.a.(iii) to a new permit condition III.L.2.a.(v).

- Re-numbered the remaining provisions of permit condition III.L.2.a., from III.L.2.a.(iv) through.(viii), to III.L.2.a.(vi) through (x).

From response #5.a.(1): Changed title of permit section III.D from “PSD BACT Emission Limits” to “PSD BACT and Other Emission Limits.” Added a footnote to permit condition III.D.3 regarding opacity limit.

From response #5.b.(2): Added requirement in permit condition III.I.8.c to keep records of the weekly Method 22 observations required by condition III.F.3.

From response #14: Added a clarifying statement to permit condition III.I.6 that if any visible emissions are observed in a quarterly observation at a baghouse or vent filter, the frequency of observation at that baghouse or vent filter shall return to monthly.

From response #16: Corrected typographical error in permit condition III.H.1.a, to cross-reference permit condition III.E.3 rather than III.E.4.

#### **Other minor administrative changes made to the draft permit:**

In permit condition III.H.3, at the end of the condition, added the phrase “and any changes required by EPA.”

In permit condition III.I.2.a, corrected the references to NSPS Subpart Da, regarding exemptions from emission standards. The meaning of the permit condition was not changed.

Added a permit condition III.L.9, to require written notification to EPA of the date that construction commences on the WCFU project, within 15 days after commencement. Re-numbered existing condition III.L.9 to III.L.10.

Updated the EPA street address in permit condition III.L.9, now condition III.L.10.

Reworded permit condition IV.B, “Permit Effective Date,” to say “This PSD Permit becomes effective 30 days after the service of notice of the final permit decision, unless review of the permit decision is requested pursuant to 40 CFR 124.19.”

## **Statement of Basis:**

### **From response #3:**

Added a new SOB subsection VI.E (“Supercritical Boiler Technology for BACT”), to explain why supercritical CFB boiler technology was eliminated as a BACT control option. Remaining subsections of section VI have been re-numbered accordingly.

### **From response #4.a:**

In SOB subsection VI.D.1 (“Alternative from Deserado mine” as a BACT option), adjusted the estimate of potential emission reductions of condensible PM that might be achieved by switching from waste coal to ROM coal at the Deserado mine. Adjusted the \$/ton annualized cost of BACT accordingly. EPA’s conclusion that cost of ROM coal is excessive for BACT remains unchanged.

In SOB section VI.D.2 (“Alternative coal from other mines” as a BACT option), expanded the explanation of why alternative coal from other mines has been eliminated as a BACT option. The explanation now includes \$/ton calculations on cost of this BACT option, along with a comparison of this cost versus the cost that other similar sources have to bear for BACT. EPA’s conclusion that cost of alternative coal from other mines is excessive for BACT remains unchanged.

### **From response #4.b.(1):**

In SOB subsection VI.K.5 (Step 5 of the SO<sub>2</sub> BACT analysis), added an explanation titled “Revision of proposed cutpoint” on why EPA has revised the “cutpoint” from 1.9 to 2.2 lb/MMBtu in permit condition III.D.1.b.(ii). Also added AES-Puerto Rico and Nevco Energy to the table titled, “Coal Scenarios and Sulfur Dioxide Control Efficiency, Comparisons for CFB Projects: EPA Compilation.”

Also corrected the calculations in subsection VI.K.5, for “worst-case” coal at AES-Puerto Rico, from 1.7 lb/MMBtu and 98.7% control efficiency to 1.3 lb/MMBtu and 98.3% control efficiency.

The numerical value of the SO<sub>2</sub> BACT emission limit itself remains unchanged.

### **From response #4.c.(1):**

In SOB subsection VI.G.1 (Step 1 of the NO<sub>x</sub> BACT analysis), added a discussion of potential NO<sub>x</sub> control options from the Nov. 1999 EPA Technical Bulletin that were not already addressed in the draft SOB, along with an explanation of why all but two of the options were eliminated at Step 1 of the top-down BACT analysis.

In SOB subsection VI.G.2, added an explanation of why the remaining two options from the Nov. 1999 Bulletin were eliminated at Step 2. EPA's conclusion that SCR and SNCR are the only technically feasible NO<sub>x</sub> control options remains unchanged.

From responses #4.c.(4) and (5):

In SOB subsection VI.G.3 (Step 3 of the NO<sub>x</sub> BACT analysis), added a statement that the potential NO<sub>x</sub> control effectiveness of SCR has been revised from 0.04 to 0.015 lb/MMBtu at Step 3 of the BACT analysis, to reflect the possibility that a rate as low as 0.015 lb/MMBtu could be achieved, rather than 0.04 lb/MMBtu. Explained that this revision is based on information from Babcock & Wilcox, cited in public comments on the draft SOB. The cost effectiveness ranking at Step 3 remains unchanged.

In SOB subsection VI.G.4 (Step 4 of the NO<sub>x</sub> BACT analysis), revised the reheat cost analysis for SCR in VI.G.4.a, to account for the aforementioned change in potential control effectiveness. EPA's conclusion that SCR should be eliminated at Step 4 remains unchanged.

From response #4.c.(8):

In SOB subsection VI.G.5 (Step 5 of the NO<sub>x</sub> BACT analysis), added the Kentucky Mountain Power Project to the table titled "Summary of Recent CFB Projects Permitted or Proposed: NO<sub>x</sub> Emission Rates Using SNCR." Also added an explanation titled "Note 1" on why EPA has discounted to some degree the significance of KMPP's initial NO<sub>x</sub> emission limit of 0.07 lb/MMBtu. EPA's conclusion on what emission limit to impose as NO<sub>x</sub> BACT remains unchanged.

From response #4.e.(2):

In SOB subsection VI.H.7 ("Proposed compliance monitoring approach" for PM/PM<sub>10</sub> filterable emissions), expanded the explanation of why no opacity limit or opacity monitoring for the CFB boiler exhaust stack are considered necessary in the permit. EPA's conclusion that no opacity limit or opacity monitoring is necessary remains unchanged.

From response #5.a.(1):

In SOB subsection VI.H.5 (Step 5 of the BACT analysis for PM/PM<sub>10</sub> filterable emissions), added an explanation of why EPA has revised the averaging time of the PM/PM<sub>10</sub> filterable emission limit in permit condition III.D.1.a from 30-day rolling to daily.

In SOB subsection VI.I.5 (Step 5 of the BACT analysis for PM/PM<sub>10</sub> condensible emissions), revised the averaging time of the total PM/PM<sub>10</sub> emission limit (including condensibles) from 30-day rolling to daily, to be consistent with the revised averaging time of the emission limit for the filterable portion.

From response #6:

In SOB subsection VIII.C.7, corrected the WCFU emission rates for 3-hour and 24-hour SO<sub>2</sub> in the table retitled, “ISC3 WCFU Stack Input Parameters Used for Modeling, As Corrected by EPA for 3-Hour and 24-Hour SO<sub>2</sub>.” The 3-hour rate was scaled up by a factor of 5.93 and the 24-hour rate was scaled up by a factor of 1.37.

In SOB subsection VIII.E.1.a, scaled up the WCFU’s 3-hour and 24-hour SO<sub>2</sub> modeling results, in the table retitled “NAAQS Compliance Demonstration for WCFU Project Sources (Results as Corrected by EPA for SO<sub>2</sub>).” Added an explanation why the results were scaled up.

In SOB subsection VIII.E.1.b, scaled up the WCFU’s contribution to the 3-hour and 24-hour SO<sub>2</sub> full impact modeling results, in the table retitled “NAAQS Compliance Demonstration for Full Impact Area Sources (Results as Corrected by EPA for SO<sub>2</sub>).” Added an explanation why the results were scaled up.

In SOB subsection VIII.E.2.a, scaled up the WCFU’s 3-hour and 24-hour SO<sub>2</sub> modeling results, in the table retitled “PSD Class II Increment Compliance for WCFU Sources (Near-field Analysis) (Results as Corrected by EPA for SO<sub>2</sub>).” Added an explanation why the results were scaled up.

In SOB subsection VIII.E.2.b, scaled up the WCFU’s contribution to the 3-hour and 24-hour SO<sub>2</sub> full impact modeling results, in the table retitled “PSD Class II Increment Compliance for Full Impact Area Sources (Results as Corrected by EPA for SO<sub>2</sub>).” Added an explanation why the results were scaled up.

(By “scale up” for the WCFU, EPA means the modeling results in micrograms per cubic meter (ug/m<sup>3</sup>) attributable to the WCFU are multiplied by 5.93 for 3-hour SO<sub>2</sub> and 1.37 for 24-hour SO<sub>2</sub>, to reflect the worst-case short-term SO<sub>2</sub> emission scenario at the WCFU.)

In SOB subsection VIII.E.3, added a reference to Deseret Power’s March 23, 2005 Class I increment analysis for Dinosaur National Monument, which revised the modeling results to account for the higher short-term SO<sub>2</sub> emission rates at Bonanza Unit 1, as well as to account for the worst-case short-term SO<sub>2</sub> emission scenario at the WCFU.

In SOB subsection VIII.E.3, included the corrected WCFU emission rates for 3-hour and 24-hour SO<sub>2</sub> in a PSD Class I increment compliance screening analysis (described by EPA in response #9).

EPA’s conclusion that the NAAQS and the PSD Class II increments will not be exceeded remains unchanged.

From response #7:

In SOB subsection VIII.C.7, corrected the Bonanza Unit 1 emission rates for 3-hour and 24-hour SO<sub>2</sub> in the table retitled, “Bonanza Unit 1 Stack Parameters Used for Modeling, As Corrected by EPA for 3-Hour and 24-Hour SO<sub>2</sub>.” The 3-hour rate was changed from 56.3 g/sec to 140 g/sec. The 24-hour rate was changed from 56.3 g/sec to 106 g/sec. These higher rates reflect maximum actual emission rates from the 2001-2002 period.

In SOB subsection VIII.E.1.b, scaled up Unit 1’s contribution to the 3-hour and 24-hour SO<sub>2</sub> full impact modeling results, in the table retitled “NAAQS Compliance Demonstration for Full Impact Area Sources (Results as Corrected by EPA for SO<sub>2</sub>).” Added an explanation why the results were scaled up.

In SOB subsection VIII.E.2.b, scaled up Unit 1’s contribution to the 3-hour and 24-hour SO<sub>2</sub> full impact modeling results, in the table retitled “PSD Class II Increment Compliance for Full Impact Area Sources (Results as Corrected by EPA for SO<sub>2</sub>).” Added an explanation why the results were scaled up.

(By “scale up” for Unit 1, EPA means the modeling results in micrograms per cubic meter (ug/m<sup>3</sup>) attributable to Unit 1 are multiplied by a factor of 140/56.3 for 3-hour SO<sub>2</sub> and by a factor of 106/56.3 for 24-hour SO<sub>2</sub>, to reflect higher short-term SO<sub>2</sub> emission rates at Unit 1.)

In SOB subsection VIII.E.3, added a reference to Deseret Power’s March 23, 2005 Class I increment analysis for Dinosaur National Monument (which revised the modeling results to account for the higher short-term SO<sub>2</sub> emission rates at Bonanza Unit 1, as well as to account for the worst-case short-term SO<sub>2</sub> emission scenario at the WCFU).

EPA’s conclusion that the NAAQS and the PSD Class II increments will not be exceeded remains unchanged.

From response #8.a:

In SOB subsection VIII.D, revised the 3-hour and 24-hour SO<sub>2</sub> “modeled maximums” in the table retitled “Near-Field WCFU Modeling Results and Comparison to Monitoring Exemption Levels (Modeled Maximums As Corrected by EPA for 3-Hour and 24-Hour SO<sub>2</sub>),” to reflect a 29% increase in Bonanza Unit 1’s SO<sub>2</sub> emissions since the 1991-1993 period.

Also expanded the explanation of why Deseret Power should still qualify for the exemption from pre-construction ambient monitoring, even though the corrected 24-hour SO<sub>2</sub> modeled maximum is above the exemption threshold in 40 CFR 52.21(i)(5)(i). EPA’s conclusion that Deseret Power should qualify for exemption remains unchanged.

From response #8.b:

In SOB subsection VIII.C.5, revised the SO<sub>2</sub> values in the table retitled “Background Pollutant Concentration Values (As Corrected by EPA for SO<sub>2</sub>),” to reflect a 29% increase in Bonanza Unit 1’s SO<sub>2</sub> emissions since the 1991-1993 period.

In SOB subsection VIII.E.1.a, revised the “Background Concentration” in the table retitled “NAAQS Compliance Demonstration for WCFU Project Sources (Results as Corrected by EPA for SO<sub>2</sub>),” to reflect a 29% increase in Bonanza Unit 1’s SO<sub>2</sub> emissions since the 1991-1993 period.

In SOB subsection VIII.E.1.b, revised the “Background Concentration” in the table retitled “NAAQS Compliance Demonstration for Full Impact Area Sources (Results as Corrected by EPA for SO<sub>2</sub>).” to reflect a 29% increase in Bonanza Unit 1’s SO<sub>2</sub> emissions since the 1991-1993 period.

EPA’s conclusion that the NAAQS and the PSD Class II increments will not be exceeded remains unchanged.

From response #9:

In SOB subsection VIII.E.3, incorporated EPA’s cumulative PSD Class I increment consumption screening analysis on nearby mandatory Federal Class I areas, as described in response #9. EPA’s conclusion that Class I increment will not be exceeded or threatened remains unchanged.

From response #14:

In SOB subsection VI.Q.6, added a clarifying statement that if any visible emissions are observed in a quarterly observation at a baghouse or vent filter, the frequency of observation at that baghouse or vent filter shall return to monthly.

**Other minor changes made to the draft SOB:**

In SOB section III, “Public Notice, Comments, Hearings and Appeals,” added a citation to public comments that were received. Also added a statement that the final WCFU permit, responses to public comments, final Statement of Basis, and Administrative Record of permit-related correspondence, will be available on EPA website. Also added a statement that since commenters requested changes in the draft permit, the effective date of the final permit is thirty days after permit issuance, unless the permit is appealed.

In SOB subsection V.C, “Application Submittals and Addendums,” added citation of two e-mails dated April 5, 2007 from Deseret Power, which constituted additional amendments to their PSD permit application of November 1, 2004.



In SOB subsection VI.D.1, corrected an error in the calculated annual cost of using waste coal. (The corrected cost is \$6 million/year.) Made corresponding corrections in the table titled, “Annualized Cost of Potential Emission Reductions if Run-of-Mine Coal is Used Rather Than Waste Coal for Deseret Power’s Proposed WCFU.”

Added document listings to Appendix A, to cover the period from June 13, 2006 until issuance of the final permit, and retitled the appendix, “List of Documents in the Administrative Record for Issuance of Federal PSD Permit #PSD-OU-0002-04.00.”