Air Pollution Control
40 CFR 52.21(i)
Prevention of Significant Deterioration Permit to Construct
Statement of Basis for Draft Permit No. PSD-UO-000004-2014.003
December 3, 2014

Deseret Power Electric Cooperative
Bonanza Power Plant
Uintah & Ouray Reservation
Uintah County, Utah

In accordance with requirements at 40 CFR 124.7, the Region 8 office of the U.S. Environmental Protection Agency (EPA) has prepared this Statement of Basis (SOB) describing the issuance of a Prevention of Significant Deterioration (PSD) correction permit to Deseret Power Electric Cooperative. This SOB discusses the background and analysis for the correction permit, which will serve as the Federal PSD permit for the Bonanza power plant upon issuance, and presents other information that is germane to this permit action.

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I. Introduction

As explained more fully below, the EPA is using its Prevention of Significant Deterioration of Air Quality (PSD) authority to correct a previously issued PSD permit. *See generally* 40 CFR 52.21. Deseret Power Electric Cooperative (hereinafter the "Permittee") owns and operates a 500 megawatt coal-fired steam electrical generating unit, known as the Bonanza power plant, near Bonanza, Utah, on the Uintah & Ouray Indian Reservation. EPA issued the original Federal PSD permit to construct the plant on February 4, 1981. The plant began operating in 1985. Thereafter, the State of Utah issued permits (Approval Orders) for various modifications to the plant in the 1980's and 1990's. The most recent of these was a permit in March of 1998 for a ruggedized rotor project, which was constructed in June of 2000. The State issued the permit as a non-PSD minor modification.

In September of 1999, consistent with a Federal court decision affirming that EPA had and continued to have jurisdiction on Uintah & Ouray Reservation, EPA wrote to Deseret Power asserting NSR permitting jurisdiction of the Bonanza plant. On February 2, 2001, EPA issued an updated Federal PSD permit to Deseret that consolidated a number of requirements from various Clean Air Act (CAA) permits and regulations into one federally enforceable permit. The 2001 PSD permit replaced various CAA permits that had been issued for the Deseret plant between 1981 and 2001, including the original 1981 Federal PSD permit and all subsequent state-issued permits, including, among others, the March 1998 non-PSD minor modification state permit for the ruggedized rotor project, which EPA said it "accepted."[1]

In August of 2002, EPA sought public comment on an initial draft Federal CAA title V operating permit for the Bonanza plant, which incorporated EPA's 2001 PSD permit. In that action, EPA received a comment that the June 2000 project at Bonanza may have caused a significant increase in actual emissions and that PSD permitting may have been triggered. EPA has evaluated this comment and additional information collected since 2002 and concluded that EPA erred in accepting the State's permit terms, including the flawed analysis underlying them, without first conducting our own independent analysis. EPA's subsequent analysis shows that the project did, in fact, cause a significant increase in actual emissions of NO_x and therefore should have been subject to PSD permitting as a major modification for NO_x.

The purpose of this proposed permit action is to correct the erroneous incorporation of the NO_x requirements from the State minor construction approval for the ruggedized rotor project into the Federal PSD permit issued on February 2, 2001 for the Bonanza power plant. The 2001 permitting action failed to include an independent EPA analysis of the PSD applicability of that project and thus the permit failed to address PSD major modification permitting requirements for NO_x for the ruggedized rotor project constructed in June of 2000. This permit action addresses the error by providing an independent analysis of the PSD applicability of that project and by proposing a NO_x emission limit which reflects Best Available Control Technology (BACT) for NO_x. The NO_x emissions limit proposed in this correction action reflects BACT as it would have

1 Note that the EPA did not issue rules regarding issuance of federal minor source construction permits in Indian Country until July 2011 (76 FR 38748).

been in 2000, when EPA made available for public comment the draft Federal PSD permit that included requirements for the ruggedized rotor project and which contained EPA's error of accepting the State's permit terms, including the flawed PSD applicability analysis underlying them, without first conducting our own independent analysis. Since the proposed BACT limit will be more stringent than the current NO_x emission limit, the result of this permit action will be a reduction in allowed NO_x emissions at the Bonanza plant. This permit action does not involve approval of any new sources of emissions at the facility.

In addition, we are also correcting the 2001 PSD permit to remove terms requiring compliance with and incorporating provisions from 40 CFR part 60, Standards of Performance for New Stationary Sources, which are not PSD requirements. This correction to the PSD permit clarifies that the authority for the applicable requirements resides in the EPA rules at 40 CFR part 60 and not in the 2001 PSD permit. Instead, consistent with the requirements of the CAA, the part 60 requirements directly apply to applicable sources and will be incorporated in the title V operating permit issued for this facility.

Terms of the 2001 permit specifying how compliance with the PSD BACT emission limits would be demonstrated generally relied on cross-references to and incorporation of part 60 requirements on emission compliance demonstrations. As these cross-references will no longer be viable when the NSPS requirements are removed from this permit, we are proposing to include stand-alone provisions with specific terms of compliance with PSD BACT requirements, rather than rely on cross-references to part 60. These proposed provisions may be found in section VII, Compliance Provisions, of the draft PSD correction permit. These proposed provisions generally reflect techniques from part 60 provisions that Deseret Power already uses for purposes of demonstrating compliance with the SO_2 and NO_x PSD BACT emission limits.

We are making available for public comment only the changes to the 2001 PSD permit, as described in section V.D of this SOB. Conditions from the 2001 permit that are proposed to be carried over unchanged into the PSD correction permit are not available for public comment. Opportunity for comment on those conditions was already provided during the permit issuance process for the 2001 permit.

We are also asking if interested parties have additional information or comments regarding the proposed PSD correction permit, EPA's proposed determinations (e.g., the applicability determinations, BACT analysis and proposed emissions limits) and in light of such information, whether the interested parties think the Agency should consider another BACT control technology option that could be finalized either instead of, or in conjunction with, BACT as proposed. The Agency is also asking if interested parties have additional information or comments on the proposed timing for the effective dates.

The Agency will take the comments received into consideration in our final permit action. Supplemental information received may lead the Agency to take a final permit action that reflects a different BACT limit based on different control technology options.

II. Authority

Authority in Indian Country. The EPA is authorized to implement the Federal PSD permit program contained in 40 CFR 52.21 where – such as here – there is no approved Tribal implementation plan for implementation of the PSD regulations. 40 CFR 52.2346. The Bonanza power plant, where the ruggedized rotor project was constructed, is 35 miles southeast of Vernal, Utah, near Bonanza, Utah in Uintah County, and within the exterior boundaries of the Uintah and Ouray Indian Reservation. Under the requirements in §52.21, sources are required to obtain a Federal PSD permit to construct new major stationary sources as well as a major modifications of existing major stationary sources. *See generally* 40 CFR 52.21(a)(2). As stated in section I above, the existing plant is a major stationary source, and as discussed below, the ruggedized rotor project has been determined by the EPA to be a major modification for NO_x as defined in PSD rules.

Authority to revise permit. The purpose of this proposed permit action is to correct an error in the Federal PSD permit issued on February 2, 2001. This action is being taken on the basis of EPA's general PSD permitting authority contained in 40 CFR 52.21 and the inherent authority of a federal agency to reconsider its own actions based on Congress's delegation of the general power to adjudicate.[2] While the Federal PSD regulations do not contain any provisions that explicitly authorize revision of PSD permits or contain procedures for correcting such errors, EPA has historically recognized the power of permitting authorities to revise previously issued PSD permits for various reasons, including the correction of an error.[3] The EPA Administrator recently re-iterated this position, explaining that "EPA has generally recognized that PSD permitting authorities have inherent authority to revise previously issued permits in some circumstances," including when "PSD permits may be revised to correct errors in the permit." [4]

In the case of the 2001 PSD permit for the Deseret plant, we have concluded that our permit contains an error regarding the relevant PSD permitting requirements that apply to the ruggedized rotor project and we are proposing to address that error through a case-specific revision of the permit. Consistent with the inherent permitting authority contained in 40 CFR 52.21 and utilizing the PSD permitting procedures contained in 40 CFR part 124, we are undertaking this PSD correction action to identify our errors and provide a corrected PSD permitting analysis for that project as laid out in this SOB. At the conclusion of this correction process, the correction permit will serve as the Federal PSD permit for the Bonanza power plant that: (1) addresses NO_x emissions from the ruggedized rotor project, based on our own independent PSD applicability analysis with an appropriate "actual-to-potential" or "actual-to-

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2 *See generally Trujillo v. Gen. Elec. Co.*, 621 F.2d 1084, 1086 (10th Cir. 1980) ("Administrative agencies have an inherent authority to reconsider their own decisions, since the power to decide in the first instance carries with it the power to reconsider."); *Dun & Bradstreet Corp. Found. V. U.S. Postal Serv.*, 946 F.2d 189, 193 (2d Cir. 1991) ("It is widely accepted that an agency may, on its own initiative, reconsider its interim or even its final decisions, regardless of whether the applicable statute and agency regulations expressly provide for such review.")

3 *See* the November 19, 1987, Memorandum titled "Request for Determination on BACT Issues - Ogden Martin Tulsa Municipal Waste Incineration Facility."

4 *In the Matter of Noranda Alumina*, Permit Number 2453-V2, Petition Number VI-2011-04 (Dec. 14, 2012) ("*Noranda* Order") at 6.

projected-actual" comparison and resulting BACT emissions limits, instead of accepting the State's analysis relying on an "allowable-to-allowable" emission comparison and non-BACT emissions limits, and (2) corrects the errors explained in the Introduction above, which include removing the NSPS requirements in the permit, which the PSD rules do not require to be included in PSD permits and which will be included more appropriately, as applicable requirements in the operating permit.

The procedures for this correction recognize that Deseret is not initiating the process by submitting an application for construction of a PSD major modification in the future. Rather, in this case, the EPA as the permitting authority is initiating this proposed PSD correction permit action to correct errors in a permit issued in the past for a project that is already constructed. Accordingly, and consistent with the inherent permitting correction authority contained in the CAA and 40 CFR 52.21, the proposed PSD correction permit and the specific analysis contained in this SOB and administrative record are different than a PSD permitting action that might happen for a major modification that might be permitted and undertaken at this time.[5] Those differences include:

Application requirements. Because EPA is correcting an error in its permit, this proposed PSD correction is not based on any new permit application from Deseret Power. Instead, the EPA has independently evaluated what action is necessary to correct the errors in its previously issued permit and has presented the results of that independent analysis in this SOB.[6] Documents EPA has relied on in developing this proposed action, including correspondence between the Permittee and EPA and any related documents, are included in the Administrative Record for issuance of this permit.[7] A chronology and description of that correspondence is included in this SOB, which also includes an explanation of why EPA concluded that the ruggedized rotor project was a PSD major modification for NO_x, and an explanation for EPA's proposed BACT determination for NO_x.

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5 *See Noranda* Order at 6, citing *In re: Chehalis Generating Facility,* PSD Appeal No. 01-06, Slip. Op. at 24-29 (EAB August 20, 2011) ("Given the absence of regulations on [revision of Federal PSD permits], EPA has generally addressed the scope of PSD requirements that must be addressed in a revision of a permit on a case-by-case basis considering the particular circumstances.").

6 Accordingly, EPA does not have a permit application that it can provide to the Federal Land Manager (FLM) and the Federal official charged with direct responsibility for management of lands within such areas, as required under 40 CFR §§ 52.21(p), 124.42. Instead, EPA is providing the FLM and the Federal official with a copy of the proposed permit and this SOB, which contains the relevant analysis.

7 While EPA has not requested an application for this correction action, we have requested information to aid our analysis from the Permittee. *See* Memorandum from Deirdre Rothery, to Deseret Title V Docket, Record of Communication – meeting with Deseret (January 30, 2014) (summarizing meeting with Deseret Power and request for information for the PSD BACT NO_x analysis); Email from David Crabtree of Deseret Power to Deirdre Rothery of EPA (February 25, 2014) (Permittee's response to meeting request); Letter from Debra H. Thomas, Acting Assistant Regional Administrator, Office of Partnerships and Regulatory Assistance, EPA Region 8, to Kimball Rasmussen, President and CEO, Deseret Power Electric Cooperative (March 26, 2014) (requesting specific information pursuant to Section 114 of the CAA); Letter from David Crabtree of Deseret Power to Carl Daly of EPA (April 17, 2014) (response to 114 request). EPA has not relied on any information from Deseret's response in preparing this draft PSD correction permit. Deseret asserted CBI claims on much of the information. EPA is in the process of evaluating and making determinations on the CBI claims.

Time period for NO_x BACT analysis. Since the PSD permitting error occurred in the permitting action that resulted in the 2001 PSD permit, the analysis we are undertaking in this proposed PSD correction permit is based on what would have been required of the Deseret plant at the time of that permitting action. Specifically, the analysis of NO_x emissions from the ruggedized rotor project, including the BACT analysis provided in this SOB, are based on what the analysis would have been in 2000, when EPA made available for public comment the draft Federal PSD permit that included requirements for the ruggedized rotor project and which contained EPA's error of accepting the State's permit terms, including the flawed PSD applicability analysis underlying them, without first conducting our own independent analysis.

Effective date for NO_x BACT limit and expiration date for the permit as a whole. Since this proposed PSD correction is not based on any new permit application or any specific planned construction by Deseret Power, the treatment of the effective date and expiration date in this proposed correction permit is different than it would be in a permit approving construction which has not yet occurred. Contrary to a normal PSD permitting action, the ruggedized rotor project has already been constructed and the plant is operating under the current PSD terms. Accordingly, the normal PSD permit terms – providing that the permit will expire after 18 months unless the source commences construction (40 CFR 52.21(r)(2)) and stating that the permit terms generally become effective upon operation – do not lend themselves to effective application in this case.

To provide for meaningful application of the PSD correction we are undertaking, we propose that the new NO_x BACT emissions limit of 0.28 pounds per million British thermal units (lb/MMBtu) become effective 18 months after the effective date of the correction permit, which should be sufficient time for Deseret to take the actions necessary to operate the source in accordance with those permit terms. In addition, as the source has already constructed and is already operating in accordance with other terms of the draft correction permit that are unchanged from the final 2001 permit, we are not proposing to include an expiration term in this permit. Such a term would not be meaningful in this case, because the requirement of §52.21(r)(2) has to a large extent been satisfied by the source commencing construction. Furthermore, §52.21(r)(2) provides discretion for EPA to extend the 18-month period based on a showing that an extension is justified. Under the circumstances here, we believe the permit adequately addresses the timing requirements of §52.21(r)(2) by providing a date by which the source must comply with the new NO_x BACT limit in the permit, which serves to ensure timely completion of any construction necessary for the source to meet that limit.

III. Public Notice, Comment, Hearings and Appeals

Public notice for this draft PSD permit has been published in the Salt Lake Tribune (Salt Lake City, UT), the Vernal Express (Vernal, UT), the Uintah Basin Standard (Roosevelt, UT) and the Ute Bulletin (Fort Duchesne, UT). The public comment period will begin on December 5, 2014, and shall extend until January 19, 2015. States, Tribes, local governmental agencies, and the public may review a copy of the permit application, analysis, draft permit prepared by EPA, and permit-related correspondence. Copies of these documents are available at:

US EPA Region 8
Technical Library
1595 Wynkoop Street
Denver, Colorado 80202-1129
Permit Contact: Mike Owens
Email: owens.mike@epa.gov
Phone: 303-312-6440
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and: Uintah County Clerk's Office
147 East Main Street, Suite 2300
Vernal, Utah 84078
Phone: 435-781-5361

and: Ute Indian Tribe
Energy and Minerals Office, Air Quality
988 South 7500 East
Fort Duchesne, Utah 84026
Phone: 435-725-4950

All documents will be available for review at the U.S. EPA Region 8, Technical Library on Monday through Thursday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays). A copy of the draft permit and draft SOB will also be available on EPA website at: http://www2.epa.gov/region8/air-permit-public-comment-opportunities.

In accordance with 40 CFR 52.21(q), *Public participation*, any interested person may submit written comments on the draft permit during the public comment period and may request a public hearing. All comments and requests for public hearing should be addressed to the Permit Contact at the US EPA Region 8 address listed above.

In accordance with 40 CFR 124.13, *Obligation to raise issues and provide information during the public comment period*, anyone, including the permit applicant, who believes any condition of the draft permit is inappropriate, or that EPA's tentative decision to prepare a draft correction permit is inappropriate, must raise all reasonably ascertainable issues and submit all arguments supporting the commenter's position, by the close of the public comment period. Any supporting materials submitted must be included in full and may not be incorporated by reference, unless the material has been already submitted as part of the administrative record in the same proceeding or consists of state or federal statutes and regulations, EPA documents of general applicability, or other generally available reference material. An extension of the 45-day public comment period for this permit action may be granted if the request for an extension adequately explains why more time is needed to prepare comments.

In accordance with 40 CFR 124.15, *Issuance and Effective Date of Permit*, the permit shall become effective immediately upon issuance as a final permit, if no comments request a change in the draft permit. If changes are requested, the permit shall become effective thirty days after issuance of a final permit decision, unless EPA specifies a later effective date in the permit or review of the permit by the Environmental Appeals Board is sought (see paragraph below for more information). Notice of the final permit decision shall be provided to the permit applicant and to each person who submitted written comments or requested notice of the final permit decision.

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

The proposed permit and SOB represent a proposed Agency action to issue a Federal PSD correction permit to Deseret Power Electric Cooperative, under Title I, Part A, *Air Quality Emission Limitations*, and Part C, *Prevention of Significant Deterioration of Air Quality*, of the CAA, as amended. For completeness, this SOB should be read in conjunction with the proposed PSD permit.

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

IV. Project Description

A. Location

The ruggedized rotor project was constructed in June of 2000 at the existing Bonanza Power Plant, approximately 35 miles southeast of Vernal, Utah, near Bonanza, Utah in Uintah County. This location is within the exterior boundaries of the Uintah and Ouray Indian Reservation. The project is located in an attainment area for all pollutants. The closest non-attainment area, Utah County, which is located approximately 125 miles west of the facility, is in non-attainment for PM_{10} and $PM_{2.5}$.

The project is located at an elevation of 5,030 feet above Mean Sea Level (MSL). Elevated terrain surrounds the Bonanza plant. The closest elevated terrain, the East Tavaputs Plateau, is located approximately six miles south of the plant. The East Tavaputs Plateau is oriented in a southwest-northeast direction with elevations ranging from approximately 6,000 to 8,000 feet MSL. Another area of elevated terrain, located northeast of the plant, is Raven Ridge. Raven

Ridge, oriented southeast to northwest, has elevations ranging from 6,000 to 6,350 feet MSL. The Blue Mountain Plateau, located approximately 17 miles northeast of the plant, has elevations ranging from 6,000 to 8,500 feet.

B. Existing Facility and Federal PSD Permitting History

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

The Bonanza plant, originally referred to in the late 1970's as the Moon Lake Power Plant Project Units 1 and 2, was issued an initial PSD permit-to-construct by the U.S. EPA Region 8 office on February 4, 1981. The permit was for construction of two 400-megawatt units. Only one unit was actually constructed, in the early 1980's. It commenced commercial operation in 1985. That unit is currently rated at 500-megawatts. Thereafter, the State of Utah issued permits (Approval Orders) for various modifications to the plant in the 1980's and 1990's. The most recent of these was a permit in March of 1998 for a ruggedized rotor project, which was constructed in June of 2000. The State issued the permit as a non-PSD minor modification. By letter to Deseret Power dated September 22, 1999, EPA Region 8 notified Deseret that, since the plant is under Federal permitting jurisdiction for New Source Review, it would be necessary for EPA to update and re-issue the 1981 Federal PSD permit. EPA issued the updated permit on February 2, 2001.

C. Company Contacts

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D. Process Description for Existing Facility

See Attachment 1

V. Description of this Permitting Action

A. Purpose

As explained in the Introduction above, the purpose of this permit action is to correct the errors in the Federal PSD permit issued on February 2, 2001.

One error was that the 2001 permit simply accepted the analysis in the State March 1998 permit and failed to conduct an independent analysis to determine whether or not PSD major modification permitting requirements applied to the ruggedized rotor project. This permit action addresses the error by undertaking the relevant applicability analysis and adding permit terms relating to a NO_x emission limit which reflects BACT for NO_x as it existed in 2000, when Deseret Power applied for a Federal PSD permit that included the ruggedized rotor project.

A second error was that the 2001 PSD permit erroneously included requirements from 40 CFR part 60, Standards of Performance for New Stationary Sources, which are not required to be in PSD permits. This permit action removes the part 60 requirements, which will instead be included, more appropriately as applicable requirements, in the final title V operating permit, which is being issued concurrently with this proposed PSD correction permit.

The proposed permit also corrects other errors as explained in Section V.D. below.

EPA is soliciting public comment only on these corrections, which are laid out in more detail in Section V.D of this SOB, which are for the most part highlighted in yellow in the proposed permit. We are not taking comment on changes related to reorganizing of the existing permit terms as reorganization does not change the substance of the existing permit terms that were finalized in the 2001 Federal PSD permit.

B. PSD Applicability

As explained above, the EPA received comments from the National Park Service (NPS) on the 2002 draft title V Permit that asserted, in regard to a ruggedized rotor project that Deseret Power constructed in 2000, that “there is reason to believe actual emissions may have increased by ‘significant’ amounts and that PSD may have been triggered,” if past actual emissions are compared to the allowable emission limits in the draft title V permit. Thus, these comments raised the possibility that the 2001 PSD permit issued by EPA did not correctly address PSD regulations due to an error created by EPA in accepting the State of Utah’s previous PSD non-applicability decision for NO_x emissions from the ruggedized rotor project. The difference between pre and post project actual emissions are explained more fully in the PSD Applicability Section below.

Given the NPS comment, the availability of information on actual emissions before and after the project, and the unusual circumstances leading to the issuance of the PSD permit, EPA made a decision to further investigate PSD applicability for the ruggedized rotor project to determine if there was an error in the 2001 PSD permit. To evaluate this issue, EPA requested and considered information from Deseret; and also independently gathered and analyzed additional information.

While EPA is sensitive to the fact that under the PSD rules, applicability of the major NSR program must be determined in advance of construction, under section 504 of the CAA, a PSD permit issued by EPA for this facility must contain terms and conditions that conform with the PSD requirements of the CAA and relevant regulations. In carrying out our CAA title V permitting obligations, EPA made the preliminary determination that EPA failed to analyze and apply the PSD regulations correctly when issuing the 2001 PSD permit and the 2001 permit omitted certain PSD permitting requirements, including a BACT analysis for NO_x.

To correct our permitting error, we are now proposing to issue a PSD correction permit for this facility. We include an analysis below of the basis for our proposed PSD applicability determination, which underlies the proposed PSD correction permit.

PSD Requirements Generally

At issue here is the PSD program contained in Part C of the CAA. The PSD program applies to areas of the country, such as the Uintah and Ouray Indian Reservation, that are designated as attainment or unclassifiable for the National Ambient Air Quality Standards (NAAQS).[8] In such areas, a major stationary source may not begin construction or undertake certain modifications without first obtaining a PSD permit.[9]

In broad overview, the PSD program includes two central requirements that must be satisfied before the permitting authority may issue a permit. The program: (1) limits the impact of new or modified major stationary sources on ambient air quality; and (2) requires the application of state-of-the-art pollution control technology, known as BACT, for each pollutant subject to regulation under the Act.[10]

The EPA has two largely identical sets of regulations implementing the PSD program: one set, found at 40 CFR 51.166, contains the requirements that state PSD programs must meet to be approved as part of a Tribal or State Implementation Plan; the other set of regulations, found at 40 CFR 52.21, contains the EPA's Federal PSD program. As EPA administers the PSD program for sources located on the Uintah and Ouray Indian Reservation,[11] the applicable requirements of the Act for new major sources or major modifications include the requirement to comply with PSD requirements, 40 CFR 52.21.[12]

The Deseret Bonanza plant is a fossil fuel-fired steam electric generating plant of more than 250

8 CAA §§ 160-169, 42 U.S.C. §§ 7470-7479.
9 CAA § 165(a)(1), 42 U.S.C. § 7475(a)(1).
10 CAA §§ 165(a)(3) & (4), 42 U.S.C. §§ 7475(a)(3) and (4).
11 40 CFR § 52.2346.
12 See, e.g., 40 C.F.R § 71.2.

MMBtu per hour (MMBtu/hr) heat input capacity, with the potential to emit 100 tons per year (tpy) or more of any pollutant subject to regulation under the Act, and therefore it is a major stationary source under the PSD regulations.[13] The PSD rules at 40 CFR 52.21(j)(3) require that a major modification to a major stationary source apply BACT for each regulated New Source Review (NSR) pollutant for which it would result in a significant net emissions increase at the source. "Major modification" is defined at 40 CFR 52.21(b)(2). The rules also allow certain emissions to be excluded from determining whether a modification will result in a significant net emissions increase. Relevant to this permitting action, the definition of "Representative actual annual emissions" at 40 CFR 52.21(b)(33) that was in effect at the time EPA issued the PSD permit in 2001 says that the projection of future actual emissions shall:

> Exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

Thus, in assessing whether modification of an existing unit will result in an increase in actual emissions, EPA has explained that the PSD regulations provide that "when a projected increase in equipment utilization is in response to a factor such as growth in the market demand," the owner or operator "may subtract the emission increases from unit's projected actual emissions"[14] if two requirements are met. The exclusion should apply only when "[t]he unit could have achieved the necessary level of utilization during the consecutive 24-month period you selected to establish the baseline actual emissions" and "the increase is not related to the physical or operational change(s) made to the unit."[15] In other words, EPA explained that where an increase in emissions "could not have occurred during the representative baseline period but for the physical or operational change, that change will be deemed to have resulted in the increase."[16] Finally, "[a]lthough a source may vary its hours of operation or production as part of its everyday operations, an increase in emissions attributable to an increase in hours of operation or production rate which is the result of a construction-related activity is not excluded from [PSD] review (see WEPCO, 893 F.2d at 916 n.11; Puerto Rican Cement, 889 F.2d at 298)."[17]

Adverse Comments on the 2002 Draft Title V Permit Regarding PSD Applicability

During the public comment period for the initial draft title V permit in 2002, the NPS commented that a ruggedized rotor installation that Deseret constructed in 2000 may have increased actual emissions by "significant" amounts as defined in the regulations, thereby

13 40 CFR § 52.21(b)(1)(i)(a).
14 67 Fed.Reg. 80,186, 80203 (Dec. 31, 2012).
15 Id.
16 57 Fed.Reg. 32,314, 32,327 (July 21, 1992).
17 Id. at 32,328 (emphasis added).

triggering the PSD major source modification permitting requirements in 40 CFR 52.21, explaining that:

> We are especially interested in how the State made the determination in 1998 that the ruggedized rotor project was only a synthetic minor modification and did not trigger PSD review. The 1998 Approval Order and supporting documentation state that boiler heat input was increased from 4,381 MMBtu/hr to 4,578 MMBtu/hr, and that approximately 20 MW from the upgrade will result from an increase in steam flow produced by the boiler. To date, the boiler has not been operated at its peak potential due to limitations of steam flow at the existing Turbine Generator. The Project will allow the Turbine Generator to accept all of the steam flow the Boiler is capable of producing. While the Ruggedized Rotor by itself will not result in any change to Bonanza 1's emissions, the increased capacity of the Turbine Generator to handle the Boiler's peak capacity will increase the Bonanza plant's overall potential to emit (PTE).
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> To our knowledge, we were never advised of, nor involved in, that action. We do not understand how this boiler could be up-rated from 440 MW to 500 MW without an increase in actual emissions, unless Deseret acted to offset the increase in actual emissions by some physical change or change in its method of operation. We are concerned that the reductions in allowable lb/MBT emission rates mentioned in the "Permitting History" [in the SOB for the draft 2002 title V permit] do not reflect a reduction in actual emissions and what we are seeing are merely "paper" reductions.
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> We believe that these concerns are justified if one looks at past actual emissions at this plant compared to emission limits contained in the March 16, 1998 "Approval Order for Modification of Bonanza One Power Plant Emission Limits." For example, EPA's emissions data for 2000 (prior to installation of the ruggedized rotor) show that SO_2 emissions were 1,038 tons, while NO_x emissions were 5,692 tons. Because the 1998 Approval Order and the draft title V permit allow SO_2 emissions of 1,968 tons and NO_x emissions of 10,030 tons, there is reason to believe actual emissions may have increased by "significant" amounts and that PSD may have been triggered. We believe that a title V permit should not be issued that essentially incorporates what may be a defective permit.[18]

Discussion of the 2001 Federal PSD Permit

As explained in the Introduction above, the 2001 Federal PSD permit was an update and reissuance of the original Federal PSD permit for the Bonanza plant which was issued in February of 1981. The 2001 permit was not intended to authorize a particular construction project, but rather to consolidate into one federally enforceable permit the emission limitations

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18 Letter from John Bunyak, Chief, Policy, Planning and Permit Review Branch, National Park Service, to Michael B. Owens, Air Technical Assistance Unit, EPA Region 8, September 19, 2002.

and other requirements that had been established for this facility in a series of permitting actions over several years.[19] In the intervening years, the State of Utah issued a permit to Deseret Power for Bonanza in 1998, regarding the ruggedized rotor project. As mentioned above, on September 22, 1999, EPA wrote to Deseret Power to explain that EPA was the CAA permitting authority since the Bonanza plant is in Indian country within the Uintah and Ouray Reservation, and that EPA must therefore issue an updated Federal PSD permit.

As stated in the record supporting the 2001 Federal PSD permit, EPA's 2001 PSD action relied on "analyses of information made available to the State of Utah" in issuing permits (otherwise referred to as Approval Orders) to the facility.[20] These analyses included the State's "Modified Source Plan Review" (MSPR) dated January 2, 1998, for an Approval Order issued on March 16, 1998. The "Emissions Summary" in the MSPR indicated that the "current emissions" of NO_x at Bonanza plant are 10,558 tpy, and the "total allowable" NO_x emissions are 10,030 tpy, the difference being an "emission change" of negative 528 tpy (i.e., an emission reduction). The MSPR did not indicate how these emission figures were calculated.

EPA's 2001 PSD permit action erred in not conducting a full independent review of the rationale for the MSPR. As stated above, EPA relied instead "on the analyses of information made available to the State of Utah in issuing [permits],"[21] which included the State and Permittee's data from the 1998 State action. EPA has since conducted an independent analysis (discussed further below) and found that the maximum actual pre-project NO_x emissions, as reported by Deseret to EPA in September of 2005, were approximately 7,005 tpy, much less than 10,558 tpy.[22]

Our current analysis of the record shows that the MSPR evaluation of emissions increases for the project, and its conclusion that the emissions increase was not significant, failed to use actual pre-project emissions as the baseline for determining the amount of increase. Since the PSD rules in effect in 2001, when EPA re-issued the Federal PSD permit, require PSD applicability to be determined from a comparison of actual pre-project emissions to either the post-project actual emissions or the post-project potential emissions, EPA is presenting its proposed determination that the 2001 PSD permit decision incorporating the rationale of the MSPR was defective, because it failed to use actual pre-project emissions as the baseline for determining whether the proposed project would constitute a major modification for NO_x and trigger PSD review. Further, our analysis of data on actual pre-project and post-project emissions, reported by Deseret to EPA, show that a significant net emission increase for NO_x occurred.

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19 Page 2 of the Fact Sheet for the 2001 PSD permit, dated September 12, 2000, says "The reason for EPA's reissuance of this Permit is that the Permittee is located in Indian country. … This Permit replaces State issued Approval Orders."

20 Federal PSD permit reissuance by US EPA Region 8 for Deseret Power's Bonanza power plant, PSD-UO-0001-2001:00, February 2, 2001.

21 Id.

22 Excel spreadsheet transmitted via email on September 21, 2005, from Howard Vickers of Deseret Power to Mike Owens of EPA Region 8. Available for viewing on EPA website at http://www2.epa.gov/region8/air-permit-public-comment-opportunities, as well as on computer disks at the Ute tribal office and at the Uintah County Clerk's office.

Thus, it is EPA's proposed determination that the Federal PSD permit issued in 2001 failed to apply the PSD regulations correctly because EPA relied on a faulty analysis conducted by the State and did not conduct a complete, independent analysis of whether the ruggedized rotor project was subject to PSD review based on the regulations in place at that time and whether a revision of the emission limits in the 1981 Federal PSD permit for the Bonanza plant was appropriate. We now recognize our error and, as noted previously in this document, EPA is issuing this correction PSD permitting action.

PSD rules allow for an actual emissions evaluation. As explained below, when pre-project actual emissions are compared to post-project actual emissions for determining PSD applicability, Continuous Emission Monitoring System (CEMS) data reported to EPA for the Bonanza plant reveal that the ruggedized rotor project caused a significant net increase in actual NO_x emissions; and therefore, it is EPA's proposed determination that the 2001 PSD permit action should have included PSD major modification review for Deseret's ruggedized rotor project.

EPA's 2003 Request to Deseret and Analysis of Deseret's Response

In response to comments from the NPS on the August 2002 draft title V permit, EPA analyzed the question of PSD applicability for the ruggedized rotor project. EPA contacted Deseret Power by phone in late 2002 and asked for submittal of a comparison of pre-project actual emissions to post-project actual emissions for all PSD pollutants. Deseret Power responded by letter on February 26, 2003, attaching an Excel spreadsheet with PM_{10}, SO_2, NO_x and CO emissions data from January 1995 through December 2002.[23] EPA reviewed Deseret Power's February 2003 response, and on September 8, 2003, EPA Region 8 sent a follow-up inquiry letter to Deseret Power, to ask for information on: (1) any "contemporaneous" plant changes; (2) emission increases of any PSD pollutants not already included on the February 2003 Excel spreadsheet; and (3) the basis for PM_{10} emission factors used in the spreadsheet.[24] Deseret Power responded on December 29, 2003 with the requested information.[25]

Pursuant to Federal PSD rules in effect at the time EPA issued the 2001 PSD permit, under the definition of "actual emissions" at 40 CFR 52.21(b)(21)(v), electric utilities that use an actual-to-projected-actual emission comparison to demonstrate PSD non-applicability are required to submit post-project annual emissions reports for a period of at least five years following resumption of regular operations after the project. Deseret Power began submitting these reports in 2003, submitting the final report for the five-year post-project period on

23 Letter and attachment dated February 26, 2003, from David Crabtree, Vice President and General Counsel, Deseret Power Electric Cooperative, to Richard R. Long, Director, Air & Radiation Program, U.S. EPA Region 8.

24 Letter dated September 8, 2003, from Richard R. Long, Director, Air & Radiation Program, U.S. EPA Region 8, to David Crabtree, Vice President and General Counsel, Deseret Power Electric Cooperative.

25 Letter dated December 29, 2003, from David Crabtree, Vice President and General Counsel, Deseret Power Electric Cooperative, to Richard R. Long, Director, Air & Radiation Program, U.S. EPA Region 8.

September 21, 2005.[26]

On September 27, 2005, Deseret Power provided an explanation of its calculation methodology for PSD applicability.[27] Deseret's explanation attempted to show that PSD was not triggered for the 2000 ruggedized rotor project. Although EPA has no information to indicate that Deseret Power projected the future actual emissions in advance of the 2000 ruggedized rotor project, the September 2005 explanation relied on the definition of "Representative actual annual emissions" at 40 CFR 52.21(b)(33) in the PSD rules that were in effect at the time of the project. Under that definition, the projection of future actual emissions shall be:

> [T]he average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of a unit, (or a different consecutive two-year period within 10 years after that change, where the Administrator determines that such period is more representative of normal source operations).

Further, at §52.21(b)(33)(ii), the definition says the projection shall:

> <u>Exclude</u>, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, <u>that portion of the unit's emissions</u> following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit <u>that is unrelated to the particular change</u>, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole. (emphasis added)

It is critical to the proper implementation of the PSD program that the calculation of the representative actual annual emissions be made prior to the project, so that the correct amount of excluded emissions can be considered in reviewing the post-project emissions that are reported. In its September 27, 2005 letter to EPA, Deseret Power did not present a pre-project calculation. Instead, Deseret interpreted the regulations and associated preambles to allow two types of adjustments to be made to the post-project emissions data. Deseret's first adjustment subtracted post-project emissions that were claimed to be "directly related to demand growth." Deseret's second adjustment subtracted "emissions that could have been accommodated" by the unit during the baseline period from the post-project emissions data. As explained below, there are fundamental flaws, not only with both of Deseret's adjustments, but also with Deseret's interpretation that post-project emissions can be adjusted at all. EPA's proposed determination is that Deseret's 2005 analysis is incorrect.

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26 Excel spreadsheet transmitted via email on September 21, 2005, from Howard Vickers of Deseret Power to Mike Owens of EPA Region 8. Available for viewing on EPA website at http://www2.epa.gov/region8/air-permit-public-comment-opportunities, as well as on computer disks at the Ute tribal office and at the Uintah County Clerk's office.

27 *Id*.

Deseret's first adjustment, for emissions "directly related to demand growth," relied on the unit's capacity factor (percentage of electricity actually produced compared to the total potential electric production of the unit) and equivalent availability (percentage of electricity the unit was actually available to produce compared to the total potential electricity production of the unit) during the baseline period. Deseret's calculation multiplies a ratio of the maximum baseline equivalent availability and the actual baseline capacity factor times the actual NO_x emissions during the selected two-year baseline period. This results in a single value that Deseret subtracted from all NO_x emissions during the post-project period.

In the 1992 Wisconsin Electric Power Company (WEPCO) rulemaking that created what is commonly known as the demand growth exclusion, EPA allowed for the exclusion in acknowledgment of the "causation requirement" that the physical and operational change result in the actual emissions increase in order to consider the change to be a major modification.[28] EPA has consistently maintained throughout the WEPCO and the 2002 NSR Reform rulemakings that in order to exclude any emissions under the definition of "representative actual annual emissions," the source must demonstrate that two regulatory requirements are met. First, the source must have been able to legally and physically accommodate the amount excluded in calculating any increase in emissions that results from the particular change or change in the method of operation at the emitting unit. Second, the source must demonstrate that none of the emissions that it could have accommodated are related to the project. Deseret's September 27, 2005 submittal did not demonstrate that any emissions it excluded as "directly related to demand growth" could meet either requirement.

Deseret's analysis of demand growth did not examine the effect the hourly capacity increase of the boiler would have on its emissions during the post-project period. Any emissions resulting from operating the unit at a higher hourly rate than the unit was previously capable of accommodating would be related to the project and not eligible for exclusion. Also, Deseret Power assumed that a uniform amount of emissions was attributable to demand growth for the entire post-project period, without quantifying post-project unit operating conditions or system demand. Without consideration of these post-project factors, Deseret Power's analysis failed to demonstrate the exclusions are caused by factors unrelated to the project. The analysis incorrectly assumed any unutilized capacity during the baseline period can be quantified and automatically excluded during the post-project period. Emission increases assumed, but not demonstrated, by Deseret Power to be excludable as demand growth may not have been able to have been accommodated and/or may have resulted from the project. Therefore, Deseret's emission adjustments for demand growth cannot necessarily be excluded under 40 CFR 52.21(b)(33)(ii).

Deseret Power's second uniform adjustment to post-project emissions was for additional emissions that Deseret claimed "could have been accommodated" prior to the project, beyond

28 57 Fed.Reg. at 32326-32328; see also, 67 Fed.Reg. at 80202-80203.

the emissions that Deseret claimed for exclusion due to "demand growth."[29] Deseret calculated this adjustment by multiplying a ratio of the NO_x emissions rate during the selected 2-year baseline period and maximum 12-month NO_x emissions rate during the 5-year baseline times the actual NO_x emission during the selected two-year baseline period. Like the demand growth adjustment, this results in a single value that Deseret subtracted from all NO_x emissions during the post-project period.

The PSD regulations specify that any emission increases that are excluded from the post-project projection, as unrelated to the project, must be emissions that the unit could have physically and legally achieved.[30] Accordingly, the emissions that the facility "could have accommodated" are a necessary part of the emissions that may be excluded for demand growth, and are not an additional exclusion. The applicability test does not allow a source to count two separate quantities of emissions for exclusion.

Deseret Power's uniform adjustments to all post-project actual emissions were effectively an upward adjustment of the pre-project actual baseline emissions, as they ignored the effect of the project itself on post-project emissions, relied only on operational data and conditions during the baseline period as opposed to post-project operations and conditions, and did not consider or quantify factors that were unrelated to the project for each post-project period evaluated. This point is illustrated by the fact that Deseret's adjustments were the same for each post-project period evaluated, regardless of actual post-project unit operational load, system demand, or quantification or consideration of other potential unrelated factors affecting emissions. Adjustments to the actual baseline emissions are not allowed by the regulations.[31]

As cited above, 40 CFR 52.21(b)(33)(ii) – the regulation in effect at the time of EPA's 2001 permitting action – says that for any portion of the emission increase to qualify for exclusion, it

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29 Letter dated September 27, 2005, from Howard Vickers, Environmental Supervisor, Deseret Power Electric Cooperative, to Michael Owens, US EPA Region 8, page 3.

30 *See* 57 Fed.Reg. at 32,326 ("Under today's rule, during a representative baseline period (see *supra*), the plant must have been able to accommodate the projected demand growth physically and legally even absent the particular change. Increased operations that could not physically and legally be accommodated during the representative baseline period but for the physical or operational change should be considered to result from the change." (Emphasis added)); 67 Fed.Reg. at 80196 ("The adjustments to the projected actual emissions allows you to exclude from your projection ***only*** the amount of the emission increase that is not related to the physical or operational change(s). In comparing your projected actual emissions to the unit's baseline actual emissions, you only count emissions increases that will result from the project. For example, as with the electric utility industry, you may be able to attribute a portion of your emissions increase to a growth in demand for your product if you were able to achieve this higher level of production during the consecutive 24-month period you selected to establish the baseline actual emissions, and the increased demand for the product is unrelated to the change." (Emphasis added)).

31 The definition of "Actual emissions" at 40 CFR §52.21(b)(21) of the PSD rules applicable at the time of the 2001 PSD permit does not provide for any adjustment to the pre-project emissions, whether due to demand growth or any other reason ("[i]n general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. … Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period. (emphasis added)). In this instance, the "particular date" is the date that the project occurred, i.e., June of 2000.

must be unrelated to the particular change. Deseret's methodology for both adjustments in its analysis ignores the regulatory requirement that emissions cannot be excluded unless they are "unrelated to the particular change." As discussed below, EPA's analysis indicates that the NO_x emission increase was, in fact, related to the ruggedized rotor project.

EPA's Analysis of the Relationship between the NO_x Emission Increase and the Project

As explained above, EPA's 2001 PSD action relied on the State's MSPR of January 2, 1998. This was a mistake not only because the EPA erred in not conducting a full independent review of the rationale for the MSPR, but also because at the time that underlying analysis was developed, Utah was not the correct permitting authority. According to the MSPR's description of the ruggedized rotor project, "[b]ecause of the increased capacity of the Turbine Generator to handle steam flow, there will be a net increase in certain emissions resulting from an overall increase in the heat input to the boiler from 4,381 MMBtu/hr to 4,578 MMBtu/hr."[32] The information analyzed by EPA demonstrates that a significant portion (if not all) of the post-project emission increase was, in fact, related to the ruggedized rotor project. The following inter-related projects involving the modification of boiler components by June 14, 2000, coincide with the construction of the ruggedized rotor project: (1) coal pulverizer mills were upgraded to substantially higher capacity; [33] (2) burners in the boiler were physically modified to increase burner nozzle tip flow capacity;[34] and (3) modifications were made to the high-pressure/intermediate-pressure and low-pressure sections of the electrical generating turbine to increase capacity.[35] These inter-related projects served to increase the capacity to burn coal and therefore increase the heat input capacity of the boiler.[36] To the extent that the increase in heat input capacity is actually utilized, an increase in NO_x emissions would be expected.

EPA has examined daily actual heat input data for the Bonanza power plant from 1997 through 2005, in an attempt to evaluate the extent to which an increase in actual heat input capacity may have occurred and been utilized as a result of the ruggedized rotor project.[37] Results are

32 Excerpt from EPA 2001 PSD Permit Record, Modified Source Plan Review dated January 2, 1998, by the State of Utah for the ruggedized rotor project, page 3. EPA notes that both the actual pre-project and post-project data show these heat input values were substantially exceeded and do not appear to be an accurate representation of actual as-fired maximum heat input capacity or operations at the plant.

33 Excerpt from EPA 2001 PSD Permit Record, Letter dated November 11, 1999, from Deseret to the State of Utah, on the planned upgrade and rebuild of pulverizers and digital control system for the boiler and turbine. Also letter dated December 17, 1999, from the State of Utah to Deseret, approving the requested changes.

34 Excerpt from EPA 2001 PSD Permit Record, Letter dated November 11, 1999, from Deseret to the State of Utah, requesting approval for replacement of boiler barrels and tips of burners. Also Letter dated December 17, 1999, from the State of Utah to Deseret, approving the requested changes.

35 Excerpt from EPA 2001 PSD Permit Record, Letter dated November 10, 1999 from Deseret to EPA, transmitting information related to the absorber, baghouse, and reliability issues surrounding the turbine. Also the State's Modified Source Plan Review dated January 2, 1998, on the turbine project, as well as the March 16, 1998 permit on the same project.

36 Heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady-state basis, as determined by the physical design and characteristics of the steam generating unit.

37 Actual heat input means the actual amount of fuel combustion in a steam generating unit, as measured in terms of thermal energy per unit of time. It relates to the actual amount of fuel burned and the heat content of that fuel.

presented in Figure 1 below. For example, if one compares the pre-project daily actual heat input values with post-project daily actual heat input values, then it appears that actual post-project heat input has, in fact, been in excess of the plant's pre-project capacity.[38] Prior to the project, the maximum actual daily heat input was 116,940 MMBtu, while after the project the maximum actual daily heat input was 142,958 MMBtu. Moreover, following the project, the actual daily heat input exceeded the pre-project maximum of 116,940 MMBtu on most days.

When considered along with the information from the MSPR cited above, the actual heat input values affirm that the project increased the heat input capacity of the boiler and that this additional capacity was utilized after the project. The physical modifications to the boiler and associated equipment, allowing for increased steam production and rate of combustion of coal, also increased the ability of the boiler to emit NO_x. None of the information in Deseret Power's September 21, 2005 submittal appears to support a finding that any substantial portion of the post-project emission increase could have been accommodated without the particular change, i.e., without the ruggedized rotor project that occurred in June of 2000, and thus cannot support Deseret's exclusion of those emissions when evaluating PSD applicability.

EPA's Analysis of Five Years' of Pre-Project and Post-Project Emission Data

Analysis of NO_x Emission Data:

An examination of five years of pre-project CEMS data and five years of post-project CEMS data for the Bonanza plant, obtained from data reported by Deseret Power to EPA,[39] and presented in Figure 2 of this document, reveals twelve rolling 12-month periods of significant net NO_x emission increases.[40] Based on this information demonstrating a significant net emissions increase in NO_x, EPA proposes to conclude that the project was a "major modification" as defined in 40 CFR 52.21(b)(2) of the PSD rules applicable at the time the 2001 PSD permit was issued,[41] and therefore subject to the requirement at 40 CFR 52.21(i)(1) of those rules to obtain a PSD permit prior to beginning actual construction.

Figure 2 below presents CEMS data covering the period from April of 1995 (five years prior to the project) through June of 2005 (five years after the project). The PSD rules applicable at the time of issuance of the PSD permit in 2001, allowed the actual pre-project emissions baseline to be determined based on the average actual emissions during any two consecutive years in the

38 Daily heat input data obtained from the Air Markets Program Data and based on the procedures found in 40 CFR Part 75, Appendix F. Refer to Figure 1 of this document.

39 Emissions spreadsheet on Bonanza power plant ("Deseret NPS Cap Fac Adjusted Data.xls"), covering May 1995 through August 2005, submitted via email from Deseret Power to EPA Region 8 on September 21, 2005.

40 "Significant" in reference to a net emissions increase means a rate of emissions that would equal or exceed the rate of 40 tons per year of nitrogen dioxide. 40 CFR § 52.21(b)(23).

41 "Major modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act. 40 CFR §52.21(b)(2)

five years preceding the project for electric utility steam generating units.[42] Based on data in Figure 2, the highest single 24-month rolling total of emissions in the five years preceding the project (April 1995 through April 2000), divided by two, yields 7,005 tpy as the NO_x baseline actual emissions.

Figure 2 also displays the difference between the pre-project actual emissions of 7,005 tpy and the post-project actual emissions for the five year period after the project. As stated above, that comparison reveals at least twelve periods of post-project actual NO_x emissions that exceed the pre-project actual emissions by more than the PSD significance threshold of 40 tpy for NO_x. These twelve periods are highlighted in bold/italics on the table. In fact, for each post-project period ending October of 2004 through August of 2005, the significance threshold was exceeded. The significant net emissions increases in Figure 2 range between 63 tpy (for the period ending in August of 2002) and 734 tpy (for the period ending in August of 2005).

Deseret's September 21, 2005 emissions spreadsheet and associated letter of explanation dated September 27, 2005 have not provided sufficient justification that these emission increases following the physical changes made in 2000 could have been accommodated during the representative baseline period and are attributable to an increase in projected capacity utilization at Unit 1 that is unrelated to the physical changes made. Therefore, EPA proposes to conclude that the ruggedized rotor project caused a significant net emission increase in actual NO_x emissions during a portion of the five-year post-project reporting period specified in PSD rules and was therefore a major modification requiring PSD review.

With regard to potential assertions that any retrospective analysis of PSD applicability for the ruggedized rotor project must take into account the contemporaneous NO_x reductions achieved by the mid-1997 low-NO_x burner project, EPA notes that we made our evaluation of whether an actual emissions increase occurred based on the highest two years of emissions during the baseline period, as shown on Figure 2. Using this baseline period essentially gives the Bonanza plant the maximum baseline emissions against which to evaluate the post-project emissions data, regardless of when any emission reduction projects might have occurred during the five years preceding the ruggedized rotor project.

With regard to potential assertions that the rules in place at the time of the ruggedized rotor project required the use of the emissions during the two-year period immediately preceding commencement of construction of the project for determining baseline emissions, EPA would point out that changes were promulgated to the NSR rules on July 21, 1992, to address a decision made by the U.S. 7th Circuit Court of Appeals in regard to an enforcement case between EPA and Wisconsin Electric Power Company, known as the WEPCO Rule. In the preamble to the WEPCO Rule, EPA created the presumption that *any* consecutive two years within the five years

42. 57 Fed.Reg. at 32326-32328. "By presumably allowing a utility to use any 2 consecutive years within the past 5, the rule better takes into consideration that electricity demand and resultant utility operations fluctuate in response to various factors such as annual variability in climatic or economic conditions that affect demand, or changes at other plants in the utility system that affect the dispatch of a particular plant. By expanding a baseline for a utility to any consecutive 2 in the last 5 years, these types of fluctuations in operations can be more realistically considered, with the result being a presumptive baseline more closely representative of normal source operation."

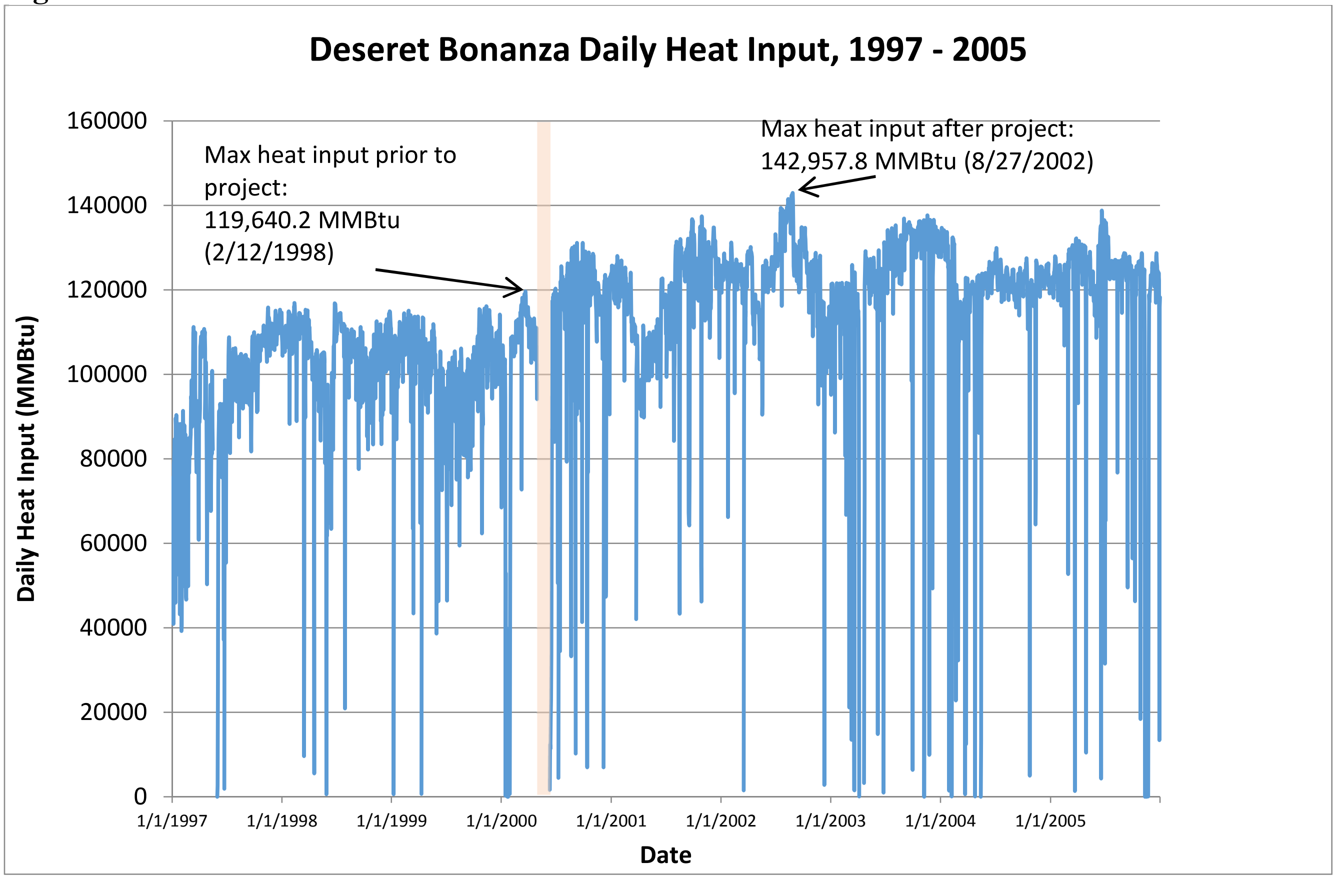
prior to the proposed change are representative of normal operation for a utility.[43] The rules in place at the time of the project therefore did not require the use of the emissions during the two-year period immediately preceding commencement of construction of the project for determining baseline emissions.

Analysis of PM_{10} and SO_2 Emission Data:

As explained above, EPA believes it is reasonable to compare the baseline emissions prior to the change that took place with the ruggedized rotor project to the actual emissions after the change, to determine PSD applicability for the 2000 ruggedized rotor project. Based on the emissions spreadsheet submitted to EPA by Deseret on September 21, 2005 (cited earlier in this discussion), EPA did not find a significant emissions increase occurred for either PM_{10} or SO_2. Specifically, following an analysis similar to that provided for NO_x emissions above, we found that when the highest annual average PM_{10} emissions over a 24-month period during the five-year baseline before the project (465.8 tpy for the period ending January 2000) are compared to the highest annual average PM_{10} emissions in the five years after the project (367.9 tpy for the period ending August 2002), the result is a decrease of 97.9 tons per year, therefore no significant emissions increase for PM_{10} occurred (see 40 CFR 52.21(b)(23)). Similarly, we found that when the highest annual average SO_2 emissions over a 24-month period during the five-year baseline before the project (1,406 tpy for the period ending May 1999) are compared to the highest annual average SO_2 emissions in the five years after the project (1,325 tpy for the period ending August 2005), the result is a decrease of 81.4 tpy, therefore no significant SO_2 emissions increase occurred (see 40 CFR 52.21(b)(23)).

43 57 Fed, Reg, 32,323 – 32,325 (July 21, 1992)

Figure 1.[44]



43 Data retrieved from the EPA Air Markets Program Data on March 27, 2014. Complete data set available in the docket.

Figure 2. PSD Applicability Test
Deseret Power
Emissions Data – Bonanza Unit 1
Date of Physical/Operational Change (May 2000)

BASELINE DATA:

Month	NOx Monthly (Tons)	NOx Rolling 24-Month/2 (Tons)
May-95	119.8	
Jun-95	5.7	
Jul-95	407.8	
Aug-95	694.6	
Sep-95	635.4	
Oct-95	589.3	
Nov-95	505.2	
Dec-95	328.7	
Jan-96	490.0	
Feb-96	431.8	
Mar-96	364.0	
Apr-96	441.2	
May-96	342.4	
Jun-96	518.7	
Jul-96	720.0	
Aug-96	947.3	
Sep-96	826.5	
Oct-96	701.3	
Nov-96	736.3	
Dec-96	642.8	
Jan-97	452.2	
Feb-97	431.8	
Mar-97	637.7	
Apr-97	705.9	6338.2
May-97	308.5	6432.6
Jun-97	323.6	6591.5
Jul-97	458.8	6617.0
Aug-97	527.4	6533.4
Sep-97	461.0	6446.2

Oct-97	496.6	6399.9	
Nov-97	576.7	6435.6	
Dec-97	647.5	6595.0	
Jan-98	620.6	6660.3	
Feb-98	640.9	6764.9	
Mar-98	593.3	6879.5	
Apr-98	519.8	6918.8	
May-98	515.7	**7005.5**	**Maximum consecutive 24 months (expressed as annual tons)**
Jun-98	444.0	6968.1	
Jul-98	583.9	6900.1	
Aug-98	596.5	6724.7	
Sep-98	534.1	6578.5	
Oct-98	497.0	6476.3	
Nov-98	581.2	6398.8	
Dec-98	630.6	6392.7	
Jan-99	475.1	6404.1	
Feb-99	500.0	6438.2	
Mar-99	500.8	6369.8	
Apr-99	483.8	6258.7	
May-99	552.2	6380.6	
Jun-99	385.5	6411.5	
Jul-99	396.9	6380.6	
Aug-99	411.1	6322.4	
Sep-99	440.7	6312.3	
Oct-99	505.9	6316.9	
Nov-99	498.6	6277.9	
Dec-99	481.8	6195.0	
Jan-00	216.0	5992.7	
Feb-00	495.3	5919.9	
Mar-00	552.5	5899.5	
Apr-00	386.8	5833.0	

POST-CHANGE DATA:

Month	NOx Monthly (Tons)	NOx Tons Rolling 24-Month/2 (Tons)	NOx Increase Over Baseline (Tons/Year)	PSD Significant Increase? (Y/N)
Sep-00	590.9			
Oct-00	655.6			
Nov-00	655.1			
Dec-00	525.8			
Jan-01	625.5			
Feb-01	551.5			
Mar-01	551.3			
Apr-01	540.7			
May-01	579.4			
Jun-01	592.2			
Jul-01	574.2			
Aug-01	621.7			
Sep-01	616.1			
Oct-01	563.5			
Nov-01	540.4			
Dec-01	626.9			
Jan-02	620.8			
Feb-02	553.4			
Mar-02	558.1			
Apr-02	615.0			
May-02	572.2			
Jun-02	559.0			
Jul-02	595.3			
Aug-02	653.0	7,068.9	***63.4***	***Y***
Sep-02	539.4	7,043.1	37.7	N
Oct-02	473.9	6,952.3	-53.2	N
Nov-02	466.0	6,857.7	-147.8	N
Dec-02	470.0	6,829.8	-175.7	N
Jan-03	551.5	6,792.8	-212.7	N
Feb-03	475.6	6,754.9	-250.6	N
Mar-03	464.8	6,711.6	-293.9	N
Apr-03	264.1	6,573.3	-432.2	N

May-03	790.1	6,678.6	-326.8	N
Jun-03	498.7	6,631.9	-373.6	N
Jul-03	628.4	6,659.0	-346.5	N
Aug-03	733.0	6,714.6	-290.9	N
Sep-03	694.6	6,753.8	-251.6	N
Oct-03	751.3	6,847.7	-157.8	N
Nov-03	631.9	6,893.4	-112.0	N
Dec-03	718.8	6,939.4	-66.1	N
Jan-04	698.4	6,978.2	-27.2	N
Feb-04	521.0	6,962.0	-43.5	N
Mar-04	612.3	6,989.1	-16.4	N
Apr-04	527.3	6,945.2	-60.2	N
May-04	459.2	6,888.7	-116.7	N
Jun-04	651.1	6,934.8	-70.7	N
Jul-04	642.2	6,958.3	-47.2	N
Aug-04	607.1	6,935.3	-70.1	N
Sep-04	660.7	6,995.9	-9.5	N
Oct-04	652.0	7,085.0	***79.6***	***Y***
Nov-04	630.4	7,167.3	***161.8***	***Y***
Dec-04	688.5	7,276.5	***271.0***	***Y***
Jan-05	723.4	7,362.4	***357.0***	***Y***
Feb-05	600.7	7,425.0	***419.5***	***Y***
Mar-05	721.3	7,553.2	***547.8***	***Y***
Apr-05	637.2	7,739.8	***734.3***	***Y***
May-05	615.6	7,652.5	***647.1***	***Y***
Jun-05	562.6	7,684.5	***679.0***	***Y***
Jul-05	659.3	7,699.9	***694.4***	***Y***
Aug-05	639.0	7,652.9	***647.4***	***Y***

C. Application Submittals and Addendums

No permit applications or addendums have been submitted by Deseret Power for this proposed PSD permit correction. As explained above, because EPA is correcting an error in its permit, EPA has independently evaluated what action is necessary to correct the errors in its previously issued permit and has presented the results of that independent analysis in this SOB.

D. Description and Explanation for Proposed Corrections to the 2001 PSD Permit

Below is a description of proposed corrections to the Federal PSD permit issued on February 2, 2001, along with an explanation for each proposed correction. The description below includes a discussion of all 51 conditions from the 2001 permit (including notation of any conditions which are proposed to remain unchanged), followed by a discussion of proposed new conditions in the draft correction permit that were not in the 2001 permit.

EPA is only seeking comment on the proposed corrections that are described below. Our prior permitting action for the 2001 permit provided an opportunity for the public to review and comment on the draft PSD permit. Therefore, we will only address comments regarding the proposed corrections described below.

EPA is also proposing to add a table of contents for the PSD correction permit, for improved readability and ease of reference. EPA is also proposing to renumber and reorganize the conditions to reflect the groupings of conditions in the table of contents. With the exception of a new section titled "Compliance Provisions" (discussed below), the titles of the groupings are the same as found in the 2001 PSD permit, although the location of the groupings within the permit may have changed.

EPA is also proposing a new section titled "Compliance Provisions," to contain the CEMS and Continuous Opacity Monitoring System (COMS) requirements applicable to demonstrations of compliance with the SO_2 and NO_x PSD BACT emission limits in the permit. These Compliance Provisions generally reflect monitoring, reporting and recordkeeping requirements for CEMS and COMS, in Subparts A and Da of 40 CFR part 60, as well as in Appendices B and F of part 60, which Deseret Power must already comply with, and which Deseret has already been using for purposes of PSD BACT compliance demonstrations. Since EPA is proposing to not include in the permit the numerous cross-references to part 60 that were in the 2001 PSD permit, EPA proposes to include the specific requirements for CEMS and COMS instead, to ensure that practical enforceability of the PSD BACT emission limits is retained without the cross-references to part 60.

<u>Conditions in the 2001 permit</u>:

> <u>Introduction</u>. The Introduction has been substantially revised and updated from the 2001 permit, to explain, in brief, the nature and basis for this draft PSD correction permit. The complete explanation of the bases for the correction may be found in various sections of this SOB.
>
> <u>Table of Contents</u>. EPA is proposing to add a Table of Contents to the permit, for improved readability and ease of reference. The 2001 permit did not have a Table of Contents.
>
> <u>Condition 1</u>. Carried over into Condition II.A of the draft PSD correction permit with the following change: The sentence that reads, "The equipment below in this PSD Permit will be operated at the following location" has been deleted, since the permit condition already identifies the plant location.
>
> <u>Conditions 2 and 3</u>. Carried over into Condition II.B of the draft PSD correction permit

with the following changes: To make it clear what this permit condition pertains to, a condition title has been added, to say "Approved Installation." Also, the last part of the Condition 2, which said "as requested in the Notice of Intent (NOI) dated December 24, 1997, and additional information submitted January 5, 1998, to the State of Utah" is proposed to be removed. For jurisdictional reasons, those requests to the State of Utah are not part of the basis for issuance of this draft PSD correction permit. Further, Deseret has not submitted an application for a correction permit.

Condition 4. Proposed to be removed. Condition 4 of the 2001 permit says, "This PSD Permit replaces the State of Utah's Approval Order, DAQE-186-98, dated March 16, 1998." This is not a valid statement for jurisdictional reasons. See the first page of the Introduction in this SOB for further discussion.

Condition 5.A. Carried over into Condition II.C of the draft PSD correction permit with the following changes: To make it clear what this permit condition pertains to, a condition title has been added, to say "Binding Application." Also, the reference to an application to the State of Utah has been removed, for jurisdictional reasons discussed above. Also, the second sentence of this condition, addressing enforceability of the permit, has been carried over into Condition II.D of the draft PSD correction permit.

Condition 5.B. Proposed to be removed. The condition was carried over from a prior State permit into the 2001 EPA permit in error. The condition referenced "changes to be made" with the installation of an upcoming ruggedized rotor project in 2000. However, the project had already been constructed by the time the 2001 EPA permit was issued.

Condition 6. Carried over into Condition II.D of the draft PSD correction permit, with the following changes: To make it clear what this permit condition pertains to, a condition title has been added, to say "Permit Effective Date." Also, the first subsection of the condition is proposed to be revised (as indicated here in underline and italics), to say "A later date is specified in the final permit decision, *including an alternative date that may be provided in a specific permit term.*

Condition 7. Carried over into Condition II.E of the draft PSD correction permit, with the following change: To make it clear what this permit condition pertains to, a condition title has been added, to say "Permit Appeals."

Condition 8. Carried over into Condition II.F of the draft PSD correction permit, with the following change: To make it clear what this permit condition pertains to, a condition title has been added, to say "Permit Rescission."

Condition 9. Carried over into Condition II.G of the draft PSD correction permit, with the following changes: To make it clear what this permit condition pertains to, a condition title has been added, to say "Notifications and Reports." Also, the EPA Region 8 street address has been updated to the current address.

<u>Conditions 10 through 22, 41, 42, 45 and 47.</u> Proposed to be removed. The conditions specify applicable emission limits and related requirements from NSPS, 40 CFR part 60. The conditions are proposed to be removed for the following reasons:

(a) The PSD rules at 40 CFR 52.21 do not require NSPS requirements to be referenced in PSD permits. The only emission limits and related requirements that are required to be in PSD permits are those that reflect BACT. *See* 40 CFR 52.21(j).

(b) The currently applicable NSPS requirements for the Bonanza power plant directly apply to the plant as required by the CAA and the relevant regulations, and these requirements will be incorporated in the title V operating permit issued for this facility. Including those same requirements in the PSD permit would be redundant.

(c) References to certain NSPS requirements for demonstrating compliance with emission limits are problematic, to the extent that such references could be construed as the means for demonstrating compliance with the PSD BACT emission limits in the permit. Examples are references to 40 CFR 60.8, 60.40Da, and 60.11(c). The NSPS rules allow for broad exemptions from emission limits during periods of startup, shutdown, malfunction and emergency conditions. *See* 40 CFR 60.48Da(a), 60.8(c), and 60.11(c).

EPA's interpretation of the CAA, and of the PSD rules in 40 CFR parts 51 and 52, is that PSD BACT emission limits apply at all times. Therefore, exemptions from emission limits provided for in 40 CFR part 60 do not apply to PSD BACT emission limits. See section VI.B of this SOB for further discussion.

While the draft PSD correction permit removes the numerous cross-references to 40 CFR part 60 that appeared in the 2001 PSD permit, EPA has carried over from the 2001 permit into the draft PSD correction permit the following references to emission measurement and recordkeeping provisions from 40 CFR part 60, where necessary and appropriate for monitoring compliance with PSD BACT emission limits, as well as certain opacity monitoring requirements from 40 CFR part 60:

- Test methods from Appendix A of Part 60, for the PSD pollutants covered in the permit. *See* Conditions III.A.1, III.A.4, VI.C thru F, and VII.C of the draft PSD correction permit.

- Emission proration for NO_x from Subpart Da of Part 60. *See* Condition III.D.1 of the draft PSD correction permit.

- CEMS quality assurance provisions from Appendix F of Part 60. *See* Condition III.C of the draft PSD correction permit.

- Emission calculation procedures from Method 19 in Appendix A of Part 60, to convert CEMS measurements into lb/MMBtu. *See* Condition VII.C of the draft

PSD correction permit.

- CEMS recordkeeping provisions from Appendices B and F of Part 60. *See* Condition VII.D of the draft PSD correction permit.

- COMS specifications and test procedures from Appendix B of Part 60. *See* Condition VII.E of the draft PSD correction permit.

Condition 23. Carried over into Condition II.H of the draft PSD correction permit with the following change: To make it clear what this permit condition pertains to, a condition title has been added, to say "Definitions."

Condition 24.A. Carried over into Condition III.A.1 of the draft PSD correction permit, with the following change: A sentence is proposed to be added, to say "The averaging time for this limit shall be consistent with the test method." This addition is considered a necessary correction for practical enforceability, to make it clear that there is an averaging time associated with the emission limit in this permit condition.

Condition 24.B. Carried over into Condition III.A.2 of the draft PSD correction permit, with the following change: A sentence is proposed to be added, to say "The averaging time for this limit shall be consistent with the test method." This addition is considered a necessary correction for practical enforceability, to make it clear that there is an averaging time associated with the emission limit in this permit condition.

Condition 24.C. Carried over with no changes into Condition III.A.3 of the draft PSD correction permit.

Condition 24.D. Carried over into Condition III.A.4 of the draft PSD correction permit, with the following change: The phrase "as required by 40 CFR § 60.47(a)(a)" is proposed to be removed. It is an incorrect reference and has been replaced by specific requirements for a Continuous Opacity Monitoring System, found in Condition VII.E of the draft PSD correction permit.

Condition 25.A. Carried over with no changes into Condition III.B.1 of the draft PSD correction permit.

Condition 25.B. Carried over into Condition III.B.2 of the draft PSD correction permit, with the following changes:

-- The phrase "30 successive boiler operating days" in the first sentence is proposed to be changed to "30-day rolling average," to be consistent with permit conditions that express BACT emission limits for other pollutants (NO_x and PM) on a 30-day rolling average.

-- The second sentence, saying "Compliance must be determined by the same methods used to determine compliance with the SO_2 emission limitation in Condition 17.D," is proposed to be replaced with the following sentence: "Compliance must be determined by calculating the arithmetic average of all valid hourly emission rates (at least two values each hour are required) for SO_2 for 30 successive boiler operating days, based on continuous emission monitoring data and fuel heat input." This replacement is considered necessary because Condition 17 references NSPS and therefore has been removed from the permit, for reasons explained above. The replacement sentence lays out the specific mathematical procedure required to calculate the emissions, using language from NSPS at 40 CFR 60.43Da(g) and 60.13(h)(2) as a guide, which was the intent of Condition 17.D.

Condition 25.C. Carried over with no changes into Condition III.B.3 of the draft PSD correction permit.

Condition 25.D. Carried over with no changes into Condition III.B.4 of the draft PSD correction permit.

Condition 25.E. Carried over with no changes into Condition III.B.5 of the draft PSD correction permit.

Condition 25.F. Carried over into Condition III.B.6 of the draft PSD correction permit, with the following change: Rather than cross-reference Condition 25.E of the 2001 permit, the condition cross-references Condition III.B.5 of the draft PSD correction permit, which corresponds to Condition 25.E of the 2001 permit.

Condition 26. Carried over into Condition III.C of the draft PSD correction permit, with the following changes: To make it clear what the permit condition pertains to, a condition title has been added, saying "Continuous Emission Monitoring System (CEMS) Quality Assurance." Also, the reference to Part E of the 2001 permit is changed to refer to Part III of the draft PSD correction permit, which corresponds to Part E of the 2001 permit.

Condition 27. Carried over into Condition III.D.1 of the draft PSD correction permit, with the following changes:

-- A phrase is proposed to be added at the beginning of the condition, saying "Until Condition III.D.2 of this permit becomes effective,…". The reason for the proposed change is to make it clear that the NO_x emission limits in this condition only remain effective until Condition III.D.2 becomes effective. See discussion below regarding proposed new Condition III.D.2.

-- The CFR citation in the second sentence has been updated from 40 CFR 60.44a(c) to 40 CFR 60.44Da(a)(2).

Conditions 28 through 33. Carried over into Condition IV.B of the draft PSD correction permit, with the following change: To make it clear what these permit conditions pertain to, a condition title applicable to all these conditions has been added, saying "Coal, Ash and Limestone Handling."

Conditions 34 through 35. Carried over into Condition IV.C of the draft PSD correction permit, with the following change: To make it clear what these permit conditions pertain to, a condition title applicable to both conditions has been added, saying "Road Dust Control."

Condition 36. Carried over into Condition IV.A of the draft PSD correction permit, with the following change: To make it clear what the permit condition pertains to, a condition title has been added, saying "Fugitive Emissions Dust Control Plan."

Condition 37.A. Carried over with no changes into Condition VI.A of the draft PSD correction permit.

Condition 37.B. Carried over into Condition VI.B of the draft PSD correction permit, with the following change: The statement that "The stack testing is done to test the accuracy of the continuous opacity monitoring system" is proposed to be deleted, as it is an incorrect statement. Stack tests do not test the accuracy of COMS. Requirements for proper operation and testing of the COMS may be found instead at Condition VII.E of the draft PSD correction permit, which says the COMS must comply with 40 CFR part 60, Appendix B, Performance Specification 1.

Condition 37.C.1. Carried over into Condition VI.C.1 with the following changes:

-- Propose to retain citation of test methods from Condition 37.C.1, with addition of Methods 201 and 201A to account for PM_{10} and addition of Method 19 to account for conversion of test results into lb/MMBtu. The condition is proposed to now read as follows: "For PM, the Permittee must use 40 CFR part 60, Appendix A, Methods 5, 5A, 5B, 5D, 5E, 5G or 5H, and 19, as appropriate. For PM_{10}, the Permittee must use 40 CFR part 51, Appendix M, Method 201 or Method 201A." Methods 201, 201A and 19 were added to make this permit condition consistent with the permit conditions that specify the PM and PM_{10} BACT emission limits.

-- Propose to not retain the remainder of Condition 37.C.1, which requires: (a) testing at the main boiler stack for condensible PM ("back half condensibles"), (b) methods be taken to eliminate liquid drops in the stack, and (c) use of 40 CFR Part 60, Appendix A, Methods 5, 5A, 5B, 5D, 5E, 5G or 5H, if the liquid drops cannot be eliminated. Below are the reasons we are proposing to not retain these requirements:

(a) Testing for condensible PM serves no apparent purpose for demonstrating compliance. There is no apparent reason in the 2001 permit to require testing for condensible PM. No reason is given in Condition 37.C.1. Conditions 24.A and 24.B in the 2001 permit, which specify the PSD BACT emission limits for total PM and for PM_{10}, require compliance to be determined by stack test methods that do not include measurement of condensible PM. Therefore, EPA does not consider the emission limits themselves to include condensible PM. To eliminate apparent contradiction between Condition 37.C.1 and Conditions 24.A and 24.B, EPA proposes to not retain the requirement to test for condensible PM. EPA supports testing for condensible PM for major sources in $PM_{2.5}$ nonattainment areas, but the Bonanza power plant is not in a $PM_{2.5}$ nonattainment area.

(b) Attempts to eliminate liquid drops in the stack would not be useful. There is no apparent reason in the 2001 permit to require an attempt to eliminate liquid drops in the stack. No reason is given in Condition 37.C.1. As explained in the Process Description attached to this SOB, the stack is wet due to use of a wet SO_2 scrubber. Given the use of a wet SO_2 scrubber, EPA is not aware of any feasible methods to prevent the stack from being wet, nor whether attempting to do so would serve any useful purpose, as far as demonstrating compliance with PM emission limits in the PSD permit.

(c) The citation of test methods to be allowed if liquid drops in the stack cannot be eliminated has no apparent reason and is not a correct list of allowed methods. No reason is given or implied in Condition 37.C.1 why the choice of test methods to be allowed should be contingent on elimination of liquid drops in the stack. Further, as explained above, the list of allowed methods in Condition 37.C.1 is not in agreement with other permit conditions. For total PM, Condition 24.A requires use of Methods 1-5-5E and 19, or other EPA approved test methods. For PM_{10}, Condition 24.B requires use of Method 201 or 201A.

Conditions 37.C.2 and 37.C 3. Carried over with no changes into Conditions VI.C.2 and VI.C.3, respectively, of the draft PSD correction permit.

Condition 37.C.4. Proposed to be removed. It exists only to cross-reference Condition 21.D, which is one of the NSPS requirements that is proposed to be removed.

Conditions 37.D and E. Carried over with no changes into Conditions VI.D and VI.E, respectively, of the draft PSD correction permit.

Condition 37.F. Carried over into Condition VI.F of the draft PSD correction permit, with the following change: To make it clear what the permit condition pertains to, a condition title has been added, saying "Removal efficiency."

Conditions 38.A, 38.B, 38.C, 39 and 40. Carried over with no changes into Conditions V.A through V.E, respectively, of the draft PSD correction permit.
Conditions 41 and 42. Proposed to be removed. See explanation above where these conditions referencing NSPS requirements are discussed.

Conditions 43 and 44. Carried over into Condition II.I of the draft PSD correction permit, with the following changes: To make it clear what this permit condition pertains to, a condition title has been added, saying “Records.” Also, the phrase “or in applicable NSPS requirements” in Condition 43 has been deleted, since citations to NSPS requirements are not required to be in PSD permits (as explained above).

Condition 45. Proposed to be removed. See explanation above where this condition referencing NSPS requirements is discussed.

Condition 46. Carried over into Condition II.J of the draft PSD correction permit, with the following change: To make it clear what this permit condition pertains to, a condition title has been added, saying “Major Modifications and Phased Construction Projects.”

Condition 47. Proposed to be removed. See explanation above where this condition referencing NSPS requirements is discussed.

Condition 48. Carried over with no changes into Condition II.K of the draft PSD correction permit.

Condition 49. Carried over with no changes into Condition II.L of the draft PSD correction permit.

Condition 50. Carried over with no changes into Condition II.M of the draft PSD correction permit.

Condition 51. Carried over into Condition VI.G of the draft PSD correction permit, with the following change: To make it clear what the permit condition pertains to, a condition title has been added, saying “Test notifications.”

Signature line. Name updated from Kerrigan G. Clough, Assistant Regional Administrator, to Callie A. Videtich, Acting Assistant Regional Administrator.

Conditions proposed in the draft PSD correction permit which are not in the 2001 permit:

The following provisions not contained in the 2001 permit, and not already discussed above, are proposed to be included in the draft PSD correction permit

Proposed new first paragraph at beginning of Section III. This paragraph, which indicates where in the regulations a definition of “boiler operating day” and a definition of “valid hourly emission rate” may be found, is proposed to be added to make it clearer how compliance with the PSD BACT emission limits for SO_2 and NO_x must be demonstrated. These definitions are integral to that demonstration, but are not included or referenced in the 2001 PSD permit.

Proposed new Condition III.D.2. This Condition is proposed to be added to reflect EPA’s proposed NO_x BACT limit which addresses PSD applicability for the 2000 ruggedized rotor project. The proposed limit is 0.28 lb/MMBtu on a 30-day rolling average (as explained in section VI below). It is proposed to take effect no later than 18 months after the effective date of the PSD correction permit (as explained in Section II above). No new emission monitoring techniques are proposed.

Proposed new Condition VII.A. This condition, titled "CEMS operation and availability," is proposed to be added as a logical outcome of the NSPS corrections to the 2001 permit. Condition 12.E of the 2001 PSD permit, referencing CEMS operation and availability under 40 CFR 60.13(e), is proposed to be removed, for reasons explained earlier in this SOB. The proposed new Condition VII.A reflects the language in §60.13(e) that will be used as the BACT/PSD compliance mechanism for this permit.

Proposed new Condition VII.B. This condition, titled "CEM data averaging," is proposed to be added for clarity, to cross-reference requirements in the permit to compute valid hourly emission rates and 30-day rolling average emission rates from CEMS data.

Proposed new Condition VII.C. This condition, titled "Calculation of emission rates in lb/MMBtu," is proposed to be added as a logical outcome of the NSPS corrections to the 2001 permit. Condition 21 of the 2001 permit, referencing the "Emission monitoring" requirements of NSPS Subpart Da, is proposed to be removed, for reasons explained earlier in this SOB. A subsection of the "Emission monitoring" requirements of Subpart Da, found at 40 CFR 60.49Da(h)(4), requires use of Method 19 to compute each 1-hour average concentration in lb/MMBtu of heat input. EPA has used this language for Condition VII.C, along with related language from the NSPS rules on determining F factors that will be used as the BACT/PSD compliance mechanism for this permit.

Proposed new Condition VII.D. This condition, titled "CEMS recordkeeping," is proposed to be added as a logical outcome of the NSPS corrections to the 2001 PSD permit. Condition 15.A of the 2001 permit, referencing CEMS and COMS requirements of Appendices B and F of 40 CFR part 60, is proposed to be removed, for reasons explained earlier in this SOB. Condition 41 of the 2001 permit, referencing the recordkeeping requirements at 40 CFR 60.7 and 60.11, is also proposed to be removed for reasons explained earlier in this SOB.

The proposed new condition identifies the specific types of records necessary to document that the CEMS monitoring required by the permit, for demonstrating compliance with the PSD BACT emission limits for SO_2 and NO_x, is conducted. This proposed new condition incorporates CEMS recordkeeping requirements found in 40 CFR 60 Appendices B and F, as well as in 40 CFR part 75, which will be used as the BACT/PSD compliance mechanism for this permit.

Proposed new Condition VII.E. This condition, titled "Continuous opacity monitoring system (COMS) operation and availability," is proposed to be added as a logical outcome of the NSPS corrections to the 2001 permit. The phrase in Condition 24.D of the 2001 permit, referencing NSPS rules at 40 CFR § 60.47(a)(a) *[sic]* for COMS requirements, is proposed to be removed, for reasons explained earlier in this SOB.

The 2001 permit did not indicate whether the COMS must operate during all periods of operation of the facility. Since EPA's interpretation of the CAA and associated rules is that PSD BACT emission limits, including opacity limits, apply at all times, including during periods of startup, shutdown and malfunctions (SSM) (as explained in section VI.B of this SOB), this proposed new condition makes it clear that the COMS must operate during all periods of operation of the facility, including periods of SSM or emergency conditions, except for COMS breakdowns or repairs. As also explained in section VI.B of this SOB, the exemptions in 40 CFR 60.11(c) from opacity limits during SSM do not apply to PSD BACT limits.

The new condition also says the COMS must comply with 40 CFR part 60, Appendix B, Performance Specification 1 (Specifications and Test Procedures for Continuous Opacity Monitoring Systems in Stationary Sources). This reference to Appendix B of Part 60 is a logical outcome of the NSPS corrections to the 2001 permit. Condition 15.A of the 2001 permit, referencing 40 CFR 60.13(a) and Appendix B of Part 60, is proposed to be removed, for reasons explained earlier in this SOB. While EPA has determined that the citation to §60.13(a) should be removed, to ensure practical enforceability of COMS data for BACT/PSD compliance purposes it is necessary to retain a reference to Appendix B, Performance Specification 1.

<u>Proposed new Condition VII.F</u>. This condition, titled "Continuous emission compliance reports," is proposed to be added as a logical outcome of the NSPS corrections to the 2001 permit. Condition 10.A of the 2001 permit, referencing NSPS Subpart Da in general, is proposed to be removed, for reasons explained earlier in this SOB. Subpart Da affected sources must submit "excess emission reports" based on CEMS data, under 40 CFR 60.7(c). However, as explained in section VI.B of this SOB, PSD BACT emission limits apply at all times, such that an exceedance of a PSD BACT emission limit for SO_2 or NO_x is not just "excess emissions," but is evidence of non-compliance. The CEMS reports are therefore properly considered to be "continuous emission compliance reports," rather than "excess emission reports." The required content of the reports, as specified in this new condition, generally follows language found in §60.7(c), which the Bonanza facility must already comply with.

<u>Proposed new Condition VII.G.</u> This condition, titled "CEMS Performance Reports," is proposed to be added as a logical outcome of the NSPS corrections to the 2001 permit. Condition 10.A of the 2001 permit, referencing NSPS Subpart Da in general, is proposed to be removed, for reasons explained earlier in this SOB. Subpart Da affected sources must submit CEMS performance reports under 40 CFR 60.7(c). The required content of the performance reports, as specified in this new condition, generally follows language in §60.7(c), which the Bonanza facility must already comply with.

<u>Proposed new Condition VII.H</u>. This condition, titled "Stack test reports," is proposed to be added as a logical outcome of the NSPS corrections to the 2001 permit. Condition 10.A of the 2001 permit, referencing NSPS Subpart Da in general, is proposed to be

removed, for reasons explained earlier in this SOB. Under Subpart Da, at 40 CFR 60.51Da(a), affected sources must submit performance test data from the initial and subsequent performance tests for SO_2, NO_x and PM. These are referred to in the 2001 permit and in this draft PSD correction permit as "stack tests." The specific types of information that must be in stack test reports are listed in this proposed new condition.

VI. <u>BACT Analysis</u>

A. <u>Approach Used in BACT Analysis</u>

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

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

EPA has explained that consistent with the definition provided in the CAA and corresponding implementing regulations (40 CFR §52.21(b)(6)), a permitting authority must conduct a BACT analysis on a case-by-case basis, and the permitting authority must evaluate the amount of emissions reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic and other costs associated with each technology or technique. Based on this assessment, the permitting authority will establish an emission limitation that reflects the maximum degree of reduction achievable for each pollutant subject to BACT through the application of the selected technology or technique.[45] Accordingly, each BACT decision is made on a case-by-case basis considering the facts of the specific permitting scenario.

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[45] *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011, EPA Document Number EPA-457/B-11-001), page 17.

On December 1, 1987, EPA issued a memorandum describing the top-down approach for determining BACT.[46] This approach was described in greater detail in EPA's 1990 NSR Workshop Manual and 2011 greenhouse gas (GHG) permitting guidance.[47] In brief, the top-down approach provides that all available control technologies be ranked in descending order of control effectiveness. Each alternative is then evaluated, starting with the most stringent, until BACT is determined. The top-down approach consists of the following steps, for each pollutant to which BACT applies:

Step 1: Identify all control technologies.

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

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

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

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

B. <u>PSD BACT Emission Limits Apply at All Times</u>

EPA's interpretation of the CAA, and of the PSD rules in 40 CFR parts 51 and 52, is that BACT emission limits must apply at all times. Exemptions from PSD BACT emission limits are not allowed for periods of startup, shutdown, malfunctions, or for any other reason (although alternative BACT limits may be created for such periods). The following EPA memoranda provide the relevant guidance on this matter:

> September 28, 1982 memorandum from Kathleen Bennett, EPA Assistant Administrator for Air, Noise and Radiation, to EPA Regional Offices, titled "Policy on Excess Emissions During Startup, Shutdown, Maintenance and Malfunctions."
>
> February 15, 1983 memorandum from Kathleen Bennett to EPA Regional Offices, same title as above.
>
> January 28, 1993 memorandum from John Rasnic of EPA's Office of Air Quality

[46] Memorandum from Craig Potter, EPA Assistant Administrator for Air and Radiation, to Regional Administrators, *Improving New Source Review Implementation* (Dec. 1, 1987); Memorandum from John Calcagni, EPA Air Quality Management Division, *Transmittal of Background Statement on "Top-Down" Best Available Control Technology (BACT)* (June 13, 1989).

[47] *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011, EPA Document Number EPA-457/B-11-001)

Planning and Standards (OAQPS) to Linda Murphy of EPA Region I.

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

In particular, the 1993 memorandum states that PSD permits cannot contain automatic exemptions which allow excess emissions during startup and shutdown. The 1982 memorandum states the same for malfunctions. These memoranda are available on EPA's NSR Policy and Guidance database, at the following website and are also in the Administrative Record for this proposed action: http://www.epa.gov/region07/air/search.htm.

C. Pollutants Subject to BACT for this Project

For major modifications to existing major stationary sources, 40 CFR 52.21(j)(3) requires that BACT be applied for each regulated NSR pollutant for which there will be a significant net emission increase at the source. The requirement applies to each emitting unit at which a net emissions increase in the pollutant would occur as a result of the physical change or change in the method of operation of the unit.

As explained in section V.B ("PSD Applicability") of this SOB, EPA proposes to find that Deseret's ruggedized rotor project, constructed in June of 2000, caused a significant emission increase for NO_x and therefore should be subject to BACT for NO_x. As also explained in section V.B, EPA proposes to find that the project did not cause a significant emission increase for PM_{10} or SO_2. Therefore, for this PSD correction permit action, a BACT analysis for NO_x is presented in this SOB.

D. BACT for NO_x Emissions from Deseret Bonanza Unit 1 Boiler

This SOB evaluates NO_x BACT for Deseret Bonanza's Unit 1, a dry bottom wall-fired pulverized coal electric generating unit (EGU) boiler rated at 500 megawatts (estimated 4,578 MMBtu/hr heat input[48]) fired with bituminous coal. Emissions of NO_x from coal combustion are formed from three chemical mechanisms:

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

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

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

[48] Utah Division of Air Quality Modified Source Plan Review, Deseret Bonanza Power Plant project: Modification of Bonanza 1 Power Plant Emission Limits, Change in Coal Pile Parameters, and Ruggedized Rotor Project. January 2, 1998 (hereafter referred to as, "*UDAQ 1998 MSRP*"). Page 4. Available at: http://www2.epa.gov/region8/air-permit-public-comment-opportunities

hydrocarbon radicals).

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

Fuel NO_x formation depends on many complex chemical characteristics in the coal and boiler. Due to the chemical complexities and large number of factors affecting fuel NO_x formation, it is difficult to accurately quantify the amount of expected fuel NO_x formation for a particular facility. The chemical reactions that take place depend on numerous factors, including fuel-bound nitrogen content, carbon to volatile matter ratio, oxygen content, calcium content, sulfur, and moisture content.

NO_x formation for coal-fired utilities is often controlled through combustion techniques. Bonanza Unit 1 was constructed in 1985 with low-NO_x burners (LNB). Deseret Power replaced the Unit 1 LNB in 1997 and currently operates those burners. No other NO_x controls are currently in place.

In the steps described below, EPA presents a description of what EPA believes Bonanza Unit 1 NO_x BACT would have been in 2000, when EPA issued the draft PSD permit that was finalized in 2001. See section II above for a discussion regarding application of this time period. Although we have attempted to identify what control technology would have been BACT in 2000, we acknowledge that any physical modifications to the Bonanza Unit 1 boiler to meet a NO_x BACT limit will be designed, built and operated at the present time and to current standards.

The proposed BACT analysis provided below has been made on a case-by-case basis considering the facts specific to this correction permit action, including the different time periods relevant to a correction action and the lack of information that would normally be included in a permit application. Thus, neither the final determination EPA will make for this permit nor the specific facts considered in the analysis below are binding on other source determinations for pollutant-emitting activities with different fact specific circumstances.

1. Step 1: Identify Potential Control Technologies

Control technologies with practical potential for application to coal-fired boilers for NO_x emission control are listed below. EPA notes that Bonanza Unit 1 already has LNB, which were replaced in 1997. During a June 18, 2014, plant visit, EPA staff learned that due to wear the burner shells were replaced in the first half of 2014.[49] It is common practice to maximize the control of NO_x through combustion controls prior to the addition of add-on controls to minimize the cost and resources required to operate the add-on control(s). Therefore, for this analysis, we have assumed that any combustion control option under consideration would be applied prior to the addition of any post combustion add on controls, such as selective catalytic reduction (SCR) or selective non-

[49] EPA Memorandum from Aaron Worstell to the Deseret PSD Correction Permit Administrative Record documenting Deseret Bonanza Site Visit. Dated November 5, 2014.

catalytic reduction (SNCR).

Post Combustion Control Options

a. Selective Catalytic Reduction (SCR)

SCR is a post-combustion technology that reduces NO_x emissions by injecting ammonia into the exhaust gas stream upstream of a catalyst. The ammonia reacts with NO_x on the catalyst to form molecular nitrogen and water vapor. For the SCR system to operate properly, the exhaust gas must be within a temperature range of 300 to 1,100 degrees Fahrenheit depending on the catalyst type used.

b. Selective Non-Catalytic Reduction (SNCR)

Selective non-catalytic reduction (SNCR) is a post-combustion control technology that reduces NO_x emissions by injection of ammonia or urea into the flue gas in the furnace. SNCR is similar to SCR in that both systems use a reagent to react with NO_x to produce nitrogen and water. However, SNCR operates at higher temperatures than SCR and does not use a catalyst. The effective temperature range for SNCR is 1,400 to 2,000 degrees Fahrenheit.[50] The effectiveness of an SNCR system will be impacted by case specific conditions including injection temperature and residence time, mixing characteristics of the flue gas and reagent, desired level of ammonia slip emissions, and constituents of the exhaust gas that may reduce the desired reduction of NO_x.

Combustion Control Options

c. Low-NO_x burners (LNB) and overfire air (OFA)

LNB restrict NO_x formation by controlling the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. This technique results in a staged combustion process by injecting fuel in a rich state and injecting excess air surrounding the fuel rich area to complete combustion and reduce the peak flame temperature and available oxygen in the initial combustion zones thereby reducing NO_x emissions.

OFA involves the staged injection of air into the firing chamber. This allows the combustion gases that have transitioned from a rich state to a lean state to complete the combustion process more fully while further controlling peak flame temperatures. Through the optimization of OFA with LNB it is possible to achieve NO_x reductions greater than or similar to other combustion controls. There are different variations of designs for OFA such as separated overfire air (SOFA), a patented process known as rotating opposed fire air (ROFA), and advanced OFA (AOFA). These other techniques may be used to improve the overfire air systems to get maximum NO_x reductions while maintaining efficient boiler operation.

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[50] Babcock & Wilcox. *STEAM: Its Generation and Use*. Ed. 41, 2005 (hereafter referred to as, "*STEAM*"), page 32-8. Note: this text book has not been included in the Administrative Record due to copyright.

Since alternate OFA configurations (such as ROFA and AOFA) will not result in significant NO_x reduction beyond LNB with OFA, they will not be considered further. Also, as explained below, LNB/OFA are capable of achieving the highest levels of combustion control for NO_x emissions.

d. Fuel Switching

Under the CAA definition of BACT, the permitting authority must consider "clean fuels" when making a BACT determination. The Bonanza Plant Unit 1 boiler could accommodate alternative coal as primary fuel without a basic redesign of the boiler. However, the ability to reduce NO_x emission by switching to a source of coal with less fuel bound nitrogen may not be possible. Although a reduction in fuel nitrogen content results in reduced NO_x emissions when firing oil fuels, there does not appear to be a similar correlation between coal nitrogen content and NO_x emissions. This may be due to more complex chemical reactions and volatile species present in coal combustion that may not be present in the combustion of oil fuels.[51] Therefore, EPA finds this option is not a control option to reduce NO_x emissions for Bonanza Unit 1.

e. Staged combustion

Staged combustion can be achieved through a wide variety of methods and techniques, but in general creates a fuel rich zone followed by a fuel lean zone. This reduces the peak flame temperature and the generation of NO_x. To create the fuel rich zone a portion of the total air required to complete combustion is withheld from the initial combustion stage. The balance of air required for complete combustion is mixed with the incomplete products of combustion only after the oxygen content of the first-stage air is consumed.

f. Low Excess Air (LEA)

Excess air flow for combustion has been correlated to the amount of NO_x generated. LEA is a technique that limits the net excess air flow. Limiting net excess air flow to less than 2% can strongly limit NO_x content of flue gas at pulverized coal fired boilers. Although there are fuel-rich and fuel-lean zones in the combustion region, the overall net excess air is limited when using this approach. A certain amount of excess air is required to maintain flame stability and provide satisfactory combustion. Limiting excess air to such a low level may cause increased emissions of carbon monoxide (CO).

g. Flue gas recirculation (FGR)

FGR is a flame-quenching technique that involves the recirculation of a portion of the flue gas from the economizer or air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through adsorption of the combustion heat by the relatively inert flue gas and to reduce the oxygen concentration in the combustion zone.

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[51] *STEAM,* page 34-2; regarding pre-combustion fuel switching.

h. Fuel Reburning

Fuel reburning is a control technique that stages combustion by the recirculation of cooled flue gas with added fuel, similar to (FGR). A fuel rich combustion zone is created above the primary burner zone that introduces nitrogen bearing material that may reduce NOx already formed to molecular nitrogen. Following this rich zone, OFA is used to complete the combustion process and minimize pollutants associated with incomplete combustion (e.g., soot, etc.).

i. Reduced Air Preheat

Preheating the combustion air cools the flue gases, reduces the heat losses, and gains efficiency. However, this can raise the temperature of combustion air to a level where NO_x forms more readily. Reducing the amount of air preheat reduces the combustion temperature and NO_x formation is suppressed. However, reducing the amount by which the incoming combustion air is preheated carries a significant efficiency penalty of up to 1% per 40°F. This reduction in efficiency would increase emissions of all criteria pollutants.

j. Reducing Residence Time (at peak temperature through injection of steam)

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

In order to control NO_x, steam is typically injected directly into the flame to reduce the adiabatic flame temperature. As with reduced air preheat, injecting steam would reduce boiler efficiency and result in increased emissions of all pollutants. In addition the increased moisture content of the flue gas may cause increased corrosion of the exhaust stack.

Finally, EPA believes that for combustion control on an EGU such as Bonanza Unit 1 it is appropriate to focus the analysis of combustion controls on LNB/OFA since this option is capable of the highest levels of combustion control for NO_x. Therefore, the combustion control techniques identified in paragraphs e., through j., above will not be considered further.

2. Step 2: Eliminate Technically Infeasible Options

For purposes of this BACT analysis, as discussed in Section II above, technical feasibility is being evaluated as of the year 2000. The evaluation of technical feasibility under BACT is specific to the source under review, in this case Deseret Bonanza's 500 MW coal-fired EGU consisting of a single dry bottom, wall-fired main boiler with an estimated rating of about 4578 million Btu per hour (MMBtu/hr) heat input capacity.[52] If a control technology has been installed and operated successfully on the type of source

[52] *UDAQ 1998 MSRP*. Page 4. Available at: http://www2.epa.gov/region8/air-permit-public-comment-opportunities

under review, EPA considers the technology to be demonstrated and technically feasible. However, if application of a technology has not been demonstrated in practice on the type of source proposed by the permit applicant, EPA next considers whether the control technology is "available" (can be obtained through commercial channels) and is "applicable" to source under review (can be installed and operated successfully on the type of source under consideration).[53]

Post Combustion Control Options

a. SCR

SCR systems have been widely employed on PC-fired boilers in the United States and have achieved emission rates as low as 0.05 lb/MMBtu on a 30-day basis.[54] When EPA proposed the PSD permit in 2000, SCR had been approved in permits and installed on some new and retrofit applications at coal-fired boilers, as shown by the following documents:

- Report from the Department of Energy (DOE) National Energy Technology Laboratory (NETL) which states that there were six coal-fired utility boiler SCR installations in the U.S. as of its publication in July 1997.[55]
- Article from Power Engineering in 1998 which describes those six installations plus one additional.[56]
- Report from EPA, published in June of 1997 which describes the performance of SCR on coal-fired steam generating units.[57]

Below, we have reproduced a table from the DOE NETL report which summarizes the commercial SCR installations on coal-fired utility boilers in the United States that had occurred as of July 1997. As there is nothing in the current permit record that would lead EPA to believe that SCR was technically infeasible for the Bonanza facility in 2000, we do not find elimination of SCR is warranted at this stage of the analysis.

[53] *See PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011, EPA Document Number EPA-457/B-11-001), pages 33-34.
[54] 78 FR 34748. Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed rule, June 10, 2013.
[55] *Clean Coal Technology – Control of Nitrogen Oxide Emissions: Selective Catalytic Reduction (SCR).* DOE NETL, July 1997.
[56] *Coal Plants Report SCR Experience.* Power Engineering, April 1, 1998.
[57] *Performance of Selective Catalytic Reduction on Coal-Fired Steam Generating Units – Final Report.* EPA Office of Air and Radiation, Acid Rain Program, June 25, 1997.

Table 1 – SCR Installations as of 1997

Commercial SCR Installations on Coal Fired Utility Boilers in the United States						
Plant	**Birchwood**	**Stanton (Unit 2)**	**Carneys Point (2 Units)**	**Logan**	**Indiantown**	**Merrimack 2**
Owner/Operator	Southern Energy, Inc./Cogentrix	Orlando Utilities Commissions	US Generating Company (a Pacific Gas and Electric Company/Bechtel partnership)	US Generating Company (a Pacific Gas and Electric Company/Bechtel partnership)	US Generating Company (a Pacific Gas and Electric Company/Bechtel partnership)	Public Service of New Hampshire
Location	King George County, VA	Orlando, FL	Carneys Point, NJ	Swedesboro, NJ	Indiantown, FL	Concord, NH
Capacity, MW (net)	220	425	260	225	330	330
Coal Sulfur, wt%	1.0	1.1 - 1.2	< 2.0	< 1.5	0.8	1.5
Boiler Type	Tangential Fired	Wall Fired	Wall Fired	Wall Fired	Wall Fired	Cyclone, Wet Bottom
Burner Type	Low NO_x Burners/Over Fire Air	Low NO_x Burners/Over Fire Air	Low NO_x Burners/Over Fire Air	Low NO_x Burners/Over Fire Air	Low NO_x Burners/Over Fire Air	Cyclone
Catalyst Supplier	Siemens	Siemens	Ishikawajima-Harima Heavy Industries	Siemens	Siemens	Siemens
Inlet NO_x, lb/MMBtu	0.17	0.32	0.32	0.35	0.25	2.66
Outlet NO_x, lb/MMBtu	0.075	0.17	0.13	0.14	0.15	0.77
NO_x Reduction, %	56	47	59	60	40	71
Ammonia Slip, ppm	< 5	2	< 5	< 5	< 5	< 2
Date SCR Became Operational	November, 1996	June, 1996	March, 1994	September, 1994	December, 1995	May, 1995
SCR Installation (new/retrofit)	New	New	New	New	New	Retrofit

b. SNCR

SNCR systems have also been widely employed in the United States and have achieved NO_x emission rates on PC-fired utility boilers as low as 0.17 lb/MMBtu on a 30-day basis.[58] When EPA proposed the PSD permit in 2000, SNCR had been approved in permits and installed at coal-fired boilers, as shown by the following sources:

[58] See RBLC – listed generally in Table 8

- EPA's RACT/BACT/LAER Clearinghouse (RBLC).

  http://cfpub.epa.gov/rblc/

- EPA's Emissions & Generation Resource Integrated Database (eGRID), Year 2000 files.[59]

  http://www.epa.gov/cleanenergy/energy-resources/egrid/

- *Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions*, Institute of Clean Air Companies, Inc. (ICAC), May 2000 and February 2008.

- *Cardinal 1 Selective Non-Catalytic Reduction (SNCR) Demonstration Test Program*, Electric Power Research Institute (EPRI), July 2000.

  http://www.alrc.doe.gov/technologies/coalpower/ewr/nox/pubs/Cardinal1SNCR.pdf.

- National Electric Energy Data System (NEEDS) Database, v2.1, 2000.

  http://www.epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html

By the year 2000, SNCR had been installed at over 30 units in the power generation industry, and more than 250 industrial units, both in new and retrofit application (ICAC, 2000). Based on the reference materials cited above, below we have listed commercial SNCR installations on coal-fired utility boilers in the United States in 2000. There is nothing in the current permit record that would lead EPA to believe that SNCR was technically infeasible for Bonanza Unit 1 in the year 2000, and thus we do not find elimination of SNCR is warranted at this stage of the analysis.

[59] EPA's eGRID database, year 2000 files gathered information from the Energy Information Administration.

Table 2 – Select SNCR Installations as of 2000

Selected Commercial SNCR Installations on Coal-Fired Utility Boilers in the United States in 2000						
Plant	**Somerset**	**Miami Fort Unit #6**	**Salem Harbor (3 units)**	**Cardinal Station Unit #1**	**Mercer Generating Station (2 Units)**	**Seward**
Owner/ Operator	Somerset Power/Eastern Utilities	Cinergy	New England Power Company	AEP	PSE&G of New Jersey	GPU Genco
Location	Somerset, MA	North Bend, OH	Salem Harbor, MA	Brilliant, OH	Hamilton Township, NJ	Seward, PA
Capacity, MW (net)	113	163	324	590	640	136
Boiler Type	Tangential fired C.E., dry bottom	Tangential fired C.E., dry bottom	Front-fired, dry bottom	Wall-fired, dry bottom	Face-fired boiler, wet bottom	Tangential fired C.E., dry bottom
Burner Type	PC	PC	PC	PC	PC	PC
Inlet NO_x, lb/MMBtu	0.49-0.89	0.55	1.0	0.57	1.4	0.89
Outlet NO_x, lb/MMBtu	0.37	0.35	0.34	0.39	0.84	0.40
NO_x Reduction, %	60 (ICAC)	35	66	30	35	55

Combustion Control Options

c. LNB and OFA

LNB and OFA are often used in conjunction and are widely used in PC-fired boilers. We note that LNB and OFA had been installed in both new and retrofit applications at the time of EPA's original permit issuance. A query of EPA's eGRID database for the year 2000 lists 558 boilers that utilized LNB.[60] With regard to OFA, eGRID lists 138 boilers as utilizing OFA in the year 2000, and six boilers are listed as utilizing AOFA.[61] There is nothing in the current permit record that would lead EPA to believe that LNB and OFA is technically infeasible for the Bonanza facility, and thus we do not find elimination of LNB and OFA is warranted at this stage of the analysis.

In assessing whether it is appropriate to analyze new LNB technology EPA believes it is appropriate to assess whether such an analysis and requirement to upgrade would have been likely during the year 2000 timeframe (when the PSD permit would have been proposed). At that time Deseret operated LNB that were relatively new (installed in 1997);[62] therefore, EPA does not believe that it would have been appropriate to reevaluate whether these LNB needed to be upgraded, since it is unlikely that LNB technology would have advanced appreciably in 3 years. Without further information from Deseret, it is also unclear whether new LNB could achieve appreciable reductions at the Bonanza Unit 1 boiler. Therefore, this analysis assumes that for purposes of evaluating BACT at the time of the ruggedized rotor project, that the LNB are operated in a manner indicative of minimal degradation achieved in the two years prior to July 2000 (that is 7/1/1998 to 6/30/2000). This calculation and the relation to reductions achievable with the addition of OFA are described below.

e. – j. Other combustion controls

None of the other combustion control options presented in step 1 of this analysis are considered to be technically infeasible. However, since LNB/OFA can achieve the highest levels of reduction from combustion controls and Deseret currently operates LNB, the remainder of the analysis will focus on LNB/OFA as the combustion control option rather than the other techniques for combustion control identified in step 1.

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

As explained above in step 2, for the purposes of this analysis EPA is assuming the existing LNB at Bonanza would be returned to and operated in a manner indicative of the burners' performance with minimal degradation as this would have been a likely outcome

[60] EGRID 2000 - pull for NOx controls
[61] *Id.*
[62] *UDAQ 1998 MSPR*. Page 5. Available at: http://www2.epa.gov/region8/air-permit-public-comment-opportunities

of any BACT determination in 2000 that took into account the level of performance that would be appropriate for the existing LNB. Therefore, the pre-project minimally degraded LNB NO_x emission rate baseline, as well as the baseline rate that will be assumed for LNB in the LNB/OFA control option analysis, is assumed to be 0.38 lb/MMBtu as a 30-day rolling average. This value is 95 percent of the 30-day rolling average emissions for the two year period prior to July 2000 (1/7/1998 through 6/30/2000; note that a 30-day rolling average requires the inclusion of the preceding month to generate the first rolling average, therefore data from June, 1998 is also included in this calculation). Data used for this calculation was obtained from EPA's Clean Air Markets Division (CAMD) database.[63] For the LNB/OFA control option we have assumed that the current burners would be returned to the pre-project baseline performance level of 0.38 lb/MMBtu with an additional 25% reduction due to the addition of OFA resulting in an emission rate of 0.28 lb/MMBtu.

To calculate the percent reduction that would actually be achieved by proposed BACT control options applied to Bonanza Unit 1, we have used an emission rate that is indicative of its current NO_x emission rate (explained further in step 4, below). Therefore, the emission rate we propose to use to represent current emissions and the emission reductions that will be achieved in practice is the 30-day rolling average emission rate for the last two years of available data (7/1/2012 to 6/30/2014). Excluding the highest 5% of emissions for this period results in an actual current 95th percentile emission rate of 0.46 lb/MMBtu as a 30-day rolling average.[64]

We note that SCR NO_x control effectiveness presented above in Table 1 vary from 47% to 71% for SCR operating around the year 2000. As noted above in step 2, current SCR can achieve emission rates as low as 0.05 lb/MMBtu with corresponding NO_x reductions varying, but as high as 90%.

SNCR NO_x control effectiveness can vary between 25% and 75% depending on a number of factors, including inlet NO_x concentration, flue gas temperature, residence time, and whether the SNCR is combined with combustion controls or enhancements (e.g., burner optimization, combustion tempering). For the purpose of EPA's Integrated Planning Model (IPM)[65] Base Case v.5.13[66] it was assumed SNCR would achieve 25% NO_x reduction for coal units, which is similar to assumptions used in recent agency actions and reports for EGUs that have assumed 30% up to a maximum of 35% control for

[63] Bonanza LNB Baselines - based on CAMD data (hereafter referred to as *Bonanza Baseline*).
[64] *Id.*
[65] http://www.epa.gov/powersectormodeling/
[66] EPA Base Case serves as the starting point against which policy scenarios are compared. See, *Documentation for EPA Base Case V.5.13 Using the Integrated Planning Model.* U.S. EPA Clean Air Markets Division. November 2013 2005 (hereafter referred to as, "*IPM V.5.13 Documentation*"). Available at: http://www.epa.gov/powersectormodeling/BaseCasev513.html#documentation

SNCR.[67] Based on these assumptions and the expected relatively low inlet NO_x concentration to any SNCR installed on Bonanza Unit 1 we believe it is appropriate to continue with this analysis assuming that SNCR would be able to achieve 35% reduction in NO_x.

In 2000, LNB with OFA may have been able to achieve 40-70% reduction in NO_x.[68] Current designs may be able to achieve 80% reduction in NOx.[69]

As noted above, it is common practice to maximize the control of NO_x through use of combustion controls prior to the addition of post combustion add-on controls to minimize the cost and resources required to operate those add-on control(s). Therefore, for the remainder of this analysis, LNB/OFA will be assumed in conjunction with the post combustion control options under consideration (i.e., LNB/OFA+ SCR or LNB/OFA+ SNCR).

[67] 78 FR 34748. Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed rule, June 10, 2013.

[68] *Ultra Low NO_x Combustion Solutions for Wall-Fired Boilers.* Babcock & Wilcox (B&W). Slideshow presenting LNB performance experience in 2000 and 2001; *Demonstartion of Advanced Combustion NO_x Control Techniques for a Wall-Fired Boiler.* Clean Coal Technology Demonstration Program, DOE/FE-0429, January 2001, page 2 and all (indicates up to 68% reduction using LNB and AOFA and additional 10-15% NOx reduction with Generic NOx Control Intelligent System); and *Analysis of Combustion Controls for Reducing NO_x Emissions From Coal-fired EGUs in the WRAP Region.* Eastern Research Group, Inc. for the Western Regional Air Partnership (WRAP), September 6, 2005.

[69] *STEAM*, page 14-1.

Table 3 – Control Technology Ranking – Estimated Reductions and Emission Rates

Rank	Control Option	Range of Control, % (year 2000)	Range of Control, % (Currently Applicable)	Control Level for this BACT Analysis, %	Emission Rate for this BACT Analysis, lb/MMBtu	Emission Rate, lb/hr (tpy) @ 100% capacity factor
1.	LNB/OFA+ SCR	60[70] - 90[71] [reduction from uncontrolled emission rate] 50 – 80 [additional reduction achievable due to SCR]	85[72] - 98[73] [reduction from uncontrolled emission rate] 75 – 90 [additional reduction achievable due to SCR]	85 [from 0.46 lb/MMBtu to 0.07 lb/MMBtu - reduction from current LNB baseline rate] 75 [from 0.28 lb/MMBtu to 0.07 lb/MMBtu - additional reduction due to SCR beyond LNB/OFA control option]	0.07[74]	320 lb/hr (1,404 tpy)
2.	LNB/OFA+ SNCR	44[75] – 85[76] [reduction from	65[77] - 95[78] reduction from uncontrolled	61 from 0.46 lb/MMBtu to	0.18	824 lb/hr (3,609 tpy)

[70] 20% reduction of NO_x emissions due to LNB/OFA and additional 50% reduction of boiler outlet NO_x emissions due to SCR.

[71] 67% reduction due to LNB/OFA and additional 80% reduction of boiler outlet NO_x due to SCR resulting in 93.4% overall reduction – assumed to be 90% for this analysis.

[72] 50% reduction due to LNB/OFA and additional 75% reduction of boiler outlet NO_x due to SCR results in 87.5% reduction overall – assumed to be 85% for this analysis.

[73] SCR may be able to reduce NOx leaving the boiler by up to 90% (*STEAM*, page 34-3) resulting in maximum potentially achievable reductions of 98%. However, the ability to achieve such high levels of overall reduction maybe limited due to many factors affecting the capacity to further reduce emissions.

[74] The analysis of the addition of SCR to Wyoming utilities for Regional Haze has concluded that 0.07 lb/MMBtu on a 30-day rolling average is appropriate for well operated LNB/OFA+SCR. See, 78 FR 34738. Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed rule, June 10, 2013.
79 FR 5032. Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan for Regional Haze; Final rule, January 30, 2014.

[75] 30% reduction due to SNCR with 20% reduction from uncontrolled NO_x rate from LNB/OFA – *STEAM* page 34-14

[76] For retrofit 50% reduction due to SNCR assumed to balance reagent use and ammonia slip – *STEAM* page 34-14. Assuming 65% reduction from uncontrolled NO_x rate and 50% reduction of boiler outlet emissions results in overall reduction of 83.5%, rounded for analysis to 85%.

[77] 50% control due to LNB/OFA and 30% additional due to SNCR.

[78] Maximum reduction due to SNCR assumed to be 75% of boiler outlet NO_x. With 80% maximum control due to LNB/OFA resulting overall control is 94%. This may not be achievable in many retrofits due to lack of residence time at appropriate temperatures.

		uncontrolled emission rate 30 – 50 [additional reduction achievable due to SNCR]	emission rate 30 – 75 [additional reduction achievable due to SNCR]	0.18 lb/MMBtu - reduction from current LNB baseline rate] 35[79] [from 0.28 lb/MMBtu to 0.18 lb/MMBtu - additional reduction due to SNCR beyond LNB/OFA control option]		
3.	LNB/OFA	20 – 67[80] [anticipated reduction due to LNB & OFA on an uncontrolled boiler] 17[81] – 60[82] [additional attributed to OFA when added to LNB]	50 – 80[83] [anticipated reduction due to LNB & OFA on an uncontrolled boiler] 20 – 60 [additional attributed to OFA when added to LNB[84]]	39 [from 0.46 lb/MMBtu to 0.28 lb/MMBtu - reduction from current actual LNB rate] 17 [from 0.46 lb/MMBtu to 0.38 lb/MMBtu - reduction assumed from returning LNB to pre project operational state] 25 [85] [from 0.38 lb/MMBtu to 0.28 lb/MMBtu - additional	0.28	1,282 lb/hr (5,614 tpy)

[79] See discussions and citations in Step 2, above regarding achievable reductions due to SNCR; See also, *STEAM,* page 34-14 for more information on achievable reductions. Note 35.7% has been expressed simply as 35%.

[80] *Demonstration of Advanced Combustion NO_x Control Techniques for a Wall-Fired Boiler.* Clean Coal Technology Demonstration Program, DOE/FE-0429, January 2001 - indicates 67% achieved from LNB/OFA near the year 2000 as a retrofit application.

[81] *Id.* – the Plant Hammond retrofit indicates 17% additional; see also, Table 9 for the range of reduction achieved by plants that retrofit with OFA.

[82] See Table 9 for percent reduction from retrofit OFA based on CAMD data.

[39] *STEAM,* page 14-1.

[84] See Table 9 for percent reduction from retrofit OFA based on CAMD data.

[85] 95th percentile percent reduction calculated from CAMD data for units that have LNBs and added OFA. See Table 9. See also, Percent Reduction LNB + OFA – pdf of excel spreadsheet percent reduction calculator.

				reduction attributed to OFA]		
4.	Current LNB [2012 – 2014 emissions	Percent control N.A. [~ pre 2000 emission rate = **0.38** lb/MMBtu]	Percent control N.A. [~ current (July 2012 – June 2014) emission rate = **0.46** lb/MMBtu]	N.A.	0.46 [used to assess reduction for options 1–3]	2,105 lb/hr (9,224 tpy)

Note that the use of percent reduction of NO_x due to a control technology may vary due to not only the effectiveness of the control technology, but also the uncontrolled NO_x emission rate. The ability to achieve high percent reductions may not exist for units with lower uncontrolled NO_x emission rates due to the relative reductions available.

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

In light of the unique nature of this proposed permit – including the lack of an application with site-specific cost estimates for installation and operation of various NO_x control options at the Bonanza plant or site-specific information regarding energy and environmental impacts, as well as the fact that this analysis is for a permit that will be issued today, but reflects BACT as it would have been in 2000 – EPA has relied upon general information to determine the likely economic environmental and energy impacts resulting from the application of the remaining control options to Bonanza Unit 1.

With regard to economic impacts, EPA developed estimates of the economic cost for the installation and operation of NO_x control technology using various sources of information to allow for the completion of an economic analysis at Step 4 of the BACT process. To accomplish this, EPA has relied on the IPM model to develop 2012 and 2011 cost estimates. EPA is also presenting some information regarding cost estimates developed in or around the year 2000 in order to analyze the likely economic impacts of each control at this facility.

In undertaking the cost analysis in this BACT analysis, we have assumed that LNB could achieve the emission rate indicative of LNB with limited degradation that was achieved during the two year period prior to July 2000 (1/7/1998 to 6/30/2000). We have assumed that OFA may be able to achieve an additional 25% reductions in NO_x from the LNB Year 2000 baseline emission rate of 0.38 lb/MMBtu (30-day rolling average), discussed in Step 3 of the analysis. Using these assumptions results in an LNB/OFA emission rate of 0.28 lb/MMBtu.

Since all control options analyzed for this project include LNB/OFA, the cost of other post combustion add-on control options must be added to any costs associated with the LNB/OFA control option. The baseline NO_x emission rate prior to installation of SCR or

SNCR will therefore be considered to be the emission rate achieved by LNB/OFA, which is 0.28 lb/MMBtu.

In order to present a cost analysis for the addition of OFA for the LNB/OFA control option, EPA believes it is appropriate to use a baseline that is indicative of the reductions achieved from current actual emissions to an emission rate indicative of LNB/OFA without significant burner degradation. This is due to the fact that this correction permit will reduce emission from current levels, which have shown increased NO_x emissions since the 1998 through 2000 period due to apparent burner wear and degradation. The baseline emission rate we propose to use to assess LNB/OFA economic costs (as well as the other control options) is the 30-day rolling average emission rate for the last two years of available data (7/1/2012 to 6/30/2014).[86] Excluding the top 5% of emissions for this period results in an actual current emission rate of 0.46 lb/MMBtu on a 30-day rolling average. Therefore, costs of control options will be assessed using the current emission rate of 0.46 lb/MMBtu and the LNB/OFA controlled emission rate of 0.28 lb/MMBtu. Note that for this analysis we have assumed that Deseret, when undertaking the project to install additional controls will also return the existing burners to their pre project minimally degraded performance although we have not attempted to assign costs since that information is not available at this time.

The heat input rate that EPA has used throughout these cost calculations is indicative of the Bonanza Unit 1 heat rate after the ruggedized rotor project as estimated by Deseret. The heat rate estimated by Deseret is 4,578 MMBtu/hr.[87]

General Cost Information

EPA used the IPM model to calculate the costs for each NOx emission control under consideration. Outputs from the IPM model include control option capital cost, annualized capital cost, and the annualized fixed and variable operating and maintenance costs. These costs are summarized in Table 4 below.[88] In doing so, and for all the control options EPA has calculated a Capital Recovery Factor (CRF) of 9.44%, representative of 20 years at an assumed real interest rate of 7%, as well as an additional interest rate of 1.2% for insurance and property tax. This results in a total charge rate of 10.64% that is used to compute the annualized capital cost which when added to the annual O&M costs results in the total annualized cost that will be used to determine the average cost effectiveness for a control option. Please note that: annual O&M costs for each control option include both fixed O&M costs as well as variable O&M costs;[89] variable O&M costs have been computed using the gross average load from July 2012 to June 2014, which is 3,658,575 Megawatt-hour (MWh); and the costs presented in the analysis below do not consider any potentially necessary burner improvements that may be

[86] *Bonanza Baseline*

[87] *UDAQ 1998 MSPR*, Page 4. Available at: http://www2.epa.gov/region8/air-permit-public-comment-opportunities

[88] IPM SCR Cost – spreadsheet calculation; IPM SNCR Cost – pdf of excel spreadsheet calculation; and *IPM V.5.13 Documentation*, Table 5-4, page 5-5.

[89] *Id.*

needed to meet the BACT limit.

EPA then compared these cost estimates to the baseline emission rate provided above and the emission reductions that would result from the various control options to examine the average cost effectiveness for each control option. The average cost effectiveness is calculated as follows:

$$\textbf{Average Cost Effectiveness} = \frac{\text{Control Option Annualized Cost}}{\text{Baseline Emissions Rate} - \text{Control Option Emission Rate}} \qquad \text{Eq. 1}$$

For SCR and SNCR, the total cost and total reduction from the baseline rate is representative of application of LNB/OFA as well as the post-combustion add-on control. Thus, in order to assess the costs and emissions reductions of the add-on technologies alone, it was necessary to compute the incremental costs and control-specific pollutant reduction calculations. Incremental cost effectiveness is used to evaluate the difference in cost between two control options, or levels of control. This calculation provides the additional dollars required per additional ton of NO_x removed by choosing a higher level of control. The incremental cost effectiveness of going from LNB/OFA alone (Option #1) to LNB/OFA+SCR or LNB/OFA+SNCR (Option #2) is calculated as follows:

$$\textbf{Incremental Cost} = \frac{\text{Total Annualized Costs of Control Option \#1} - \text{Total Annualized Cost of Control Option \#2}}{\text{Control Option \#2 Emission Rate} - \text{Control Option \#1 Emission Rate}} \qquad \text{Eq. 2}$$

As explained more fully below, EPA has computed economic costs for each pollution control option under consideration, using control specific emission reductions and cost estimates based on IPM estimates, Equations 1 and 2, and the equations provided below as follows:

Table 4 – Economic Costs of NO_X BACT Options Under Consideration (SCR and SNCR are 2012 dollars; OFA costs are 2011 dollars)

Control Alternatives	Emission Rate (lb/MMBtu) / (tpy)	Emissions Reduction vs. LNB (tpy)	Total Capital Cost ($)	Operating and Maintenance Cost ($/year)	Total Annualized Cost ($/year)	Average Cost Effectiveness ($/ton reduced)	Incremental Cost Effectiveness ($/ton reduced)
Existing LNB (Baseline)	0.46 9,224 tpy	NA	NA	NA	NA	NA	NA
LNB/OFA (Cost for OFA addition, as explained below)	0.28 5,614 tpy	3,610 tpy	$7,076,000	$156,172	$909,058	$252	NA
LNB/OFA + SNCR	0.18 3,609 tpy	5,615 tpy	$11,193,000+ $7,076,000 = $18,269,000	$7,300,000+ $156,172 = $7,456,172	$8,491,000 + 909,058 = 9,400,058	$1,674	$4,235 for incremental cost effectiveness for addition of SNCR to LNB/OFA
LNB/OFA + SCR	0.07 lb/MMBtu 1,404 tpy	7,820 tpy	$152,865,425 + $7,076,000 = $159,941,425	$4,757,000 + $156,172 = $4,913,172	$21,021,000+ 909,058 = 21,930,058	$ 2,804	$4,992 for incremental cost effectiveness for addition of SCR to LNB/OFA

a. SCR

The economic, energy, and environmental impacts associated with SCR (in addition to LNB/OFA) are discussed below.

SCR systems 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 eliminating SCR technology as BACT for coal-fired power plants. EPA is not aware of any fact-specific circumstances for Bonanza Unit 1 that would warrant elimination of SCR based on energy impacts such as the need for significant flue gas reheat.

With any SCR installation, there are some commonly noted adverse environmental impacts.

These would include ammonia slip emissions, catalyst disposal, and potential ammonia handling hazards. These impacts are usually deemed to be offset by the environmental benefits of significant NO_x reduction from the SCR system. Additional impacts that may occur as a result of operation of SCR systems is the conversion of sulfur in the flue gas to H_2SO_4 as well as the potential generation of N_2O, which is a potent GHG. SCR catalyst should be designed and installed to minimize the potential to generate these air pollutants. These various environmental impacts have not generally been proven to be significant enough to eliminate SCR technology as BACT for coal-fired power plants, and EPA is not aware of any fact-specific circumstances for Bonanza Unit 1 that would warrant elimination of SCR based on environmental impacts.

In order to assess potential economic impacts and calculate the average cost effectiveness of SCR, the NO_x reduction attributed to the control option must be calculated (see, Equation 1). Using the current baseline of 0.46 lb/MMBtu and a controlled emission rate of 0.07 lb/MMBtu that can currently be achieved with LNB/OFA+SCR, the emission reduction attributable to this control option is calculated as follows:

$$(0.46 \text{ lb/MMBtu} - 0.07 \text{ lb/MMBtu}) \times (4{,}578 \text{ MMBtu/hr}) \times (8{,}760 \text{ hr/yr}) (1 \text{ ton}/2{,}000 \text{ lb}) = 7{,}820 \text{ tons } NO_x \text{ reduced/year}$$

Using the SCR costs provided in Table 4 above, this results in an average cost effectiveness for LNB/OFA+SCR of $2,804 per ton of NO_x removed, and an incremental cost effectiveness for LNB/OFA to LNB/OFA+SCR of $4,992 per additional ton of NO_x removed by SCR, which consistent with the nature of this analysis is equal to the average cost effectiveness calculated using the IPM cost spreadsheet.[90] This also means that the annual average cost from the IPM calculation is representative of the additional yearly cost that Deseret would have to bear to install SCR, which is $21,021,000 additional per year.

To determine whether a control option should be eliminated based on economic impacts, EPA has generally tried to determine whether the costs associated with a control options for the facility under consideration are outside the range of costs borne in other recently-issued PSD permits for similar types of facilities. However, we don't think such an approach is warranted in this case, where EPA is undertaking the BACT analysis in a proposed PSD correction action today to address a PSD permitting error that occurred in a permit issued (and for a project completed) more than 14 years ago, because such comparisons have little relevance. Instead, EPA is using a more qualitative cost assessment, which the Agency has provided for in specific instances in which comparative cost information is lacking and overall costs are disproportionately high.[91] In this case, given the gap in time from the 2000 analysis period to the present day permitting action, EPA was unable to compile and analyze specific past PSD permit information regarding the costs that permitting authorities considered to be economically feasible or infeasible in BACT determinations for this type of source in 2000. EPA has instead considered the overall capital cost of the control option under consideration given the specific

[90] IPM SCR Cost – spreadsheet calculation.

[91] *See PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011, EPA Document Number EPA-457/B-11-001), page 42-43; *In re City of Palmdale*, PSD Appeal No. 11-07 (EAB, Sept. 17, 2012).

facts of this case. Where, as here, the permitting authority is undertaking a permitting action to correct a permitting error made more than 14 years ago which will result in an unplanned pollution control upgrade at Bonanza Unit 1, we believe the capital cost of $152,865,425 for SCR – in addition to the $7,076,000 for the addition of OFA which computes to $21,021,000 of additional cost per year (Total Annualized Cost) – is too high to represent BACT for Bonanza Unit 1. Therefore, in light of the unique nature and timing of the PSD correction permitting action and considering the cost to install and operate SCR on this specific facility at this time, EPA proposes to eliminate SCR as BACT for Bonanza Unit 1.

b. SNCR

The economic, energy, and environmental impacts associated with SNCR (in addition to LNB/OFA) are discussed below. SNCR systems require some additional energy in order to operate the reagent injection system and move the increased mass through the boiler and exhaust system; however, this energy impact has not proven to be a significant driver eliminating SNCR technology as BACT for coal-fired power plants. EPA is not aware of any fact-specific circumstances for Bonanza Unit 1 that would warrant elimination of SNCR based on energy impacts.

As is the case with SCR, an SNCR installation may have adverse environmental impacts. These would include ammonia slip emissions (which may be higher for SNCR than SCR due to the lack of a catalyst and depending on the control system employed with the SNCR system), and potential ammonia handling hazards. Ammonia slip from SNCR on coal-fired boilers is generally equal to or less than 5 ppm upstream of the air heater (ICAC, 2000). These impacts are usually deemed to be offset by the environmental benefits of NO_x reduction from the SNCR system if appreciable emission reductions can be achieved. Thus, these various environmental impacts have not generally been proven to be significant enough to eliminate SNCR technology as BACT for coal-fired power plants, and EPA is not aware of any fact-specific circumstances for Bonanza Unit 1 that would warrant elimination of SNCR based on environmental impacts.

In order to assess potential economic impacts and calculate the average cost effectiveness of SNCR, the NO_x reduction attributed to the control option must be calculated (see, Equation 1). Using the current baseline emission rate of 0.46 lb/MMBtu, as explained above, and using a controlled emission rate of 0.18 lb/MMBtu achieved with LNB/OFA+SNCR, the emission reduction attributable to this control option is calculated as follows:

(0.46 lb/MMBtu – 0.18 lb/MMBtu) x (4,578 MMBtu/hr) x (8,760 hr/yr) (1 ton/2,000 lb) = 5,615 tons NO_x reduced/year

Using the SNCR costs provided in Table 4 above, the resulting average cost effectiveness is $1,674 per ton NO_x removed, and an incremental cost effectiveness of $4,235 per additional ton NO_x removed.[92]

[92] IPM SNCR Cost – spreadsheet calculation

As noted above, given the given the unique nature and timing of EPA's correction action, we do not think it is appropriate to consider these costs as compared to other similar sources. Instead, we look to a more qualitative cost assessment. Where, as here, the permitting authority is undertaking a permitting action to correct a permitting error made more than 14 years ago which will result in an unplanned pollution control upgrade at Bonanza Unit 1, we believe the total capital costs of $18,269,000, of which $11,193,000 are attributed to installation of SNCR, is too high to represent BACT for Bonanza Unit 1. Therefore, EPA proposes to eliminate SNCR as BACT for Bonanza Unit 1.

c. LNB/OFA

The economic, energy, and environmental impacts associated with LNB/OFA are discussed below.

LNB/OFA systems can have energy impacts associated with increased excess oxygen requirements, loss on ignition (LOI) increase, and increased flow rate to downstream controls, as well as environmental impacts associated with potential increases in CO emissions. However, none of these impacts have proven to be a significant driver eliminating LNB/OFA technology as BACT for coal-fired power plants, and EPA is not aware of any fact-specific circumstances for the Bonanza facility that would warrant elimination of LNB/OFA based on these impacts.

To assess the economic impacts of LNB/OFA, we have used IPM v5.13, table 5-4: Cost (2011 dollars) of NO_x Combustion Controls for Coal Boilers (300 MW Size) to estimate the cost to add OFA to the Bonanza Unit 1 boiler.[93] This IPM table does not include cost for OFA, but by subtracting the cost provided for LNB alone from the cost provided for LNB/OFA together we can estimate the cost for OFA alone. The resulting costs (which have been scaled from 300 MW to 500 MW for the Bonanza boiler using the scaling technique in IPM table 5-4) are as follows:

<u>Table 5 – OFA Costs</u>

	Capital Cost – scaled to 500 MW ($/kW)	Fixed O&M – scaled to 500 MW ($/kW-yr)	Variable O&M ($/MWh) – no scaling factor is applied when calculating variable O&M costs
LNB	39.96	0.25	0.07
LNB/OFA	54.11	0.42	0.09
OFA – estimated	14.15	0.17	0.02
	Total Capital Cost ($)	Total Fixed O&M ($/year)	Total Variable O&M ($/year)
OFA – estimated	7,076,000	83,000	73,172
		Total O&M Cost ($)	
		156,172	

Using the current baseline of 0.46 lb/MMBtu and a controlled emission rate of 0.28 lb/MMBtu

[93] *IPM V.5.13 Documentation*, Table 5-4, page 5-5.

that can currently be achieved with LNB/OFA, the emission reduction attributable to this control option is calculated as follows:

(0.46 lb/MMBtu – 0.28 lb/MMBtu) x (4,578 MMBtu/hr) x (8,760 hr/yr) (1 ton/2,000 lb) = 3,610 tons NO_x reduced/year

Using the LNB/OFA costs and emissions reductions as computed above and provided in Table 4, the average cost effectiveness is calculated to be $252 per ton NO_x reduced.

Although it is unclear whether Deseret would have undertaken the ruggedized rotor project if an additional cost for OFA were required, we believe it is appropriate to propose to conclude that LNB/OFA is BACT for the Bonanza Unit 1 PSD permit correction. Although we have not included any assumptions for cost to return the existing burners' performance to pre-project levels, the estimate of more than $7 million for OFA may still be an overestimate even if burner performance costs were included, as indicated by the discussion below which cites a cost of $4.4 million to install OFA on a facility in 1995 dollars (as burner performance costs are expected to be minimal in comparison).

As noted above, given the unique nature and timing of EPA's correction action, we do not think it is appropriate to consider these costs as compared to other similar sources. Instead, we are undertaking a more qualitative cost assessment. In this case, we believe the LNB/OFA average cost effectiveness of $252 per ton NO_x reduced and the total capital costs of $7,076,000 are reasonable under the current circumstances. While EPA was unable to compile and analyze specific past PSD permit information regarding the costs that permitting authorities considered to be economically feasible or infeasible in BACT determinations for this type of source in 2000, we do have general permitting information that supports our conclusion not to eliminate LNB/OFA as BACT for Bonanza Unit 1 in 2000 based on economic impacts.

EPA examined a DOE case study published in January 2001 for the Clean Coal Technology Demonstration Program entitled: Demonstration of Advanced Combustion NO_x Control Techniques for a Wall-Fired Boiler (DOE/FE-0429). This study applied LNB and AOFA in a retrofit application to a 500 MW wall fired boiler at Georgia Power Company's Plant Hammond Unit 4 between August 1990 and May 1996. The costs from the DOE are presented below in Table 6 in an attempt to analyze the application of this control option near the year 2000. The costs presented in this study were generated at the time of the study and may not be indicative of costs that would be incurred today for the same project. We note that the total project cost in the DOE study was listed at $15,853,900, but that included an automated optimization system that is not being assessed as part of the BACT analysis in this permitting action. Using the information in the DOE study, as summarized below, it appears that the capitol cost for the AOFA component was $4,400,000 and that the average cost effectiveness of the AOFA component was $134/ton NO_x removed.

Table 6 – Cost to Retrofit LNB & AOFA on Plant Hammond 500 MW Wall-Fired Boiler (in 1995 dollars)

	Capital Cost per kW	Capital Cost (500 MW)
LNB	$10/kW	$5 million
AOFA	$8.80/kW	$4.4 million
LNB/AOFA	$18.80/kW	$9.4 million

Although cost effectiveness ranged somewhat depending on the load profile of the boiler (base load, peaking, etc.), cost were summarized as follows:

Table 7 – Cost Effectiveness for Plant Hammond Retrofit (1995 dollars)

	Average Cost Effectiveness ($/ton NO_x removed)
LNB	$54/ton
OFA (AOFA)	$134/ton
LNB/AOFA	$79/ton

We also believe selection of LNB/OFA as BACT for this permitting action is reasonable in light a general analysis of the application of NO_x BACT in the years leading up to 2000, when the NO_x BACT determination for the Federal PSD permit for this facility would have been made. We have generated a list of projects at other facilities that were entered into the RBLC between 1990 and 2000 for utility boilers greater than 250 MMBtu/hr. This information is contained in Table 8 below. While EPA was unable to compile and analyze specific past PSD permit information regarding the costs that permitting authorities considered to be economically feasible or infeasible in the BACT determinations included in this Table, it is clear that in the year 2000 and the years leading up to it, many sources were required to install LNB and OFA. EPA is not aware of any cost-specific circumstances for Bonanza Unit 1 that would differentiate it from these many other facilities and thus warrant elimination of LNB/OFA based on economic impacts. Thus, we propose that LNB/OFA be considered as BACT for NO_x emissions from Bonanza Unit 1.

Table 8 – NO_x control technology from the RBLC 1990 to 2000

Facility	**RBLC ID**	**Date**	**control**
AES Beaver Valley Partners	PA-0163	6/1/1999	LNB/SOFA
Orion Power Midwest	PA-0176	4/8/1999	LNB/OFA
Two Elk (Never Constructed)	WY-0039	2/27/1998	LNB/OFA + SCR
Encoal Corporation -	WY-	10/10/1997	LNB/OFA + SCR

Encoal North Rochelle Facility	0047		
WYGEN, Inc – WYGEN I	WY-0048	9/6/1996	LNB/OFA
Waynesburg Plant/Mon Valley	PA-0107	8/2/1995	LNB + SCR
West Penn Power Company	PA-0123	6/12/1995	LNB/SOFA (LNCFS Level III)
Pennsylvania Power and Light Company	PA-0112	5/25/1995	O/M According to Manufacturer
Metropolitan Edison Company	PA-0129	3/9/1995	LNB/CCOFA and SOFA LNCFS Level III
Pennsylvania Power Company - Units 1 and 2	PA-0105	12/29/1994	LNB/SOFA
Pennsylvania Power Company - Unit 3	PA-0105	12/29/1994	LNB/SOFA
Zinc Corporation of America	PA-0109	12/29/1994	Modification to Incorporate Bias Firing Technology - Automated Air Controllers
Pennsylvania Electric Company - Boiler 1	PA-0115	12/29/1994	LNB/SOFA LNCFS Level III
Pennsylvania Electric Company - Boiler 2	PA-0115	12/29/1994	LNB/SOFA LNCFS Level III
West Penn Power Company - Boiler 1	PA-0116	12/29/1994	LNB/SOFA
West Penn Power Company - Boiler 2	PA-0116	12/29/1994	LNB/SOFA
West Penn Power Company - Boiler 3	PA-0116	12/29/1994	LNB/SOFA
Duquesne Light Company - Boiler 1	PA-0117	12/29/1994	LNB/SOFA
Duquesne Light Company - Boiler 2	PA-0117	12/29/1994	LNB/SOFA
Duquesne Light Company - Boiler 3	PA-0117	12/29/1994	LNB/SOFA
Duquesne Light Company - Boiler 4	PA-0117	12/29/1994	LNB/SOFA
Pennsylvania	PA-	12/29/1994	LNB/SOFA

Electric Company - boiler 1	0119		
Pennsylvania Electric Company - boiler 2	PA-0119	12/29/1994	LNB/SOFA
Pennsylvania Electric Company - boiler 3	PA-0119	12/29/1994	LNB/SOFA
West Penn Power Company - boiler 1	PA-0125	12/29/1994	LNB
West Penn Power Company - boiler 2	PA-0125	12/29/1994	LNB
Pennsylvania Electric Company - boiler 1	PA-0126	12/29/1994	LNB/SOFA LNCFS Level III
Pennsylvania Electric Company - boiler 2	PA-0126	12/29/1994	LNB/SOFA LNCFS Level III
PECO Energy Co. - boiler 1	PA-0108	12/28/1994	LNB/CCOFA and SOFA LNCFS Level III
PECO Energy Co. - boiler 2	PA-0108	12/28/1994	LNB/CCOFA and SOFA LNCFS Level III
P.H. Glatfelter - Unit 1	PA-0142	12/28/1994	LNB/SOFA
P.H. Glatfelter - Unit 2	PA-0142	12/28/1994	LNB/SOFA
Pennsylvania Electric Company - Units 1 and 2	PA-0111	12/27/1994	LNB
Pennsylvania Electric Company - Units 3 and 4	PA-0111	12/27/1994	LNB/SOFA LNCFS Level III
Pennsylvania Power and Light Company - Unit 1	PA-0113	12/27/1994	LNB/SOFA
Pennsylvania Power and Light Company - Unit 2	PA-0113	12/27/1994	LNB/SOFA
Pennsylvania Power and Light Company - boiler 1	PA-0128	12/22/1994	LNB/SOFA LNCFS Level III
Pennsylvania Power	PA-	12/22/1994	LNB/SOFA

and Light Company - boiler 2	0128		LNCFS Level III
Pennsylvania Power and Light Company - boiler 3	PA-0128	12/22/1994	LNB/SOFA LNCFS Level III
Pennsylvania Power and Light Company - boiler 1	PA-0114	12/14/1994	LNB/SOFA
Pennsylvania Power and Light Company - boiler 2	PA-0114	12/14/1994	LNB/SOFA
Metropolitan Edison Company - boiler 1	PA-0121	12/14/1994	LNB/CCOFA and SOFA LNCFS Level III
Metropolitan Edison Company - boiler 2	PA-0121	12/14/1994	LNB/CCOFA and SOFA LNCFS Level III
Pennsylvania Power and Light Co.	PA-0100	11/27/1994	LNB/SOFA
SEI Birchwood, Inc.	VA-0213	8/23/1993	SCR
Black Hills Power and Light Company - Neil Simpson	WY-0046	4/14/1993	Combustion Control
Indelk Energy Services of Otsego	MI-0228	3/16/1993	SNCR
Roanoke Valley Project II	NC-0057	12/7/1992	LNB/OFA + SNCR
South Carolina Electric and Gas Company - Unit 1	SC-0027	7/15/1992	LNB/OFA
South Carolina Electric and Gas Company - Unit 2	SC-0027	7/15/1992	LNB/OFA
South Carolina Electric and Gas Company - Unit 3	SC-0027	7/15/1992	LNB/OFA
Tennessee Eastman Company - Boiler #31	TN-0119	4/29/1992	LNB
Cargill, Inc. - boiler #8500	TN-0121	1/2/1992	LNB
Cargill, Inc. - boiler #8001	TN-0121	1/2/1992	FGR

Orlando Utilities Commission	FL-0044	12/23/1991	LNB + SCR
Maple Street Powerhouse Unit 2	MA-0012	12/2/1991	LNB + SNCR (NOx Out Process)
Ware Cogen - Unit 2	MA-0033	12/2/1991	LNB + SNCR
Keystone Cogeneration Systems, Inc.	NJ-0015	9/6/1991	SNCR OR SCR
Old Dominion Electric Cooperative - boiler 2	VA-0181	4/29/1991	LNB/AOFA
Roanoke Valley Project	NC-0054	1/24/1991	LNB/AOFA
Cogentrix of Richmond - Boiler, Stoker, 8	VA-0178	1/2/1991	SNCR
Chambers Cogeneration Limited Partnership - Boilers (2)	NJ-0014	12/26/1990	SCR
Santee Cooper (S.C. Public Service Authority)	SC-0028	11/28/1990	LNB
Hadson Power 13	VA-0176	8/17/1990	LEA + SNCR
Mecklenburg Cogeneration Limited Partnership	VA-0171	5/9/1990	LNB/AOFA

5. Step 5: Proposed NO_x BACT for Unit 1 Boiler.

EPA has determined that the control level offered by the application of LNB/OFA to Bonanza Unit 1 would represent NO_x BACT for this permit correction. An emission limit must now be established that represents the maximum degree of reduction achievable for LNB/OFA for this project, with available information. EPA estimated an additional 25% reduction of NO_x as a result of the application of OFA from the pre project minimally degraded LNB emission rate of 0.38 lb/MMBtu. This results in an emission rate of 0.28 lb/MMBtu on a 30-day rolling average. The overall reduction assumed by this analysis for the LNB/OFA control option when compared to the two year current baseline period (mid-2012 to mid-2014) is therefore a 39% reduction in NO_x.

The 25% reduction due to OFA was estimated to be appropriate based on a review of

CAMD data for similar boilers that had existing LNB and then added OFA.[94] The CAMD data indicate that 95% of facilities with LNB that install OFA should be able to achieve at least 21% additional reduction where LNB/OFA is installed rather than just LNB. The best performing facilities (excluding the top 5% of best performing facilities) should be able to achieve 53% reduction, although we note that the small sample size resulted in only two facilities that achieve 53% reduction and none that achieve any higher reductions attributed to OFA (note: we have also included information relying on 99th percentile emissions). Due to the design of the Bonanza Unit 1 boiler and a retrofit OFA system and the statistical analysis performed on other OFA retrofits[95] we believe that the appropriate level of control to propose for this retrofit is 25% reduction due to the addition of OFA.

Table 9 – Percent Reduction Attributed to OFA for similar facilities to Bonanza

State	Facility Name	Unit ID	Capacity Input (MMBtu/h)	Low NOx Burners	Low NOx Burners + Overfire Air	Average NOx Rate w/ LNB (lb/MMBtu)	Average NOx Rate w/ LNB + OFA (lb/MMBtu)	Percent Reduction from Addition of OFA
IA	Walter Scott Jr. Energy Center	3	8,500		10/17/06	0.43	0.20	53
KS	La Cygne	2	7,700		06/13/13	0.31	0.22	29
KS	Quindaro	2	1,394		11/29/11	0.31	0.19	39
MI	Erickson	1	1,668		04/01/04	0.42	0.21	50
MN	Hoot Lake	3	1,163	06/19/98	10/12/06	0.30	0.19	37
MO	Meramec	4	3,782	06/30/96	01/01/02	0.33	0.18	45
MO	Thomas Hill Energy Center	MB3	8,182	11/01/02	05/01/06	0.31	0.23	26
TX	W A Parish	WAP5	8,545		10/15/00	0.35	0.17	51
WI	Edgewater (4050)	5	5,424		11/22/06	0.22	0.14	36
WI	Pulliam	7	1,507		07/14/09	0.38	0.23	39
WI	Pulliam	8	1,627		11/20/09	0.33	0.23	30
CO	Craig	C1	6,000		09/13/03	0.35	0.28	20
CO	Craig	C2	6,000		03/13/04	0.39	0.27	31
CO	Craig	C3	6,000		05/26/09	0.37	0.30	19

[94] See, Percent Reduction LNB + OFA – pdf of excel spreadsheet percent reduction calculator.
[95] *Id.*

LA	Big Cajun 2	2B1	7,200		04/29/05	0.32	0.20	38
LA	Big Cajun 2	2B2	7,200		04/01/04	0.33	0.20	39
LA	Big Cajun 2	2B3	7,200		04/26/02	0.29	0.15	48
KS	Nearman Creek	N1	2,433		05/16/12	0.42	0.25	40
TX	Welsh Power Plant	1	6,896	11/04/99	10/14/01	0.30	0.18	40
TX	Welsh Power Plant	2	7,046		05/19/05	0.36	0.17	53
TX	Welsh Power Plant	3	6,909		11/06/00	0.36	0.19	47
WY	Laramie River	1	7,000		06/30/09	0.26	0.18	31
WY	Laramie River	2	7,000		06/01/10	0.26	0.18	31
WY	Laramie River	3	7,600		05/26/11	0.27	0.20	26

The above discussion and analysis indicates that application of LNB/OFA on Bonanza Unit 1 should achieve a NO_x emission rate of 0.28 lb/MMBtu on a 30-day rolling average. This rate is indicative of LNB during the 1998-2000 pre project period when the burners were relatively new, and an additional 25% reduction due to OFA.

As discussed above, EPA conducted a search of the RBLC database for the period between 1990 and 2000 for coal fired utility boilers greater than 250 MMBtu/hr, which is presented above in Table 8. In Table 10, below, we have removed all RBLC entries for that time period except for those that include LNB with or without some form of OFA. Upon review of the entries we find that the proposed limit of 0.28 lb/MMBtu is an appropriate emission rate given the design of the Bonanza Unit 1 boiler. Only 2 of the 48 entries in Table 10 indicate a limit lower than the proposed Bonanza emission limit of 0.28 lb/MMBtu.

Table 10 – Comparison of PC Boiler NO_X Emission Controls and Emission Rates for Combustion Control Options - RACT/BACT/LAER Clearinghouse Data

Entry #	Facility	RBLC ID	Date	control	Limit (lb/MMBtu)
1	AES Beaver Valley Partners	PA-0163	6/1/1999	LNB/SOFA	0.7
2	Orion Power Midwest	PA-0176	4/8/1999	LNB/OFA	0.5
3	WYGEN, Inc - WYGEN I	WY-0048	9/6/1996	LNB/OFA	0.22

4	West Penn Power Company	PA-0123	6/12/1995	LNB/SOFA (LNCFS Level III)	0.45
5	Metropolitan Edison Company	PA-0129	3/9/1995	LNB/CCOFA and SOFA LNCFS Level III	0.45
6	Pennsylvania Power Company - Units 1 and 2	PA-0105	12/29/1994	LNB/SOFA	0.5
7	Pennsylvania Power Company - Unit 3	PA-0105	12/29/1994	LNB/SOFA	0.5
8	Pennsylvania Electric Company - Boiler 1	PA-0115	12/29/1994	LNB/SOFA LNCFS Level III	0.45
9	Pennsylvania Electric Company - Boiler 2	PA-0115	12/29/1994	LNB/SOFA LNCFS Level III	0.45
10	West Penn Power Company - Boiler 1	PA-0116	12/29/1994	LNB/SOFA	0.58
11	West Penn Power Company - Boiler 2	PA-0116	12/29/1994	LNB/SOFA	0.58
12	West Penn Power Company - Boiler 3	PA-0116	12/29/1994	LNB/SOFA	0.58
13	Duquesne Light Company - Boiler 1	PA-0117	12/29/1994	LNB/SOFA	0.5
14	Duquesne Light Company - Boiler 2	PA-0117	12/29/1994	LNB/SOFA	0.5
15	Duquesne Light Company - Boiler 3	PA-0117	12/29/1994	LNB/SOFA	0.5
16	Duquesne Light Company - Boiler 4	PA-0117	12/29/1994	LNB/SOFA	0.5
17	Pennsylvania Electric Company - boiler 1	PA-0119	12/29/1994	LNB/SOFA	0.5
18	Pennsylvania Electric Company - boiler 2	PA-0119	12/29/1994	LNB/SOFA	0.5
19	Pennsylvania Electric Company - boiler 3	PA-0119	12/29/1994	LNB/SOFA	0.5
20	West Penn Power Company - boiler 1	PA-0125	12/29/1994	LNB	0.45
21	West Penn Power Company - boiler 2	PA-0125	12/29/1994	LNB	0.45
22	Pennsylvania Electric Company - boiler 1	PA-0126	12/29/1994	LNB/SOFA LNCFS Level III	0.45
23	Pennsylvania Electric Company - boiler 2	PA-0126	12/29/1994	LNB/SOFA LNCFS Level III	0.45
24	PECO Energy Co. - boiler 1	PA-0108	12/28/1994	LNB/CCOFA and SOFA LNCFS Level III	0.45
25	PECO Energy Co. - boiler 2	PA-0108	12/28/1994	LNB/CCOFA and SOFA LNCFS Level III	0.45

26	P.H. Glatfelter - Unit 1	PA-0142	12/28/1994	LNB/SOFA	0.74
27	P.H. Glatfelter - Unit 2	PA-0142	12/28/1994	LNB/SOFA	0.51
28	Pennsylvania Electric Company - Units 1 and 2	PA-0111	12/27/1994	LNB	0.5
29	Pennsylvania Electric Company - Units 3 and 4	PA-0111	12/27/1994	LNB/SOFA LNCFS Level III	0.45
30	Pennsylvania Power and Light Company - Unit 1	PA-0113	12/27/1994	LNB/SOFA	0.5
31	Pennsylvania Power and Light Company - Unit 2	PA-0113	12/27/1994	LNB/SOFA	0.5
32	Pennsylvania Power and Light Company - boiler 1	PA-0128	12/22/1994	LNB/SOFA LNCFS Level III	0.45
33	Pennsylvania Power and Light Company - boiler 2	PA-0128	12/22/1994	LNB/SOFA LNCFS Level III	0.45
34	Pennsylvania Power and Light Company - boiler 3	PA-0128	12/22/1994	LNB/SOFA LNCFS Level III	0.45
35	Pennsylvania Power and Light Company - boiler 1	PA-0114	12/14/1994	LNB/SOFA	0.5
36	Pennsylvania Power and Light Company - boiler 2	PA-0114	12/14/1994	LNB/SOFA	0.5
37	Metropolitan Edison Company - boiler 1	PA-0121	12/14/1994	LNB/CCOFA and SOFA LNCFS Level III	0.37
38	Metropolitan Edison Company - boiler 2	PA-0121	12/14/1994	LNB/CCOFA and SOFA LNCFS Level III	0.43
39	Pennsylvania Power and Light Co.	PA-0100	11/27/1994	LNB/SOFA	0.5
40	South Carolina Electric and Gas Company - Unit 1	SC-0027	7/15/1992	LNB/OFA	0.32
41	South Carolina Electric and Gas Company - Unit 2	SC-0027	7/15/1992	LNB/OFA	0.32
42	South Carolina Electric and Gas Company - Unit 3	SC-0027	7/15/1992	LNB/OFA	0.32
43	Tennessee Eastman Company - Boiler #31	TN-0119	4/29/1992	LNB	0.4
44	Cargill, Inc. - boiler #8500	TN-0121	1/2/1992	LNB	0.1
45	Old Dominion Electric Cooperative	VA-0181	4/29/1991	LNB/AOFA	0.3

	- boiler 2				
46	Roanoke Valley Project	NC-0054	1/24/1991	LNB/AOFA	0.33
47	Santee Cooper (S.C. Public Service Authority)	SC-0028	11/28/1990	LNB	0.39
48	Mecklenburg Cogeneration Limited Partnership	VA-0171	5/9/1990	LNB/AOFA	0.33

Based on the NO_x BACT analysis above, EPA proposes the following emission limit as NO_x BACT:

- **0.28 lb/MMBtu on a rolling 30-day average.**

Comparison to applicable NSPS emission standard.

The definition of BACT in 40 CFR 52.21(b)(12) contains the statement that, "*In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61*." The applicable NO_x emission standard, in Subpart Da of 40 CFR part 60 (New Source Performance Standards), is 0.5 lb/MMBtu while firing subbituminous coal and 0.6 lb/MMBtu while firing bituminous coal both expressed as 30-day rolling averages (40 CFR 60.44Da(a) and (a)(1)). The proposed BACT limit of 0.28 lb/MMBtu is more stringent than these applicable NSPS NO_x limits and thus complies with the requirement presented in the definition of BACT.

Proposed compliance monitoring approach.

For compliance demonstrations, EPA proposes to require use of NO_x CEMS.

VII. Air Quality Impact Analysis

A. Required Analysis

The Federal PSD rules, at 40 CFR 52.21(k)(1), requires a demonstration that the allowable emission increases (including secondary emissions) from the proposed source modification (in this case, the ruggedized rotor project at Deseret's Bonanza power plant), in conjunction with all other applicable emission increases or reductions at the source would not cause or contribute to a violation of any NAAQS, nor cause or contribute to a violation of any applicable "maximum allowable increase" over the baseline concentration in any area. Section 52.21(m)(1)(i)(b) says that a permit application must include an analysis of ambient air quality in the area for all pollutants that would be emitted in excess of the significance thresholds at §52.21(b)(23)(i).

NAAQS have been promulgated for the purpose of protecting human health and welfare with an adequate margin of safety. Pollutants for which standards have been promulgated include sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone (O_3), particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), and lead. A PSD increment, on the other hand, is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. PSD increments prevent the air quality in clean areas from deteriorating to the level set by the NAAQS.

This Air Quality Impact Analysis has been prepared by EPA based on information collected by the Agency and any related documents. Those documents are included in the Administrative Record for issuance of this permit.

This analysis by EPA includes a review of current air quality in the Uinta Basin where the Bonanza power plant is located, and an assessment of emission reductions resulting from the project after applying the NO_x BACT emission limit of 0.28 lb/MMBtu, which is proposed in EPA's PSD correction permit action, to evaluate compliance with PSD requirements at §52.21(k).96

B. Current Air Quality Conditions

The facility is located in the eastern side of the Uinta Basin, a semiarid, mid-continental climate region typified by dry, windy conditions and limited precipitation. The Uinta Basin is subject to abundant sunshine and rapid nighttime cooling. Wide seasonal temperature variations typical of a mid-continental climate region are also common. The Uinta Basin is designated as attainment or unclassified for criteria pollutants for which EPA has established NAAQS.

Exceedances of the NAAQS for ozone have been observed in the Uinta Basin. While EPA has not made a nonattainment determination for ozone, exceedances of the ozone NAAQS have been observed in the Uinta Basin during the winters of 2009-2010, 2010-2011, 2012-2013, and 2013-2014. No exceedances of the ozone NAAQS have been observed during the winter of 2011-2012.

Exceedances of the $PM_{2.5}$ NAAQS have been observed at a PSD pre-construction monitoring site about 18 miles southeast of the Bonanza power plant in June and July of 2012, when impacted by wildfire smoke. One exceedance of the PM_{10} NAAQS was also observed at that location in May of 2012, under high wind conditions. These exceedances were not sufficient to cause NAAQS violations. $PM_{2.5}$ NAAQS exceedances, but not violations, have also been observed in the towns of Vernal and Roosevelt, Utah, outside of the Uintah and Ouray Reservation.

[96] In light of the proposed NO_x emission reductions from this permitting action, we find that the requirements of 40 CFR 52.21(m)(1) are satisfied, and that the upgrades at the existing facility required to achieve the reductions required by this permit will not have additional impacts under 40 CFR 52.21(o).

Traditionally, ozone has been considered a summertime air pollutant because it is a secondary pollutant produced by photochemical reactions of its precursor species, volatile organic compounds (VOC) and NO_x. Typically, ozone formation is greatest during summer when increased solar radiation and warm temperatures promote the photochemical reactions of VOC and NO_x that form ozone. As explained above, however, the ozone NAAQS exceedances that have been observed in the Uinta Basin occurred in the winter.

Field studies have been carried out in the Uinta Basin each winter since 2010-2011 to understand the mechanisms that cause high ozone concentration in winter and to identify the sources of VOC and NO_x that contribute to ozone formation. Summaries and reports on the Uinta Basin ozone studies are publicly available at the Utah DEQ webpage[97]. These studies have demonstrated that high ozone concentrations occur in the Uinta Basin within a shallow inversion layer near the surface as a result of strong, persistent cold pool conditions. The Summary of Findings from the Uintah Basin Ozone Study for the 2012-2013 study concluded that:

The Bonanza power plant plume does not appear to contribute any significant amount of nitrogen oxides or other contaminants to the polluted boundary layer during ozone episodes; the thermally buoyant Bonanza plume rises upwards from the 183 m (600 ft) stack and penetrates through the temperature inversion layer. As a result, emissions from the Bonanza plant are effectively isolated from the boundary layer in which the high ozone concentrations occur.[98]

These findings are also described in the Final Report for the 2013 Uinta Basin Winter Ozone Study, which indicated that it was unlikely that Bonanza emissions contributed significantly to the pollution observed at the surface during the strong temperature inversion events in the winter season.[99] Given that emissions from the facility are not expected to contribute to pollutants within the shallow winter inversion layer, any changes in emissions at the facility are not expected to significantly affect winter ozone concentrations in the Uinta Basin.

97 Uinta Basin Ozone study reports from the Utah Uinta Basin Winter Ozone Study are publicly available on this webpage: http://www.deq.utah.gov/locations/U/uintahbasin/problem.htm

98 "Summary of Findings from the Uintah Basin Ozone Study: Preliminary Update from 2013 Field Study." Prepared by researchers and air quality managers at Utah State University, University of Utah, National Oceanic and Atmospheric Administration, ENVIRON, University of Colorado, Utah Department of Environmental Quality and EPA, September 23, 2013, page 3.

99 Final Report. 2013 Uinta Basin Winter Ozone Study ("Uinta Basin Study"). Prepared for: Brock LeBaron, Utah Division of Air Quality, 1950 West 150 North, Salt Lake City, UT 84116. Edited by: Till Stoeckenius. ENVIRON International Corporation and Dennis McNally Alpine Geophysics. March, 2014, page ES-2.

C. Emissions From the Project

As explained in section V.B above, after examination of pre-project actual emissions versus post-project actual emissions, EPA has found that NO_x is the only pollutant for which a significant emission increase occurred as a result of the ruggedized rotor project constructed in June of 2000, and is therefore the only pollutant subject to PSD review for the project. The current NO_x BACT emission limit in the 2001 Federal PSD permit is 0.50 lb/MMBtu heat input when subbituminous coal is fired, or 0.55 lb/MMBtu when bituminous is coal is fired. EPA notes that the Bonanza plant currently uses bituminous coal as its primary fuel. (See Process Description attached to this SOB.) EPA proposes a NO_x BACT emission limit of 0.28 lb/MMBtu for the PSD correction permit, nearly 50% lower than the current limit of 0.55 lb/MMBtu.

Pre-project actual emissions of NO_x (i.e., prior to the ruggedized rotor project) were determined by EPA to be 7,005 tons per year (tpy). Applying the NO_x BACT emission limit of 0.28 lb/MMBtu proposed by EPA for the PSD correction permit, the maximum potential post-project NO_x emissions under the correction permit would be 5,618 tpy (given Deseret's estimated post-project heat input capacity of 4,578 MMBtu/hr and assuming full-time operation all year). Therefore, we expect that under the correction permit, there will be a reduction in NO_x emissions, when compared to the NO_x emissions prior to the ruggedized rotor project.

D. Conclusion

Based on the existing air quality information and the fact that there will be a net reduction in NO_x emissions for this facility under the proposed PSD correction permit, we conclude that after application of NO_x BACT under the correction permit, the ruggedized rotor project will not cause or contribute to a NAAQS or increment violation, or have potentially adverse effects on ambient air. We also conclude, from our technical analysis, that dispersion modeling is not necessary for purposes of making this showing in the context of this PSD correction permit, because the proposed correction permit does not allow any increase in NO_x emissions.

VIII. Environmental Justice Assessment

On February 11, 1994, the President issued Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." The Executive Order calls on each federal agency to make environmental justice a part of its mission by "identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies and activities on minority populations and low-income populations."

The EPA defines "Environmental Justice" as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and polices. The EPA's goal with respect to Environmental Justice in permitting is to enable overburdened communities to have full and meaningful access to the permitting process and to develop permits that address environmental justice issues to the greatest extent practicable under existing environmental laws. *Overburdened* is used to describe the minority, low-income, tribal and indigenous populations or communities in the United States that potentially experience disproportionate environmental harms and risks as a result of greater vulnerability to environmental hazards.

A. Air Quality Impact Analysis and Compliance with the NAAQS

The Air Quality Impact Analysis (AQIA) above indicates that there is no evidence the Bonanza plant is currently causing or contributing to an exceedance of any NAAQS or PSD increment. For purposes of Executive Order 12898 on environmental justice, the EPA has recognized that compliance with the NAAQS is "emblematic of achieving a level of public health protection that, based on the level of protection afforded by a primary NAAQS, demonstrates that minority or low-income populations will not experience disproportionately high and adverse human health or environmental effects due to the exposure to relevant criteria pollutants." *In re Shell Gulf of Mexico, Inc. & Shell Offshore, Inc.*, 15 E.A.D. ___, slip op. at 74 (EAB 2010). This is because the NAAQS are health-based standards, designed to protect public health with an adequate margin of safety, including sensitive populations such as children, the elderly, and asthmatics.

Based on the results of the AQIA, which incorporates the net reduction in NO_x emissions for this project under the proposed PSD correction permit, we conclude that after application of NO_x BACT under the correction permit, the ruggedized rotor project will not cause or contribute to a NAAQS or increment violation, result in increased potential NOx emissions, or have potentially adverse effects on ambient air. We also conclude that dispersion modeling is not necessary for purposes of this PSD correction permit, because the proposed correction permit does not allow any increase in NO_x emissions, nor any increase in emissions of any other pollutant.

B. Demographics of Potential Environmental Justice Communities

This portion of the analysis provides summary information on the prevalence of minority, low income, or indigenous populations near the Deseret Bonanza plant. The EPA consulted the following resources for demographic and socioeconomic data:

1. EJScreen[100]
2. U.S. Bureau of the Census, American Quick Facts http://quickfacts.census.gov/qfd/states/49/49047.html

100 EJSCREEN, a web-based Geographic Information System (GIS) screening tool, considers both environmental conditions and characteristics of the potentially affected population. The information provided in EJSCREEN can be considered in a wide range of program contexts, and will help meet E.O. 12898's call for EPA to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of our programs, policies, and activities. EJSCREEN is currently only an internal EPA EJ Screening tool. It includes publicly available demographic data from the US Census 2006-2010 ACS blockgroup level data and national EPA environmental datasets.

EJSCREEN includes publicly available demographic data from U.S. Bureau of the Census (Census) 2006-2010 ACS blockgroup level data and national EPA environmental datasets. The Bonanza Power Plant is located in a sparsely populated area of Uintah County. EJSCREEN and 2010 Census data indicate that there are no persons living within 3 miles of the facility. Additional review of 2010 Census blocks surrounding the facility indicated that the nearest populated block (490479402011370) is approximately 5 ½ miles from the facility with a population of one (1) person. The next nearest block (490479402011376) is approximately six (6) miles from the facility with a population of five (5) persons. The nearest town is Dinosaur, Colorado approximately 17 miles from Bonanza, see attached map.

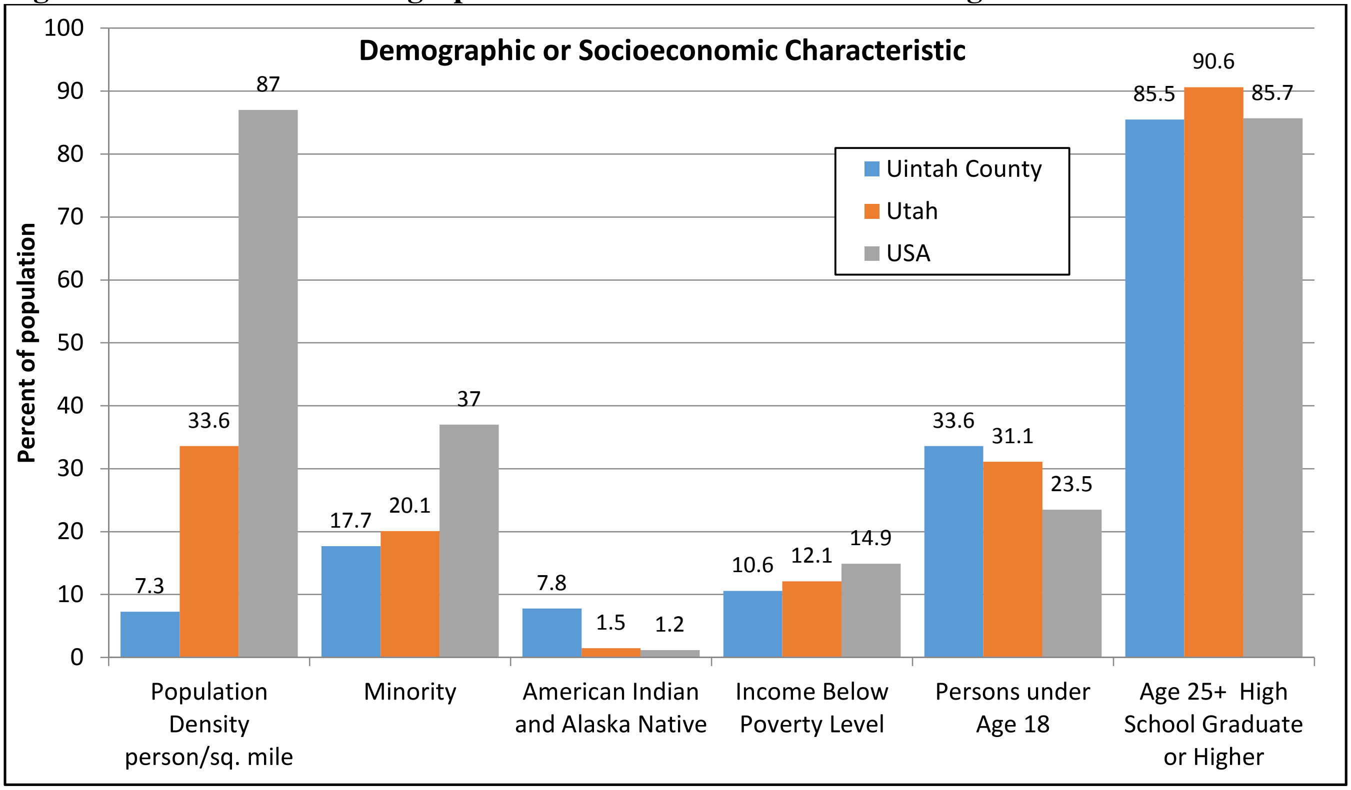
Despite the sparse population immediately surrounding the facility, the EPA reviewed demographic data from Uintah County, and compared it to demographic data from the State of Utah and the United States in order to characterize the general area surrounding the facility. The table below summarizes the percent of the total population that has a given demographic and socioeconomic characteristic. The same information is presented graphically in the following bar chart:

Figure 3. Demographic and Socioeconomic Data

Demographic or Socioeconomic Characteristic101	Uintah County	Utah	USA
Population Density person/sq. mile	7.3	33.6	87.0
Minority	17.7	20.1	37
American Indian and Alaska Native	7.8	1.5	1.2
Income Below Poverty Level	10.6	12.1	14.9
Persons under Age 18	33.6	31.1	23.5
Age 25+ High School Graduate or Higher	85.5	90.6	85.7

101 The information in this table comes from American Quick Facts (summary information from US Census Bureau).

Figure 4. Bar Chart of Demographic and Socioeconomic Data from Figure 3



C. Environmental Impacts to Potential Environmental Justice Communities

The AQIA indicates that there is no evidence that emissions from the Bonanza plant are currently exceeding any NAAQS or PSD increment. This proposed permit action does not authorize the construction of any new emission sources nor does it otherwise authorize any emission increases from existing units. Since the BACT limit will be more stringent than the current NO_x emission limit, the result of this permit action will be a reduction in allowed NO_x emissions. This proposed permit action does not otherwise authorize any other physical modifications to the facility or its operations. The emissions from the existing facility will not increase due to the associated permit action and will continue to be well controlled at all times.

Based on the remote location of the Bonanza plant, sparse population in the areas surrounding the location and the overall reduction in emissions that will occur as a result of the emissions limits contained in this proposed permit, the EPA has determined that the proposed project will not result in disproportionately high and adverse human health or environmental effects on minority or low-income populations.

IX. Tribal Consultation

The EPA offers Tribal Government Leaders an opportunity to consult on each proposed permit action. The Tribal Government Leaders are asked to respond to the EPA's offer to consult within

30 days and if no response is received within that time, the EPA notifies the Tribal Government Leaders that the consultation period has closed. The Chairman of the Ute Tribe was offered an opportunity to consult on this permit action via letter dated September 17, 2014. The Tribe accepted on October 6, 2014. The consultation was held on October 16, 2014, at the US EPA Region 8 office in Denver, Colorado. The EPA provided a brief summary of past discussions with the Tribe regarding air permitting for the Deseret facility, an overview of the facility, related permitting history, and current litigation. A subsequent consultation meeting was conducted between U.S. EPA and the Ute Tribe on November 13, 2014, in Washington, D.C.

A copy of the draft PSD correction permit, technical support document, and other documents related to the proposed decision has been sent to the Ute Indian Tribe, Energy and Minerals Department, to be made available for public review at 910 South 7500 East, in Fort Duchesne, Utah, for 45 calendar days, starting on December 5, 2014 and ending on January 19, 2015. The Tribe will also be notified of the issuance of the final permit.

Given the location of this facility on the Uintah & Ouray Indian Reservation, the EPA is providing an enhanced public participation process for this permit. Interested parties can subscribe to an EPA listserve that notifies them of public comment opportunities on the Uintah and Ouray Indian Reservation for draft air pollution control permits via email at http://www2.epa.gov/region8/air-permit-public-comment-opportunities.

Attachment 1: Bonanza Plant Process Description

General plant description: The Bonanza power plant is a 500-megawatt (estimated), coal-fired electrical generating facility. It consists of a dry bottom wall-fired Foster-Wheeler steam generator capable of producing over 3.2 million pounds of steam per hour. The turbine generator is a Westinghouse tandem compound two flow reheat unit.

Water for the unit is transported about 20 miles from the Green River near Jensen, Utah. Coal for the unit is mined in Colorado near Rangely, at the Cooperative's Deserado mine, and transported via an electric railroad 35 miles to the plant site. Occasionally, as needed, coal is also purchased on the open market and trucked to the site.

The project was originally developed for two generating units; however, due to the downturn of the petroleum industry and cancellation of defense weapons in the late 1980's, the development of the second unit has been indefinitely postponed. Most of the power produced is used by the Cooperative's members in Utah and surrounding states, or sold under bilateral wholesale power purchase contracts, or sold on the open market.

Fuel systems: Bituminous low-sulfur coal is the primary fuel source for the plant. The coal comes into the plant by train from the Deserado coal mine. From the train the coal can be delivered to the outdoor coal storage pile or to the coal storage silo. From the storage silo the coal is conveyed to the crusher. Coal can also be reclaimed from the outdoor storage pile by conveying it to the crusher. Years ago the crusher was only used occasionally, but is now used routinely, as it helps the pulverizers run more smoothly.

Crushed coal is conveyed from the crusher to the bunkers just upstream of the pulverizers. There are five pulverizers. Each pulverizer has its own bunker. Stored coal is conveyed from the bunkers to the pulverizers. At the pulverizers the coal is pulverized to the consistency of talcum powder and fired into the boiler. The unit at full load burns about 250 tons of coal per hour and 6000 tons of coal every 24 hours. Full load heat input rate to the boiler is about 4578 MMBtu per hour, as reported to EPA in a March 7, 2000 electronic supplied spreadsheet. Low-NO_x burners are used in the boiler for NO_x emission control.

Fuel oil is used to start up the main boiler from a cold start, to change pulverizing equipment on line, and to operate the auxiliary boiler during shutdowns and for cold unit starts. Natural gas may be used for firing these boilers in the future as economics dictate. Fuel oil is also used to operate the plant's emergency diesel generator and emergency diesel fire pump. Fuel oil is stored in two 288,000 gallon tanks on site.

Diesel refueling is performed on site for heavy equipment via above-ground 20,000-gallon storage tanks. Propane is used to heat outlying coal handling buildings via construction heaters. The propane storage tank holds 30,000 gallons. A gasoline refueling station using a 10,000 gallon above-ground storage tank is also on the plant site for smaller vehicles.

Turbine generator system: The turbine generator uses steam at 1,005°F and 2,485 psi produced by the boiler to generate electricity. The turbine generator uses a lube oil system which includes a main reservoir, clean and dirty storage tanks, pumps and filters. The generating process involves converting mechanical energy to electrical energy supplying the plant site and for sales on the Western grid.

Steam generator system: Coal is pulverized and fed into the boilers via hot air streams to produce the steam needed for energy demands. Coal usage and steam production vary with energy needs. Fuel oil is used in the igniters to support starting and stopping of the coal pulverizing equipment and for flame stabilization during transients. Fuel oil is also used for start-up steam production in a unit cold start. Auxiliary steam is produced by the package boiler for unit cold starts or supplemental heating during unit outages. The package boiler uses fuel oil and is rated at 150,000 pounds of steam an hour at 150 psi.

Pollution control systems: The power plant uses an Ecolaire baghouse for particulate control, a Combustion Engineering wet scrubber for SO_2 control, and low-NO_x burners for NO_x control.

Baghouse: The baghouse system for the main boiler is divided into two separate sections, each consisting of 12 compartments. The two sections (1-1 and 1-2) are on separate duct fan trains. Each compartment contains 450, 12-inch diameter, 37-foot long bags, for a total of 10,800 bags (both sections combined). Average pressure drop is 5.5 inches of water. The ducting allows for the use of any combination of compartments in a section at any time. Under normal circumstances, both sections of the baghouse are in use at the same time and all compartments are in use except during maintenance. Gas flow at full load through the baghouse and scrubber is approximately 1.16 million SCFM. The baghouse is designed to be 99.9% efficient.

The baghouse system is a reverse gas design using not only reverse gas but sonic horns for bag cleaning. Ash removal is accomplished by passing the boiler flue gas through the glass fabric bags where the ash is filtered by the fabric and trapped inside the bag. At a preset differential pressure, the compartment is removed from the gas stream and the bags are collapsed via a reverse gas stream. The collapsed bags release the trapped ash and it falls into a hopper below the compartment. From the hopper, the ash is transported to a silo where it is mixed with scrubber waste streams for landfill.

Scrubber: The SO_2 scrubber is a wet limestone system, built by Combustion Engineering. It consists of three identical countercurrent absorber modules, of which at least two are on line any time the plant is in service. Each absorber module uses three levels of counterflow limestone slurry sprays at 12,000 GPM to react with the flue gas. The spray is collected on a slotted tray which forces the gas through 1.5 inch diameter holes. This not only straightens the gas flow but provides a 100% contact between the gas and the slurry.

Limestone is ground on site in ball mills and mixed with water to a density of 35% to produce the needed slurry. The slurry is mixed into the absorber modules to the module percent solids between 13% and 17%, with a pH between 5.5 and 6.0. The base and lower portion of each module tower is the slurry reaction tank. Each module also includes a bulk entrainment separator and mist eliminator vanes for water droplet removal. A mist eliminator cleaning system is used to clean the vanes. On occasion, scrubber enhancers such as adipic acid are added to the slurry as needed to aid in the removal process. The solids formed in the scrubbing process are removed by a sludge handling system, mixed with flyash and conveyed or trucked to an on-site landfill.

Low-NO_x burners: The low-NO_x burners were installed by Foster-Wheeler during the initial design and construction of the boiler. In 1997, a new generation of low-NO_x burners designed by Advanced Burner Technologies were installed to help the boiler meet its Acid Rain Program Phase II early election emission limit (0.50 lb/MMBtu). The low-NO_x burners work on the principle that a cooler flame combusts less of the nitrogen in the coal, therefore creating less NO_x emissions. The early election limit expired at the end of 2007 and cannot be renewed. The Acid Rain emission limit for NO_x has reverted to the standard Phase II limit of 0.46 lb/MMBtu, effective starting January 1, 2008.

Emission monitoring equipment: A Spectrum extractive dilution system continuously monitors the gaseous pollutants (SO_2 and NO_x) and diluent (CO_2) and flow rate at a level of the stack which is 334.5 feet above grade, and monitors SO_2 at the inlet ducts to the scrubber. Gas samples are carried by heated sample lines to the 6th floor of the scrubber where the analyzer and computer shelter is located. The data from the analyzers are sent to the data handling and acquisition system, where it is stored and used to generate reports to the EPA.

Inlet monitoring or coal analysis may be used to calculate inlet SO_2 in lb/MMBtu for removal calculation purposes. Coal sampling and analysis is done according to the applicable ASTM methods and 40 CFR 60 method 19 calculations.

Opacity is measured from the two ducts between the baghouses and the induced draft fans. The opacity monitors are located in the ductwork because the stack is a wet stack. Data from the two opacity monitors are averaged to report the stack opacity.

Stack parameters: The plant's main boiler stack is 604 feet high. It is constructed with a concrete shell and acid resistant brick liner. The exit diameter is 26 feet with an average exit temperature of about 120 degrees F. The stack flow rate at full load is estimated to be about 1.3 million SCFM with the new ruggedized rotor installed and operating.

The plant's auxiliary boiler stack is located in the Main Boiler building and extends through the roof. It is 240 feet high and has an exit diameter of 4.75 feet. The average exit temperature is

600 degrees F when the unit is in operation. The stack flow rate is about 1,000 SCFM.

Water supply system: Water is transported approximately twenty miles from the Cooperative's wells along the Green River. The system discharges through a maximum 450 kilowatt hydro-generator into the Raw Water Storage pond on site prior to treatment. The system is capable of transporting at least 13,000 GPM.

Boiler feedwater must be extremely clean and demineralized prior to use. All treatment is performed on site. Two stages of cleaning occur, the first in the Water Treatment facility where boiler water goes through a reverse osmosis process. The second is in the turbine building where boiler water is then demineralized. The recirculation of the plant's condensate is also constantly polished to maintain strict compliance with boiler chemistry. Due to the remote location of the plant, the Cooperative also produces potable water on site.

The Bonanza power plant is a zero discharge facility. All waste water and storm water is collected and re-used where possible. All remaining water is sent to the evaporation ponds where it is impounded.