BEFORE THE ENVIRONMENTAL APPEALS BOARD
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C.

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In re:	)
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Deseret Power Cooperative,	)
Bonanza Power Plant,	)
	)
Permit No. V-UO-000004-00.00	)
	)

PETITION FOR REVIEW
OF A CLEAN AIR ACT PART 71 PERMIT TO OPERATE

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INTRODUCTION

On December 5, 2014, U.S. Environmental Protection Agency ("EPA") Region 8 issued a permit for the Deseret Power Cooperative (hereafter "Deseret") to operate the Bonanza Power Plant (hereafter "Bonanza Plant" or "Plant"), a 500-megawatt coal-fired power plant located in northeastern Utah, pursuant to Title V of the Clean Air Act and regulations at 40 C.F.R. § 71.

Unfortunately, in issuing the final Title V permit, the agency failed to fully comply with its permitting duties, namely by failing to ensure the Bonanza Plant operates in compliance with all applicable requirements under the Clean Air Act. Of particular concern is that, although the EPA acknowledges that Deseret failed to obtain a necessary prevention of significant deterioration ("PSD") permit after undertaking a major modification of the Plant, the Title V permit fails to include provisions to bring the facility into compliance with PSD. The result is that the permit fails to ensure the Bonanza Plant operates in compliance with best available control technology ("BACT") and other applicable requirements under PSD.

Therefore, pursuant to 40 C.F.R. § 71.11(l), WildEarth Guardians petitions the Environmental Appeals Board ("EAB") to review EPA Region 8's issuance of a federal operating permit pursuant to Title V of the Clean Air Act and 40 C.F.R. § 71 for Deseret to operate the Bonanza Plant. Guardians requests EAB review on the basis that the Title V permit is based on a finding of fact or conclusion of law that is clearly erroneous. Specifically, EPA Region 8 failed to ensure the Plant will operate in compliance with the Clean Air Act in accordance with 42 U.S.C. § 7661c(a) and 40 C.F.R. § 71.5(c)(8)(iii)(C) by failing to:

1. Ensure the Bonanza Plant operates in compliance with PSD requirements under the Clean Air Act and to include a schedule of compliance to bring the sPlant into compliance; and

2. Ensure the Bonanza Plant operates in compliance with represented heat input rates set forth in Deseret's PSD permit application and to include a schedule of compliance to bring the Plant into compliance.

Below, we detail the basis for seeking review. We request the EAB grant this petition for review and either vacate the permit or remand it back to the EPA Region 8 and order the agency to promptly remedy all deficiencies. Most importantly, we request the EAB ensure the Bonanza Plant operates in full compliance with the Clean Air Act.

LEGAL BACKGROUND

Title V of the Clean Air Act requires that major sources of air pollution "obtain comprehensive operating permits to assure compliance with the requirements of the [Clean Air] Act." *In re: Peabody Western Coal Co.*, CAA Appeal No. 11-01, slip op. at 3, 15 E.A.D. ___ (EAB March 13, 2012). To this end, a Title V permit must be explicitly written to assure compliance with all applicable requirements under the Clean Air Act. *See* 42 U.S.C. § 7661c(a); *see also* 40 C.F.R. § 71.7(a)(iv) (a permit may only be issued if "[t]he conditions of the permit provide for compliance with all applicable requirements and the requirements of this part"). As the EPA has explained, "the title V operating permits program is a vehicle for ensuring that air quality control requirements are appropriately applied to facility emission units and that compliance with these requirements is assured." *In the Matter of Public Service Company of New Mexico, San Juan Generating Station*, Order, Title V Petition VI-2010-04 at 2 (Feb. 15, 2012), available online at http://www.epa.gov/region7/air/title5/petitiondb/petitions/san_juan_response2010.pdf (last accessed January 7, 2015).

Applicable requirements include, among other things, PSD requirements under Part C of the Clean Air Act. *See* 40 C.F.R. § 71.2 (definition of "[a]pplicable requirement" including terms or conditions of any permits issued pursuant to Part C of the Clean Air Act). Under PSD, major stationary sources of air pollution, as defined under 40 C.F.R. § 52.21(b)(1), which are located in areas designated as in attainment with national ambient air quality standards ("NAAQS"), are subject to certain preconstruction permitting requirements.[1] Specifically, a major source must apply for and obtain a permit before undertaking any "major modification." 40 C.F.R. § 52.21(a)(2). A major modification occurs whenever a "physical change" of a major source leads to a "significant net emission increase of any pollutant subject to regulation under the [Clean Air] Act." 40 C.F.R. § 52.21(b)(2)(i). A significant net emissions increase occurs when post-project potential emissions exceed pre-project actual emissions by certain rates. 40 C.F.R. §§ 52.21(b)(3) and (b)(23) (defining "net emissions increase" and "significant" emission rates).

A PSD permit must require that a source meet BACT limits on emissions, as well as meet other requirements. 40 C.F.R. § 52.21(j); *see also e.g.* 40 C.F.R. § 52.21(k) (requiring that a permit ensure a source does not cause or contribute to air pollution in violation of any NAAQS and other air quality standards). Where a major source undergoes a major modification, BACT limits apply to each pollutant for which a significant net emissions increase would occur. 40 C.F.R. § 52.21(j)(3). Upon issuance of a PSD permit, a source must operate in compliance with the terms of its permit, as well as in accordance with its permit application. 40 C.F.R. § 52.21(r)(1).

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[1] Unless otherwise noted, we refer to the most up-to-date version of 40 C.F.R. § 52.21.

Where a source is "not in compliance with all applicable requirements at the time of permit issuance," a Title V permit must include a "schedule of compliance." 40 C.F.R. § 71.5(c)(8)(iii)(C); *see also* 42 U.S.C. §§ 7661b(b)(1) and 7661c(a) (requiring Title V permits to contain a "schedule of compliance"). This schedule must include, among other things, "an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements." *Id.*; *see also* 42 U.S.C. § 7661(3) (defining "Schedule of compliance" to mean "a schedule of remedial measures, including an enforceable sequence of actions or operations, leading to compliance[.]"). Such a schedule "shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject." *Id*.

FACTUAL BACKGROUND

The Bonanza Plant is a 500-megawatt coal-fired power located in Uintah County, Utah. It is located 28 miles southeast of Vernal, Utah and lies within the exterior boundaries of the Uintah and Ouray Indian Reservation. *See* Administrative Record ("AR") Doc. 138 at Attachment 2, p. 1 (Title V permit, description of facility).[2] The Plant is a stationary source of air pollution consisting of a single coal-fired boiler, a 604-foot tall smokestack, coal handling and conveying systems, and other pollutant emitting activities. *Id.*

The Plant releases significant amounts of harmful air pollution, including criteria pollutants, hazardous air pollutants, and greenhouse gases. On an annual basis, the Bonanza Power Plant has the potential to emit 1,968 tons of sulfur dioxide ("SO_2"), 9,228 tons of nitrogen

[2] We cite Administrative Record Documents in accordance with the index and record produced by EPA Region 8 in conjunction with issuance of the final Bonanza Power Plant Title V permit. This record is available on EPA's website at http://www2.epa.gov/sites/production/files/2014-12/documents/deseret_bonanza_titlev_administrative_record.pdf (last accessed Jan. 7, 2015).

oxides ("NO_x"), 574 tons of particulate matter ("PM_{10}"), 68 tons of hazardous air pollutants, and more than three million tons of carbon dioxide ("CO_2"). *See* AR Docs. 082 at 5 (disclosing potential to emit for criteria pollutants and hazardous air pollutants) and 134 at 8 (disclosing total greenhouse gas emissions). According to the EPA's Toxic Release Inventory, in 2013 the Plant's smokestack released 17,259 pounds of sulfuric acid, 17,148 pounds of hydrochloric acid, 7,222 pounds of hydrofluoric acid, 30 pounds of lead, and 1.9 pounds of mercury, as well as other toxic emissions. *See* Exhibit 1, EPA, "Toxic Release Inventory Data for Bonanza Power Plant," website available at http://oaspub.epa.gov/enviro/tris_control.tris_print?tris_id=84078BNNZP12500 (last accessed Jan. 7, 2015). The Plant currently operates with no add-on controls for NO_x emissions, a baghouse to control particulate matter emissions, and a scrubber to control SO_2 emissions.

Due to its location within the exterior boundaries of the Uintah and Ouray Indian Reservation, the Bonanza Plant has never been subject to Clean Air Act jurisdiction by the State of Utah. Instead, it has been and continues to be subject to federal jurisdiction under the Clean Air Act, meaning the EPA—and only the EPA—has been and continues to be empowered to regulate air pollution from the Plant. That the Bonanza Plant is located within Indian Country, and therefore subject to federal jurisdiction, has been confirmed since at least 1985 and reconfirmed since then through additional court rulings. *See* AR Doc. 134 at 32-34 (response to comments regarding federal jurisdiction).

Because it is a major emitting facility, the Bonanza Plant has been permitted under the PSD program of the Clean Air Act. Deseret first obtained a PSD permit from the EPA on February 4, 1981. *See* AR Doc. 002. This permit authorized the construction and operation of the Plant. The EPA later "reissued" the PSD permit on February 2, 2001, largely reincorporating the limits from the 1981 PSD permit. *See* AR Doc. 026. Any "major modification" of the Plant triggers the need for a new PSD permit prior to construction and operation. AR Doc. 138 at 65 (Title V permit condition 6.f).

Title V permitting for sources within Indian Country initially became effective March 2, 1999 and required that EPA take final action on permit applications by March 2, 2001. 40 C.F.R. §§ 71.4(b)(2) and (3). In March of 2000, Deseret submitted its first Title V permit application to EPA for review. *See* AR Doc. 082 at 2. In August of 2002, a draft Title V permit was circulated for public comment in August of 2002. AR Doc. 082 at 3. Deseret submitted an updated application to EPA on April 3, 2012. *See* AR Doc. 049. The EPA finally issued Deseret's Title V permit on December 5, 2014. *See* AR Doc. 138.

The need for final action on Deseret's Title V permit application has been critical in light of clear signs that the Bonanza Plant has been operating out of compliance with the Clean Air Act. Specifically, the facility has been operating out of compliance with PSD requirements for years in at least two key ways. First, Deseret undertook a major modification of the Plant without first obtaining a requisite PSD permit in accordance with 40 C.F.R. § 52.21. As acknowledged by the EPA, Deseret undertook a "ruggedized rotor" project in 2000 that led to a significant increase in NO_x emissions. AR Doc. 082 at 47. The result is that the Bonanza Plant has not been operating in compliance with PSD requirements, particularly with BACT limits for NO_x emissions in accordance with 40 C.F.R. § 52.21(j)(3).

Second, Deseret has been regularly operating the Bonanza Plant out of compliance with its PSD permit applications and with the terms of its PSD permit, in violation of 40 C.F.R. § 52.21(r)(1). Specifically, the Plant has been operated at much higher heat input rates (i.e., coal consumption rates) than were originally represented to EPA and that formed the basis for prior findings that operation would not cause or contribute to violations of NAAQS or PSD increment standards in accordance with 40 C.F.R. § 52.21(k)(1). This is of particular concern given that all the emission limits applicable to the Bonanza Plant are expressed as a "pound per million Btu" ("lb/mmBtu") rate, meaning that more Btus means more pounds of pollution. More pounds means more tons of emissions on an annual basis.

In issuing the Title V permit for the Bonanza Plant, the EPA did not include provisions to bring the Bonanza Plant into compliance with PSD or otherwise include any schedule of compliance to address outstanding violations. With regards to the "ruggedized rotor" project and the significant increase in NO_x emissions, EPA argues that it simply made an administrative "error." AR Doc. 134 at 3. The agency argues the proper mechanism for addressing this outstanding noncompliance is to issue a "corrected" PSD permit, rather than a schedule of compliance in the Title V permit. With regards to limits on heat input, the EPA asserts that "there is no limit on heat input rate." AR Doc. 134 at 30.

THRESHOLD REQUIREMENTS

This Petition for Review is timely filed in accordance with 40 C.F.R. § 71.11(l)(1). In a December 2, 2014 letter sent on December 5, 2014 via e-mail and U.S. Post to WildEarth Guardians and other parties, EPA Region 8 stated that petitions for review of the Bonanza Plant Title V permit must be filed by January 7, 2014. *See* AR Doc. 136. Part 71 regulations provide that petitions for review must be filed within 30 days of receiving notice from the EPA "unless a later date is specified in that notice[.]" 40 C.F.R. § 71.11(l)(1). Given that EPA specified in its notice that petitions must be filed by January 7, 2015, this petition is thus timely filed.

Guardians further satisfies the threshold requirements for filing a petition for review under 40 C.F.R. § 71.11(h). Regulations provide that, "[A]ny person who filed comments on the draft permit or participated in the public hearing may petition the Environmental Appeals Board to review any condition of the permit decision." 40 C.F.R. § 71.11(l). In this case, WildEarth Guardians submitted comments on the draft Bonanza Plant Title V permit on June 16, 2014. *See* AR Doc. 110. Thus, WildEarth Guardians has the right to file this appeal.

Furthermore, the issues raised in this petition were raised by Guardians during the public comment period and therefore were preserved for review. This petition presents three primary issues, namely whether EPA violated the Clean Air Act by: 1) Issuing the Title V permit without including a schedule of compliance to address ongoing noncompliance with PSD permitting requirements; 2) Issuing the Title V permit without including a schedule of compliance to address ongoing noncompliance with presumed heat input rates; and 3) Issuing the Title V permit without appropriately defining the major source subject to permitting such that PSD and Title V permitting requirements are complied with. These issues were all raised in thorough detail in Guardians' comments. *See* AR Doc. 110 at 2-22, 22-26, and 27-29. Thus, the EAB has jurisdiction to fully review this Petition and issue a decision accordingly.

ARGUMENT

The decision to issue the Title V permit for the Bonanza Plant should be reversed and either vacated or remanded by the EAB. As will be explained, the decision is based on a "finding of fact or conclusion of law which is clearly erroneous." 40 C.F.R. § 71.11(l)(1)(i).

I. The Title V permit Fails to Ensure the Bonanza Plant Operates in Compliance with PSD Requirements under the Clean Air Act and to Include a Schedule of Compliance to Bring the Bonanza Plant into Compliance

There is no question that Deseret undertook a major modification of the Bonanza Plant without first obtaining a PSD permit and has since failed to operate in compliance with applicable requirements under 40 C.F.R. § 52.21. In spite of ongoing violations, the EPA did not include a schedule of compliance in the Title V permit to bring the Plant into compliance with PSD and otherwise ensure that operations are in full accord with all applicable requirements.

It is critical to first point out that EPA does not dispute that the Bonanza Plant underwent a major modification in 2000. As the agency discloses, a "ruggedized rotor project" was completed at that time, representing a physical change in the Plant that caused a "significant net increase in actual NO_x emissions[.]" AR Doc. 082 at 36-37.[3] The ruggedized rotor project consisted of a series of interrelated upgrades at the Bonanza Plant that aimed to increase the capacity to burn coal. AR Doc. 082 at 43-44. Although Deseret asserted there would be no significant net increase in emissions, this assertion was based on a fatally flawed analysis of pre-project emissions. EPA explains, "[Deseret] failed to use actual pre-project emissions as the baseline" and instead inappropriately relied on pre-project potential emissions. *Id*. at 35. As EPA concluded, "the 2000 ruggedized rotor project should have undergone PSD review for NO_x, including a BACT analysis." *Id*. at 49.

It is further undisputed that Deseret did not apply for or obtain a PSD permit for its major modification. The Bonanza Plant did not undergo the requisite BACT analysis for NO_x

[3] To aid the EAB in understanding in more detail the ruggedized rotor project, a description prepared by Deseret is attached to this Petition for Review as Exhibit 2. While stamped "CONFIDENTIAL," this document was fully released by EPA Region 8 to Guardians under the Freedom of Information Act (FOIA No. 08-FOIA-00029-12). Although this description illustrates the full scope of the ruggedized rotor project, it inaccurately asserts that the project would "significantly reduce NO_x emissions." Exhibit 2 at 2.

emissions or any other analysis otherwise required by the Clean Air Act. As EPA acknowledges, the emission limits that currently apply to the Bonanza Plant "do not represent the outcome of a required BACT determination." AR Doc. 082 at 49. To this end, there is no question that the Plant is currently operating out of compliance with all applicable requirements.

Nevertheless, EPA disagrees that it was required to address in any way this ongoing noncompliance in the Bonanza Plant Title V permit. Although originally the agency proposed to include a schedule of compliance in the draft Title V permit, such a schedule was stripped from the final. *See* AR Doc. at 1 (noting the change from draft to final). According to the agency, the failure of Deseret to obtain and operate in compliance with the requisite PSD permit is actually the result of EPA's own "mistake." AR Doc. 082 at 43. Accordingly, EPA believes the proper course of action is to issue a "corrected" PSD permit, which the agency proposed on December 3, 2014. *See* Exhibits 3 and 4, EPA, Statement of Basis and Draft Air Pollution Control Prevention of Significant Deterioration permit to Construct, PSD-UO-000004-2014.003 (Dec. 4, 2014), available online at http://www2.epa.gov/sites/production/files/2014-12/documents/deseret_bonanza_-_unit_1_psd_-_sob_12-3-14.pdf (last accessed Jan. 7, 2015) and http://www2.epa.gov/sites/production/files/2014-12/documents/deseret_bonanza_-_unit_1_psd_-_draft_correction_permit_12-3-14.pdf (last accessed Jan. 7, 2015). Unfortunately, EPA's preferred course of action squarely defies Title V.

The basis for EPA's preferred course of action stems from the agency's belief that in reissuing the PSD permit for the Bonanza Plant in 2001, it erred by "rel[ying] on a faulty analysis conducted by the State [of Utah] and [by not] conduct[ing] a complete, independent analysis of whether the ruggedized rotor project was subject to PSD review based on the regulations in place at that time[.]" AR Doc. 082 at 36. To this end, EPA somehow believes that the 2001 PSD permit condones or otherwise shields Deseret from PSD liability. This perspective, however, is misplaced.

To begin with, the 2001 PSD permit was issued clearly based on Deseret's inaccurate representation to both EPA and the State of Utah that the ruggedized rotor project would decrease NO_x emissions. *See e.g.* Exhibit 2 at 2 (Deseret's representation that the ruggedized rotor project would "significantly" reduce NO_x emissions). As the 2001 permit states, "This Permit is issued in reliance upon the accuracy and completeness of the information set forth in the application to the State of Utah and that provided by EPA." AR Doc. 026 at 6. The accuracy and completeness of the information, however, was clearly erroneous and EPA cannot be at fault for reasonably relying on purportedly legitimate data. In fact, PSD rules in place at the time put the responsibility on Deseret to submit accurate information necessary to determine the applicability of PSD. *See* 40 C.F.R. § 52.21(n) (2000) (requiring sources to "submit all information necessary to perform any analysis or make any determination required under this section."). EPA cannot be expected to second-guess all information submitted by sources and nothing in the PSD rules indicates that permitting authorities shoulder such a burdensome duty.[4] On the contrary, the duty to comply with PSD, including the duty to accurately calculate pre-project actual and post-project potential emissions, falls squarely on the shoulders of sources.

Guardians acknowledges that the 2001 permit states that it "pertains" to the 2000 ruggedized rotor project. AR Doc. 026 at 6. However, the permit clearly only pertains insofar as Deseret asserted the project was not a major modification. Again, as EPA expressly

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[4] The Clean Air Act in fact appears to carry a significant presumption that sources will strive to submit accurate data. Notably, the law actually provides for criminal penalties for "[a]ny person who knowingly makes any false material statement, representation, or certification in, or omits material information from, or knowingly alters conceals, or fails to file or maintain any notice, application, record, report, plan, or other document required pursuant to this chapter to be either filed or maintained." 42 U.S.C. § 7413(c)(2)(A).

acknowledged, it accepted Deseret's representations at the time as valid. While permitting the ruggedized rotor project, it did so under the reasonable belief that PSD was not previously triggered. For the EPA to assert that simply by "pertaining" to the 2000 ruggedized rotor project, the PSD permit universally shields Deseret for its misdeeds is completely groundless.

Indeed, permits do not and cannot serve to shield liability in such an extreme way. If sources could submit inaccurate information and legitimize illegal actions by securing permits, it would completely undermine the PSD permitting program and foster an unhealthy atmosphere of rampant noncompliance. It is telling the 2001 permit itself expressly states that it "does not release the Permittee from any liability for compliance with other applicable federal and Tribal environmental law and regulations, including the Clean Air Act." AR Doc. 026 at 23.

Regardless, the 2001 PSD permit, mistaken or not, simply does not override the fact that Deseret undertook a major modification of the Bonanza Power Plant without applying for, obtaining, and complying with a PSD permit. The issuance of the 2001 permit did not somehow erase Deseret's liability or otherwise remedy the noncompliance. This is plainly confirmed by the EPA's own move to "correct" the 2001 PSD permit. To this end, the 2001 permit did not override the EPA's duty to issue a Title V permit that assured compliance with PSD and included an appropriate schedule of compliance.

To be certain, it could be argued that in issuing a "corrected" PSD permit, the EPA is functionally complying with Title V. Although Guardians' position is that EPA lacks legal authority to issue a novel "corrected" PSD permit, the fact remains that the agency's chosen path does not remotely substitute for compliance with Title V. For one thing, Deseret must submit an application for a PSD permit in accordance with 40 C.F.R. § 124.3(a)(1). Not only is the duty to submit an application an applicable requirement under the Clean Air Act, but an application is also necessary to ensure proper EPA review and disposition of the permit pursuant to 40 C.F.R. §§ 124.3(c) and (c). Furthermore, if EPA would have drafted a permit in accordance with Title V, a schedule of compliance with remedial measures and an enforceable sequence of actions, such as deadlines, would have been included to bring the Bonanza Plant into compliance with PSD. Currently, no remedial measures are actually required in the Title V permit and EPA is under no deadline to complete its "corrected" PSD permit or to incorporate any new requirements into the Title V permit.[5]

EPA asserts that it is "not appropriate or equitable" to address PSD compliance in the Title V permit. However, considerations of "equitability" and "appropriateness" do not trump the agency's foremost duty to assure a Title V permit ensures compliance with applicable requirements under the Clean Air Act. *See* 42 U.S.C. § 7661c(a) (Title V permits "shall" include "conditions necessary to assure compliance with applicable requirements"). The failure of EPA Region 8 to issue a Title V permit that assures the Bonanza Plant operates into compliance with applicable PSD requirements and that includes a legally required schedule of compliance is therefore based on a finding of fact or conclusion of law which is clearly erroneous. The EAB must either vacate the Title V permit or remand to the agency and order that the Title V permit be revised to ensure the Bonanza Plant operates in full compliance with the Clean Air Act.

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[5] We also are concerned that the "corrected" PSD permit does not appear on track to bring the Bonanza Plant into full compliance with PSD. According to EPA, a new permit is not being issued. Rather, the agency is only "correcting" a previously issued permit. To this end, EPA has proposed to issue the permit based on an analysis of "what would have been required of the Deseret plant at the time of the [2001] permitting action." Exhibit 3 at 8. Accordingly, EPA has proposed a new emission rate for NO_x that is actually higher than what is currently considered BACT. As the EPA acknowledges, current selective catalytic reduction systems can achieve emission rates of 0.05 lbs./mmBtu on a 30-day basis. *Id*. at 47. However, the agency has proposed to require Deseret to meet a NO_x emission rate of 0.28 lbs/mmBtu over 30 days as BACT. *Id*. at 73.

II. The Title V permit Fails to Ensure the Bonanza Plant Operates in Compliance with Represented Heat Input Rates Set forth in Deseret's PSD Permit Application and to Include a Schedule of Compliance to Bring the Plant into Compliance

In issuing the Title V permit, EPA inappropriately rejected Guardians' comments that the Bonanza Plant is operating out of compliance with heat input rates represented in Deseret's PSD permit application, in violation of 40 C.F.R. § 52.21(r)(1), an applicable requirement. In doing so, the agency failed to acknowledge ongoing violations of heat input rates, to include a schedule of compliance to address the ongoing violations, and to otherwise ensure the Plant operates in compliance with represented heat input rates.

Heat input, which is measured on a mmBtu/hour basis, is basically a measure of coal consumption. It is significant given that emission limits for the Bonanza Plant are based upon heat input. For example, PM_{10} emissions are limited to no more than 0.0286 lbs. per mmBtu, SO_2 emissions are limited to no more than 1.2 pounds per mmBtu, and NO_x emissions are limited to 0.55 lbs. per mmBtu. The higher the heat input, or coal usage, the more emissions come from the Plant. The EPA has explicitly acknowledged that at the Bonanza Plant, an increase in heat input capacity would lead to an expected "increase in NO_x emissions." AR Doc. 082 at 44.

Here, in applying for its original PSD permit, Deseret represented that the Bonanza Plant would be operated at a "design heat input" rate of 4,055 mmBtu/hour. AR Doc. 002 at Application Analysis 2 (PDF page 27). As the company noted in a 1994 letter to the State of Utah, this presumed heat input rate of 4,055 mmBtu/hour, which was represented in a 1980 application, was "used for air quality modeling." Exhibit 5, Letter from Deseret to Russell A. Roberts, Executive Secretary, Utah Air Quality Board, "Response to Utah Division of Air Quality's PSD Applicability/Major Modification Determination" (December 9, 1994) at 2. In other words, based on an assumed heat input rate of 4,055 mmBtu/hour, Deseret represented, and the EPA agreed in issuing the 1981 PSD permit, that operation of the Bonanza Plant would comply with all applicable PSD requirements, such as the protection of NAAQS.

This heat input rate was and continues to be enforceable pursuant to 40 C.F.R. § 52.21(r), which states that a source must operate in accordance "with the application submitted pursuant to this section" or be subject to "appropriate enforcement action." Although EPA has asserted the 2001 PSD permit "replaced" the 1981 PSD permit, it does not appear that this rendered Deseret's 1980 permit application null and void. For one thing, Deseret never submitted a new application to EPA in conjunction with the 2001 PSD permit that would otherwise supplant its 1980 permit application. Additionally, EPA expressly stated in the 2001 permit that Deseret's "original Permit applications," including its 1980 application, are among the documents that "constitute the basis for the conditions" in the permit. AR Doc. 4.

As the permit application assumed the plant would operate at a 4,055 mmBtu per hour heat input rate, Deseret was and continues to be obligated to operate the Bonanza Plant consistent with this assumption in accordance with 40 C.F.R. § 52.21(r)(1). This is especially true given that compliance with PSD requirements was premised upon the 4,055 mmBtu per hour heat input rate. If Deseret were allowed to exceed this heat input rate, then there would be no assurance that the Bonanza Plant would not jeopardize the NAAQS or other air quality standards, or comply with other applicable PSD requirements.

Despite the fact that Deseret has been bound to operate the Bonanza Plant consistent with a heat input rate of 4,055 mmBtu per hour, a review of data reported by the company to the EPA's Air Markets Program Database (available online at http://ampd.epa.gov/ampd/ (last viewed Jan. 7, 2015)) indicates that this heat input rate has been and continues to be violated thousands upon thousands of times. Essentially, Deseret has been burning more coal than it has represented it would.

As Guardians disclosed in its comments, just in 2013, the 4,055 mmBtu/hour heat input rate was violated 6,658 times. AR Doc. 110 at 24. These violations show no sign of relenting. Although Deseret has yet to submit all its 2014 data to EPA's Air Markets Program Database, an assessment of heat input just from January 1st to March 31st indicates the 4,055 mmBtu/hour rate was violated more than 2,000 times, more than 90% of the Plant's operating hours. *See* Exhibit 6, Heat Input Data for Bonanza Plant from EPA Air Markets Program Database, Jan. 1, 2014-March 31, 2014. During this time, heat input frequently exceeded 5,000 mmBtu/hour and peaked at 5,304.2 mmBtu for an hour on March 28, 2014. It appears more likely than not that Deseret was in violation of this heat input rate when the Title V permit was issued.

In the alternative, it could be that a higher heat input rate of 4,578 mmBtu/hour may apply. Deseret has represented on numerous occasions and EPA has acknowledged the heat input capacity of the Bonanza Plant's boiler to be 4,578 mmBtu per hour. *See* AR Doc. 026 at 2 (boiler rated "at about 4578 MMBTU/hr); *see also* AR Doc. 082 at 2, AR Doc. 138 at 9 ("heat input capacity of about 4,578 MMBtu/hr"). This heat input capacity was initially presented in Deseret's application to the State of Utah for the ruggedized rotor project and "approved" in 1998. *See* AR Doc. 014 at 3. As part of this "permitting" action, the heat input capacity was "raised" from 4,381 to 4,578 mmBtu/hr. *Id*. The EPA's 2001 permit "pertains" to this permitting action and could be interpreted to have accordingly incorporated Deseret's application to the State of Utah. AR Doc. 026 at 3. Even in its most recent Title V permit application, Deseret stated, "As referenced in the State of Utah Approval Order DAQE-186-98 dated March 16, 1998 and the PSD permit PSD-UO-0001-2001:00 dated February 2, 2001, potential emissions are calculated based on average heat input of about 4,578 mmBtu/hr[.]" AR Doc. 049 at D-5.

However, even if a heat input rate of 4,578 mmbtu/hr is presumed to the capacity of the Bonanza Plant, Deseret regularly violates even this limit. Between January 1 and March 31 of 2014 alone, this limit was violated more than 1,700 times. *See* Exhibit 6.

Unfortunately, the Title V permit does not address these ongoing violations of 40 C.F.R. § 52.21(r)(1), whether based on the 4,055 mmbtu/hr heat input rate or the 4,578 mmBtu/hour rate. The permit is not written to ensure that this applicable requirement is met and does not contain a schedule of compliance to bring the Bonanza Plant into compliance. In response to this issue, EPA primarily responded that it does not believe that an exceedance of any heat rate would constitute a violation, asserting "[t]here is no limit on heat input rate in the 2001 PSD permit (nor in the 1981 PSD permit[)]." AR Doc. 134 at 30. However, the issue here is not whether there is an explicit limit in the PSD permits, the issue here is whether Deseret is bound to adhere to its PSD permit application. According to 40 C.F.R. § 52.21(r)(1), the company is bound to operate in accordance with its application. The rule explicitly requires sources to comply both with the terms of their PSD permits ***and*** with their application. The EPA's refusal to acknowledge this applicable requirement only underscores the shortcoming of the Title V permit.

EPA finally asserts that it cannot limit heat input because it "does not have the authority to create such a limit." AR Doc. 134 at 30. This simply misses the point. The issue here is not whether a new limit should be adopted, but whether the Title V permit assures Deseret operates the Bonanza Plant consistent with 40 C.F.R. § 52.21(r)(1), an applicable requirement. Necessarily, the Title V permit must, in some way, limit the heat input rate in order to ensure the

Plant is operated in compliance with PSD rules and include a schedule of compliance to achieve this outcome.

The failure of EPA Region 8 to issue a Title V permit that assures the Bonanza Plant operates in compliance with represented heat input rates in accordance with 40 C.F.R. § 52.21(r)(1) and that includes a legally required schedule of compliance to bring the facility into compliance is based on a finding of fact or conclusion of law which is clearly erroneous. Thus, the EAB must either vacate the permit or remand to the agency and order that the Title V permit be revised to ensure the Bonanza Plant operates in full compliance with the Clean Air Act.

CONCLUSION

The Title V permit for the Bonanza Plant fails to ensure compliance with applicable requirements under the Clean Air Act. WildEarth Guardians requests the EAB review whether the EPA erred in its factual and legal conclusions by not adequately addressing outstanding PSD compliance issues. Guardians requests the EAB either vacate the Title V permit based on the aforementioned deficiencies or remand to the EPA to address the aforementioned deficiencies and approve a Title V permit that fully complies with the Clean Air Act.

Respectfully submitted this 7th day of January 2015

Jeremy Nichols
Climate and Energy Program Director
WildEarth Guardians
1536 Wynkoop, Suite 310
Denver, CO 80202
(303) 437-7663
jnichols@wildearthguardians.org

TABLE OF EXHIBITS

1. EPA, "Toxic Release Inventory Data for Bonanza Power Plant," website available at http://oaspub.epa.gov/enviro/tris_control.tris_print?tris_id=84078BNNZP12500 (last accessed Jan. 7, 2015).

2. Deseret Generation and Transmission Co-operative, "Request for Approval Order for DG&T Bonanza Unit (1) Emission Limits and Ruggedized Rotor Project, Uintah County" (Aug. 4, 197).

3. EPA, Statement of Basis, Draft Air Pollution Control Prevention of Significant Deterioration permit to Construct, PSD-UO-000004-2014.003 (Dec. 4, 2014), available online at http://www2.epa.gov/sites/production/files/2014-12/documents/deseret_bonanza_-_unit_1_psd_-_sob_12-3-14.pdf (last accessed Jan. 7, 2015).

4. EPA, Draft Air Pollution Control Prevention of Significant Deterioration permit to Construct, PSD-UO-000004-2014.003 (Dec. 4, 2014), available online at http://www2.epa.gov/sites/production/files/2014-12/documents/deseret_bonanza_-_unit_1_psd_-_draft_correction_permit_12-3-14.pdf (last accessed Jan. 7, 2015).

5. Letter from Deseret to Russell A. Roberts, Executive Secretary, Utah Air Quality Board, "Response to Utah Division of Air Quality's PSD Applicability/Major Modification Determination" (December 9, 1994).

6. Heat Input Data for Bonanza Plant from EPA Air Markets Program Database, Jan. 1, 2014-March 31, 2014.

CERTIFICATE OF SERVICE

I certify that on January 7, 2015, I served this Petition for Review electronically via the Environmental Appeals Board's eFiling system. This Petition will also be served by priority U.S. mail within one business day to:

U.S. Environmental Protection Agency
Clerk of the Board, Environmental Appeals Board
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

Deseret Power Electric Cooperative
10714 South Jordan Gateway, Suite 300
South Jordan, UT 84095

Shaun McGrath
Region 8 Administrator
U.S. Environmental Protection Agency
1595 Wynkoop
Denver, CO 80202

____
Jeremy Nichols

Exhibit 1

United States Environmental Protection Agency

Envirofacts
Search Results

TRI

Envirofacts Report

<< Return

Query executed on JAN-02-2015
Results are based on data extracted on OCT-15-2014

Click on "View Facility Information" to view EPA Facility information for the facility.

Facility Name:	BONANZA POWER PLANT	Mailing Name:	BONANZA POWER PLANT		
Address:	12500 E 25500 S VERNAL UT 84078	Mailing Address:	12500 E 25500 SVERNAL UT 84078-		
County:	UINTAH	Region:	8		
Facility Information:	View Facility Information	TRI ID:	84078BNNZP12500	DUNS Number:	
		FRS ID	110015757670		
Latitude:	40.08466	Longitude:	-109.29325		
Public Contact:	GENE GRINDLE	Phone:	4357815701		
Parent Company:	DESERET POWER	Standardized Parent Company:	DESERET POWER	Parent DUNS:	098814395
BIA Tribal Code:	687	Tribe:	Ute Indian Tribe of the Uintah & Ouray Reservation, Utah		

Starting with Reporting Year 2006, TRI Facilities began reporting NAICS codes, instead of SIC codes, to identify their Primary Business Activities.

NAICS Codes for 2013

NAICS CODE	PRIMARY	NAICS DESCRIPTION
221112	YES	Fossil Fuel Electric Power Generation

The above information comes from 2013, which was the last year NAICS code data was reported for this facility. The earliest NAICS code data on file for this facility was reported in 1998.

Map this facility

Map this facility using one of Envirofact's mapping utilities.

Besides TRI, this facility also does the following:

- handles hazardous waste
- has permits to discharge to water
- has reported air releases under the Clean Air Act
- has reported greenhouse gas (GHG) data

More information about these additional regulatory aspects of this facility can be found by pressing the other regulatory data button below.

Other Regulatory Data

Total Aggregate Releases of TRI Chemicals to the Environment:

For all releases estimated as a range, the mid-point of the range was used in these calculations. This table summarizes the releases reported by the facility. ***NR*** *- signifies nothing reported by this facility for the corresponding medium.*

Total Aggregate Releases of TRI Chemicals excluding Dioxin and Dioxin-like Compounds
(Measured in Pounds)

Media	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001

Air Emissions	43495.803	39082.658	42881.822	50329.015	59237.23	83448.344	63168.609	68494.924	65152.11	61936.049	59563.7	62384.8	782
Surface Water Discharges	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	
Releases to Land	1783297	1533796	1660825	1807791.2	1525013.7	1539229	1385893.2	1607628.7	1487532.5	1486093.208	1411546.6	1575228.7	15011
Underground Injection	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	
Total On-Site Releases	1826792.803	1572878.658	1703706.822	1858120.215	1584250.93	1622677.344	1449061.809	1676123.624	1552684.61	1548029.257	1471110.3	1637613.5	15793
Transfer Off-Site to Disposal	30903.016	18688.492	NR	NR	20720.983	20535.191	25390.709	682.07	762.081	1095.118	1306.13	NR	47
Total Releases	1857695.819	1591567.15	1703706.822	1858120.215	1604971.913	1643212.535	1474452.518	1676805.694	1553446.691	1549124.375	1472416.43	1637613.5	1584

Graphic Summary of this Table

Total Aggregate Releases of Dioxin and Dioxin-like Compounds (Measured in Grams)

Media	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
Air Emissions	.001637	.0014353	.0015366	.0017	2.8	4.8	3.1693	3.6251	3.3538	3.3958	3.2261	3.5475	3.4311	5.8634	NR	NR
Surface Water Discharges	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Releases to Land	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Underground Injection	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Total On-Site Releases	.001637	.0014353	.0015366	.0017	2.8	4.8	3.1693	3.6251	3.3538	3.3958	3.2261	3.5475	3.4311	5.8634	NR	NR
Transfer Off-Site to Disposal	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Total Releases	.001637	.0014353	.0015366	.0017	2.8	4.8	3.1693	3.6251	3.3538	3.3958	3.2261	3.5475	3.4311	5.8634	NR	NR

Graphic Summary of this Table

TRI Chemicals Reported on Form A:

Please note that there were no chemicals reported on Form A for this facility

NOTE:

All chemicals reported below have release or transfer amounts greater than zero. To see a list of all chemicals reported by this facility click here.

Names and Amounts of Chemicals Released to the Environment by Year.

For all releases estimated as a range, the mid-point of the range was used in these calculations. ***NR*** *- signifies nothing reported for this facility by the corresponding medium. Rows with all "0" or "NR" values were not listed.*

Chemical Name	Media	Unit Of Measure	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000
BARIUM (TRI Chemical ID: 007440393)	AIR STACK	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
BARIUM (TRI Chemical ID: 007440393)	SURF IMP	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
BARIUM COMPOUNDS (TRI Chemical ID: N040)	AIR FUG	Pounds	5.4	0	0	20	20	20	20	11	11	0	0	0	1080	510
BARIUM COMPOUNDS (TRI Chemical ID: N040)	AIR STACK	Pounds	1595	1428	574	478	677	677	1746	883	1161	1340	1546	133	2982	2311
BARIUM COMPOUNDS (TRI Chemical ID: N040)	DISP METALS	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	4333	1358
BARIUM COMPOUNDS (TRI Chemical ID:	DISP NON METALS	Pounds	176	16220	NR	NR	18386	18386	22735	611	682	993	1186	NR	NR	NR

N040)																
BARIUM COMPOUNDS (TRI Chemical ID: N040)	LAND TREA	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	0	1214	1333	13662
BARIUM COMPOUNDS (TRI Chemical ID: N040)	OTH LANDF	Pounds	1531562	1319463	1433104	1544835	1367070	1367070	1229480.5	1432901	1325118	1341292	1273677	1402332	1352689	1007331
BARIUM COMPOUNDS (TRI Chemical ID: N040)	SURF IMP	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
CHLORINE (TRI Chemical ID: 007782505)	AIR STACK	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	AIR FUG	Pounds	.1	0	0	0	0	0	0	0	0	0	0	0	23	11
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	AIR STACK	Pounds	36	42	16	233	211	518	245	232	242	44	54	24	69	77
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	DISP METALS	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	94	29
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	DISP NON METALS	Pounds	4	339	NR	NR	431	397	490	13	15	21	25	NR	NR	NR
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	LAND TREA	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	0	26	29	295
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	OTH LANDF	Pounds	32293	27878	30209	32414	26356	29508	26560	30924	28616	29114	27658	30417	29295	21801
COPPER COMPOUNDS (TRI Chemical ID: N100)	AIR FUG	Pounds	.1	0	0	0	0	0	0	0	0	NR	NR	NR	NR	NR
COPPER COMPOUNDS (TRI Chemical ID: N100)	AIR STACK	Pounds	27	24	16	8	9	199	25	9	17	NR	NR	13	NR	NR
COPPER COMPOUNDS (TRI Chemical ID: N100)	DISP NON METALS	Pounds	3	271	NR	NR	276	255	315	9	9	NR	NR	NR	NR	NR
COPPER COMPOUNDS (TRI Chemical ID: N100)	LAND TREA	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	17	NR	NR

COPPER COMPOUNDS (TRI Chemical ID: N100)	OTH LANDF	Pounds	27148	24489	25234	28010	18785	20277.2	18367	21191	19694	NR	NR	20502	NR	NR
COPPER COMPOUNDS (TRI Chemical ID: N100)	SI 5.5.3B	Pounds	NR	NR	NR	NR	NR	1390	1390	1390	1390	NR	NR	NR	NR	NR
DIOXIN AND DIOXIN-LIKE COMPOUNDS (TRI Chemical ID: N150)	AIR STACK	Grams	.001637	.0014353	.0015366	.0017	2.8	4.8	3.1693	3.6251	3.3538	3.3958	3.2261	3.5475	3.4311	5.8634
ETHYLENE GLYCOL (TRI Chemical ID: 000107211)	AIR FUG	Pounds	5	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
ETHYLENE GLYCOL (TRI Chemical ID: 000107211)	AIR STACK	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	0
ETHYLENE GLYCOL (TRI Chemical ID: 000107211)	DISP NON METALS	Pounds	30700	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
ETHYLENE GLYCOL (TRI Chemical ID: 000107211)	LAND TREA	Pounds	NR	NR	NR	NR	4956	4956	4956	NR	NR	NR	NR	NR	NR	NR
ETHYLENE GLYCOL (TRI Chemical ID: 000107211)	OTH DISP	Pounds	6900	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	5876
ETHYLENE GLYCOL (TRI Chemical ID: 000107211)	OTH LANDF	Pounds	250	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
HYDROCHLORIC ACID (1995 AND AFTER "ACID AEROSOLS" ONLY) (TRI Chemical ID: 007647010)	AIR STACK	Pounds	17148	14950	16132	17284	17891	28312	18797	20323	18931	19108	18333	19735	19278	15426
HYDROGEN FLUORIDE (TRI Chemical ID: 007664393)	AIR STACK	Pounds	7222	6296	6827	7289	27983	37817	28880	32533	29041	29360	28028	30502	29644	23002
LEAD (TRI Chemical ID: 007439921)	AIR STACK	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
LEAD (TRI Chemical ID: 007439921)	SURF IMP	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
LEAD COMPOUNDS (TRI Chemical ID: N420)	AIR FUG	Pounds	.1	0	0	1	1	1	1	1	1	NR	NR	NR	29	14
LEAD COMPOUNDS (TRI Chemical ID: N420)	AIR STACK	Pounds	30	28	12	856	1000	1484	1043	1163	1081	41	41	25	80	62
LEAD COMPOUNDS (TRI Chemical ID: N420)	DISP METALS	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	116	36
LEAD COMPOUNDS (TRI Chemical ID: N420)	DISP NON METALS	Pounds	3	298	NR	NR	534	491	607	16	18	27	31	NR	NR	NR
LEAD COMPOUNDS (TRI Chemical ID: N420)	LAND TREA	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	0	32	36	365
LEAD COMPOUNDS (TRI Chemical ID: N420)	OTH LANDF	Pounds	32957	29656	30312	34444	37511	39506	35936	41226	38435	39112	37310	40724	40006	29306
LEAD COMPOUNDS (TRI Chemical ID: N420)	SURF IMP	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
MANGANESE (TRI Chemical ID: 007439965)	AIR STACK	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR

MANGANESE (TRI Chemical ID: 007439965)	SURF IMP	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	AIR FUG	Pounds	.1	0	0	2	2	2	2	2	2	NR	NR	NR	23	11
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	AIR STACK	Pounds	118	148	57	7914	2127	2609	2216	2402	2326	88	129	37	82	170
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	DISP METALS	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	93	29
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	DISP NON METALS	Pounds	12	1071	NR	NR	428	394	487	13	15	21	25	NR	NR	NR
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	LAND TREA	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	0	26	28	293
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	OTH LANDF	Pounds	104461	90821	97444	98749	28022	29736	27004	31064	28935	30933	29487	32227	31554	23177
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	SURF IMP	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	0	0	1
MERCURY COMPOUNDS (TRI Chemical ID: N458)	AIR FUG	Pounds	0	0	0	0	0	0	NR	NR	NR	NR	NR	NR	.108	0
MERCURY COMPOUNDS (TRI Chemical ID: N458)	AIR STACK	Pounds	1.903	1.658	1.822	2.265	2.43	4.344	2.609	48.724	45.11	41.049	20.7	23.8	26.017	19.885
MERCURY COMPOUNDS (TRI Chemical ID: N458)	DISP METALS	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	.516	.162
MERCURY COMPOUNDS (TRI Chemical ID: N458)	DISP NON METALS	Pounds	.016	1.492	NR	NR	2.383	2.191	2.709	.07	.081	.118	.13	NR	NR	NR
MERCURY COMPOUNDS (TRI Chemical ID: N458)	LAND TREA	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	0	.1	.159	1.628
MERCURY COMPOUNDS (TRI Chemical ID: N458)	OTH LANDF	Pounds	141	122	132	142.2	144.7	161.8	145.7	123.7	114.5	120.208	132.6	144.6	136.49	101.223
SULFURIC ACID (1994 AND AFTER "ACID AEROSOLS" ONLY) (TRI Chemical ID: 007664939)	AIR STACK	Pounds	17259	16122	19229	16218.75	9291	11329	10132	10858	12255	11865	11362	11861	24829	22090
VANADIUM (EXCEPT WHEN CONTAINED IN AN ALLOY) (TRI Chemical ID: 007440622)	AIR STACK	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
VANADIUM (EXCEPT WHEN CONTAINED IN AN ALLOY) (TRI Chemical ID: 007440622)	SURF IMP	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
VANADIUM COMPOUNDS	AIR FUG	Pounds	.1	0	0	1	1	1	NR	NR	NR	NR	NR	NR	36	17

(TRI Chemical ID: N770)																
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	AIR STACK	Pounds	48	43	17	15	21.8	475	59	29.2	39	49	50	31	99	77
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	DISP METALS	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	144	45
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	DISP NON METALS	Pounds	5	488	NR	NR	663.6	610	754	20	23	33	39	NR	NR	NR
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	LAND TREA	Pounds	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	0	40	44	453
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	OTH LANDF	Pounds	47585	41367	44390	48562	42169	46624	42054	48809	45230	45522	43282	47527	45960	34092
ZINC (FUME OR DUST) (TRI Chemical ID: 007440666)	AIR FUG	Pounds	NR	NR	NR	1	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
ZINC (FUME OR DUST) (TRI Chemical ID: 007440666)	AIR STACK	Pounds	NR	NR	NR	6	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
ZINC (FUME OR DUST) (TRI Chemical ID: 007440666)	OTH LANDF	Pounds	NR	NR	NR	20635	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR

Discharge of Chemicals into Streams or Bodies of Water:

Please note that either there were no releases of chemicals into streams or bodies of water reported by this facility or the facility did not file a TRI form R for the years 1987 to 2013. Rows with Release Amount equal to "0" were not listed.

Transfer of Chemicals to Off-Site Locations other than POTWs:

For all releases estimated as a range, the mid-point of the range was used in these calculations. Rows with Total Transfer Amount equal to "0" were not listed.

Chemical Name	Year	Unit Of Measure	Total Transfer Amount	Transfer Site Name and Address	Type Of Waste Management
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2013	Pounds	50	**NAPLES CITY 1420 E 2850 S NAPLES, UT 84078**	Unknown
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2013	Pounds	101	**RECOVERY SYSTEMS INC. 7849 NEWPORT WAY SALT LAKE CITY, UT 84121**	Unknown
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2013	Pounds	25	**SCOTT/WEST PAC LLC 239 N 1250 W CENTERVILLE, UT 84014**	Unknown
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2012	Pounds	637	**CITY OF NAPLES 1420 E. 2850 S. NAPLES, UT 84078**	Unknown
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2012	Pounds	4647	**NILE CHAPMAN CONSTRUCTION, INC. 244 W HIGHWAY 40 ROOSEVELT, UT 84066**	Unknown
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2012	Pounds	10936	**R. CHAPMAN CONSTRUCTION 140 W 425 S ROOSEVELT, UT 84066**	Unknown
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2009	Pounds	18386	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment

BARIUM COMPOUNDS (TRI Chemical ID: N040)	2008	Pounds	18386	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2007	Pounds	22735	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2006	Pounds	611	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2005	Pounds	682	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2004	Pounds	993	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2003	Pounds	1186	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2003	Pounds	6	**ENSEN TECH 239 NORTH 1250 WEST CENTERVILLE, UT 84014**	Other Reuse or Recovery
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2001	Pounds	4333	**BLUE MOUNTAIN ENERGY DESERADO MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Solidification/Stabilization-Metals and Metal Compounds only
BARIUM COMPOUNDS (TRI Chemical ID: N040)	2000	Pounds	1358	**BLUE MOUNTAIN ENERGY DESERADO MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Solidification/Stabilization-Metals and Metal Compounds only
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2013	Pounds	1.1	**NAPLES CITY 1420 E 2850 S NAPLES, UT 84078**	Unknown
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2013	Pounds	2.3	**RECOVERY SYSTEMS INC. 7849 NEWPORT WAY SALT LAKE CITY, UT 84121**	Unknown
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2013	Pounds	.6	**SCOTT/WEST PAC LLC 239 N 1250 W CENTERVILLE, UT 84014**	Unknown
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2012	Pounds	13	**CITY OF NAPLES 1420 E. 2850 S. NAPLES, UT 84078**	Unknown
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2012	Pounds	97	**NILE CHAPMAN CONSTRUCTION, INC. 244 W HIGHWAY 40 ROOSEVELT, UT 84066**	Unknown
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2012	Pounds	229	**R. CHAPMAN CONSTRUCTION 140 W 425 S ROOSEVELT, UT 84066**	Unknown
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2009	Pounds	431	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2008	Pounds	397	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION)	2007	Pounds	490	**UINTAH COUNTY 152 E 100 N**	Land Treatment

(TRI Chemical ID: N090)					VERNAL, UT 84078	
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2006	Pounds	13	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2005	Pounds	15	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2004	Pounds	21	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2003	Pounds	25	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGLEY, CO 81648**	Other Off-Site Management
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2003	Pounds	1	**ENSEN TECH 239 NORTH 1250 WEST CENTERVILLE, UT 84014**	Other Reuse or Recovery
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2001	Pounds	94	**BLUE MOUNTAIN ENERGY DESERADO MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Solidification/Stabilization-Metals and Metal Compounds only
CHROMIUM COMPOUNDS(EXCEPT CHROMITE ORE MINED IN THE TRANSVAAL REGION) (TRI Chemical ID: N090)	2000	Pounds	29	**BLUE MOUNTAIN ENERGY DESERADO MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Solidification/Stabilization-Metals and Metal Compounds only
COPPER COMPOUNDS (TRI Chemical ID: N100)	2013	Pounds	.9	**NAPLES CITY 1420 E 2850 S NAPLES, UT 84078**	Unknown
COPPER COMPOUNDS (TRI Chemical ID: N100)	2013	Pounds	1.7	**RECOVERY SYSTEMS INC. 7849 NEWPORT WAY SALT LAKE CITY, UT 84121**	Unknown
COPPER COMPOUNDS (TRI Chemical ID: N100)	2013	Pounds	.4	**SCOTT/WEST PAC LLC 239 N 1250 W CENTERVILLE, UT 84014**	Unknown
COPPER COMPOUNDS (TRI Chemical ID: N100)	2012	Pounds	10	**CITY OF NAPLES 1420 E. 2850 S. NAPLES, UT 84078**	Unknown
COPPER COMPOUNDS (TRI Chemical ID: N100)	2012	Pounds	78	**NILE CHAPMAN CONSTRUCTION, INC. 244 W HIGHWAY 40 ROOSEVELT, UT 84066**	Unknown
COPPER COMPOUNDS (TRI Chemical ID: N100)	2012	Pounds	183	**R. CHAPMAN CONSTRUCTION 140 W 425 S ROOSEVELT, UT 84066**	Unknown
COPPER COMPOUNDS (TRI Chemical ID: N100)	2009	Pounds	276	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
COPPER COMPOUNDS (TRI Chemical ID: N100)	2008	Pounds	255	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
COPPER COMPOUNDS (TRI Chemical ID: N100)	2007	Pounds	315	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
COPPER COMPOUNDS (TRI Chemical ID: N100)	2006	Pounds	9	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management

COPPER COMPOUNDS (TRI Chemical ID: N100)	2005	Pounds	9	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
ETHYLENE GLYCOL (TRI Chemical ID: 000107211)	2013	Pounds	30700	**UINTAH COUNTY LANDFILL 133 S 500 E VERNAL, UT 84078**	Other Landfills
LEAD COMPOUNDS (TRI Chemical ID: N420)	2013	Pounds	.9	**NAPLES CITY 1420 E 2850 S NAPLES, UT 84078**	Unknown
LEAD COMPOUNDS (TRI Chemical ID: N420)	2013	Pounds	1.7	**RECOVERY SYSTEMS INC. 7849 NEWPORT WAY SALT LAKE CITY, UT 84121**	Unknown
LEAD COMPOUNDS (TRI Chemical ID: N420)	2013	Pounds	.4	**SCOTT/WEST PAC LLC 239 N 1250 W CENTERVILLE, UT 84014**	Unknown
LEAD COMPOUNDS (TRI Chemical ID: N420)	2012	Pounds	12	**CITY OF NAPLES 1420 E. 2850 S. NAPLES, UT 84078**	Unknown
LEAD COMPOUNDS (TRI Chemical ID: N420)	2012	Pounds	85	**NILE CHAPMAN CONSTRUCTION, INC. 244 W HIGHWAY 40 ROOSEVELT, UT 84066**	Unknown
LEAD COMPOUNDS (TRI Chemical ID: N420)	2012	Pounds	201	**R. CHAPMAN CONSTRUCTION 140 W 425 S ROOSEVELT, UT 84066**	Unknown
LEAD COMPOUNDS (TRI Chemical ID: N420)	2009	Pounds	534	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
LEAD COMPOUNDS (TRI Chemical ID: N420)	2008	Pounds	491	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
LEAD COMPOUNDS (TRI Chemical ID: N420)	2007	Pounds	607	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
LEAD COMPOUNDS (TRI Chemical ID: N420)	2006	Pounds	16	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
LEAD COMPOUNDS (TRI Chemical ID: N420)	2005	Pounds	18	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
LEAD COMPOUNDS (TRI Chemical ID: N420)	2004	Pounds	27	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
LEAD COMPOUNDS (TRI Chemical ID: N420)	2003	Pounds	31	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGLEY, CO 81648**	Other Off-Site Management
LEAD COMPOUNDS (TRI Chemical ID: N420)	2003	Pounds	1	**ENSEN TECH 239 NORTH 1250 WEST CENTERVILLE, UT 84014**	Other Reuse or Recovery
LEAD COMPOUNDS (TRI Chemical ID: N420)	2001	Pounds	116	**BLUE MOUNTAIN ENERGY DESERADO MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Solidification/Stabilization-Metals and Metal Compounds only
LEAD COMPOUNDS	2000	Pounds	36	**BLUE MOUNTAIN ENERGY**	Solidification/Stabilization-Metals and Metal

(TRI Chemical ID: N420)				**DESERADO MINE** **3607 COUNTY ROAD 65** **RANGELY, CO 81648**	Compounds only
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2013	Pounds	3.4	**NAPLES CITY** **1420 E 2850 S** **NAPLES, UT 84078**	Unknown
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2013	Pounds	6.9	**RECOVERY SYSTEMS INC.** **7849 NEWPORT WAY** **SALT LAKE CITY, UT 84121**	Unknown
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2013	Pounds	1.7	**SCOTT/WEST PAC LLC** **239 N 1250 W** **CENTERVILLE, UT 84014**	Unknown
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2012	Pounds	42	**CITY OF NAPLES** **1420 E. 2850 S.** **NAPLES, UT 84078**	Unknown
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2012	Pounds	307	**NILE CHAPMAN CONSTRUCTION, INC.** **244 W HIGHWAY 40** **ROOSEVELT, UT 84066**	Unknown
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2012	Pounds	722	**R. CHAPMAN CONSTRUCTION** **140 W 425 S** **ROOSEVELT, UT 84066**	Unknown
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2009	Pounds	428	**UINTAH COUNTY** **152 E 100 N** **VERNAL, UT 84078**	Land Treatment
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2008	Pounds	394	**UINTAH COUNTY** **152 E 100 N** **VERNAL, UT 84078**	Land Treatment
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2007	Pounds	487	**UINTAH COUNTY** **152 E 100 N** **VERNAL, UT 84078**	Land Treatment
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2006	Pounds	13	**DESERADO COAL MINE** **3607 COUNTY ROAD 65** **RANGELY, CO 81648**	Other Off-Site Management
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2005	Pounds	15	**DESERADO COAL MINE** **3607 COUNTY ROAD 65** **RANGELY, CO 81648**	Other Off-Site Management
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2004	Pounds	21	**DESERADO COAL MINE** **3607 COUNTY ROAD 65** **RANGELY, CO 81648**	Other Off-Site Management
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2003	Pounds	25	**DESERADO COAL MINE** **3607 COUNTY ROAD 65** **RANGLEY, CO 81648**	Other Off-Site Management
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2003	Pounds	1	**ENSEN TECH** **239 NORTH 1250 WEST** **CENTERVILLE, UT 84014**	Other Reuse or Recovery
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2001	Pounds	93	**BLUE MOUNTAIN ENERGY DESERADO MINE** **3607 COUNTY ROAD 65** **RANGELY, CO 81648**	Solidification/Stabilization-Metals and Metal Compounds only
MANGANESE COMPOUNDS (TRI Chemical ID: N450)	2000	Pounds	29	**BLUE MOUNTAIN ENERGY DESERADO MINE** **3607 COUNTY ROAD 65** **RANGELY, CO 81648**	Solidification/Stabilization-Metals and Metal Compounds only
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2013	Pounds	.00457	**NAPLES CITY** **1420 E 2850 S** **NAPLES, UT 84078**	Unknown

MERCURY COMPOUNDS (TRI Chemical ID: N458)	2013	Pounds	.00914	**RECOVERY SYSTEMS INC. 7849 NEWPORT WAY SALT LAKE CITY, UT 84121**	Unknown
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2013	Pounds	.00229	**SCOTT/WEST PAC LLC 239 N 1250 W CENTERVILLE, UT 84014**	Unknown
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2012	Pounds	.059	**CITY OF NAPLES 1420 E. 2850 S. NAPLES, UT 84078**	Unknown
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2012	Pounds	.427	**NILE CHAPMAN CONSTRUCTION, INC. 244 W HIGHWAY 40 ROOSEVELT, UT 84066**	Unknown
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2012	Pounds	1.006	**R. CHAPMAN CONSTRUCTION 140 W 425 S ROOSEVELT, UT 84066**	Unknown
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2009	Pounds	2.383	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2008	Pounds	2.191	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2007	Pounds	2.709	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2006	Pounds	.07	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2005	Pounds	.081	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2004	Pounds	.118	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2003	Pounds	.13	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGLEY, CO 81648**	Other Off-Site Management
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2003	Pounds	.01	**ENSEN TECH 239 NORTH 1250 WEST CENTERVILLE, UT 84014**	Other Reuse or Recovery
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2001	Pounds	.516	**BLUE MOUNTAIN ENERGY DESERADO MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Solidification/Stabilization-Metals and Metal Compounds only
MERCURY COMPOUNDS (TRI Chemical ID: N458)	2000	Pounds	.162	**BLUE MOUNTAIN ENERGY DESERADO MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Solidification/Stabilization-Metals and Metal Compounds only
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2013	Pounds	1.4	**NAPLES CITY 1420 E 2850 S NAPLES, UT 84078**	Unknown
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2013	Pounds	2.9	**RECOVERY SYSTEMS INC. 7849 NEWPORT WAY SALT LAKE CITY, UT 84121**	Unknown

VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2013	Pounds	.7	**SCOTT/WEST PAC LLC 239 N 1250 W CENTERVILLE, UT 84014**	Unknown
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2012	Pounds	19	**CITY OF NAPLES 1420 E. 2850 S. NAPLES, UT 84078**	Unknown
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2012	Pounds	140	**NILE CHAPMAN CONSTRUCTION, INC. 244 W HIGHWAY 40 ROOSEVELT, UT 84066**	Unknown
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2012	Pounds	329	**R. CHAPMAN CONSTRUCTION 140 W 425 S ROOSEVELT, UT 84066**	Unknown
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2009	Pounds	663.6	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2008	Pounds	610	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2007	Pounds	754	**UINTAH COUNTY 152 E 100 N VERNAL, UT 84078**	Land Treatment
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2006	Pounds	20	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2005	Pounds	23	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2004	Pounds	33	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Other Off-Site Management
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2003	Pounds	39	**DESERADO COAL MINE 3607 COUNTY ROAD 65 RANGLEY, CO 81648**	Other Off-Site Management
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2003	Pounds	1	**ENSEN TECH 239 NORTH 1250 WEST CENTERVILLE, UT 84014**	Other Reuse or Recovery
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2001	Pounds	144	**BLUE MOUNTAIN ENERGY DESERADO MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Solidification/Stabilization-Metals and Metal Compounds only
VANADIUM COMPOUNDS (TRI Chemical ID: N770)	2000	Pounds	45	**BLUE MOUNTAIN ENERGY DESERADO MINE 3607 COUNTY ROAD 65 RANGELY, CO 81648**	Solidification/Stabilization-Metals and Metal Compounds only

Summary of Waste Management Activities

Please note that chemical amounts shown here are not included in Total Aggregate Releases shown above.

Summary of Waste Management Activities excluding Dioxin and Dioxin-like Compounds (Measured in Pounds)

Year	On-Site Recycling	Off-Site Recycling	On-Site Energy Recovery	Off-Site Energy Recovery	On-Site Treatment	Off-Site Treatment	Total Amount
2012	0	0	0	0	1227483	0	1227483
2013	0	0	0	0	1408264	0	1408264

2014 (Projected)	0	0	0	0	1457700	0	1457700
2015 (Projected)	0	0	0	0	1457700	0	1457700

Summary of Waste Management Activities for Dioxin and Dioxin-like Compounds
(Measured in Grams)

This facility did not report any waste management activities for Dioxin and Dioxin-like Compounds.

Chemicals Under Waste Management:

Please note that chemical amounts shown here are not included in the Total Aggregate Releases shown above. Transfers to Publicly Owned Treatment Works are listed on a separate table.

Chemical Name	Year	Unit Of Measure	On-Site Recycling	Off-Site Recycling	On-Site Energy Recovery	Off-Site Energy Recovery	On-Site Treated	Off-Site Treated	Total Amount
BARIUM COMPOUNDS	2012	Pounds	0	0	0	0	7484	0	7484
	2013	Pounds	0	0	0	0	7642	0	7642
	2014 (Projected)	Pounds	0	0	0	0	7700	0	7700
	2015 (Projected)	Pounds	0	0	0	0	7700	0	7700
HYDROCHLORIC ACID (1995 AND AFTER "ACID AEROSOLS" ONLY)	2012	Pounds	0	0	0	0	537417	0	537417
	2013	Pounds	0	0	0	0	616427	0	616427
	2014 (Projected)	Pounds	0	0	0	0	650000	0	650000
	2015 (Projected)	Pounds	0	0	0	0	650000	0	650000
HYDROGEN FLUORIDE	2012	Pounds	0	0	0	0	427520	0	427520
	2013	Pounds	0	0	0	0	490373	0	490373
	2014 (Projected)	Pounds	0	0	0	0	500000	0	500000
	2015 (Projected)	Pounds	0	0	0	0	500000	0	500000
SULFURIC ACID (1994 AND AFTER "ACID AEROSOLS" ONLY)	2012	Pounds	0	0	0	0	255062	0	255062
	2013	Pounds	0	0	0	0	293822	0	293822
	2014 (Projected)	Pounds	0	0	0	0	300000	0	300000
	2015 (Projected)	Pounds	0	0	0	0	300000	0	300000

Publicly Owned Treatment Works (POTW) that Chemicals were Transferred to in 2011 and after:

This facility did not transfer any chemicals to a Publicly Owned Treatment Works (POTW) in 2011 and after.

Publicly Owned Treatment Works (POTW) that Chemicals were Transferred to PRIOR to 2011:

This facility did not transfer any chemicals to a Publicly Owned Treatment Works (POTW) PRIOR to 2011.

Non Production Releases:

This facility did not report any Non-Production releases.

Additional Source Reduction and Pollution Prevention Data:

***The P2 Report** summarizes chemical-specific Pollution Prevention (P2) data for multiple years, including Newly Implemented Source Reduction Activities (Section 8.10) and Optional Pollution Prevention Information (Section 8.11). A "P2 Data" data entry indicates that P2 data was reported for that specific chemical and year. A NR signifies that no Pollution Prevention data was reported for that specific chemical and year.*

View all P2 Information for this facility

Chemical Name	P2 Report	5-Year Waste Trend	2000	1999	1998
CHLORINE	P2 Details	NA	NR	P2	P2

ETHYLENE GLYCOL	P2 Details	NA	**P2**	No P2	No P2

"**P2**" indicates that P2 activity codes and/or descriptions were provided for the chemical and year in question. "**B**" indicates barriers to P2 was reported. "No P2" indicates that a Form R was submitted but no P2 information was included. "NR" indicates that no Form R was submitted.

Additional links for TRI:

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Exhibit 2

Deseret
Generation & Transmission Co-operative
5295 South 300 West • Suite 500 • Murray, Utah 84107
801-892-6500 • FAX: 801-892-6599

Ursula Trueman
Utah Division of Air Quality
1950 West North Temple
Salt Lake City, UT 84004

Attn. J. Tim Blanchard

RE: Request for Approval Order for DG&T Bonanza Unit (1) Power Plant Emission Limits and Ruggedized Rotor Project, Uintah County

CONFIDENTIAL

Dear Ms. Trueman:

Deseret Generation & Transmission Co-operative (DG&T) hereby respectfully submits its notice of intent (NOI) requesting revised emission limits for its Bonanza Unit (1) Power Plant and Ruggedized Rotor Project. Attachment 1 provides a description of the Ruggedized Rotor Project.

The Project will increase the maximum heat input capacity of the Turbine. The increased heat input has the potential to increase the potential to emit for certain Bonanza 1 emissions. DG&T is voluntarily requesting more stringent emission limits for Bonanza 1 to reduce its NO_x emissions by 528.17 tons per year. DG&T is also requesting certain annual emission limits for other emissions, resulting in an overall increase in the annual potential to emit (PTE) for the Project that is below the levels that might trigger additional review pursuant to new source review (NSR) and prevention of significant deterioration (PSD) requirements. The new emission limits are set forth in Attachment 2. A summary of the pre- and post-change emissions are summarized in Attachment 3. Detailed emission data and supporting calculations are set forth in Attachment 4. Also, included with this NOI is a summary of the emission control equipment upgrades completed or planned for Bonanza 1.

If you have any questions or comments regarding the enclosed, please contact Howard Vickers at (435) 781-5706.

Sincerely,

Stan Gordon

Stan Gordon
Plant Manager

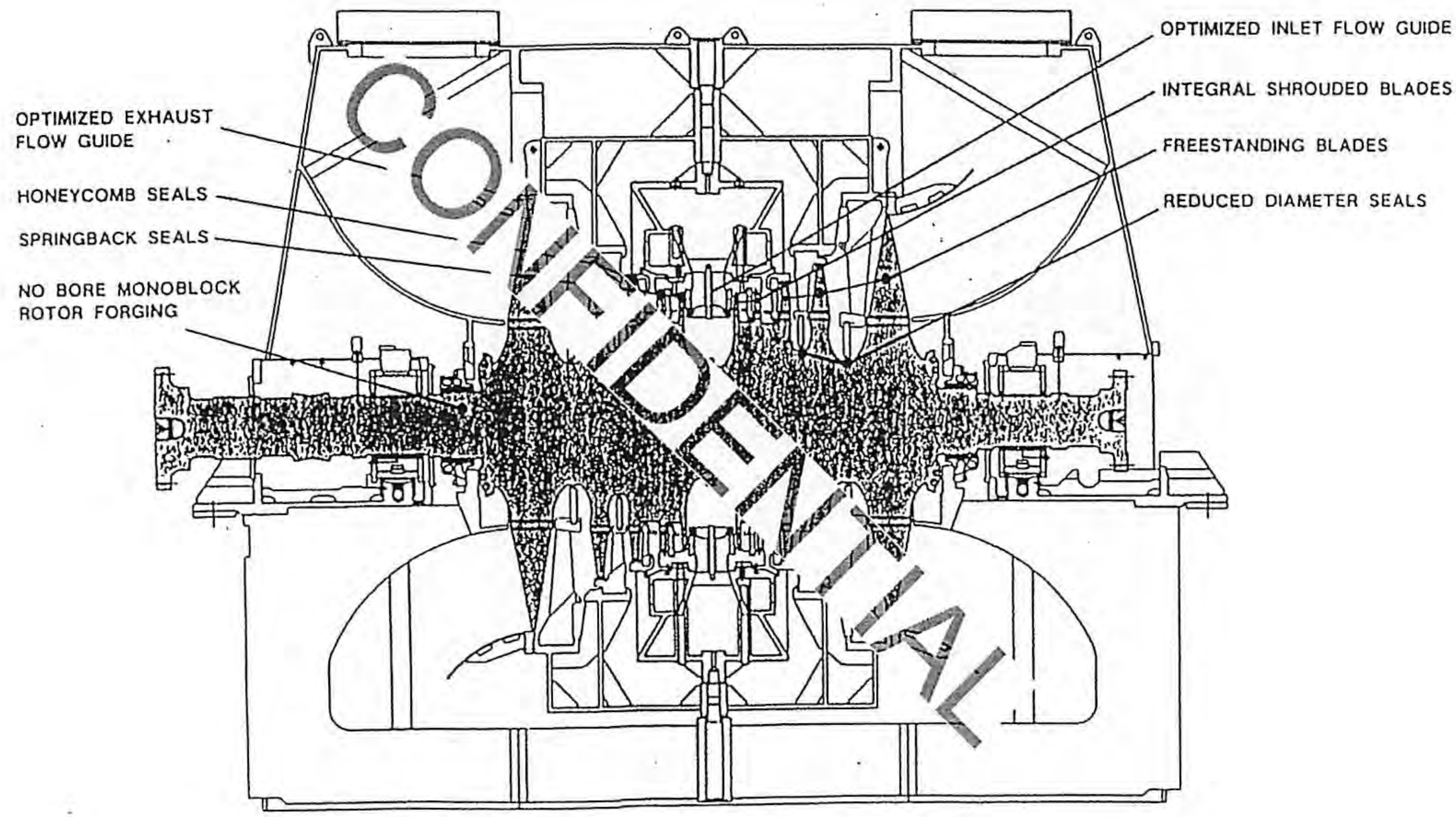
Attachment 1

Ruggedized Rotor Project Description

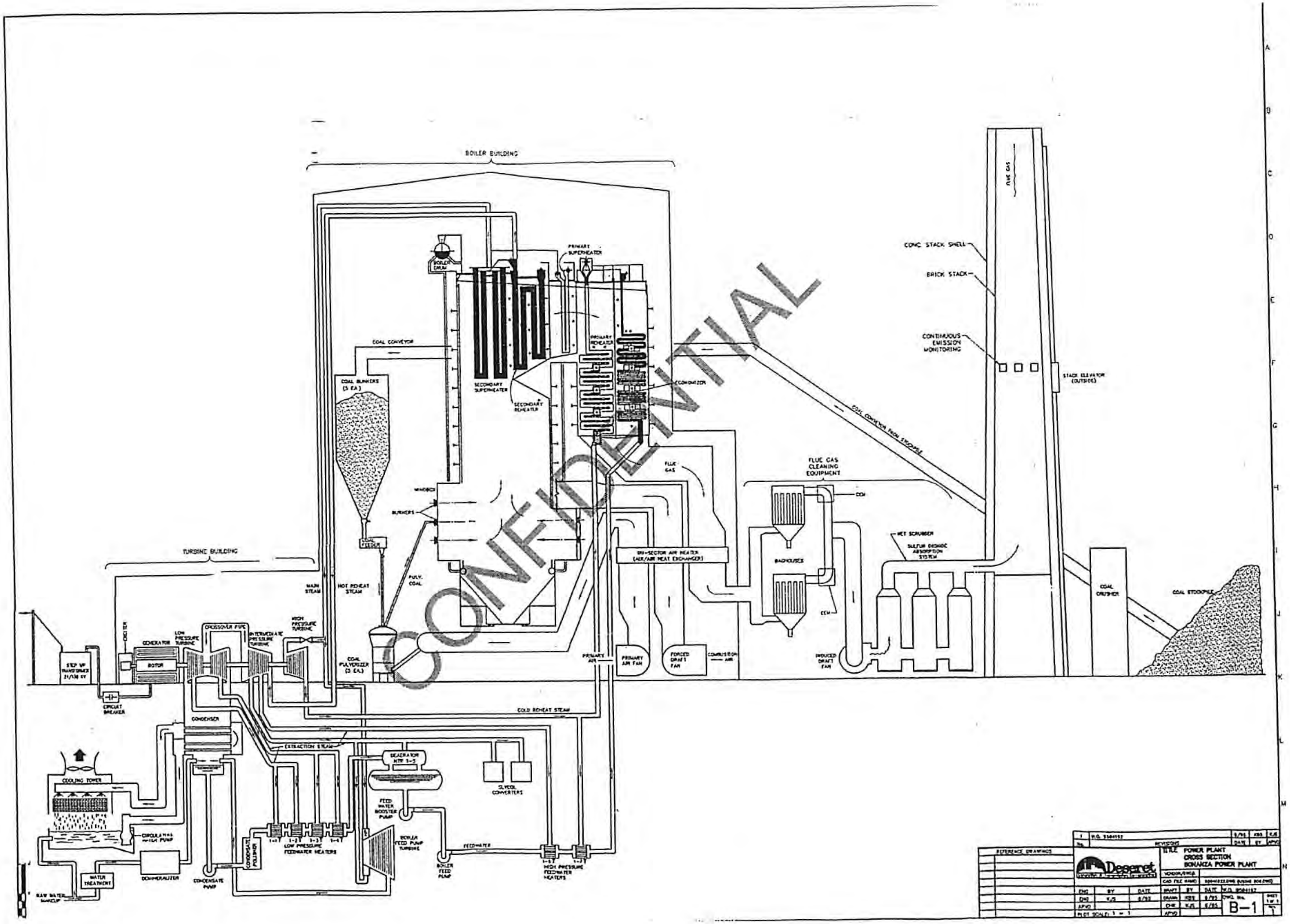
DG&T plans to upgrade the Turbine Generator at Bonanza 1 during the year 2000 or 2001 Unit Outage (A cross section diagram of Bonanza 1 indicating the location of the turbine is attached hereto). The upgrade–referred to as the "Ruggedized Rotor Project"–involves the replacement of the HP/IP and LP rotating and stationary equipment (A cross section diagram of the Ruggedized Rotor LP Rotor is attached hereto). Because the equipment necessary for the Project has a long lead time for design, construction and installation, DG&T is entering into contracts within the next few months to commence construction of the Ruggedized Rotor components. Final installation of the Ruggedized Rotor will take place in the 2000-2001 ti[illegible]rame and is expected to take about 6 weeks. The Project will increase Bonanza 1's gener[illegible]city by at least 28 MW (per vendor representations). DG&T believes that the gross [illegible]onanza 1 could be as much as 500 MW or more (referred to as 500 est. MW) after th[illegible]

Approximately 20 MW from the upgrade will result from [illegible] in the steam flow produced by the Boiler. To date, the Boiler has not been operat[illegible]ak potential due to limitations of steam flow at the existing Turbine Generator. The [illegible] allow the Turbine Generator to accept all of the steam flow the Boiler is capable [illegible]g. While the Ruggedized Rotor, by itself, will not result in any change in Bonanz[illegible]ons, the increased capacity of the Turbine Generator to handle the Boiler's peak capa[illegible]crease Bonanza 1's overall potential to emit (PTE).

DG&T has prepared this NOI to [illegible] necessary increases in Bonanza 1's overall PTE to allow operation of the Boiler a[illegible] Generator at their full capacity. DG&T also recently installed improved low-NO[illegible]nology at the boiler which allows DG&T to voluntarily significantly reduce NO_x [illegible] The net effect of the proposed emission changes will be to significantly reduce o[illegible] wide emissions as a result of lower NO_x limits.



RUGGEDIZED LP ROTOR



BOILER BUILDING
TURBINE BUILDING
BOILER DRUM
PRIMARY SUPERHEATER
PRIMARY REHEATER
ECONOMIZER
SECONDARY SUPERHEATER
SECONDARY REHEATER
COAL CONVEYOR
COAL BUNKERS (3 EA.)
WINDBOX
BURNERS
PULV. COAL
MAIN STEAM
HOT REHEAT STEAM
HIGH PRESSURE TURBINE
INTERMEDIATE PRESSURE TURBINE
CROSSOVER PIPE
LOW PRESSURE TURBINE
GENERATOR
ROTOR
EXCITER
CIRCUIT BREAKER
STEP UP TRANSFORMER
COAL PULVERIZER (3 EA.)
PRIMARY AIR
PRIMARY AIR FAN
FORCED DRAFT FAN
COMBUSTION AIR
FLUE GAS
TRI-SECTOR AIR HEATER (AIR/AIR HEAT EXCHANGER)
FLUE GAS CLEANING EQUIPMENT
BAGHOUSES
INDUCED DRAFT FAN
WET SCRUBBER
SULFUR DIOXIDE ABSORPTION SYSTEM
COAL CONVEYOR FROM STOCKPILE
CONC STACK SHELL
BRICK STACK
CONTINUOUS EMISSION MONITORING
STACK ELEVATOR (OUTSIDE)
FLUE GAS
COAL CRUSHER
COAL STOCKPILE
COLD REHEAT STEAM
CONDENSER
EXTRACTION STEAM
DEAERATOR
GLYCOL CONVERTERS
FEED WATER BOOSTER PUMP
BOILER FEED PUMP TURBINE
FEEDWATER
BOILER FEED PUMP
HIGH PRESSURE FEEDWATER HEATERS
LOW PRESSURE FEEDWATER HEATERS
CONDENSATE POLISHER
CONDENSATE PUMP
COOLING TOWER
CIRCULATING WATER PUMP
DEMINERALIZER
WATER TREATMENT
RAW WATER MAKEUP
CONFIDENTIAL
REFERENCE DRAWINGS
REVISIONS
Deseret
TITLE POWER PLANT
CROSS SECTION
BONANZA POWER PLANT
CAD FILE NAME
DRAWN
CHK
APVD
PLOT SCALE: 1 = 1
DWG. No.
B-1

Attachment 2

Proposed New Emission Limits for Bonanza 1

1. **Revise condition 7.A to read as follows:**

7. Sulfur Emission Control

A. Bonanza 1 shall not discharge to the atmosphere sulfur as SO_2 at a rate exceeding 0.0976 lb/MM BTU heat input over a rolling 12-month average. Compliance with this emission limitation shall be based on CEM data and fuel heat input. Compliance shall be determined by calculating the roll[illegible] 12-month average. On the first day of each month a new 12-month averag[illegible] calculated using data from the previous 12 months.

2. **Revise condition 8.A to read as follows:**

8. Nitrogen Oxides Emission Control

A. Bonanza 1 shall not discharg[illegible]mosphere nitrogen oxide (NO_x) at a rate exceeding 0.50 lb/MM [illegible]put on an annual average. Compliance with this emission limitatio[illegible] based on CEM data and fuel heat input. Compliance shall [illegible] in accordance with 40 CFR 76.5(b).

3. **Revise condition 9.A [illegible]ollows:**

9. Particulate [illegible]nission Control

A. [illegible] shall not discharge to the atmosphere particulate matter at a rate [illegible]ing 0.0297 lbs/MMBTU heat input as determined by 40 CFR 60, [illegible]ppendix A, Methods 1-5 and 19.

4. **Revise condition 9.B to read as follows:**

9.B Unit No. 1 shall not discharge to the atmosphere PM_{10} particulate matter at a rate exceeding 0.0286 lbs/MMBTU heat input as determined by 40 CFR 60, Appendix A, Methods 1, 2, 4, 201, 201a and 19.

5. **Revise condition 13 to read as follows:**

13. The coal pile shall not exceed 22 acres in total area. The active reclaim area shall not exceed 11 acres at any one time. The reclaim area may be moved to any location on the coal pile. The remainder of the coal pile shall be the long-term storage area. Emissions of particulate from the long-term storage area shall be

controlled by compaction of the coal pile surface and sealing with a surfactant initially and be subsequent application of sealing agent as warranted. A surfactant and spray mechanism to apply it shall be available and operative at all times. Conditions which warrant application of the surfactant are defined as any time the 20% opacity limitation is in jeopardy of being violated. To insure ~~that the sprays are always operative, the equipment shall be tested at~~ least once per month. A log ~~of testing and~~ operation shall be kept. The log shall include:

~~A.~~ Times of testing
B. Times of spray operation
C. Compaction operation
D. Weather conditions
E. Surface conditions (dry, crumbled, moist, etc.)

Attachment 3 cont.

PM_{10} Emission Source Summary

Emission Source	Pre Change Emissions	Post change Emissions	Net Change
Boiler- coal [a]	575.60	589.52	13.92
Boiler- fuel oil [a]	0.05	0.05	0.00
Auxiliary Boiler	0.03	[illegible]	0.00
Emergency Generator	0.06	[illegible]	0.00
Fire Pump	0.02	[illegible]	0.00
Construction Heaters	0.00	[illegible]	0.00
Access Road	1.77	[illegible].77	0.00
Perimeter Road	1.05	0.29	<0.76>
Coal Reclaim	0.32	0.43	0.11
Coal Unloading [a]	0.01	0.01	0.00
Coal Conveyors 1&2 [a]	0.00	0.00	0.00
Coal Conveyors 3,4&5 [a]	0.00	0.00	0.00
Coal Crusher [a]	0.46	0.46	0.00
Coal Pile loadout [a]	[illegible]	0.04	0.00
Coal Pile wind Erosion	[illegible]	0.02	0.00
Limestone Conveyors 1&2 [a]	[illegible]	0.00	0.00
Dozers on the Limestone Piles	[illegible]	0.01	0.00
Limestone pile Wind Erosion	1.58	2.38	0.80
Sludge Pile Conveyors	0.13	0.14	0.01
Dozers on the Sludge [illegible]	0.09	0.11	0.02
Sludge Pile Wind Er[illegible]	12.01	12.01	0.00
Cooling Tower [illegible]	318.40	318.40	0.00
Totals	911.65	925.76	14.11

Net change for fugitives	0.19
Net change for point sources	13.92

[a] Non fugitive sources

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL & ASH HANDLING OPERATIONS
SOURCE DESCRIPT: ACCESS HAUL ROAD

PROCESS DATA

YEAR: 1995 / SCC CODE	ROAD SILT CONTENT (%)	MEAN VEHICLE SPEED (MPH)	MEAN VEHICLE WEIGHT (TONS)	MAXIMUM & ACTUAL MILES TRAVELED		MEAN NO. OF WHEELS	DAYS W/ > 0.01" RAIN PER YEAR	HAUL DISTANCE ROUNDTRIP (MILES)	TRUCK CAPACITY (TONS)
30300833	5.00	25	[illegible]	7,000	M	8	60	2	10.00
				5,120	A				

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	CONT[illegible] EFF[illegible] (%) (EPRI)	EMISSION FACTOR (LBS/VMT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Watering	Chemical	75.[illegible]	5.6234		AP-42	3.60	1.12	4.92
PM10	Watering	Chemical	75.00	[illegible].0244		AP-42	1.30	0.40	1.77

NOTES:

AP-42 EQUATION - UNPAVED ROADS (PM & PM10)

E = k(5.9)(s/12)(S/30)(W/3)^0.7 (w/4)^0.5 ((365-p)/365) lbs/VMT

where:

E = emission factor (lbs/VMT)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.36

s = silt content of road surface material (%); Estimated to be 5% based on information published in EPR[illegible]

S = mean vehicle speed (mph); Estimated to be 25

W = mean vehicle weight (ton); Estimated to be 10 tons (the wt. which gives an avg emissions factor to accoun[illegible] [illegible]oaded hauling wts)

w = mean number of wheels; Estimated to be 8

p = number of days with >= 0.01 inches of precipitation per year; Estimated to be 95 based on AP-42 weather chart

VMT = vehicle miles traveled; Estimated based on a roundtrip distance of 2 miles (measured) and an estimated average [illegible] tons

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of periodic watering or chemical addition on an as-needed basis.

5) Control efficiency for watering based on information published in EPRI.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: SECURITY OPERATIONS
SOURCE DESCRIPT: PERIMETER ROAD

YEAR: 1995 / SCC CODE	ROAD SILT CONTENT (%)	MEAN VEHICLE SPEED (MPH)	MEAN VEHICLE WEIGHT (TONS)	PROCESS DATA MAXIMUM & ACTUAL MILES TRAVELED		MEAN NO. OF WHEELS	DAYS W/ > 0.01" RAIN PER YEAR	HAUL DISTANCE ROUNDTRIP (MILES)
30300833	5.00	25		2,000	M	4	60	2
				1,500	A			

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	EFF (%) (EPRI)	EMISSION FACTOR (LBS/VMT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			0.0[illegible]	0.7934		AP-42	0.60	0.18	0.79
PM10			0.00	[illegible].2856		AP-42	0.21	0.07	0.29

NOTES:

AP-42 EQUATION - UNPAVED ROADS (PM & PM10)

E = k(5.9)(s/12)(S/30)(W/3)^0.7 (w/4)^0.5 ((365-p)/365) lbs/VMT

where:

E = emission factor (lbs/VMT)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.36

s = silt content of road surface material (%); Estimated to be 5% based on information published in EPRI [illegible]

S = mean vehicle speed (mph); Estimated to be 25

W = mean vehicle weight (ton); Estimated to be 10 tons (the wt. which gives an avg emissions factor to account [illegible] un[illegible]aded hauling wts)

w = mean number of wheels; Estimated to be 8

p = number of days with >= 0.01 inches of precipitation per year; Estimated to be 95 based on AP-42 weather chart

VMT = vehicle miles traveled; Estimated based on a roundtrip distance of 2 miles (measured) and an estimated average [illegible] tons

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of periodic watering or chemical addition on an as-needed basis.

5) Control efficiency for watering based on information published in EPRI.

↖ IIII

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: INACTIVE STORAGE - WIND EROSION, (p. 8 of 8)
rev. 2

PROCESS DATA

YEAR: 1997

SCC CODE	COAL SILT CONTENT (%)	TIME WINDSPEED EXCEEDS 12 MPH AT MEAN PILE H[illegible] (%)		MAXIMUM & ACTUAL PILE SIZE (ACRES)		SCC UNITS	NO. DAYS WITH >= 0.01" PRECIP PER YEAR
	0.01	29.[illegible]		22.00	M	TON	60
		(Estimated)		22.00	A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	SECONDARY	[illegible] CONT[illegible] EF[illegible] (%) (EPRI)	EMISSION FACTOR ([illegible]S/DAY/ACRE)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	(TONS/YEAR)
PM	Chemical	Compaction	50.[illegible]	0.0289		AP-42	0.06	0.01	0.06
PM10	Chemical	Compaction	50.00	[illegible]0145		ENGR JUDGMT	0.03	0.01	0.03

NOTES:

AP-42 EQUATION - WIND EROSION OF STORAGE PILES

E = 1.7 (s/1.5)((365-p)/235)(f/15) lb/day/acre

where:

E = emission factor (lb/day/acre)

s = silt content of aggregate (%); Estimated to be 6.2% based on data published in AP-42 a[illegible] [illegible]rn coal.

p = number of days with >= 0.01 inch of precipitation per year; Estimated to be 85 based on A[illegible]

f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to be 2[illegible] climatological summary for local airport

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of st[illegible]

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage p[illegible]

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

3) Emissions control consists of periodic watering.
4) Control efficiency for PM based on data published in EPRI.
5) Control efficiency for PM10 based on engineering judgement.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: DOZER RECLAIM (p.1 of 8)
rev. 2

YEAR: 1997

PROCESS DATA

SCC CODE	SILT CONTENT (%)	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS	MOISTURE CONTENT (%)
30501040	0.0[illegible]	[illegible]00	2,000,000	M	TON	12.00
		[illegible]	1,100,000	A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			0.0[illegible]	0.01234		AP-42	6.79	2.82	12.34
PM10			0.00	[illegible]43		AP-42	0.24	0.10	0.43

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS
E = k(0.0032)(U/5)^1.3/(M/2)^1.4 lbs/ton
where:
E = emission factor (lbs/ton)
k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35
U = mean wind speed (mph); Estimated to be 10.9 mph based on climatology data from local a[illegible]
M = material moisture content (%); Estimated to be 4.5% based on AP-42 and EPRI data

ACTUAL 1994 EMISSIONS
1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or contin[illegible] [illegible]ns.

POTENTIAL CONTROLLED EMISSIONS
2) Maximum process rate based on 100% fuel delivery by truck, full load unlimited operation of combustion units, and a [illegible] 8,200 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop [illegible]

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES
4) No emissions control equipment.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: RAILCAR AND TRUCK UNLOADING, (p.2 of 8)
rev. 2

YEAR: 1997	MEAN WIND SPEED (MPH)	PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS	MOISTURE CONTENT (%)
SCC CODE	[illegible]00	2,006,000		TON	12.00
	([illegible]ed)	1,700,000	A		(Recieved)

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	[illegible] EFF[illegible] (%)	EMISSION FACTOR ([illegible]BS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Dust Suppression		(Estimate[illegible]) 95.[illegible]	0.00064		AP-42	0.027	0.007	0.032
PM10	Dust Suppression		(Estimated) 95.00	[illegible].00022		AP-42	0.010	0.003	0.011

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS

E = k(0.0032)(U/5)^1.3/(M/2)^1.4 lbs/ton

where:

E = emission factor (lbs/ton)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

U = mean wind speed (mph); Estimated to be 10 mph based on climatology data from PSD and NOI.

M = material moisture content (%); 6% recieved, based on plant data worse case.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop [illegible]

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on 100% fuel delivery by train or truck, full load unlimited operation of combustion units, and a co[illegible] [illegible],381 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5). Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: CONV. 1 AND 2 TO STORAGE, (p. 3 of 8)
rev. 2

YEAR: 1997

PROCESS DATA

SCC CODE	NUMBER OF TRANSFER POINTS	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS	MOISTURE CONTENT (%)
30501011	3	[illegible].00	2,006,000	TON	12.00
		[illegible]d)	1,700,000 A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	[illegible] EFF[illegible] (%,	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Fabric Filter	Dust Suppression	(EPRI: EP[illegible]) 99.[illegible]	0.00064		AP-42	0.00	0.00	0.01
PM10	Fabric Filter	Dust Suppression	(Calculated) 99.27	[illegible].00022		AP-42	0.00	0.00	0.00

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS

E = k(0.0032)(U/5)^1.3/(M/2)^1.4 lbs/ton

where:

E = emission factor (lbs/ton)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

U = mean wind speed (mph); Estimated to be 10 mph based on climatology data from PSD and NOI.

M = material moisture content (%); 6% recieved based on plant data worse case.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop [illegible]

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on full load unlimited operation of combustion units, and a coal heat content of 9,381 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: CONVs. 3,4, AND 5 TO PLANT, (p. 4 of 8)
rev. 2

YEAR: 1997 SCC CODE	NUMBER OF TRANSFER POINTS	MEAN WIND SPEED (MPH)	PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS	MOISTURE CONTENT (%)
30501011	3	[illegible].00 [illegible]ed)	2,006,000 1,700,000	A	TON	12.00

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	[illegible] EFF[illegible] (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Fabric Filter		(EPRI; EPA) 99.7[illegible]	0.00064		AP-42	0.00	0.00	0.00
PM10	Fabric Filter		(Calculated) 99.27	[illegible].00022		AP-42	0.00	0.00	0.00

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS

E = k(0.0032)(U/5)^1.3/(M/2)^1.4 lbs/ton

where:

E = emission factor (lbs/ton)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

U = mean wind speed (mph); Estimated to be 10 mph based on climatology data from PSD and NOI.

M = material moisture content (%); 6% recieved based on plant data worse case.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop [illegible]

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on full load unlimited operation of combustion units, and a coal heat content of 9,381 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: COAL CRUSHING, (p. 5 of 8)
rev. 2

YEAR: 1997	PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS
SCC CODE	2,006,000		TON
	1,700,000	A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	SECONDARY	CONT[illegible] EF[illegible] (%[illegible]	EMISSION FACTOR [illegible]LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	(TONS/YEAR)
PM	Fabric Filter		(EPRI: EF[illegible] 99.[illegible]	0.1800		EPRI	0.46	0.12	0.54
PM10	Fabric Filter		(Calculated) 99.49	[illegible].0900		ENGR JUDGMT	0.39	0.10	0.46

NOTES:

ACTUAL 1994 EMISSIONS

1) Actual emissions based on emissions factor published in EPRI and engineering judgement, [illegible] pollutant.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on full load unlimited operation of combustion units, and a coal heat co[illegible]
3) Potential emissions based on emissions factor published in EPRI and engineering judgement, as noted [illegible]

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: ACTIVE STORAGE - LOAD-IN BY CONVEYOR 1, (p. 6 of 6)
rev.2

PROCESS DATA

YEAR: 1997	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS	MOISTURE CONTENT (%)
SCC CODE	[illegible]0	1,500,000		TON	12.00
	[illegible]ed)	550,000	A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	SECONDARY	[illegible] CONT[illegible] EFF[illegible] (%) (AWMA)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	(TONS/YEAR)
PM	Dust Suppression		75.[illegible]	0.00064		AP-42	0.04	0.03	0.12
PM10	Dust Suppression		75.00	[illegible]00022		AP-42	0.02	0.01	0.04

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS

E = k(0.0032)(U/5)^1.3/(M/2)^1.4 lbs/ton

where:

E = emission factor (lbs/ton)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

U = mean wind speed (mph); Estimated to be 10 mph based on climatology data from PSD and NOI.

M = material moisture content (%); 6% recieved based on plant data worse case.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop [illegible]

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on full load unlimited operation of combustion units, and a coal heat content of 9,381 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: LIMESTONE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: CONVs. L1 AND L2 (p. 1 of 3)
rev. 2

YEAR: 1997 SCC CODE		NUMBER OF TRANSFER POINTS	MEAN WIND SPEED (MPH)	PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS	MOISTURE CONTENT (%)
30501011		3	[illegible]00	60,000		TON	3.00
			([illegible]ted)	40,000	A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	[illegible]AL CON[illegible] EFF[illegible] (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	PROCESS CONTROLLED EMISSIONS (LBS/HR)	PROCESS CONTROLLED EMISSIONS (TONS/YEAR)
PM	Fabric Filter		(EPRI: EP[illegible]) 99.[illegible]	0.00447		AP-42	0.00	0.00	0.00
PM10	Fabric Filter		(Calculated) 99.43	0.[illegible]0156		AP-42	0.00	0.00	0.00

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS

E = k(0.0032)(U/5)^1.3/(M/2)^1.4 lbs/ton

where:

E = emission factor (lbs/ton)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

U = mean wind speed (mph); Estimated to be 10 mph based on climatology data from PSD and NOI.

M = material moisture content (%); 6% recieved based on plant data worse case.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop [illegible]

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on full load unlimited operation of combustion units, and a coal heat content of 9,381 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: LIMESTONE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: DOZERS ON STORAGE PILE (p. 2 of 3)
rev. 2

PROCESS DATA

YEAR: 1997 SCC CODE	LIMESTONE SILT CONTENT (%)	MEAN VEHICLE SPEED (MPH)	MEAN VEHICLE WEIGHT (TONS)	MAXIMUM & ACTUAL MILES TRAVELED		SCC UNITS	MEAN NO. OF WHEELS	DAYS W/ > 0.01" RAIN PER YEAR
	1.50	5	[illegible]	300 150	A	TON	4	60

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	CONTROL EFFICIENCY (%) (EPRI)	EMISSION FACTOR (LBS/VMT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			[illegible]	0.2386		AP-42	0.02	0.01	0.04
PM10			0.00	0.0859		AP-42	0.01	0.00	0.01

NOTES:

AP-42 EQUATION - UNPAVED ROADS (PM & PM10)

E = k(5.9)(s/12)(S/30)(W/3)^0.7 (w/4)^0.5 ((365-p)/365) lbs/VMT

where:

E = emission factor (lbs/VMT)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.36

s = silt content of surface material (%); Estimated to be 6.2% based on information published in AP-42 an[illegible] coal.

S = mean vehicle speed (mph); Estimated to be 5 mph

W = mean vehicle weight (ton); 10 tons

w = mean number of wheels; 4

p = number of days with >= 0.01 inches of precipitation per year; Estimated to be 85 based on AP-42 weather chart

VMT = vehicle miles traveled; Estimated based on an average of 8 dozer-hours on piles per day

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum rate based on 16 dozer-hours on piles per day.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of periodic watering on an as-needed basis.
5) Control efficiency for watering based on information published in EPRI.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: LIMESTONE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: ACTIVE STORAGE - WIND EROSION (p. 3 of 3)
rev. 2

PROCESS DATA

YEAR: 1997 / SCC CODE	LIMESTONE SILT CONTENT (%)	TIME WINDSPEED EXCEEDS 12 MPH AT MEAN PILE HT (%)	MAXIMUM & ACTUAL PILE SIZE (ACRES)	SCC UNITS	NO. DAYS WITH >= 0.01" PRECIP PER YEAR
	1.50	29.50 (Estimated)	6.00 / 2.00 A	TON	60

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	CONTROL EFFICIENCY (%) (EPRI)	EMISSION FACTOR (LBS/DAY/ACRE)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			0.[illegible]	4.3392		AP-42	1.58	1.08	4.75
PM10			0.00	[illegible]1696		ENGR JUDGMT	0.79	0.54	2.38

NOTES:

AP-42 EQUATION - WIND EROSION OF STORAGE PILES

E = 1.7 (s/1.5)((365-p)/235)(f/15) lb/day/acre

where:

E = emission factor (lb/day/acre)

s = silt content of aggregate (%); Estimated to be 6.2% based on data published in AP-42 and EPRI f[illegible]

p = number of days with >= 0.01 inch of precipitation per year; Estimated to be 85 based on AP-42 weath[illegible]

f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to be 29.5% based [illegible] summary from PSD and NOI.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

3) Emissions control consists of periodic watering.
4) Control efficiency for PM based on data published in EPRI.
5) Control efficiency for PM10 based on engineering judgement.

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DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: SLUDGE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: CONVs. S1, S2, S3, S4, S5, S6, and RADIAL STACKER (p. 2 of 4)
rev. 2

PROCESS DATA

YEAR: 1997 / SCC CODE	NUMBER OF TRANSFER POINTS	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS	MOISTURE CONTENT (%)
30501011	7	[illegible]0	245,000		TON	15.00
		[illegible]	145,000	A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			0.0[illegible]	0.00047		AP-42	0.24	0.09	0.40
PM10			0.00	0.00016		AP-42	0.08	0.03	0.14

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS
E = k(0.0032)(U/5)^1.3/(M/2)^1.4 lbs/ton
where:
E = emission factor (lbs/ton)
k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35
U = mean wind speed (mph); Estimated to be 10 mph based on climatology data from PSD and NOI.
M = material moisture content (%); 6% recieved based on plant data worse case.

ACTUAL 1994 EMISSIONS
1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop [illegible]

POTENTIAL CONTROLLED EMISSIONS
2) Maximum process rate based on full load unlimited operation of combustion units, and a coal heat content of 9,381 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES
4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: SLUDGE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: DOZERS ON STORAGE PILE (p. 3 of 4)
rev. 2

PROCESS DATA

YEAR: 1997 / SCC CODE	SLUDGE SILT CONTENT (%)	MEAN VEHICLE SPEED (MPH)	MEAN VEHICLE WEIGHT (TONS)	MAXIMUM & ACTUAL MILES TRAVELED	SCC UNITS	MEAN NO. OF WHEELS	DAYS W/ > 0.01" RAIN PER YEAR
	6.50	5	[illegible]	1,200	TON	4	60
				800 A			

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	[illegible] EFF[illegible] (%) (EPRI)	EMISSION FACTOR (LBS/VMT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Watering		50.[illegible]	1.0338		AP-42	0.21	0.07	0.31
PM10	Watering		50.00	[illegible]3722		AP-42	0.07	0.03	0.11

NOTES:

AP-42 EQUATION - UNPAVED ROADS (PM & PM10)

E = k(5.9)(s/12)(S/30)(W/3)^0.7 (w/4)^0.5 ((365-p)/365) lbs/VMT

where:

E = emission factor (lbs/VMT)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.36

s = silt content of surface material (%); Estimated to be 6.2% based on information published in AP-42 an[illegible] P[illegible] [illegible] coal.

S = mean vehicle speed (mph); Estimated to be 5 mph

W = mean vehicle weight (ton); 10 tons

w = mean number of wheels; 4

p = number of days with >= 0.01 inches of precipitation per year; Estimated to be 85 based on AP-42 weather chart

VMT = vehicle miles traveled; Estimated based on an average of 8 dozer-hours on piles per day

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum rate based on 16 dozer-hours on piles per day.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of periodic watering on an as-needed basis.
5) Control efficiency for watering based on information published in EPRI.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: SLUDGE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: ACTIVE STORAGE - WIND EROSION (p. 4 of 4)
rev. 2

PROCESS DATA

YEAR: 1997 / SCC CODE	SLUDGE SILT CONTENT (%)	TIME WINDSPEED EXCEEDS 12 MPH AT MEAN PILE HT (%)	MAXIMUM & ACTUAL PILE SIZE (ACRES)	SCC UNITS	NO. DAYS WITH >= 0.01" PRECIP PER YEAR
	6.50	29.50	14.00	TON	60
		(Estimated)	14.00 A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	CONTROL EFFICIENCY (%) (EPRI)	EMISSION FACTOR (LBS/DAY/ACRE)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Watering		50.[illegible]	18.8033		AP-42	24.02	5.48	24.02
PM10	Watering		50.00	[illegible]4016		ENGR JUDGMT	12.01	2.74	12.01

NOTES:

AP-42 EQUATION - WIND EROSION OF STORAGE PILES

E = 1.7 (s/1.5)((365-p)/235)(f/15) lb/day/acre

where:

E = emission factor (lb/day/acre)

s = silt content of aggregate (%); Estimated to be 6.2% based on data published in AP-42 and EPRI [illegible]

p = number of days with >= 0.01 inch of precipitation per year; Estimated to be 85 based on AP-42 weat[illegible]

f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to be 29.5% based [illegible] summary from PSD and NOI.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

3) Emissions control consists of periodic watering.
4) Control efficiency for PM based on data published in EPRI.
5) Control efficiency for PM10 based on engineering judgement.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: RAW LIMESTONE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: ACTIVE STORAGE - WIND EROSION (p. 3 of 3)
rev. 2

YEAR: 1997 / SCC CODE	LIMESTONE SILT CONTENT (%)	TIME WINDSPEED EXCEEDS 12 MPH AT MEAN PILE HT (%)		PROCESS DATA MAXIMUM & ACTUAL PILE SIZE (ACRES)	SCC UNITS	NO. DAYS WITH >= 0.01" PRECIP PER YEAR
	0.50	29.50 (Estimated)		3.00 2.00 A	TON	60

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/DAY/ACRE)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			(EPRI) 0.00	1.4464		AP-42	0.53	0.18	0.79
PM10			0.00	0.7232		ENGR JUDGMT	0.26	0.09	0.40

NOTES:

AP-42 EQUATION - WIND EROSION OF STORAGE PI[illegible]
E = 1.7 (s/1.5)((365-p)/235)(f/15) lb/day/acre
where:
E = emission factor (lb/day/acre)
s = silt content of aggregate (%); Estimated to be 6.2% based on [illegible] AP-42 and EPRI for western coal.
p = number of days with >= 0.01 inch of precipitation per year; Estima[illegible] on AP-42 weather chart.
f = time unobstructed wind speed exceeds 12 mph at the mean pile heig[illegible] be 29.5% based on climatological summary from PSD and NOI.

ACTUAL 1994 EMISSIONS
1) Actual emissions based on calculated emissions factors using the above AP-42 equ[illegible]on of storage piles.

POTENTIAL CONTROLLED EMISSIONS
2) Potential emissions based on calculated emissions factors using the above AP-42 equation [illegible] storage piles.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES
3) Emissions control consists of periodic watering.
4) Control efficiency for PM based on data published in EPRI.
5) Control efficiency for PM10 based on engineering judgement.

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DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: BALLAST LIMESTONE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: ACTIVE STORAGE - WIND EROSION (p. 3 of 3)
rev. 2

YEAR: 1997 / SCC CODE	LIMESTONE SILT CONTENT (%)	TIME WINDSPEED EXCEEDS 12 MPH AT MEAN PILE HT (%)		PROCESS DATA MAXIMUM & ACTUAL PILE SIZE (ACRES)	SCC UNITS	NO. DAYS WITH >= 0.01" PRECIP PER YEAR
	1.00	29.50 (Estimated)		2.00 2.00 A	TON	60

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/DAY/ACRE)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			(EPRI) 0.00	2.8928		AP-42	1.06	0.24	1.06
PM10			0.00	1.4464		ENGR JUDGMT	0.53	0.12	0.53

NOTES:

AP-42 EQUATION - WIND EROSION OF STORAGE [illegible]

$E = 1.7 (s/1.5)((365-p)/235)(f/15)$ lb/day/acre

where:

E = emission factor (lb/day/acre)

s = silt content of aggregate (%); Estimated to be 6.2% based on [illegible] AP-42 and EPRI for western coal.

p = number of days with >= 0.01 inch of precipitation per year; Estima[illegible] on AP-42 weather chart.

f = time unobstructed wind speed exceeds 12 mph at the mean pile heigh[illegible] be 29.5% based on climatological summary from PSD and NOI.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equ[illegible]on of storage piles.

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation [illegible] storage piles.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

3) Emissions control consists of periodic watering.
4) Control efficiency for PM based on data published in EPRI.
5) Control efficiency for PM10 based on engineering judgement.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: FUEL OIL STORAGE TANK 1- 288,000 GALLONS
SOURCE DESCRIPT: No. 2 Fuel Oil Evaporation

YEAR: 1995	PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS
SCC CODE		
40400413	293,000	GAL
	168,809	A

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	[illegible] EFF[illegible] (%)		EMISSION FACTOR ([illegible]BS/SCC UNIT)		EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
VOC			0.[illegible]		0.0036		AP-42	0.30	0.12	0.53
HAPs			0.00		[illegible]0000		ENGR JUDGMT	0.00	0.00	0.00

NOTES:

ACTUAL 1994 EMISSIONS

1) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for actual VOC emiss[illegible] pl[illegible] data was used in the VOC calculations.
2) Actual 1995 HAPs emissions negligible.

POTENTIAL CONTROLLED EMISSIONS

3) The maximum potential throughput is based on the maximum (approximate) amount of fuel oil which could b[illegible] [illegible]ombustion units.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions. Actual [illegible] in the VOC calculations.
5) Potential 1995 HAPs emissions insignificant.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

6) There is no emissions control equipment.

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DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: FUEL OIL STORAGE TANK 2- 288,000 GALLONS
SOURCE DESCRIPT: No. 2 Fuel Oil Evaporation

YEAR: 1995	PROCESS DATA MAQXIMUM & ACTUAL PROCESS RATE		SCC UNITS
SCC CODE			
40400413	0.00		GAL
	0.00	A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)		EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
VOC			0.[illegible]	0.2100		AP-42	0.00	0.00	0.00
HAPs			0.00	[illegible].0000		ENGR JUDGMT	0.00	#DIV/0!	0.00

NOTES:

ACTUAL 1994 EMISSIONS

1) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for actual VOC emissio[illegible] data was used in the VOC calculations.
2) Actual 1995 HAPs emissions negligible.

POTENTIAL CONTROLLED EMISSIONS

3) The maximum potential throughput is based on the maximum (approximate) amount of fuel oil which could b[illegible] combustion units.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions. Actual [illegible] in the VOC calculations.
5) Potential 1995 HAPs emissions insignificant.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

6) There is no emissions control equipment.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COOLING TOWER
SOURCE DESCRIPT: Drift and Evaporation
rev. 2

YEAR: 1997 / SCC CODE	AVERAGE DRIFT RATE (SCC UNIT/HR)	AVERAGE EVAPORATION RATE (SCC UNIT/HR)	AVERAGE TEMPERATURE DIFFERENTIAL (F)	PROCESS RATE MAXIMUM & ACTUAL PROCESS RATE (GPM)	SCC UNITS	RECIRC RATE (SCC UNIT/HR)	CHLORINE RESIDUAL 3-HR SHOCK (ppm)	TDS IN CIRC WATER (ppm)	DRIFT % OF RECIRC (%)
	11.85	210		125,000	GALS^3	7,500	0.05	8,000	0.00158
				125,000	A		0.05		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFIC. (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM10	Drift Eliminators		(CALCULATED) 76.93	[illegible]126		AP-42, 13-4	318.42	72.70	318.42
Chlorine									

NOTES:

ACTUAL 1997 EMISSIONS

1) Actual PM and PM10 emissions calculated based on drift rate and total disolved solids (TDS) in recircul[illegible] water.
2) Actual chlorine emissions calculated based on a continuous Cl2 level of 0.0 ppm and a daily shock chlorina[illegible] [illegible]ppm for three hours.

POTENTIAL CONTROLLED EMISSIONS

3) Potential controlled emissions are based on maximum capacity and unlimited hours of operation (8,760 hrs/yr).
4) Potential PM and PM10 emissions calculated based on drift rate and total disolved solids (TDS) in recirculation water.
5) Potential chlorine emissions calculated based on a continuous Cl2 level of 0.0 ppm and a daily shock chlorination level of 0.[illegible] [illegible] hours.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

6) Emissions control equipment consists of drift eliminators.
7) Control efficiencies for drift eliminators calculated based on comparing calculated controlled emissions to predicted uncontrolled emissions using AP-42 emissions factors.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: UNLEADED GASOLINE UST - 1,000 GALLONS
SOURCE DESCRIPT: Fuel Evaporation

YEAR:	PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS
1995		
SCC CODE	20,000	GAL
	17,000	A

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	[illegible] EF[illegible] (%)	EMISSION FACTOR (LBS/SCC UNIT)		EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
VOC			0.[illegible]0	[illegible]ES (1) & (4)		AP-42	0.11	0.03	0.13
HAPs			0.00	[illegible] (4)		ENGR JUDGMT	5.50E-03	1.48E-03	6.50E-03

NOTES:

ACTUAL 1994 EMISSIONS

1) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for actual 1995 VOC e[illegible]
2) The unleaded gasoline was assumed to have a Reid Vapor Pressure of 13 (RVP 13).
3) Actual 1995 HAPs emissions calculated as a percentage of VOC emissions (5% by weight for typical [illegible]) [illegible] on EPA information. HAPs may include benzene, toluene, hexane, ethylbenzene, napthalene, cumene, xylenes, n-hexane, 2,2,4-trimethylpentane, MBTE, [illegible]

POTENTIAL CONTROLLED EMISSIONS

3) The maximum potential throughput is estimated.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions.
5) The unleaded gasoline was assumed to have a Reid Vapor Pressure of 13 (RVP 13).
6) Potential 1995 HAPs emissions calculated as a percentage of VOC emissions (5% by weight for typical gasoline), based on [illegible] HAPs may include benzene, toluene, hexane, ethylbenzene, napthalene, cumene, xylenes, n-hexane, 2,2,4-trimethylpentane, MBTE, and others.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

7) There is no emissions control equipment.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: UNLEADED GASOLINE UST - 1,000 GALLONS
SOURCE DESCRIPT: Fuel Evaporation

YEAR: 1995	PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS
SCC CODE	20,000		GAL
	17,000	A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)		EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
VOC			0.[illegible]	[illegible]ES (1) & (4)		AP-42	0.11	0.03	0.13
HAPs			0.00	[illegible] & (4)		ENGR JUDGMT	5.50E-03	1.48E-03	6.50E-03

NOTES:

ACTUAL 1994 EMISSIONS

1) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for actual 1995 VOC [illegible]
2) The unleaded gasoline was assumed to have a Reid Vapor Pressure of 13 (RVP 13).
3) Actual 1995 HAPs emissions calculated as a percentage of VOC emissions (5% by weight for typical [illegible] EPA information. HAPs may include benzene, toluene, hexane, ethylbenzene, napthalene, cumene, xylenes, n-hexane, 2,2,4-trimethylpentane, MBTE, [illegible]

POTENTIAL CONTROLLED EMISSIONS

3) The maximum potential throughput is estimated.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions.
5) The unleaded gasoline was assumed to have a Reid Vapor Pressure of 13 (RVP 13).
6) Potential 1995 HAPs emissions calculated as a percentage of VOC emissions (5% by weight for typical gasoline), based on [illegible] HAPs may include benzene, toluene, hexane, ethylbenzene, napthalene, cumene, xylenes, n-hexane, 2,2,4-trimethylpentane, MBTE, and others.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

7) There is no emissions control equipment.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: FUEL OIL STORAGE TANK 1- 288,000 GALLONS
SOURCE DESCRIPT: No. 2 Fuel Oil Evaporation

YEAR: 1995	PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS
SCC CODE			
40400413	293,000		GAL
	168,809	A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)		EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
VOC			[illegible]	0.0036		AP-42	0.30	0.12	0.53
HAPs			0.00	0.0000		ENGR JUDGMT	0.00	0.00	0.00

NOTES:

ACTUAL 1994 EMISSIONS

1) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for actual VOC emissions. [illegible] data was used in the VOC calculations.
2) Actual 1995 HAPs emissions negligible.

POTENTIAL CONTROLLED EMISSIONS

3) The maximum potential throughput is based on the maximum (approximate) amount of fuel oil which could be [illegible] combustion units.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions. Actual [illegible] data was used in the VOC calculations.
5) Potential 1995 HAPs emissions insignificant.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

6) There is no emissions control equipment.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: FUEL OIL STORAGE TANK 2- 288,000 GALLONS
SOURCE DESCRIPT: No. 2 Fuel Oil Evaporation

YEAR: 1995 / SCC CODE	PROCESS DATA MAQXIMUM & ACTUAL PROCESS RATE		SCC UNITS
40400413	0.00		GAL
	0.00	A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)		EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
VOC			0.[illegible]	0.2100		AP-42	0.00	0.00	0.00
HAPs			0.00	0.0000		ENGR JUDGMT	0.00	#DIV/0!	0.00

NOTES:

ACTUAL 1994 EMISSIONS

1) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for actual VOC emiss[illegible] data was used in the VOC calculations.
2) Actual 1995 HAPs emissions negligible.

POTENTIAL CONTROLLED EMISSIONS

3) The maximum potential throughput is based on the maximum (approximate) amount of fuel oil which could b[illegible] combustion units.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions. Actual [illegible] in the VOC calculations.
5) Potential 1995 HAPs emissions insignificant.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

6) There is no emissions control equipment.

ATTACHMENT 5

EMISSION CONTROL EQUIPMENT UPGRADE SUMMARY

The following is a brief summary of the emission Control Equipment upgrades completed or planned by D G & T for Bonanza 1.

1. Low NOx Burners:

During the May 1997 Outage, D G & T replaced all of its burners. The new Low NOx Burners have reduced actual NOx emissions the Bonanza 1.

2. Replacement Bags for the Baghouse:

The new fiberglass Bags are used to completely replace the [illegible] bags. There are 450 Bags in each compartment, 24 compartments, for a tot[illegible] Bags.

3. Grasshopper Conveyors:

These portable conveyors will be used to move [illegible] landfill material from the Radial Stacker to the area being landfilled. This will [illegible] emissions by eliminating the need of heavy equipment hauling material from [illegible] Stacker to the landfill area.

4. New Bull Gear on the Ball Mill:

D G & T is replacing the Bull [illegible] a redesigned model on a Ball Mill to improve efficiency of the Grinding [illegible]

5. New Absorber In[illegible] Damper Seals:

During the Ma[illegible] Outage, D G & T upgraded the Absorber Inlet Damper seals. This new Seal design [illegible] the flow of untreated Flue Gas.

6. New Thickener Rake:

D G & T has ordered a new Sludge Thickener Rake. This new rake will improve the efficiency of the original equipment.

7. New Underflow Sludge Pump:

D G & T has installed a new Underflow Sludge pump to upgrade the operation of the Sludge system.

8. New Bulk Entrainment/Mist Eliminator Section (BE/MES) in all three Absorbers:

D G & T is in the process of upgrading all of its Absorber Modules. New design BE/MES are being installed. Carryover and Differential Pressure are reduced in each Absorber improving operational efficiency.

Exhibit 3

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.

Table of Contents

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:

<u>Application requirements.</u> 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.

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
Fax: 303-312-6064

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. <u>Project Description</u>

A. <u>Location</u>

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

Ed Thatcher, Vice President and Chief Engineer
David Crabtree, Vice President and General Counsel
Eric Olsen, Environmental Coordinator
Deseret Power Electric Cooperative
10714 South Jordan Gateway
South Jordan, Utah 84095
Phone: (801) 619-6500

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).
>
> 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.
>
> 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."

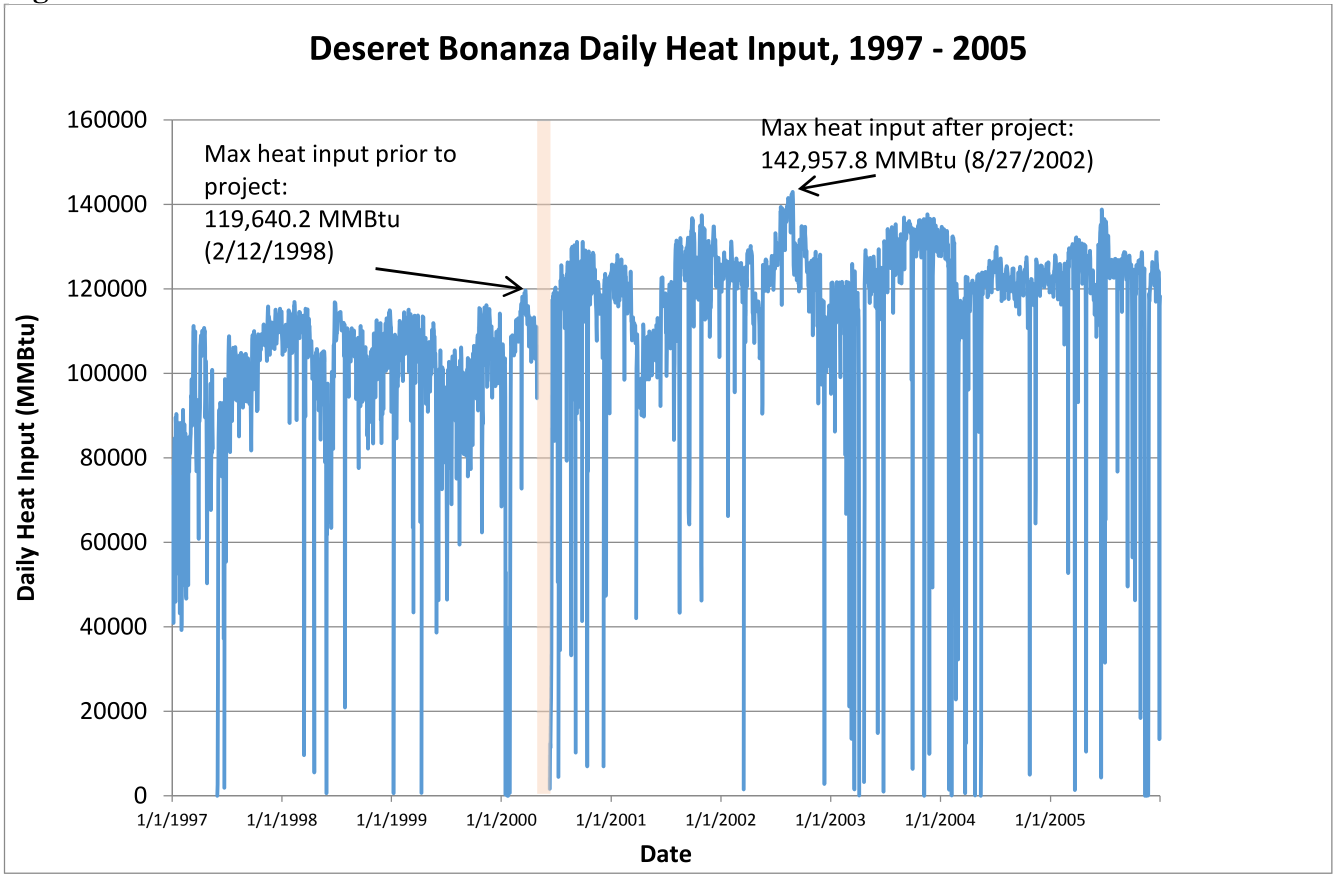
prior to the proposed change are representative of normal operation for a utility.[43] The rules in place at the time of the project therefore did not require the use of the emissions during the two-year period immediately preceding commencement of construction of the project for determining baseline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

Conditions 10 through 22, 41, 42, 45 and 47. 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.

Proposed new Condition VII.F. 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.

Proposed new Condition VII.G. 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.

Proposed new Condition VII.H. 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. BACT Analysis

A. Approach Used in BACT Analysis

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. PSD BACT Emission Limits Apply at All Times

EPA's interpretation of the CAA, and of the PSD rules in 40 CFR parts 51 and 52, is that 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).

<u>Post Combustion Control Options</u>

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.

<u>Combustion Control Options</u>

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.

[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.

<u>Table 2 – Select SNCR Installations as of 2000</u>

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

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 lb/MMBtu – 0.07 lb/MMBtu) x (4,578 MMBtu/hr) x (8,760 hr/yr) (1 ton/2,000 lb) =
7,820 tons NO_x 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:

$$(0.46 \text{ lb/MMBtu} - 0.18 \text{ lb/MMBtu}) \times (4{,}578 \text{ MMBtu/hr}) \times (8{,}760 \text{ hr/yr}) (1 \text{ ton}/2{,}000 \text{ lb}) = 5{,}615 \text{ tons } NO_x \text{ reduced/year}$$

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:

Table 5 – OFA Costs

	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:

$$(0.46 \text{ lb/MMBtu} - 0.28 \text{ lb/MMBtu}) \times (4{,}578 \text{ MMBtu/hr}) \times (8{,}760 \text{ hr/yr}) (1 \text{ ton/2,000 lb}) = 3{,}610 \text{ tons } NO_x \text{ reduced/year}$$

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: <u>Demonstration of Advanced Combustion NO_x Control Techniques for a Wall-Fired Boiler</u> (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.

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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. <u>Environmental Justice Assessment</u>

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.

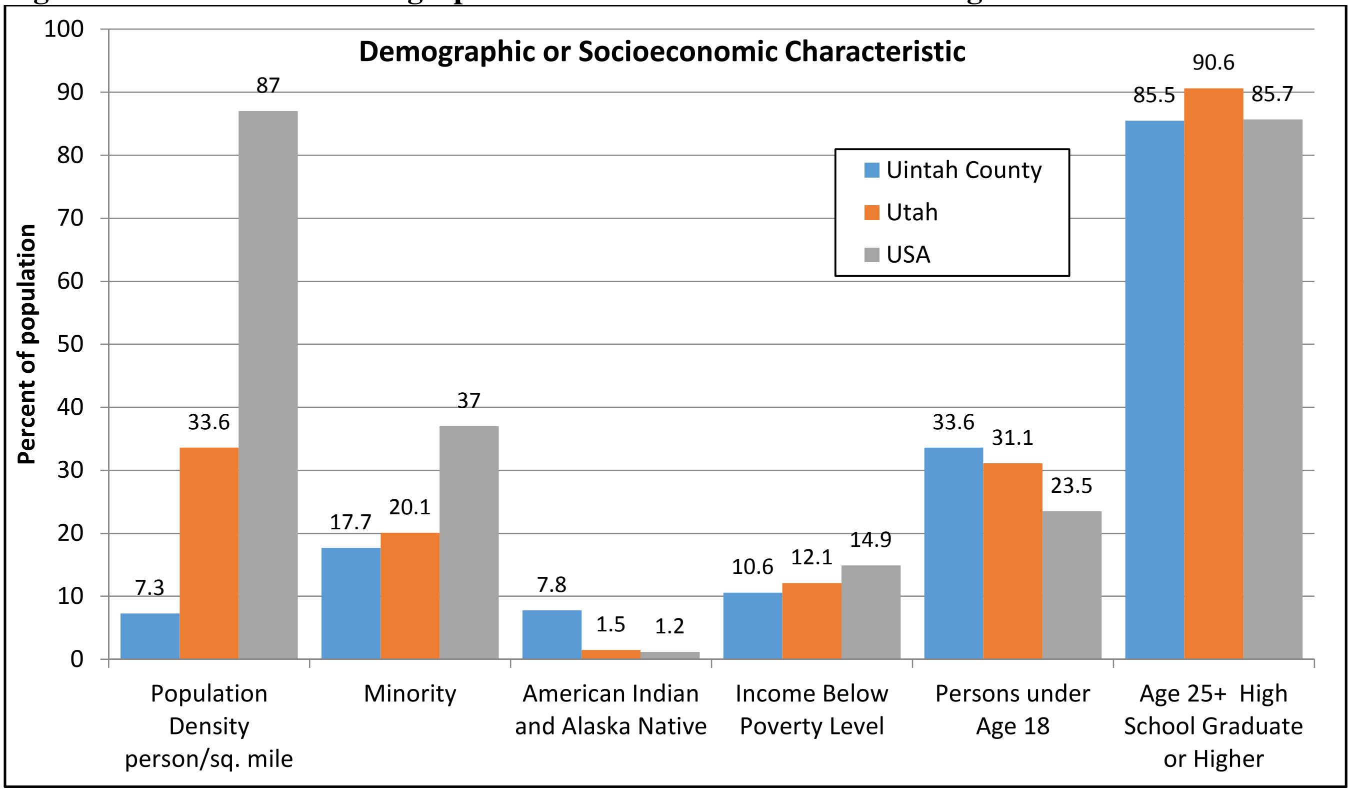
Despite the sparse population immediately surrounding the facility, the EPA reviewed demographic data from Uintah County, and compared it to demographic data from the State of Utah and the United States in order to characterize the general area surrounding the facility. The table below summarizes the 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.

Exhibit 4

United States Environmental Protection Agency
Region 8
Air Program
1595 Wynkoop Street
Denver, Colorado 80202-1129
December 3, 2014

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

PSD-UO-000004-2014.003

Permittee:
Deseret Power Electric Cooperative
10714 South Jordan Gateway
South Jordan, Utah 84095

Permitted Facility:
Bonanza Power Plant
Uintah County, Utah

Table of Contents

I. Introduction

The EPA is using its authority to reopen and correct a previously issued PSD permit. The proposed provisions are authorized under authority of 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality (PSD). 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 2, 1981. The plant began operating in 1985. Due to confusion over the territorial boundaries of the Reservation, after EPA approved Utah's PSD rules into the SIP in the early 1980's, the State of Utah took over permitting for the facility. The State issued permits (Approval Orders) for various modifications to the plant in the 1980's and 1990's. This included a permit in March of 1998 for a "ruggedized rotor project," which was constructed in June of 2000. The March 1998 permit did not identify the project as a PSD major modification for any pollutants and did not impose PSD BACT for any pollutants.

In September of 1999, pursuant to a Federal court decision on jurisdiction on Uintah & Ouray Reservation, EPA wrote to Deseret Power to assert permitting jurisdiction over the Bonanza plant. On February 2, 2001, EPA issued an updated Federal PSD permit to Deseret that consolidated a number of applicable Clean Air Act requirements from various permits and regulations into one federally enforceable permit. The 2001 PSD permit replaced various construction permits, including the original 1981 Federal PSD permit and all subsequent state-issued permits, among others the March 1998 state permit, which EPA said it "accepted." While this 2001 permit was considered a PSD permit, the action did not include any PSD review of previous modifications to the facility, including the 2000 ruggedized rotor project.

In August of 2002, EPA sought public comment on an initial draft Federal title V operating permit for the Bonanza plant, which incorporated EPA's 2001 PSD permit. The National Park Service commented that the June 2000 project at Bonanza may have caused a significant increase in actual emissions and that PSD may have been triggered. EPA has evaluated this comment and proposes to conclude 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 permit action is to correct an erroneous incorporation of a State minor construction requirement into the Federal PSD permit issued on February 2, 2001. The 2001 permit failed to address PSD major modification permitting requirements for NO_x for the "ruggedized rotor project." This permit action addresses the error by imposing a NO_x emission limit which reflects Best Available Control Technology for NO_x as it existed in 2000, when EPA made the draft PSD permit available for public comment.

In addition, we are proposing an administrative amendment to the 2001 permit to remove the applicable provisions under 40 C.F.R. part 60, Standards of Performance for New Stationary Sources, which are not PSD requirements. This administrative revision to the PSD permit clarifies that the authority for the applicable part 60 requirements resides in the EPA rules as opposed to the 2001 PSD permit. As required under the title V rules, the part 60 requirements are incorporated into the title V operating permit. The draft title V permit originally proposed in 2002 has been updated and is being issued as a final permit at the same time as this draft PSD correction permit.

Correspondence between the Permittee and EPA pertaining to this permit is included in the Administrative Record for issuance of this permit. A chronology and description of that correspondence is included in the Statement of Basis for issuance of this permit, which also includes an explanation of why EPA proposes to conclude that the "ruggedized rotor project" was a PSD major modification for NO_x, and EPA's proposed Best Available Control Technology (BACT) determination for NO_x.

II. General Conditions

A. Plant Location and Owner/Operator

Plant Location	Owner/Operator
Bonanza Power Plant	Deseret Power Electric Cooperative
12500 East 25500 South	10714 South Jordan Gateway
Vernal, Utah 84078	South Jordan, Utah 84095
Phone: 435-789-9000	Phone: 801-619-6500
Fax: 435-781-5816	Fax: 801-619-6599

Bonanza Power Station Unit No. 1:
7.45 miles northwest of Bonanza, Uintah County, Utah and 28 miles southeast of Vernal,Utah.

Universal Transverse Mercator (UTM) Coordinate System:
4,438,606 meters Northing, 646,206 meters Easting

B. Approved Installation. The Permittee's approved installation shall consist of a 500 (estimated) megawatt coal fired steam electric generating station (Bonanza Unit No. 1) and associated equipment. The Permittee shall operate the approved installation according to the terms and conditions of this PSD permit.

C. Binding Application. This permit is issued in reliance upon the accuracy and completeness, with proposed corrections as explained in the Administrative Record, of the information set forth in permit applications to the EPA, dating back to August 14, 1980, the 2001 EPA issued PSD permit, and subsequent information provided by the Permittee to the EPA, as listed in the Administrative Record for issuance of this permit. Appendix A of the Statement of Basis for this permit contains a list of the documents in the Administrative Record.

D. Permit Effective Date. Under 40 C.F.R. 124.15, "Issuance and effective date of permit," this permit is effective thirty days after receipt, unless

1. A later date is specified in the final permit decision, including an alternative date that may be provided in a specific permit term; or

2. Review is requested by the Permittee or other party under 40 C.F.R. 124.19, "Appeal of RCRA, UIC, NPDES, and PSD Permits;" or

3. No comments requested a change in the draft permit, in which case the final permit shall become effective immediately upon issuance.

On the effective date of this Permit, the Conditions herein become enforceable by EPA pursuant to any remedies it has or may have in the future, under the Clean Air Act, as amended.

E. Permit Appeals. This permit may be appealed to the Environmental Appeals Board under 40 C.F.R. 124.19. Motions to reconsider a final order on appeal are provided at 40 C.F.R. 124.19(g). Judicial review is available at 40 C.F.R. 124.19(f).

F. Permit Rescission. This permit may be rescinded following requirements at 40 C.F.R. 52.21(w). The Administrator may be requested to rescind the permit or a particular portion of the permit under this regulation.

G. Notifications and Reports. The Permittee must send all notifications and reports required by this permit to:

Director, Air Program (8P-AR)
U. S. Environmental Protection Agency, Region 8
1595 Wynkoop Street
Denver, Colorado 80202-1129

H. Definitions. Definitions of terms, abbreviations, and references used in this PSD Permit conform to those used in the Prevention of Significant Deterioration of Air Quality, 40 C.F.R. 52.21(b), Definitions. These terms, definitions, abbreviations, and references take precedence over those in this PSD permit.

I. Records. All records referenced in this PSD Permit which are required to be kept by the Permittee, must be made available by the Permittee to EPA upon verbal or written request. The Permittee must keep records for a period of five years, unless EPA requires that the records be maintained for a longer period of time.

J. Major Modifications and Phased Construction Projects. The Permittee must comply with BACT requirements at 40 C.F.R. 52.21(j), Control technology review, for major modifications or phased construction projects.

K. Sale or Name Change. The Permittee must notify EPA in writing if the company is sold or changes its name. The notification must be submitted within 30 days of such proposed action.

L. Compliance with Environmental Laws. This PSD Permit does not release the Permittee from any liability for compliance with other applicable federal and Tribal environmental law and regulations, including the Clean Air Act.

M. Inspections and Notifications. The Permittee must allow EPA or its authorized representatives to inspect the source during normal business hours for purposes of ascertaining compliance with all the conditions of this PSD Permit in accordance with requirements at Part 113, Federal enforcement, and Part 114, Recordkeeping, inspections, monitoring, and entry of the Clean Air Act, as amended.

III. PSD BACT Emission Limitations and Test Procedures

The term "boiler operating day," as used in this permit, shall have the meaning given in 40 C.F.R. 60.41Da, as it applies to units constructed, reconstructed, or modified on or before February 28, 2005: *"Boiler operating day* … means a 24-hour period during which fossil fuel is combusted in a steam generating unit for the entire 24 hours." The term "valid hourly emission rate" shall have the meaning given in 40 C.F.R. 75.10(d)(1).

A. Particulate Matter (PM) and PM_{10} Emission Limitations

1. The Permittee's Bonanza Unit No. 1 must not discharge to the atmosphere PM at a rate exceeding 0.0297 lbs/MMBTU heat input as determined by test methods in 40 C.F.R. part 60, Appendix A, Methods 1-5-5e and 19 or other EPA approved test methods. The averaging time for this limit shall be consistent with the test method.

2. The Permittee's Bonanza Unit No.1 must not discharge to the atmosphere PM_{10} particulate matter at a rate exceeding 0.0286 lbs/MMBTU heat input

as determined by 40 C.F.R. part 51, Appendix M, Method 201, Determination of PM_{10} Emissions or Method 201A, Determination of PM_{10} Emissions (Constant Sampling Rate Procedure). The averaging time for this limit shall be consistent with the test method.

3. The Permittee may use the PM_{10} particulate matter test results as allowed in condition III.A.2 above that are less than 0.0286 lbs/MMBTU heat input to demonstrate compliance with conditions III.A.1 and III.A.2.

4. The Permittee's visible emissions from the affected facility must not exceed 20% opacity, as determined by continuous opacity monitoring system (6-minute average), except for one six-minute period per hour of not more than 27% opacity, as determined by the continuous opacity monitoring system. The Permittee may use EPA Method 9 when the opacity continuous monitoring or backup system is not operating.

B. <u>Sulfur Dioxide (SO_2) Emission Limitations</u>

1. The Permittee's Bonanza Unit No. 1 must not discharge to the atmosphere SO_2 at a rate exceeding 0.0976 lbs/MMBTU heat input over a rolling 12-month average. Compliance must be determined by calculating the rolling 12-month average, based on CEM data and fuel heat input. On the first day of each month, a new 12-month average must be calculated using data from the previous 12 months.

2. The Permittee's Bonanza Unit No. 1 must not discharge SO_2 to the atmosphere at a rate exceeding 0.15 lbs/MMBTU heat input, based on a 30-day rolling average. 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.

3. The Permittee must achieve at least 90% SO_2 removal efficiency based on a 30-day rolling average.

4. The Permittee may use scrubber slurry additives, such as adipic acid, lime, etc., to increase the dissolved alkalinity of the slurry reagent used in the fluid gas desulfurization (FGD) scrubber.

5. The Permittee's compliance with the SO_2 removal requirements must be based on data from the outlet SO_2 CEM and either inlet SO_2 data from the CEM or coal analysis data, over a 30-day rolling average. The total

percent removal must be computed using the total available sulfur from the coal analysis and overall sulfur removal. Compliance must be determined by calculating the arithmetic average for all valid hourly emission rates for SO_2 for the 30 successive boiler operating days.

6. The Permittee may suggest for EPA approval a method for sulfur analysis in the coal for compliance with condition III.B.5. The method must be an EPA approved Method for sulfur analysis in coal, or be an acceptable industrial analytical procedure for determining sulfur in coal.

C. <u>Continuous Emission Monitoring System (CEMS) Quality Assurance</u>.

The Permittee must conduct continuous emission monitoring system (CEMS) quality assurance testing for NO_x and SO_2 in the tall stack as required by 40 C.F.R. Part 60, Appendix F, Quality Assurance Procedures. The Permittee must perform calibration drift (CD), relative accuracy (RA), cylinder gas audit (CGA), reference methods analysis (RMs), relative accuracy test audit (RATA), and relative accuracy audit (RAA) determinations at 40 C.F.R. Part 60, Appendix F. The testing frequency can be no less than that specified in Appendix F and applies to part III of this Permit. The Permittee must provide EPA with information required by the Data Assessment Report (DAR) for each quarterly audit with the report of emissions required by Appendix F.

D. <u>Nitrogen Oxides (NO_x) Emission Limitations</u>

1. Until condition III.D.2 of this permit becomes effective, the Permittee's Bonanza Unit No. 1 must not discharge into the atmosphere NO_x in excess of 0.50 lbs/MMBTU heat input when subbituminous coal is fired, or 0.55 lbs/MMBTU heat input when bituminous coal is fired, based on a 30-day rolling average. If subbituminous and bituminous coal are fired simultaneously, the applicable NO_x emission standard must be determined by proration using the formula in 40 C.F.R. 60.44Da(a)(2), but must not have NO_x emissions in excess of 0.55 lbs/MMBTU heat input, based on a 30-day rolling average. Compliance must be determined by calculating the arithmetic average of all valid hourly emission rates (at least two values each hour are required) for NO_x for 30 successive boiler operating days, based on continuous emission monitoring data and fuel heat input.

2. Beginning no later than 18 months after the effective date of this permit, the Permittee's Bonanza Unit No. 1 must not discharge into the atmosphere NO_x in excess of 0.28 lbs/MMBTU heat input, based on a 30-

day rolling average. Compliance must be determined by calculating the arithmetic average of all valid hourly emission rates (at least two values each hour are required) for NO_x for 30 successive boiler operating days, based on continuous emission monitoring data and fuel heat input.

IV. PSD BACT for Roads and Fugitive Emissions

A. Fugitive Emissions Dust Control Plan

The Permittee must develop a Fugitive Emissions Dust Control Plan and provide EPA with a copy of this Plan 90 days after the effective date of this Permit. The Plan must address all applicable Conditions in this Permit. The Permittee must review this Plan annually, by the anniversary date of this Permit, and, if necessary, update or change the Plan to ensure that fugitive emissions are minimized from the facility. The Permittee must provide EPA with the most current copy of the Fugitive Emissions Dust Control Plan within 90 days after revisions are made to it.

B. Coal, Ash and Limestone Handling

1. The Permittee must enclose the coal and limestone conveyors and all drop points must be vented to fabric dust collectors.

2. The Permittee must ensure that the track hopper for bottom dump coal shall have water sprays in place. The water spray must be used during dumping when conditions warrant. Conditions which warrant operation of the sprays are defined as any time the 20% opacity level is in jeopardy of being exceeded. To ensure that the sprays are always operative, the equipment must be tested at least once per month, except when weather conditions prohibit. A log of testing and operation must be kept. The log must include:

   a. Times of testing and results
   b. Times of coal deliveries
   c. Times of spray operation
   d. Weather conditions at time of coal deliveries
   e. Coal conditions (washed, unwashed, dry, moist, etc.)

3. The Permittee's coal pile shall not exceed 22 acres in total area. The active reclaim area must not exceed 11 acres at any one time. The reclaim area may be moved to any location on the coal pile. The remainder of the coal pile must be the long-term storage area. Emissions of particulate

from the long-term storage area must be controlled by compaction of the coal pile surface and sealing with a surfactant initially and by subsequent application of sealing agent as warranted. A surfactant and spray mechanism to apply it must be available and operative at all times. Conditions which warrant application of the surfactant are defined as any time the 20% opacity level might be exceeded. A log of operation must be kept. The log must include:

a. Times of spray operation
b. Compaction operation
c. Weather conditions
d. Surface conditions (dry, crumbled, moist, etc.)

4. The Permittee's limestone storage must be sealed with a surfactant as dry conditions warrant or as determined necessary by the EPA.

5. The Permittee must manage the fly ash/FGD sludge mixture at the end of the conveyor and prior to being completely covered in accordance with landfill procedures. The Permittee must add sprayed water to minimize fugitive emissions as conditions warrant, in accordance with the facility's fugitive dust control plan.

6. The Permittee must maintain a record/log of stabilization work done which includes dates, type of stabilizing agent, amount applied, and area of application.

C. <u>Road Dust Control</u>

1. The Permittee must water spray and/or chemically treat all unpaved roads and other unpaved operational areas that are used by mobile equipment to control fugitive dust. Treatment must be of sufficient frequency and quantity to maintain the surface material in a damp/moist condition. The opacity must not exceed 20% during all times the areas are in use or the outside temperature is below freezing. If chemical treatment is to be used, the plan must be approved by the EPA. The Permittee must maintain records of water treatment for all periods when the plant is in operation. The records must include the following items:

a. Date
b. Number of treatments made, dilution ratio, and quantity
c. Rainfall received, if any, and approximate amount
d. Time of day treatments were made

Records of treatment must be made available to the EPA upon request and must include a period of two years ending with the date of the request.

2. The Permittee must control visible emissions from haul-road traffic and mobile equipment in operational areas by implementing procedures in its dust control plan.

V. Air Pollution Equipment Operation and Operator Training

A. The Permittee must adequately and properly maintain all installations and facilities authorized by this PSD permit. Instructions from the vendor or established maintenance practices that maximize pollution control must be used. All necessary equipment control and operating devices, such as electronic monitoring displays, pressure gauges, amperes and voltage measurements, flow rate indicators, temperature gauges, CEMs, etc., must be installed and operated properly and easily accessible to compliance inspectors.

B. A copy of all manufacturers' operating instruction for pollution control equipment and pollution emitting equipment must be kept on site. These instructions must be available to all employees and personnel who operate the equipment and must be made available to compliance inspectors upon their request.

C. The Permittee may have written dated guidance available to ensure the proper operation and maintenance of pollution control equipment that supplements or complements manufacturer's instructions. This guidance may be prepared based on the Permittee's experience with operating pollution control equipment. These instructions must be made available to all employees and personnel who operate the equipment and must be made available to compliance inspectors upon their request.

D. The Permittee must provide adequate training and periodic re-training to all employees or personnel who operate air pollution control equipment.

E. Records of operator training must be made available to EPA upon verbal or written request. This permit must be made available to all employees or personnel by the Permittee who operate the equipment in this permit.

VI. PSD Monitoring Requirements Table

The Permittee must perform stack testing to show accuracy of continuous emission monitoring systems with the emission limitations stated in the above conditions, and as specified below:

A.

Emission Point	Pollutant	Testing Status	Test Frequency
Unit #1	PM	*	***
600 foot tall stack	PM_{10}	*	***
	SO_2	**	***
	NO_x	**	***

B. Testing Status (to be applied above)

* Compliance testing is required. EPA may require testing at any time in accordance with 40 CFR 60.8, Performance tests. The Permittee may elect to use any approved EPA method cited in this permit. The Permittee may request that alternative EPA approved methods be used instead of those cited in this permit.

** Stack testing is done to verify the accuracy of the continuous emission monitoring systems.

*** Test every year unless a lesser testing frequency is requested by the Permittee and is approved by EPA.

C. Particulate Matter (PM) and PM_{10}

1. 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.

2. The sample location must be as specified in 40 CFR part 60, Appendix A, Method 1.

3. The volumetric flow rate must be determined as specified in 40 CFR part 60, Appendix A, Method 2, Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube) or Methods 2E, 2F, 2G, and 3D or an alternative method that has EPA's approval.

D. Sulfur Dioxide (SO_2)

40 CFR part 60, Appendix A, Method 6, Determination of Sulfur Dioxide Emissions from Stationary Sources or Method 6A, 6B, or 6C or an approved EPA

Method.

E. Nitrogen Oxides (NO_X)

40 CFR part 60, Appendix A, Method 7, Determination of Nitrogen Oxide Emissions From Stationary Sources, or Methods 7A-7E or an approved EPA method.

F. Removal efficiency. The Permittee must report emission rates and removal efficiency in accordance with 40 CFR part 60, Appendix A, Method 19, Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates.

G. Test notifications. The Permittee must provide notification of the test date to EPA at least 30 days before the test for each of the above pollutants. A pretest conference must be held, if requested by EPA. The conference must be held at least 30 days before the test, between the Permittee, the tester, and EPA. The emission point must be designed to conform to the requirements of 40 CFR Part 60, Appendix A, Method 1, and approvable access must be provided to the test location by Permittee.

VII. Compliance Provisions

A. CEMS operation and availability. Except for unavoidable monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each continuous emission monitoring system must be operated and data recorded during all periods of operation of the boiler, including periods of startup, shutdown, malfunction, or emergency conditions as defined in 40 CFR part 60, Subpart Da. Each monitoring system must meet minimum frequency of operation requirements as follows: the CEMS shall complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period.

B. CEMS data averaging. For CEMS measurements, valid hourly emission rates and 30-day rolling average emission rates must be computed as specified in this Permit.

C. Calculation of emission rates in lb/MMBtu. The Permittee must convert pollutant concentration data recorded by the SO_2 and NO_x CEMS into units of pounds per million Btu of heat input (lb/MMBtu), in accordance with F factors calculated from 40 CFR part 60, Appendix A, Method 19, and using data from the diluent monitoring system. Fuel sampling and analysis must be conducted for determining F factors, using ASTM Methods.

D. CEMS recordkeeping. For each CEMS, the Permittee must keep a record of the following: all emission measurements, all measurements and other data pertaining to monitoring system performance evaluations, all monitoring device or monitoring system calibration checks, all adjustments, repairs and maintenance performed on these systems or devices, any monitor inoperative periods, and all other monitoring system information required by 40 CFR part 60 Appendices B and F, and 40 CFR part 75.

E. Continuous opacity monitoring system (COMS) operation and availability. The Permittee must maintain and operate a COMS at the main boiler stack, during all periods of operation of the facility, including periods of startup, shutdown, malfunction or emergency conditions, except for COMS breakdowns and repairs. 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).

F. Continuous emission compliance reports.

1. Reports for demonstrating compliance with PSD BACT emission limits on 30-day rolling averages. Within 30 days after the end of each calendar quarter, the Permittee must submit written reports to EPA of 30-day rolling average emissions in lb/MMBtu from the boiler for sulfur dioxide and nitrogen oxide. Each report shall identify the pollutant and applicable emission limit and shall include all of the following information for each 24-hour period:

a. Calendar date.

b. The average emission rate in lb/MMBtu for each 30 successive boiler operating days, ending with the last 30-day period in the quarter, identification of any periods of non-compliance with the applicable PSD BACT emission limit, reasons for non-compliance, and description of corrective actions taken. Periods of boiler operation during startup, shutdown or malfunctions must be included in the calculation of average emission rates. No periods of boiler operation may be excluded.

c. Identification of any boiler operating days for which pollutant or diluent data have not been obtained by an approved method under this permit, reasons for not obtaining the data, and description of corrective actions taken.

d. Identification of the "F" factor used for calculations, method of determination, and type of fuel combusted.

e. Identification of any times when hourly emission averages have been obtained based on manual sampling methods rather than continuous monitoring system data.

f. Identification of any times when the pollutant concentration exceeded full span of the continuous monitoring system.

g. Description of any modifications to the CEMS which could affect the ability of the continuous monitoring system to comply with applicable Performance Specifications in 40 CFR part 60 Appendix B.

2. Reports for demonstrating compliance with PSD BACT emission limits on 12-month rolling averages. Within 30 days after the end of each calendar quarter, the Permittee must submit written reports to EPA of 12-month rolling average sulfur dioxide emissions in lb/MMBtu from the boiler. Each report shall include all of the following information for each 24-hour period:

a. Calendar date.

b. The average emission rate in lb/MMBtu for each successive 12-month period, identification of any periods of non-compliance with the applicable PSD BACT emission limit, reasons for non-compliance, and description of corrective actions taken. Periods of boiler operation during startup, shutdown or malfunctions shall be included in the calculation of average emission rates. No periods of boiler operation may be excluded.

c. Identification of any boiler operating days for which pollutant or diluent data have not been obtained by an approved method under this permit, reasons for not obtaining the data, and description of corrective actions taken.

d. Identification of the "F" factor used for calculations, method of determination, and type of fuel combusted.

e. Identification of any times when hourly emission averages have been obtained based on manual sampling methods rather than continuous monitoring system data.

f. Identification of any times when the pollutant concentration exceeded full span of the continuous monitoring system.

g. Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with applicable Performance Specifications in 40 CFR part 60 Appendix B.

3. Reports for demonstrating opacity compliance. Within 30 days after the end of each calendar quarter, the Permittee must submit written reports to EPA of any exceedances of the opacity limit in this permit, as determined from the COMS. Each report must include all of the following information for each opacity exceedance:

a. Date, duration and magnitude of the exceedance.

b. Specific identification of each period of excess opacity that occurs during startups, shutdowns, and malfunctions of the affected facility, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted.

c. Date and time identifying each period during which the COMS was inoperative, and the nature of the system repairs or adjustments.

d. When no excess opacity has occurred or the COMS has not been inoperative, repaired or adjusted, such information must be stated in the report.

The continuous emission compliance reporting requirements in this permit do not constitute a waiver of any emission reporting requirements in 40 CFR parts 60, 75 or 77, nor does compliance with the emission reporting requirements in this permit excuse or otherwise constitute a defense to any violation of this permit, or of any applicable law or regulation, that may be caused by the emissions.

G. CEMS performance reports. Within 30 days after the end of each calendar quarter, the Permittee must submit written reports to EPA of the performance of the CEMS at the boiler for emissions of sulfur dioxide, nitrogen oxide, and diluent (CO_2 or O_2). The report for each monitoring system must contain the following information:

1. Baseline monitor information: pollutant, monitor manufacturer and model number, date of latest monitor certification or audit;

2. Date(s) and duration of each period during which the monitoring system was inoperative, except for zero and span adjustments and calibration checks;

3. For each period during which the monitoring system was inoperative, reason(s) it was inoperative;

4. Date(s) and duration of each period during which the monitoring system was "out-of-control," as defined in 40 CFR part 60, Appendix F, section 5.2.

5. For each period during which the monitoring system was out-of-control, reason(s) it was out of control;

6. Total duration of monitor inoperative and out-of-control periods for the quarter, as a percentage of total boiler operating time for the quarter;

7. For monitor inoperative or out-of-control periods caused by equipment malfunctions, steps and procedures taken to prevent reoccurrence of the malfunctions;

8. Any monitoring system repairs or adjustments, regardless of whether the repairs or adjustments were made to correct an equipment malfunction;

9. Date(s) and results of any Relative Accuracy Test Audits, Cylinder Gas Audits, or Relative Accuracy Audits conducted during the quarter to comply with 40 CFR part 60, Appendix F; and

10. If a monitoring system has not been inoperative, repaired or adjusted during the quarter, such information must be stated in the report for that monitoring system.

The monitoring system performance reporting requirements in this permit do not constitute a waiver of any monitoring system performance reporting requirements in 40 CFR parts 60 or 75.

H. Stack test reports. Within 60 calendar days after the stack test is conducted, the

Permittee must submit to EPA a written report of any stack test required by this permit. Each report must include the following information:

1. Date of test

2. Emitting unit tested

3. Pollutant measured

4. Applicable emission limit

5. Information regarding representative conditions during testing at the main boiler, as follows:

   a. Installed boiler maximum heat input capacity,
   b. Average heat input during the test, as a percent of capacity, and
   c. Average sulfur content and average heat content of coal being fired in the boiler during the test.

6. Emission measurement results from each test run, expressed in units of the applicable emission limit

7. Sampling and analysis procedures:
   a. Sampling locations
   b. Test methods used
   c. Analysis procedures and laboratory identification

8. Quality assurance procedures:
   a. Calibration procedures and frequency
   b. Sample recovery and field documentation
   c. Chain-of-custody procedures

9. Data handling and quality control procedures

United States Environmental Protection Agency, Region 8

By: ____

Callie A. Videtich, Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

Date: ____

Exhibit 5

DESERET
Generation & Transmission Co-operative
8722 South 300 West Sandy, Utah 84070 (801) 566-8721

RECEIVED
DEC 1 2 1994
Air Quality

December 9, 1994

Russell A. Roberts, Executive Secretary
UTAH AIR QUALITY BOARD
150 North 1950 West
P.O. Box 144820
Salt Lake City, UT 84114-4820

Re: Response to Utah Division of Air Quality's PSD Applicability/Major Modification Determination.

Dear Russell:

I. Introduction.

Representatives of Deseret Generation and Transmission ("DG&T") have met with the Utah Division of Air Quality ("DAQ") on several occasions to discuss whether the Notice of Intent for Bonanza I dated September 27, 1993 ("Bonanza I NOI") constitutes a "major modification" under the State of Utah's Prevention of Significant Deterioration ("PSD") rules. To err on the side of caution, DG&T prepared the NOI to satisfy all substantive PSD requirements in case the DAQ made a major modification determination. As a result, DG&T believes that the DAQ's final determination as to whether or not the NOI is a major modification is essentially a procedural matter.

During the initial public comment period on the NOI, certain comments were received alleging that the NOI constituted a PSD major modification. DG&T submitted written responses to the DAQ addressing these comments on June 2, 1994. See Letter to Russell A. Roberts, DAQ, from Lynn W. Mitton, DG&T, Re: Response to Comments on Bonanza I Notice of Intent ("NOI") - PSD Applicability (June 2, 1994) ["DG&T's June 2, 1994 Letter"], see also Letter to J. Tim Blanchard, DAQ, from Lynn W. Mitton, DG&T, Re: Bonanza I Notice of Intent ("NOI") (July 13, 1994) [hereinafter "DG&T's July 13, 1994 Letter"]. While DG&T continues to believe that the NOI is not a major modification, we have cooperated with the DAQ to ensure that the NOI satisfies all substantive and procedural PSD requirements pending the DAQ's final determination of PSD applicability.

At DG&T's request, the DAQ agreed to provide a formal written finding setting forth its final PSD applicability determination and the basis for such determination. The DAQ submitted a letter to DG&T on November 7, 1994 concluding that the NOI is a PSD major modification. See Letter to Lynn W. Mitton, DG&T, from Russell A.

Roberts, Executive Secretary, Utah Air Quality Board, Re: Major Modification Status of the Bonanza Unit 1 Power Plant (November 7, 1994) [hereinafter "DAQ's November 7, 1994 Letter"]. This letter states that Bonanza I's operating heat input was increased from 4,055 million British Thermal Units per hour ("MMBtu/hr") to 4,381 MMBtu/hr and this increase "would result in a significant increase in emissions from a change in the method of operation of Bonanza I . . ." which would be a PSD major modification. Id.

DG&T has researched the issues raised by the DAQ's November 7, 1994 Letter and determined that there are certain statements made therein that are incorrect. This letter has been prepared to respond to these issues.

II. Discussion.

A. DG&T's Current Operation of Bonanza I and the Operation Proposed in the NOI are Consistent With the Original NOI and the Current Approval Order.

The DAQ states that the original NOI dated August 4, 1980 ("Original NOI") and the original approval order ("Original AO") issued by the DAQ showed that the proposed operating heat input for Bonanza I was 4,055 MMBtu/hr. Id. This statement is only partially correct. The 4,055 MMBtu/hr heat input was used for air quality modeling but was not imposed as an operating limit on Bonanza I. The Original NOI and supporting documentation submitted to the DAQ indicated that Bonanza I's was capable of being operated at a higher maximum heat input of 4,381 MMBtu/hr.

The Original NOI was submitted as an amendment to an application for review that had been previously submitted to Region VIII of the U.S Environmental Protection Agency ("EPA Region VIII") on January 18, 1980. See Original NOI at 1. The Original NOI provided supplemental information regarding Bonanza I and added a second unit, Bonanza II, to the overall plans for the Bonanza Station. The Original NOI set forth the maximum generating capacity and heat input for both units. The Original NOI stated that the Bonanza Station "will consist of two conventional coal-fired steam electric generating units each with a nominal gross rating of 400 megawatts (440 megawatts, maximum gross)." Id. at II-2. The Original NOI also states that the "maximum instantaneous heat input to each furnace will be 4,381 million Btu per hour; heat input at 100 percent load will be 4,055 million Btu per hour." Id. at III-1.

DG&T also submitted details of the construction contract for Bonanza I to the DAQ. See DG&T's July 13, 1994 Letter. The amended construction contract stated that the heat input would be 4,381 MMBtu/hr. See id.; see also Burns & McDonnell, DG&T Moon Lake Station Unit No. 1, Contract 103 Sulfur Dioxide Absorption System Addendum No. 1, at 7, para. A3-5.A. (March 18, 1980). The original AO for Bonanza I provided that "[a]ll pollution control procedures and facilities shall be adopted or installed as proposed and equipment shall be operated to the manufacturer's specifications and/or to good engineering practices." Letter to Merrill J. Millett, DG&T, from Brent C. Bradford, Utah Air Conservation Committee ("UACC"), Re: Air Quality Approval Order for a Coal Fired Power Generation Plant (Two 400 MW Units) in Unitah County (Moon Lake) at § 1 (April 29, 1981) [hereinafter "Original AO"]. Similar language is included in Bonanza I's current AO. See Letter to Merrill Millett, DG&T, from F. Burnell Cordner, UACC, Re: Approval Order for Electric Utility Steam Generating Plant Unit #1 Unitah County, CDS A1 at § 1 (July 2, 1987) [hereinafter "Current AO"]. *Operation of Bonanza I at the maximum heat input of 4,381 MMBtu/hr* is consistent with the Original NOI, the manufacturer's specifications and the requirements of the Current AO. Therefore, DG&T's operation of Bonanza I at a heat input of 4,381 MMBtu/hr does not require any additional review, approval or modification of the Current AO.

Even if there was a basis to conclude that the NOI could be a major modification, State and Federal PSD rules provide specific exceptions to PSD requirements which are directly applicable to Bonanza I's circumstances. Under the Federal PSD rules, a change in the method of operation does not include "[a]n increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition." See 40 C.F.R. § 52.21(2)(iii)(e). State PSD rules likewise exempt "[a]n increase in the hours of operation or in the production rate unless such change would be prohibited under any enforceable permit condition." See UACR R307-1-1.89.5; see also DG&T's June 2, 1994 Letter at 4-5.

The Current AO does not include any enforceable limit for either power production or heat input because the actual limit is the maximum design of Bonanza I. Moreover, DG&T is allowed by its Current AO to operate Bonanza I at its maximum design heat input of 4,381 MMBtu/hr. Even if such operation were not provided by the Current AO, it would nevertheless be allowed because such increase is expressly exempt from PSD review.

B. <u>The Permitting Approach and Air Quality Modeling Followed By EPA Region VIII for Bonanza I is Consistent With Other Permitted Facilities.</u>

Even though the maximum heat input and design operation of Bonanza I was 4,381 MMBtu/hr, the 4,055 MMBtu/hr value was used for air quality modeling. Even so, it was described in the Original NOI and supporting documentation and understood that the maximum design heat input for Bonanza I and II was 4,381 MMBtu/hr for each unit. Such approach, however, is consistent with the permitting procedures followed by EPA Region VIII for other facilities in the early 1980's. It is important to note that such modeling was based upon two units at 4,055 MMBtu/hr each for a combined heat input and emission rate based upon 8,110 MMBtu/hr for Bonanza I and II. Therefore, even if modeling was performed at the 4,055 MMBtu/hr level, the combined heat input that was modeled was still substantially higher than the maximum 4,381 MMBtu/hr level for a single unit.

Although the DAQ is the current permitting authority for Bonanza I, the original construction permit was issued by EPA Region VIII. EPA Region VIII was also the permitting authority for Platte River Power Authority's ("Platte River") Rawhide Facility ("Rawhide"). <u>See</u> EPA, <u>Rawhide Unit No. 1 - Platte River Power Authority, Applicability Determination</u> at 1 (February 27, 1980). Comparison of the permits for Bonanza I and Rawhide demonstrates that the same permitting procedures were followed for both units. Short-term air quality impacts for both facilities were based upon the assumed "100%" heat input without regard to the true maximum heat input. An annual load factor of 80% for Bonanza I and 70% for Rawhide was used to predict annual air quality impacts. Even though air quality modeling was based upon the 100% heat input level, no conditions were included in either permit that restricted the actual operating heat input. As a result, the practical maximum heat input limit for both facilities is their maximum design.

Discussing the Rawhide permit, DG&T's June 2, 1994 Letter states:

> Although each PSD permit is unique and they cannot be generalized to other PSD permits, certain aspects of Rawhide's permit provide an example of the types of significant changes that can and have occurred at a PSD major source without triggering the requirements of PSD review as a major modification. The Rawhide application for a 279 MWG coal-fired power plant, as amended, was filed in 1979. The Rawhide plant is located 20 miles

north of Fort Collins, Colorado and is also located approximately 56 kilometers northeast of the Class I area of Rocky Mountain National Park ("RMNP"). EPA, Rawhide Unit #1 - Platte River Power Authority, Applicability Determination at 1 (February 27, 1980).

EPA estimated that at a generation of 230 megawatts net ("MWN"), the maximum coal consumption for the Rawhide unit was estimated to be 155 tons per hour ("TPH") [sic], with a heat input of 2,630 MMBtu/hr and an annual coal consumption of 872,000 TPY. . . .

An air quality analysis was performed by EPA for the Rawhide unit. EPA estimated that the 24-hour SO_2 ground level concentrations would be negligible at RMNP. Memorandum, Analysis of Air Quality Impact from the Rawhide Generating Station at 1 (March 10, 1980). Based upon these results, it was assumed that air quality impacts of the Rawhide unit on other Class I increments would be acceptable. Id. EPA Region VIII issued a PSD permit for the Rawhide unit in 1980. EPA, Conditional Permit to Commence Construction and Operate (May 22, 1980). EPA has not delegated PSD authority for the Rawhide unit to the State of Colorado. As a result of a request by Platte River, EPA revised the Rawhide PSD permit on December 21, 1992 to incorporate certain references in the original permit. EPA, Conditional Permit to Commence Construction and Operate (December 21, 1992). Although the Rawhide PSD permit is based upon a maximum heat input of 2,630 MMBtu/hr and a maximum coal consumption of 872,000 TPY (based upon 70% utilization), there are no permit limits in its current permit which limit heat input or coal consumption. Since there is no coal consumption limit, the actual potential air quality impacts of the Rawhide unit are limited to its actual design capacity for coal consumption.

At the same time that EPA was permitting the Rawhide unit under federal PSD requirements, the State of Colorado was permitting it under state new source review requirements. The Colorado Department of Health ("CDH") issued initial approval for the Rawhide unit in 1979 assuming SO_2 limits of 512 lb/hr, 1795 TPY and 0.3% sulfur content coal. CDH, Initial Approval, Emission Permit No. C-12,525-1 - Platte River Power Authority (November 2, 1979). Unlike the PSD permit for Rawhide, the CDH permit included a coal consumption limit. It appears that no additional air quality analysis was performed by

EPA Region VIII for the increase in coal consumption from the 872,000 TPY assumed for the PSD permit to the 1.3 million TPY included in the CDH permit.

A final emission permit was issued by the CDH to Platte River in 1986 based upon a SO_2 limit of 0.19 lb/MMBtu (which is approximately 70.0% removal based upon a 3-hour averaging period) and a maximum coal consumption of 155 tons per hour ("TPH") and 1.3 million TPY. CDH, *Final Approval, Emission Permit No. 12LR525 - Platte River Power Authority* (November 25, 1986). Contrary to EPA Region VIII's air quality analysis, CDH estimated that coal consumption of 155 TPH or 1,086,240 TPY (based upon 80% utilization) would result in 50% consumption of the Class I increment for RMNP. CDH, Source Impact Analysis - Attachment 1 (August 9, 1979). This permit was later modified at the request of Platte River to increase the maximum coal consumption to 175 TPH and 1.5 million TPY to reflect the actual operating conditions of the Rawhide unit. CDH, Modification of Final Approval, Emission Permit No. 12LR525 - Platte River Power Authority (November 25, 1986). It also appears that no additional impacts analysis was performed by either CDH or EPA Region III for this increase in coal consumption.

Even though the original PSD review and current PSD permit assumes an ambient impacts analysis based upon 872,000 TPY of coal, no additional impacts analysis has been performed for the Rawhide unit. Because the CDH does not have PSD authority for Rawhide, any limits contained in the CDH permits could be revised without PSD review. Moreover, consistent with federal PSD rules, Platte River can increase production (i.e., coal consumption) at Rawhide without triggering PSD requirements--despite the original estimates for coal consumption that were relied upon for the original PSD application.

Although exact details of the Rawhide situation are different from Bonanza I, the principal is the same. Rawhide has increased estimated coal consumption by two-fold without undergoing additional PSD review. Clearly, the increased coal consumption will result in increased emissions--which are likely above the significance levels for PSD review. However, Rawhide is not restricted under any PSD permit from increasing its coal consumption.

> Therefore, like Bonanza I and the NOI, Platte River may increase coal consumption without triggering PSD review as a major modification.

See DG&T's June 2, 1994 Letter at 14-16 (emphasis added).

As stated above, because Rawhide does not have any coal consumption or heat input limits it may increase its operations up to the maximum design of its equipment--even though air quality modeling may have been based upon the 100% heat input level. Therefore, Rawhide has increased its total coal consumption above the level modeled for its original PSD application without obtaining a modification of its PSD permit from EPA Region VIII. As stated above, operation of Bonanza I at a heat input of 4,381 MMBtu/hr is allowed by the Current AO. Even if operation at 4,381 MMBtu/hr was not specifically allowed, it would nevertheless be exempt from PSD review under State and Federal rules. Like Rawhide, DG&T can operate Bonanza I at the maximum heat input of 4,381 MMBtu/hr without triggering PSD applicability.

VII. Conclusion.

For the reasons stated in their November 7, 1994 letter, the DAQ has determined that the NOI constitutes a major modification subject to PSD review. DG&T continues to believe that the NOI does not constitute a major modification. Nevertheless, DG&T has cooperated with the DAQ to ensure that the NOI satisfied all substantive and procedural PSD requirements. Operation of Bonanza I at a heat input of 4,381 MMBtu/hr is consistent with the Original AO, manufacturer's specifications and the Current AO. Even if operating at 4,381 MMBtu/hr was not specifically authorized, it would be exempt from PSD review under both State and Federal rules.

Sincerely,

Lynn W. Mitton/DBH

Lynn W. Mitton,
General Manager

cc: Montie Keller
J. Tim Blanchard
Ben Wilson
Fred G. Nelson

dbh\dg&t\DGT-MAJ.noi

Exhibit 6

	A	B	C	D	E	F	G	H
1	Hourly Heat Input Data for Bonanza Power Plant, Jan. 1, 2014-March 31, 2014							
2	Data downloaded from EPA's Air Markets Program Database, http://ampd.epa.gov/ampd/							
3								
4	**State**	**Facility Name**	**Facility ID (ORISPL)**	**Year**	**Date**	**Hour**	**Program(s)**	**Heat Input (MMBtu)**
5	UT	Bonanza	7790	2014	3/28/14	8	ARP	5304.2
6	UT	Bonanza	7790	2014	3/28/14	9	ARP	5299.6
7	UT	Bonanza	7790	2014	3/28/14	7	ARP	5290.5
8	UT	Bonanza	7790	2014	3/28/14	11	ARP	5285.1
9	UT	Bonanza	7790	2014	3/28/14	10	ARP	5280.8
10	UT	Bonanza	7790	2014	3/28/14	19	ARP	5277.3
11	UT	Bonanza	7790	2014	3/28/14	18	ARP	5271
12	UT	Bonanza	7790	2014	3/28/14	20	ARP	5263.1
13	UT	Bonanza	7790	2014	3/28/14	21	ARP	5262.6
14	UT	Bonanza	7790	2014	3/28/14	22	ARP	5258.7
15	UT	Bonanza	7790	2014	3/12/14	11	ARP	5252.2
16	UT	Bonanza	7790	2014	3/12/14	10	ARP	5227.1
17	UT	Bonanza	7790	2014	3/12/14	12	ARP	5215.5
18	UT	Bonanza	7790	2014	3/28/14	6	ARP	5212.7
19	UT	Bonanza	7790	2014	3/8/14	7	ARP	5208.8
20	UT	Bonanza	7790	2014	3/12/14	9	ARP	5202.1
21	UT	Bonanza	7790	2014	3/8/14	19	ARP	5201
22	UT	Bonanza	7790	2014	3/16/14	7	ARP	5196.3
23	UT	Bonanza	7790	2014	3/12/14	7	ARP	5196.2
24	UT	Bonanza	7790	2014	3/5/14	22	ARP	5195.3
25	UT	Bonanza	7790	2014	3/12/14	8	ARP	5187.7
26	UT	Bonanza	7790	2014	3/3/14	9	ARP	5186.9
27	UT	Bonanza	7790	2014	3/12/14	23	ARP	5185.6
28	UT	Bonanza	7790	2014	3/8/14	18	ARP	5184.2
29	UT	Bonanza	7790	2014	3/3/14	10	ARP	5173.7
30	UT	Bonanza	7790	2014	3/8/14	12	ARP	5171.9
31	UT	Bonanza	7790	2014	3/16/14	5	ARP	5171.9
32	UT	Bonanza	7790	2014	3/3/14	22	ARP	5168.3
33	UT	Bonanza	7790	2014	3/9/14	9	ARP	5168

	A	B	C	D	E	F	G	H
34	UT	Bonanza	7790	2014	3/8/14	8	ARP	5167.1
35	UT	Bonanza	7790	2014	3/3/14	8	ARP	5165.3
36	UT	Bonanza	7790	2014	3/5/14	21	ARP	5161.8
37	UT	Bonanza	7790	2014	3/8/14	23	ARP	5161.3
38	UT	Bonanza	7790	2014	3/13/14	1	ARP	5161.2
39	UT	Bonanza	7790	2014	3/16/14	9	ARP	5159.6
40	UT	Bonanza	7790	2014	3/13/14	5	ARP	5159.2
41	UT	Bonanza	7790	2014	3/27/14	7	ARP	5159.2
42	UT	Bonanza	7790	2014	3/28/14	5	ARP	5159.1
43	UT	Bonanza	7790	2014	3/9/14	2	ARP	5156.7
44	UT	Bonanza	7790	2014	3/3/14	7	ARP	5156.3
45	UT	Bonanza	7790	2014	3/3/14	12	ARP	5156
46	UT	Bonanza	7790	2014	3/9/14	4	ARP	5154.9
47	UT	Bonanza	7790	2014	3/9/14	7	ARP	5154.4
48	UT	Bonanza	7790	2014	3/8/14	9	ARP	5153.9
49	UT	Bonanza	7790	2014	3/13/14	0	ARP	5153.8
50	UT	Bonanza	7790	2014	1/20/14	2	ARP	5152.8
51	UT	Bonanza	7790	2014	3/5/14	8	ARP	5151.5
52	UT	Bonanza	7790	2014	3/11/14	10	ARP	5151.5
53	UT	Bonanza	7790	2014	3/5/14	9	ARP	5150.6
54	UT	Bonanza	7790	2014	3/3/14	14	ARP	5149.9
55	UT	Bonanza	7790	2014	3/8/14	22	ARP	5149.4
56	UT	Bonanza	7790	2014	3/5/14	23	ARP	5149
57	UT	Bonanza	7790	2014	3/3/14	13	ARP	5148.6
58	UT	Bonanza	7790	2014	3/6/14	11	ARP	5148.6
59	UT	Bonanza	7790	2014	3/15/14	21	ARP	5148.6
60	UT	Bonanza	7790	2014	3/3/14	21	ARP	5147.4
61	UT	Bonanza	7790	2014	3/27/14	12	ARP	5147.2
62	UT	Bonanza	7790	2014	3/8/14	17	ARP	5146.8
63	UT	Bonanza	7790	2014	3/5/14	13	ARP	5146.5
64	UT	Bonanza	7790	2014	3/13/14	2	ARP	5146.4
65	UT	Bonanza	7790	2014	3/8/14	11	ARP	5145.9
66	UT	Bonanza	7790	2014	3/8/14	13	ARP	5145.4
67	UT	Bonanza	7790	2014	3/9/14	13	ARP	5145.2

	A	B	C	D	E	F	G	H
68	UT	Bonanza	7790	2014	3/15/14	20	ARP	5145.1
69	UT	Bonanza	7790	2014	3/7/14	16	ARP	5144.6
70	UT	Bonanza	7790	2014	3/8/14	16	ARP	5144.6
71	UT	Bonanza	7790	2014	3/3/14	16	ARP	5142.8
72	UT	Bonanza	7790	2014	3/10/14	4	ARP	5142.4
73	UT	Bonanza	7790	2014	3/3/14	15	ARP	5141.9
74	UT	Bonanza	7790	2014	3/9/14	5	ARP	5141.8
75	UT	Bonanza	7790	2014	3/7/14	18	ARP	5141.5
76	UT	Bonanza	7790	2014	3/15/14	22	ARP	5140.7
77	UT	Bonanza	7790	2014	3/12/14	20	ARP	5139.8
78	UT	Bonanza	7790	2014	3/9/14	11	ARP	5138.9
79	UT	Bonanza	7790	2014	3/9/14	22	ARP	5138.9
80	UT	Bonanza	7790	2014	3/10/14	9	ARP	5138.9
81	UT	Bonanza	7790	2014	3/24/14	7	ARP	5138.9
82	UT	Bonanza	7790	2014	3/9/14	12	ARP	5138
83	UT	Bonanza	7790	2014	3/6/14	13	ARP	5137.9
84	UT	Bonanza	7790	2014	3/9/14	10	ARP	5137.6
85	UT	Bonanza	7790	2014	3/10/14	7	ARP	5136.8
86	UT	Bonanza	7790	2014	3/3/14	11	ARP	5136.3
87	UT	Bonanza	7790	2014	3/5/14	10	ARP	5136.3
88	UT	Bonanza	7790	2014	3/8/14	21	ARP	5136.2
89	UT	Bonanza	7790	2014	3/27/14	14	ARP	5136.2
90	UT	Bonanza	7790	2014	2/11/14	3	ARP	5135.9
91	UT	Bonanza	7790	2014	3/6/14	12	ARP	5135.9
92	UT	Bonanza	7790	2014	3/10/14	8	ARP	5135.5
93	UT	Bonanza	7790	2014	3/12/14	21	ARP	5135.5
94	UT	Bonanza	7790	2014	3/7/14	19	ARP	5135.3
95	UT	Bonanza	7790	2014	3/8/14	10	ARP	5135.3
96	UT	Bonanza	7790	2014	3/16/14	10	ARP	5135.3
97	UT	Bonanza	7790	2014	3/12/14	5	ARP	5135
98	UT	Bonanza	7790	2014	3/13/14	7	ARP	5134.9
99	UT	Bonanza	7790	2014	3/14/14	8	ARP	5134.9
100	UT	Bonanza	7790	2014	3/13/14	4	ARP	5134.6
101	UT	Bonanza	7790	2014	3/13/14	3	ARP	5133.7

	A	B	C	D	E	F	G	H
102	UT	Bonanza	7790	2014	3/3/14	19	ARP	5133.6
103	UT	Bonanza	7790	2014	3/8/14	5	ARP	5133.6
104	UT	Bonanza	7790	2014	3/12/14	22	ARP	5132.4
105	UT	Bonanza	7790	2014	3/8/14	15	ARP	5131.4
106	UT	Bonanza	7790	2014	3/10/14	2	ARP	5130.7
107	UT	Bonanza	7790	2014	3/5/14	12	ARP	5130.1
108	UT	Bonanza	7790	2014	3/5/14	20	ARP	5129.6
109	UT	Bonanza	7790	2014	3/10/14	10	ARP	5129.3
110	UT	Bonanza	7790	2014	3/8/14	2	ARP	5129.2
111	UT	Bonanza	7790	2014	3/11/14	9	ARP	5129.2
112	UT	Bonanza	7790	2014	3/27/14	10	ARP	5129.2
113	UT	Bonanza	7790	2014	3/3/14	20	ARP	5128.7
114	UT	Bonanza	7790	2014	3/7/14	17	ARP	5127.9
115	UT	Bonanza	7790	2014	3/9/14	20	ARP	5127.9
116	UT	Bonanza	7790	2014	3/9/14	3	ARP	5127.3
117	UT	Bonanza	7790	2014	3/9/14	8	ARP	5126.9
118	UT	Bonanza	7790	2014	3/5/14	14	ARP	5126.5
119	UT	Bonanza	7790	2014	3/11/14	8	ARP	5126.3
120	UT	Bonanza	7790	2014	3/11/14	15	ARP	5126.1
121	UT	Bonanza	7790	2014	3/12/14	4	ARP	5126.1
122	UT	Bonanza	7790	2014	3/8/14	20	ARP	5125.2
123	UT	Bonanza	7790	2014	3/10/14	12	ARP	5124.9
124	UT	Bonanza	7790	2014	3/6/14	7	ARP	5124.8
125	UT	Bonanza	7790	2014	3/23/14	5	ARP	5124.5
126	UT	Bonanza	7790	2014	3/5/14	19	ARP	5124.3
127	UT	Bonanza	7790	2014	3/6/14	10	ARP	5124.1
128	UT	Bonanza	7790	2014	3/27/14	5	ARP	5124.1
129	UT	Bonanza	7790	2014	1/2/14	4	ARP	5123.9
130	UT	Bonanza	7790	2014	3/10/14	3	ARP	5123.6
131	UT	Bonanza	7790	2014	3/8/14	4	ARP	5123.5
132	UT	Bonanza	7790	2014	3/7/14	21	ARP	5121.7
133	UT	Bonanza	7790	2014	2/11/14	7	ARP	5121.4
134	UT	Bonanza	7790	2014	3/5/14	11	ARP	5121.3
135	UT	Bonanza	7790	2014	3/11/14	12	ARP	5119.5

	A	B	C	D	E	F	G	H
136	UT	Bonanza	7790	2014	2/10/14	22	ARP	5119
137	UT	Bonanza	7790	2014	3/23/14	9	ARP	5118.8
138	UT	Bonanza	7790	2014	3/11/14	13	ARP	5117.8
139	UT	Bonanza	7790	2014	3/28/14	17	ARP	5116.8
140	UT	Bonanza	7790	2014	3/6/14	23	ARP	5116.3
141	UT	Bonanza	7790	2014	3/16/14	8	ARP	5116
142	UT	Bonanza	7790	2014	3/27/14	13	ARP	5116
143	UT	Bonanza	7790	2014	3/15/14	9	ARP	5115.6
144	UT	Bonanza	7790	2014	3/10/14	5	ARP	5115.4
145	UT	Bonanza	7790	2014	3/10/14	11	ARP	5115.4
146	UT	Bonanza	7790	2014	3/24/14	5	ARP	5114.9
147	UT	Bonanza	7790	2014	3/20/14	5	ARP	5114.3
148	UT	Bonanza	7790	2014	3/3/14	23	ARP	5113.8
149	UT	Bonanza	7790	2014	3/11/14	7	ARP	5112.9
150	UT	Bonanza	7790	2014	3/11/14	14	ARP	5112.4
151	UT	Bonanza	7790	2014	3/8/14	1	ARP	5111.6
152	UT	Bonanza	7790	2014	3/5/14	7	ARP	5111.1
153	UT	Bonanza	7790	2014	3/9/14	16	ARP	5111
154	UT	Bonanza	7790	2014	2/10/14	7	ARP	5110.6
155	UT	Bonanza	7790	2014	3/10/14	18	ARP	5109.8
156	UT	Bonanza	7790	2014	3/7/14	15	ARP	5109.4
157	UT	Bonanza	7790	2014	2/11/14	12	ARP	5109.2
158	UT	Bonanza	7790	2014	3/9/14	19	ARP	5109.2
159	UT	Bonanza	7790	2014	2/11/14	2	ARP	5108.9
160	UT	Bonanza	7790	2014	3/7/14	14	ARP	5108.9
161	UT	Bonanza	7790	2014	3/15/14	8	ARP	5108.9
162	UT	Bonanza	7790	2014	3/3/14	18	ARP	5108.8
163	UT	Bonanza	7790	2014	3/4/14	0	ARP	5106.3
164	UT	Bonanza	7790	2014	3/15/14	10	ARP	5106.3
165	UT	Bonanza	7790	2014	3/9/14	0	ARP	5106.2
166	UT	Bonanza	7790	2014	3/10/14	1	ARP	5105.7
167	UT	Bonanza	7790	2014	3/16/14	6	ARP	5104.9
168	UT	Bonanza	7790	2014	3/9/14	18	ARP	5104.8
169	UT	Bonanza	7790	2014	3/26/14	7	ARP	5104.4

	A	B	C	D	E	F	G	H
170	UT	Bonanza	7790	2014	3/9/14	15	ARP	5104
171	UT	Bonanza	7790	2014	3/11/14	18	ARP	5103.9
172	UT	Bonanza	7790	2014	3/25/14	4	ARP	5103.7
173	UT	Bonanza	7790	2014	3/4/14	20	ARP	5103.6
174	UT	Bonanza	7790	2014	3/11/14	11	ARP	5103.6
175	UT	Bonanza	7790	2014	3/9/14	17	ARP	5103.1
176	UT	Bonanza	7790	2014	3/9/14	23	ARP	5102.2
177	UT	Bonanza	7790	2014	3/24/14	2	ARP	5102
178	UT	Bonanza	7790	2014	3/7/14	20	ARP	5101.8
179	UT	Bonanza	7790	2014	3/9/14	21	ARP	5101.8
180	UT	Bonanza	7790	2014	3/15/14	7	ARP	5101.8
181	UT	Bonanza	7790	2014	3/3/14	17	ARP	5101.4
182	UT	Bonanza	7790	2014	3/27/14	6	ARP	5100.8
183	UT	Bonanza	7790	2014	3/13/14	8	ARP	5100.5
184	UT	Bonanza	7790	2014	3/10/14	0	ARP	5099.6
185	UT	Bonanza	7790	2014	3/24/14	3	ARP	5099.3
186	UT	Bonanza	7790	2014	3/25/14	3	ARP	5099.3
187	UT	Bonanza	7790	2014	2/10/14	21	ARP	5098.4
188	UT	Bonanza	7790	2014	3/8/14	3	ARP	5098.3
189	UT	Bonanza	7790	2014	3/27/14	11	ARP	5098.3
190	UT	Bonanza	7790	2014	3/8/14	14	ARP	5097.9
191	UT	Bonanza	7790	2014	3/6/14	22	ARP	5097.6
192	UT	Bonanza	7790	2014	3/18/14	9	ARP	5097.5
193	UT	Bonanza	7790	2014	3/11/14	19	ARP	5097.2
194	UT	Bonanza	7790	2014	3/25/14	7	ARP	5097.2
195	UT	Bonanza	7790	2014	3/11/14	16	ARP	5095.9
196	UT	Bonanza	7790	2014	3/27/14	9	ARP	5095.7
197	UT	Bonanza	7790	2014	1/2/14	2	ARP	5095.1
198	UT	Bonanza	7790	2014	3/12/14	3	ARP	5095.1
199	UT	Bonanza	7790	2014	3/3/14	5	ARP	5094.8
200	UT	Bonanza	7790	2014	3/12/14	2	ARP	5094.2
201	UT	Bonanza	7790	2014	3/13/14	18	ARP	5094.1
202	UT	Bonanza	7790	2014	3/15/14	19	ARP	5093.1
203	UT	Bonanza	7790	2014	3/6/14	14	ARP	5092.8

	A	B	C	D	E	F	G	H
204	UT	Bonanza	7790	2014	3/6/14	0	ARP	5092.6
205	UT	Bonanza	7790	2014	3/18/14	7	ARP	5092.6
206	UT	Bonanza	7790	2014	2/11/14	1	ARP	5091.5
207	UT	Bonanza	7790	2014	3/11/14	17	ARP	5091.5
208	UT	Bonanza	7790	2014	3/24/14	8	ARP	5091.5
209	UT	Bonanza	7790	2014	3/5/14	15	ARP	5090.8
210	UT	Bonanza	7790	2014	3/8/14	0	ARP	5090
211	UT	Bonanza	7790	2014	3/2/14	17	ARP	5089.5
212	UT	Bonanza	7790	2014	3/12/14	19	ARP	5089.5
213	UT	Bonanza	7790	2014	3/18/14	8	ARP	5089.5
214	UT	Bonanza	7790	2014	3/27/14	8	ARP	5089.5
215	UT	Bonanza	7790	2014	3/23/14	7	ARP	5089.4
216	UT	Bonanza	7790	2014	3/3/14	6	ARP	5088.8
217	UT	Bonanza	7790	2014	3/9/14	1	ARP	5088.4
218	UT	Bonanza	7790	2014	3/13/14	22	ARP	5088.2
219	UT	Bonanza	7790	2014	3/14/14	7	ARP	5088.2
220	UT	Bonanza	7790	2014	2/10/14	23	ARP	5087.2
221	UT	Bonanza	7790	2014	1/21/14	10	ARP	5086.6
222	UT	Bonanza	7790	2014	2/10/14	12	ARP	5086.4
223	UT	Bonanza	7790	2014	3/4/14	22	ARP	5086.4
224	UT	Bonanza	7790	2014	2/11/14	0	ARP	5086.3
225	UT	Bonanza	7790	2014	3/13/14	9	ARP	5086.1
226	UT	Bonanza	7790	2014	2/10/14	2	ARP	5085.9
227	UT	Bonanza	7790	2014	3/25/14	5	ARP	5085.4
228	UT	Bonanza	7790	2014	2/10/14	14	ARP	5085
229	UT	Bonanza	7790	2014	3/23/14	22	ARP	5084.8
230	UT	Bonanza	7790	2014	2/11/14	8	ARP	5082.9
231	UT	Bonanza	7790	2014	3/4/14	21	ARP	5082.9
232	UT	Bonanza	7790	2014	3/10/14	20	ARP	5082.9
233	UT	Bonanza	7790	2014	3/24/14	10	ARP	5082.5
234	UT	Bonanza	7790	2014	2/11/14	4	ARP	5082
235	UT	Bonanza	7790	2014	3/6/14	20	ARP	5081.2
236	UT	Bonanza	7790	2014	3/9/14	6	ARP	5080.4
237	UT	Bonanza	7790	2014	3/12/14	0	ARP	5080.3

	A	B	C	D	E	F	G	H
238	UT	Bonanza	7790	2014	3/13/14	23	ARP	5080.3
239	UT	Bonanza	7790	2014	3/25/14	8	ARP	5080.3
240	UT	Bonanza	7790	2014	3/24/14	9	ARP	5079.4
241	UT	Bonanza	7790	2014	2/10/14	19	ARP	5078.5
242	UT	Bonanza	7790	2014	3/24/14	23	ARP	5078.4
243	UT	Bonanza	7790	2014	3/7/14	22	ARP	5078.1
244	UT	Bonanza	7790	2014	3/23/14	8	ARP	5078.1
245	UT	Bonanza	7790	2014	3/24/14	4	ARP	5077.2
246	UT	Bonanza	7790	2014	1/2/14	1	ARP	5076.4
247	UT	Bonanza	7790	2014	3/11/14	21	ARP	5076.4
248	UT	Bonanza	7790	2014	3/5/14	17	ARP	5076.3
249	UT	Bonanza	7790	2014	3/14/14	9	ARP	5076.3
250	UT	Bonanza	7790	2014	3/5/14	16	ARP	5075.9
251	UT	Bonanza	7790	2014	1/19/14	21	ARP	5075.5
252	UT	Bonanza	7790	2014	2/10/14	5	ARP	5075.1
253	UT	Bonanza	7790	2014	2/11/14	5	ARP	5074.7
254	UT	Bonanza	7790	2014	1/2/14	3	ARP	5074.2
255	UT	Bonanza	7790	2014	3/13/14	10	ARP	5073.8
256	UT	Bonanza	7790	2014	3/31/14	7	ARP	5073.3
257	UT	Bonanza	7790	2014	3/28/14	23	ARP	5073.1
258	UT	Bonanza	7790	2014	1/21/14	11	ARP	5072.7
259	UT	Bonanza	7790	2014	3/5/14	18	ARP	5072.4
260	UT	Bonanza	7790	2014	3/13/14	21	ARP	5072.1
261	UT	Bonanza	7790	2014	1/2/14	5	ARP	5071.9
262	UT	Bonanza	7790	2014	2/11/14	11	ARP	5071.6
263	UT	Bonanza	7790	2014	3/7/14	0	ARP	5071.6
264	UT	Bonanza	7790	2014	3/14/14	12	ARP	5071.6
265	UT	Bonanza	7790	2014	3/23/14	10	ARP	5071.6
266	UT	Bonanza	7790	2014	3/12/14	1	ARP	5071.5
267	UT	Bonanza	7790	2014	2/10/14	0	ARP	5071.3
268	UT	Bonanza	7790	2014	2/10/14	13	ARP	5071.3
269	UT	Bonanza	7790	2014	2/10/14	9	ARP	5071.1
270	UT	Bonanza	7790	2014	3/25/14	11	ARP	5071.1
271	UT	Bonanza	7790	2014	2/25/14	15	ARP	5070.7

	A	B	C	D	E	F	G	H
272	UT	Bonanza	7790	2014	3/24/14	6	ARP	5070.6
273	UT	Bonanza	7790	2014	3/11/14	20	ARP	5070.1
274	UT	Bonanza	7790	2014	3/27/14	15	ARP	5069.9
275	UT	Bonanza	7790	2014	3/4/14	1	ARP	5069.7
276	UT	Bonanza	7790	2014	2/10/14	20	ARP	5069.6
277	UT	Bonanza	7790	2014	3/14/14	11	ARP	5069.4
278	UT	Bonanza	7790	2014	2/10/14	4	ARP	5069.2
279	UT	Bonanza	7790	2014	1/2/14	7	ARP	5068.6
280	UT	Bonanza	7790	2014	3/7/14	8	ARP	5068.4
281	UT	Bonanza	7790	2014	2/10/14	8	ARP	5068.2
282	UT	Bonanza	7790	2014	3/14/14	10	ARP	5067.9
283	UT	Bonanza	7790	2014	3/2/14	18	ARP	5067.7
284	UT	Bonanza	7790	2014	2/15/14	7	ARP	5066.5
285	UT	Bonanza	7790	2014	2/11/14	13	ARP	5066.4
286	UT	Bonanza	7790	2014	2/10/14	16	ARP	5066.1
287	UT	Bonanza	7790	2014	3/20/14	9	ARP	5066.1
288	UT	Bonanza	7790	2014	3/14/14	18	ARP	5066
289	UT	Bonanza	7790	2014	3/24/14	20	ARP	5065.7
290	UT	Bonanza	7790	2014	3/5/14	5	ARP	5065.6
291	UT	Bonanza	7790	2014	3/24/14	11	ARP	5065.6
292	UT	Bonanza	7790	2014	3/24/14	12	ARP	5065.2
293	UT	Bonanza	7790	2014	3/26/14	15	ARP	5065.1
294	UT	Bonanza	7790	2014	3/6/14	19	ARP	5064.6
295	UT	Bonanza	7790	2014	2/15/14	18	ARP	5064.4
296	UT	Bonanza	7790	2014	3/7/14	9	ARP	5064
297	UT	Bonanza	7790	2014	3/11/14	23	ARP	5063.5
298	UT	Bonanza	7790	2014	3/23/14	3	ARP	5062.5
299	UT	Bonanza	7790	2014	3/19/14	2	ARP	5062.3
300	UT	Bonanza	7790	2014	3/24/14	15	ARP	5061.9
301	UT	Bonanza	7790	2014	3/25/14	0	ARP	5061.8
302	UT	Bonanza	7790	2014	1/28/14	17	ARP	5061.7
303	UT	Bonanza	7790	2014	3/4/14	23	ARP	5061.3
304	UT	Bonanza	7790	2014	3/10/14	21	ARP	5061.2
305	UT	Bonanza	7790	2014	3/2/14	15	ARP	5060.4

	A	B	C	D	E	F	G	H
306	UT	Bonanza	7790	2014	3/13/14	6	ARP	5060.4
307	UT	Bonanza	7790	2014	3/7/14	13	ARP	5060
308	UT	Bonanza	7790	2014	1/20/14	1	ARP	5059.5
309	UT	Bonanza	7790	2014	3/25/14	9	ARP	5058.8
310	UT	Bonanza	7790	2014	1/21/14	20	ARP	5058.6
311	UT	Bonanza	7790	2014	1/28/14	7	ARP	5058.5
312	UT	Bonanza	7790	2014	3/3/14	1	ARP	5058.5
313	UT	Bonanza	7790	2014	3/22/14	12	ARP	5058.4
314	UT	Bonanza	7790	2014	3/6/14	16	ARP	5058.2
315	UT	Bonanza	7790	2014	3/25/14	2	ARP	5058
316	UT	Bonanza	7790	2014	2/17/14	7	ARP	5057.8
317	UT	Bonanza	7790	2014	3/27/14	17	ARP	5057.8
318	UT	Bonanza	7790	2014	3/6/14	18	ARP	5057.7
319	UT	Bonanza	7790	2014	3/11/14	22	ARP	5057.7
320	UT	Bonanza	7790	2014	3/7/14	12	ARP	5057.3
321	UT	Bonanza	7790	2014	2/10/14	15	ARP	5056.3
322	UT	Bonanza	7790	2014	1/21/14	8	ARP	5056
323	UT	Bonanza	7790	2014	3/26/14	9	ARP	5056
324	UT	Bonanza	7790	2014	1/20/14	0	ARP	5055.9
325	UT	Bonanza	7790	2014	1/28/14	4	ARP	5055.9
326	UT	Bonanza	7790	2014	3/2/14	19	ARP	5055.5
327	UT	Bonanza	7790	2014	1/22/14	3	ARP	5055.1
328	UT	Bonanza	7790	2014	3/10/14	6	ARP	5055.1
329	UT	Bonanza	7790	2014	1/19/14	23	ARP	5054.7
330	UT	Bonanza	7790	2014	2/10/14	11	ARP	5054.7
331	UT	Bonanza	7790	2014	3/2/14	13	ARP	5054.6
332	UT	Bonanza	7790	2014	2/10/14	1	ARP	5054.5
333	UT	Bonanza	7790	2014	3/2/14	11	ARP	5054.1
334	UT	Bonanza	7790	2014	1/21/14	19	ARP	5053.8
335	UT	Bonanza	7790	2014	3/2/14	14	ARP	5052.1
336	UT	Bonanza	7790	2014	3/20/14	11	ARP	5051.7
337	UT	Bonanza	7790	2014	3/7/14	11	ARP	5051.6
338	UT	Bonanza	7790	2014	3/24/14	21	ARP	5051.5
339	UT	Bonanza	7790	2014	3/25/14	12	ARP	5050.8

	A	B	C	D	E	F	G	H
340	UT	Bonanza	7790	2014	3/10/14	14	ARP	5050.2
341	UT	Bonanza	7790	2014	2/15/14	19	ARP	5049.8
342	UT	Bonanza	7790	2014	3/10/14	19	ARP	5049.4
343	UT	Bonanza	7790	2014	3/6/14	21	ARP	5048.9
344	UT	Bonanza	7790	2014	2/11/14	9	ARP	5047.3
345	UT	Bonanza	7790	2014	3/13/14	11	ARP	5047.3
346	UT	Bonanza	7790	2014	2/17/14	9	ARP	5047.2
347	UT	Bonanza	7790	2014	2/11/14	10	ARP	5046.9
348	UT	Bonanza	7790	2014	3/13/14	16	ARP	5046.9
349	UT	Bonanza	7790	2014	3/2/14	16	ARP	5046.8
350	UT	Bonanza	7790	2014	3/24/14	14	ARP	5046.7
351	UT	Bonanza	7790	2014	3/24/14	22	ARP	5046.4
352	UT	Bonanza	7790	2014	1/28/14	19	ARP	5046.3
353	UT	Bonanza	7790	2014	2/10/14	17	ARP	5045.9
354	UT	Bonanza	7790	2014	3/14/14	13	ARP	5045.9
355	UT	Bonanza	7790	2014	1/21/14	7	ARP	5045.8
356	UT	Bonanza	7790	2014	3/25/14	1	ARP	5045.6
357	UT	Bonanza	7790	2014	3/3/14	2	ARP	5045.4
358	UT	Bonanza	7790	2014	3/23/14	13	ARP	5045.2
359	UT	Bonanza	7790	2014	3/4/14	19	ARP	5044.6
360	UT	Bonanza	7790	2014	3/21/14	7	ARP	5044.6
361	UT	Bonanza	7790	2014	3/26/14	22	ARP	5044.6
362	UT	Bonanza	7790	2014	3/2/14	4	ARP	5044.3
363	UT	Bonanza	7790	2014	3/23/14	12	ARP	5044.3
364	UT	Bonanza	7790	2014	3/2/14	20	ARP	5044.1
365	UT	Bonanza	7790	2014	3/23/14	23	ARP	5043.4
366	UT	Bonanza	7790	2014	3/24/14	19	ARP	5043.3
367	UT	Bonanza	7790	2014	2/10/14	18	ARP	5042.9
368	UT	Bonanza	7790	2014	1/19/14	19	ARP	5042.4
369	UT	Bonanza	7790	2014	3/23/14	4	ARP	5041.2
370	UT	Bonanza	7790	2014	3/18/14	23	ARP	5040.9
371	UT	Bonanza	7790	2014	3/13/14	17	ARP	5040.3
372	UT	Bonanza	7790	2014	2/10/14	10	ARP	5040
373	UT	Bonanza	7790	2014	3/14/14	5	ARP	5039.7

	A	B	C	D	E	F	G	H
374	UT	Bonanza	7790	2014	3/2/14	5	ARP	5039.5
375	UT	Bonanza	7790	2014	3/5/14	6	ARP	5039.5
376	UT	Bonanza	7790	2014	3/26/14	19	ARP	5039.5
377	UT	Bonanza	7790	2014	2/17/14	11	ARP	5039.3
378	UT	Bonanza	7790	2014	3/2/14	12	ARP	5039.3
379	UT	Bonanza	7790	2014	3/24/14	17	ARP	5039.2
380	UT	Bonanza	7790	2014	3/12/14	6	ARP	5039.1
381	UT	Bonanza	7790	2014	2/17/14	4	ARP	5038.8
382	UT	Bonanza	7790	2014	3/5/14	1	ARP	5038.8
383	UT	Bonanza	7790	2014	1/3/14	5	ARP	5038
384	UT	Bonanza	7790	2014	2/15/14	17	ARP	5037.8
385	UT	Bonanza	7790	2014	3/24/14	13	ARP	5037.8
386	UT	Bonanza	7790	2014	3/2/14	7	ARP	5037.5
387	UT	Bonanza	7790	2014	3/7/14	23	ARP	5036.7
388	UT	Bonanza	7790	2014	1/28/14	23	ARP	5036.2
389	UT	Bonanza	7790	2014	1/28/14	5	ARP	5035.3
390	UT	Bonanza	7790	2014	3/3/14	0	ARP	5035.3
391	UT	Bonanza	7790	2014	2/16/14	7	ARP	5034.9
392	UT	Bonanza	7790	2014	1/20/14	5	ARP	5034.5
393	UT	Bonanza	7790	2014	3/22/14	8	ARP	5034.5
394	UT	Bonanza	7790	2014	3/26/14	14	ARP	5034.3
395	UT	Bonanza	7790	2014	2/17/14	3	ARP	5034
396	UT	Bonanza	7790	2014	3/2/14	9	ARP	5034
397	UT	Bonanza	7790	2014	1/28/14	11	ARP	5033.6
398	UT	Bonanza	7790	2014	3/5/14	2	ARP	5033.2
399	UT	Bonanza	7790	2014	3/6/14	17	ARP	5033.1
400	UT	Bonanza	7790	2014	3/29/14	0	ARP	5033.1
401	UT	Bonanza	7790	2014	1/28/14	16	ARP	5032.8
402	UT	Bonanza	7790	2014	3/6/14	9	ARP	5032.8
403	UT	Bonanza	7790	2014	1/2/14	0	ARP	5032.3
404	UT	Bonanza	7790	2014	2/11/14	6	ARP	5032.3
405	UT	Bonanza	7790	2014	3/5/14	4	ARP	5032.3
406	UT	Bonanza	7790	2014	2/15/14	16	ARP	5031.3
407	UT	Bonanza	7790	2014	3/26/14	10	ARP	5031.3

	A	B	C	D	E	F	G	H
408	UT	Bonanza	7790	2014	3/8/14	6	ARP	5031
409	UT	Bonanza	7790	2014	3/26/14	13	ARP	5030.9
410	UT	Bonanza	7790	2014	3/31/14	8	ARP	5030.4
411	UT	Bonanza	7790	2014	3/27/14	19	ARP	5029.6
412	UT	Bonanza	7790	2014	3/5/14	0	ARP	5029.3
413	UT	Bonanza	7790	2014	1/31/14	13	ARP	5028.8
414	UT	Bonanza	7790	2014	2/15/14	15	ARP	5028.8
415	UT	Bonanza	7790	2014	3/22/14	10	ARP	5028.8
416	UT	Bonanza	7790	2014	3/2/14	8	ARP	5028.4
417	UT	Bonanza	7790	2014	2/16/14	21	ARP	5027.3
418	UT	Bonanza	7790	2014	3/19/14	23	ARP	5027
419	UT	Bonanza	7790	2014	3/20/14	8	ARP	5027
420	UT	Bonanza	7790	2014	3/22/14	13	ARP	5026.8
421	UT	Bonanza	7790	2014	3/18/14	10	ARP	5026.6
422	UT	Bonanza	7790	2014	1/18/14	18	ARP	5026.5
423	UT	Bonanza	7790	2014	3/24/14	18	ARP	5026.4
424	UT	Bonanza	7790	2014	1/3/14	0	ARP	5026.1
425	UT	Bonanza	7790	2014	2/10/14	3	ARP	5026.1
426	UT	Bonanza	7790	2014	2/12/14	21	ARP	5026.1
427	UT	Bonanza	7790	2014	3/22/14	16	ARP	5026.1
428	UT	Bonanza	7790	2014	3/23/14	1	ARP	5026.1
429	UT	Bonanza	7790	2014	3/4/14	4	ARP	5025.7
430	UT	Bonanza	7790	2014	3/22/14	11	ARP	5025.7
431	UT	Bonanza	7790	2014	2/15/14	1	ARP	5025.5
432	UT	Bonanza	7790	2014	1/28/14	18	ARP	5025.3
433	UT	Bonanza	7790	2014	3/25/14	6	ARP	5025.3
434	UT	Bonanza	7790	2014	1/21/14	18	ARP	5025.2
435	UT	Bonanza	7790	2014	1/22/14	4	ARP	5025.2
436	UT	Bonanza	7790	2014	3/23/14	18	ARP	5025.2
437	UT	Bonanza	7790	2014	3/23/14	2	ARP	5024.9
438	UT	Bonanza	7790	2014	3/19/14	0	ARP	5024.7
439	UT	Bonanza	7790	2014	3/31/14	10	ARP	5024.5
440	UT	Bonanza	7790	2014	1/28/14	12	ARP	5024
441	UT	Bonanza	7790	2014	3/10/14	17	ARP	5024

	A	B	C	D	E	F	G	H
442	UT	Bonanza	7790	2014	3/22/14	22	ARP	5024
443	UT	Bonanza	7790	2014	3/2/14	21	ARP	5023.6
444	UT	Bonanza	7790	2014	3/23/14	20	ARP	5023
445	UT	Bonanza	7790	2014	2/16/14	20	ARP	5021.7
446	UT	Bonanza	7790	2014	1/18/14	19	ARP	5021.2
447	UT	Bonanza	7790	2014	3/22/14	21	ARP	5021
448	UT	Bonanza	7790	2014	2/15/14	4	ARP	5020.9
449	UT	Bonanza	7790	2014	3/2/14	0	ARP	5020.9
450	UT	Bonanza	7790	2014	3/24/14	16	ARP	5020.9
451	UT	Bonanza	7790	2014	3/27/14	21	ARP	5020.8
452	UT	Bonanza	7790	2014	3/2/14	23	ARP	5020.5
453	UT	Bonanza	7790	2014	1/3/14	3	ARP	5020.3
454	UT	Bonanza	7790	2014	2/10/14	6	ARP	5019.6
455	UT	Bonanza	7790	2014	1/21/14	9	ARP	5019.5
456	UT	Bonanza	7790	2014	1/3/14	2	ARP	5019
457	UT	Bonanza	7790	2014	1/21/14	14	ARP	5019
458	UT	Bonanza	7790	2014	3/2/14	22	ARP	5018.7
459	UT	Bonanza	7790	2014	3/19/14	4	ARP	5018.7
460	UT	Bonanza	7790	2014	3/22/14	19	ARP	5018.4
461	UT	Bonanza	7790	2014	3/18/14	15	ARP	5018.3
462	UT	Bonanza	7790	2014	3/27/14	4	ARP	5018.3
463	UT	Bonanza	7790	2014	1/19/14	20	ARP	5017.9
464	UT	Bonanza	7790	2014	1/21/14	15	ARP	5017.7
465	UT	Bonanza	7790	2014	1/19/14	22	ARP	5017.4
466	UT	Bonanza	7790	2014	3/2/14	3	ARP	5017
467	UT	Bonanza	7790	2014	3/5/14	3	ARP	5017
468	UT	Bonanza	7790	2014	3/26/14	20	ARP	5017
469	UT	Bonanza	7790	2014	1/2/14	8	ARP	5016.4
470	UT	Bonanza	7790	2014	2/15/14	2	ARP	5016.2
471	UT	Bonanza	7790	2014	3/18/14	11	ARP	5016.2
472	UT	Bonanza	7790	2014	3/20/14	12	ARP	5016.2
473	UT	Bonanza	7790	2014	2/12/14	23	ARP	5015.7
474	UT	Bonanza	7790	2014	2/15/14	13	ARP	5015.4
475	UT	Bonanza	7790	2014	3/27/14	16	ARP	5015.3

	A	B	C	D	E	F	G	H
476	UT	Bonanza	7790	2014	2/16/14	23	ARP	5014.8
477	UT	Bonanza	7790	2014	3/23/14	21	ARP	5014.8
478	UT	Bonanza	7790	2014	3/22/14	18	ARP	5012
479	UT	Bonanza	7790	2014	3/22/14	23	ARP	5012
480	UT	Bonanza	7790	2014	3/23/14	0	ARP	5012
481	UT	Bonanza	7790	2014	3/10/14	23	ARP	5011.8
482	UT	Bonanza	7790	2014	3/21/14	10	ARP	5011.5
483	UT	Bonanza	7790	2014	2/12/14	20	ARP	5011.4
484	UT	Bonanza	7790	2014	1/19/14	18	ARP	5011.1
485	UT	Bonanza	7790	2014	1/21/14	23	ARP	5011.1
486	UT	Bonanza	7790	2014	2/15/14	14	ARP	5011.1
487	UT	Bonanza	7790	2014	2/16/14	8	ARP	5010.9
488	UT	Bonanza	7790	2014	3/16/14	11	ARP	5010.5
489	UT	Bonanza	7790	2014	3/23/14	17	ARP	5010.5
490	UT	Bonanza	7790	2014	3/22/14	9	ARP	5010.2
491	UT	Bonanza	7790	2014	3/2/14	10	ARP	5010
492	UT	Bonanza	7790	2014	1/18/14	17	ARP	5009.8
493	UT	Bonanza	7790	2014	2/16/14	22	ARP	5009.6
494	UT	Bonanza	7790	2014	2/17/14	8	ARP	5009.6
495	UT	Bonanza	7790	2014	1/18/14	20	ARP	5009.3
496	UT	Bonanza	7790	2014	3/14/14	6	ARP	5009.3
497	UT	Bonanza	7790	2014	3/21/14	9	ARP	5009.3
498	UT	Bonanza	7790	2014	1/21/14	21	ARP	5008.9
499	UT	Bonanza	7790	2014	3/20/14	19	ARP	5008.9
500	UT	Bonanza	7790	2014	3/27/14	20	ARP	5008.9
501	UT	Bonanza	7790	2014	3/20/14	10	ARP	5008.5
502	UT	Bonanza	7790	2014	3/22/14	14	ARP	5008.5
503	UT	Bonanza	7790	2014	1/18/14	21	ARP	5008.4
504	UT	Bonanza	7790	2014	3/13/14	12	ARP	5008.1
505	UT	Bonanza	7790	2014	3/4/14	5	ARP	5008
506	UT	Bonanza	7790	2014	3/7/14	7	ARP	5008
507	UT	Bonanza	7790	2014	3/26/14	21	ARP	5007.9
508	UT	Bonanza	7790	2014	3/7/14	10	ARP	5007.8
509	UT	Bonanza	7790	2014	3/20/14	18	ARP	5007.7

	A	B	C	D	E	F	G	H
510	UT	Bonanza	7790	2014	2/12/14	22	ARP	5007.4
511	UT	Bonanza	7790	2014	2/17/14	12	ARP	5007.4
512	UT	Bonanza	7790	2014	2/17/14	5	ARP	5006.5
513	UT	Bonanza	7790	2014	3/26/14	11	ARP	5006.4
514	UT	Bonanza	7790	2014	3/23/14	19	ARP	5006.1
515	UT	Bonanza	7790	2014	3/26/14	17	ARP	5006
516	UT	Bonanza	7790	2014	1/3/14	1	ARP	5005.8
517	UT	Bonanza	7790	2014	3/29/14	1	ARP	5005.8
518	UT	Bonanza	7790	2014	1/28/14	3	ARP	5005.2
519	UT	Bonanza	7790	2014	3/19/14	5	ARP	5005.1
520	UT	Bonanza	7790	2014	2/26/14	4	ARP	5004.9
521	UT	Bonanza	7790	2014	3/19/14	14	ARP	5004.8
522	UT	Bonanza	7790	2014	1/20/14	7	ARP	5004.5
523	UT	Bonanza	7790	2014	1/28/14	20	ARP	5004.4
524	UT	Bonanza	7790	2014	3/18/14	13	ARP	5004.2
525	UT	Bonanza	7790	2014	2/26/14	2	ARP	5003.1
526	UT	Bonanza	7790	2014	2/9/14	23	ARP	5002.9
527	UT	Bonanza	7790	2014	3/23/14	11	ARP	5002.9
528	UT	Bonanza	7790	2014	1/19/14	2	ARP	5002.3
529	UT	Bonanza	7790	2014	2/15/14	5	ARP	5002.3
530	UT	Bonanza	7790	2014	3/20/14	17	ARP	5002.1
531	UT	Bonanza	7790	2014	1/18/14	22	ARP	5001.8
532	UT	Bonanza	7790	2014	1/21/14	17	ARP	5000.8
533	UT	Bonanza	7790	2014	3/19/14	1	ARP	5000.8
534	UT	Bonanza	7790	2014	2/17/14	2	ARP	5000.4
535	UT	Bonanza	7790	2014	3/11/14	6	ARP	5000.1
536	UT	Bonanza	7790	2014	3/27/14	18	ARP	5000
537	UT	Bonanza	7790	2014	3/10/14	22	ARP	4999.9
538	UT	Bonanza	7790	2014	2/16/14	19	ARP	4999.6
539	UT	Bonanza	7790	2014	2/15/14	0	ARP	4999.5
540	UT	Bonanza	7790	2014	1/22/14	5	ARP	4999.1
541	UT	Bonanza	7790	2014	2/17/14	15	ARP	4998.7
542	UT	Bonanza	7790	2014	3/18/14	14	ARP	4998.7
543	UT	Bonanza	7790	2014	3/18/14	5	ARP	4998.2

	A	B	C	D	E	F	G	H
544	UT	Bonanza	7790	2014	3/25/14	15	ARP	4997.8
545	UT	Bonanza	7790	2014	1/19/14	0	ARP	4996.6
546	UT	Bonanza	7790	2014	3/4/14	12	ARP	4996.6
547	UT	Bonanza	7790	2014	3/22/14	17	ARP	4996.1
548	UT	Bonanza	7790	2014	3/23/14	14	ARP	4995.8
549	UT	Bonanza	7790	2014	3/23/14	15	ARP	4995.8
550	UT	Bonanza	7790	2014	1/15/14	11	ARP	4995.7
551	UT	Bonanza	7790	2014	2/14/14	15	ARP	4995.7
552	UT	Bonanza	7790	2014	3/4/14	18	ARP	4995.2
553	UT	Bonanza	7790	2014	3/31/14	6	ARP	4995.2
554	UT	Bonanza	7790	2014	1/21/14	22	ARP	4994.8
555	UT	Bonanza	7790	2014	1/28/14	15	ARP	4994.4
556	UT	Bonanza	7790	2014	2/13/14	0	ARP	4994.4
557	UT	Bonanza	7790	2014	2/14/14	18	ARP	4993.6
558	UT	Bonanza	7790	2014	1/20/14	21	ARP	4993.5
559	UT	Bonanza	7790	2014	1/27/14	7	ARP	4993
560	UT	Bonanza	7790	2014	2/28/14	9	ARP	4993
561	UT	Bonanza	7790	2014	3/13/14	15	ARP	4992.6
562	UT	Bonanza	7790	2014	3/24/14	0	ARP	4992.2
563	UT	Bonanza	7790	2014	3/21/14	11	ARP	4991.5
564	UT	Bonanza	7790	2014	2/16/14	0	ARP	4991.4
565	UT	Bonanza	7790	2014	2/17/14	13	ARP	4991.4
566	UT	Bonanza	7790	2014	3/2/14	2	ARP	4991.4
567	UT	Bonanza	7790	2014	1/3/14	7	ARP	4991.3
568	UT	Bonanza	7790	2014	3/13/14	14	ARP	4991.3
569	UT	Bonanza	7790	2014	1/21/14	12	ARP	4991.1
570	UT	Bonanza	7790	2014	3/21/14	8	ARP	4991
571	UT	Bonanza	7790	2014	2/13/14	2	ARP	4990.4
572	UT	Bonanza	7790	2014	3/24/14	1	ARP	4990.4
573	UT	Bonanza	7790	2014	3/25/14	17	ARP	4990.4
574	UT	Bonanza	7790	2014	1/28/14	21	ARP	4990.1
575	UT	Bonanza	7790	2014	2/14/14	23	ARP	4990.1
576	UT	Bonanza	7790	2014	2/16/14	2	ARP	4990.1
577	UT	Bonanza	7790	2014	2/15/14	3	ARP	4989.6

	A	B	C	D	E	F	G	H
578	UT	Bonanza	7790	2014	3/13/14	13	ARP	4989.6
579	UT	Bonanza	7790	2014	3/20/14	15	ARP	4989.6
580	UT	Bonanza	7790	2014	1/28/14	10	ARP	4989.5
581	UT	Bonanza	7790	2014	1/29/14	0	ARP	4989.5
582	UT	Bonanza	7790	2014	3/19/14	7	ARP	4989.3
583	UT	Bonanza	7790	2014	3/21/14	12	ARP	4989.3
584	UT	Bonanza	7790	2014	3/23/14	6	ARP	4989
585	UT	Bonanza	7790	2014	1/18/14	23	ARP	4988.7
586	UT	Bonanza	7790	2014	3/18/14	22	ARP	4988.7
587	UT	Bonanza	7790	2014	2/15/14	20	ARP	4987.6
588	UT	Bonanza	7790	2014	2/11/14	14	ARP	4987.5
589	UT	Bonanza	7790	2014	3/18/14	19	ARP	4987
590	UT	Bonanza	7790	2014	3/27/14	22	ARP	4986.8
591	UT	Bonanza	7790	2014	2/16/14	17	ARP	4986.6
592	UT	Bonanza	7790	2014	3/4/14	11	ARP	4986.4
593	UT	Bonanza	7790	2014	3/4/14	15	ARP	4986.4
594	UT	Bonanza	7790	2014	3/25/14	10	ARP	4986.3
595	UT	Bonanza	7790	2014	2/14/14	16	ARP	4985.9
596	UT	Bonanza	7790	2014	1/15/14	12	ARP	4985.6
597	UT	Bonanza	7790	2014	3/18/14	6	ARP	4985.1
598	UT	Bonanza	7790	2014	1/28/14	13	ARP	4984.9
599	UT	Bonanza	7790	2014	3/14/14	17	ARP	4984.9
600	UT	Bonanza	7790	2014	2/14/14	17	ARP	4984.6
601	UT	Bonanza	7790	2014	3/20/14	13	ARP	4984.5
602	UT	Bonanza	7790	2014	1/6/14	4	ARP	4984.2
603	UT	Bonanza	7790	2014	1/22/14	0	ARP	4984.2
604	UT	Bonanza	7790	2014	2/16/14	5	ARP	4984
605	UT	Bonanza	7790	2014	3/1/14	2	ARP	4984
606	UT	Bonanza	7790	2014	3/23/14	16	ARP	4984
607	UT	Bonanza	7790	2014	1/3/14	4	ARP	4983.8
608	UT	Bonanza	7790	2014	3/18/14	16	ARP	4983.7
609	UT	Bonanza	7790	2014	3/19/14	3	ARP	4983.3
610	UT	Bonanza	7790	2014	3/21/14	21	ARP	4983.2
611	UT	Bonanza	7790	2014	3/4/14	16	ARP	4982.9

	A	B	C	D	E	F	G	H
612	UT	Bonanza	7790	2014	2/14/14	14	ARP	4982.7
613	UT	Bonanza	7790	2014	2/17/14	0	ARP	4981.9
614	UT	Bonanza	7790	2014	1/2/14	23	ARP	4981.6
615	UT	Bonanza	7790	2014	3/19/14	8	ARP	4981.6
616	UT	Bonanza	7790	2014	1/29/14	1	ARP	4981.2
617	UT	Bonanza	7790	2014	1/29/14	13	ARP	4981
618	UT	Bonanza	7790	2014	3/11/14	0	ARP	4980.6
619	UT	Bonanza	7790	2014	2/13/14	13	ARP	4980.3
620	UT	Bonanza	7790	2014	2/15/14	22	ARP	4980.3
621	UT	Bonanza	7790	2014	3/18/14	21	ARP	4980.3
622	UT	Bonanza	7790	2014	2/28/14	11	ARP	4979.8
623	UT	Bonanza	7790	2014	1/2/14	6	ARP	4979.5
624	UT	Bonanza	7790	2014	1/19/14	3	ARP	4979.4
625	UT	Bonanza	7790	2014	3/20/14	4	ARP	4979.3
626	UT	Bonanza	7790	2014	2/17/14	14	ARP	4979.2
627	UT	Bonanza	7790	2014	3/18/14	20	ARP	4979
628	UT	Bonanza	7790	2014	3/4/14	17	ARP	4978.9
629	UT	Bonanza	7790	2014	3/31/14	11	ARP	4978.9
630	UT	Bonanza	7790	2014	1/28/14	14	ARP	4978.8
631	UT	Bonanza	7790	2014	2/14/14	8	ARP	4978.6
632	UT	Bonanza	7790	2014	3/25/14	16	ARP	4978.4
633	UT	Bonanza	7790	2014	2/13/14	7	ARP	4978.1
634	UT	Bonanza	7790	2014	2/17/14	1	ARP	4977.9
635	UT	Bonanza	7790	2014	2/15/14	21	ARP	4977.8
636	UT	Bonanza	7790	2014	3/26/14	6	ARP	4977.3
637	UT	Bonanza	7790	2014	2/12/14	19	ARP	4977.1
638	UT	Bonanza	7790	2014	2/16/14	3	ARP	4976.7
639	UT	Bonanza	7790	2014	2/13/14	8	ARP	4975.9
640	UT	Bonanza	7790	2014	2/14/14	12	ARP	4974.9
641	UT	Bonanza	7790	2014	2/28/14	10	ARP	4974.9
642	UT	Bonanza	7790	2014	1/21/14	13	ARP	4974.5
643	UT	Bonanza	7790	2014	1/20/14	6	ARP	4974.2
644	UT	Bonanza	7790	2014	2/14/14	7	ARP	4974.2
645	UT	Bonanza	7790	2014	2/16/14	18	ARP	4974.1

	A	B	C	D	E	F	G	H
646	UT	Bonanza	7790	2014	3/18/14	12	ARP	4973.9
647	UT	Bonanza	7790	2014	2/14/14	19	ARP	4973.5
648	UT	Bonanza	7790	2014	1/1/14	23	ARP	4973.2
649	UT	Bonanza	7790	2014	3/22/14	15	ARP	4973.1
650	UT	Bonanza	7790	2014	3/20/14	14	ARP	4972.7
651	UT	Bonanza	7790	2014	3/1/14	0	ARP	4972.4
652	UT	Bonanza	7790	2014	3/2/14	6	ARP	4972.3
653	UT	Bonanza	7790	2014	3/1/14	3	ARP	4971.4
654	UT	Bonanza	7790	2014	3/18/14	18	ARP	4971.4
655	UT	Bonanza	7790	2014	3/1/14	7	ARP	4971.1
656	UT	Bonanza	7790	2014	2/15/14	23	ARP	4970.3
657	UT	Bonanza	7790	2014	2/16/14	1	ARP	4970.3
658	UT	Bonanza	7790	2014	1/1/14	12	ARP	4969.6
659	UT	Bonanza	7790	2014	3/21/14	13	ARP	4969.3
660	UT	Bonanza	7790	2014	1/21/14	1	ARP	4968.5
661	UT	Bonanza	7790	2014	2/13/14	1	ARP	4968.5
662	UT	Bonanza	7790	2014	1/6/14	5	ARP	4968.3
663	UT	Bonanza	7790	2014	2/17/14	6	ARP	4968.3
664	UT	Bonanza	7790	2014	3/1/14	4	ARP	4968
665	UT	Bonanza	7790	2014	3/20/14	20	ARP	4968
666	UT	Bonanza	7790	2014	2/17/14	16	ARP	4967.3
667	UT	Bonanza	7790	2014	1/19/14	16	ARP	4967
668	UT	Bonanza	7790	2014	1/27/14	8	ARP	4966.7
669	UT	Bonanza	7790	2014	2/28/14	22	ARP	4966.7
670	UT	Bonanza	7790	2014	2/28/14	23	ARP	4966.7
671	UT	Bonanza	7790	2014	3/22/14	0	ARP	4966.7
672	UT	Bonanza	7790	2014	1/15/14	10	ARP	4966.6
673	UT	Bonanza	7790	2014	1/15/14	13	ARP	4966.6
674	UT	Bonanza	7790	2014	3/1/14	1	ARP	4966.3
675	UT	Bonanza	7790	2014	3/2/14	1	ARP	4966.3
676	UT	Bonanza	7790	2014	3/17/14	18	ARP	4966.3
677	UT	Bonanza	7790	2014	3/4/14	10	ARP	4965.4
678	UT	Bonanza	7790	2014	2/8/14	17	ARP	4965.1
679	UT	Bonanza	7790	2014	2/14/14	13	ARP	4965.1

	A	B	C	D	E	F	G	H
680	UT	Bonanza	7790	2014	2/15/14	6	ARP	4965
681	UT	Bonanza	7790	2014	1/20/14	19	ARP	4964.4
682	UT	Bonanza	7790	2014	2/13/14	4	ARP	4964.1
683	UT	Bonanza	7790	2014	3/1/14	23	ARP	4964.1
684	UT	Bonanza	7790	2014	3/20/14	7	ARP	4963.8
685	UT	Bonanza	7790	2014	2/16/14	4	ARP	4962.9
686	UT	Bonanza	7790	2014	1/28/14	22	ARP	4962.8
687	UT	Bonanza	7790	2014	1/20/14	10	ARP	4962.6
688	UT	Bonanza	7790	2014	1/19/14	17	ARP	4962.4
689	UT	Bonanza	7790	2014	1/19/14	7	ARP	4962.2
690	UT	Bonanza	7790	2014	2/12/14	18	ARP	4962.1
691	UT	Bonanza	7790	2014	3/18/14	4	ARP	4962.1
692	UT	Bonanza	7790	2014	3/26/14	12	ARP	4962.1
693	UT	Bonanza	7790	2014	3/16/14	4	ARP	4962
694	UT	Bonanza	7790	2014	1/19/14	4	ARP	4961.7
695	UT	Bonanza	7790	2014	2/16/14	15	ARP	4961.7
696	UT	Bonanza	7790	2014	3/31/14	9	ARP	4961.7
697	UT	Bonanza	7790	2014	3/22/14	20	ARP	4961.6
698	UT	Bonanza	7790	2014	1/1/14	22	ARP	4961.3
699	UT	Bonanza	7790	2014	3/4/14	7	ARP	4961.1
700	UT	Bonanza	7790	2014	3/20/14	6	ARP	4961.1
701	UT	Bonanza	7790	2014	2/28/14	8	ARP	4960.9
702	UT	Bonanza	7790	2014	1/18/14	16	ARP	4960.7
703	UT	Bonanza	7790	2014	3/20/14	16	ARP	4960.4
704	UT	Bonanza	7790	2014	1/1/14	13	ARP	4960
705	UT	Bonanza	7790	2014	3/4/14	13	ARP	4960
706	UT	Bonanza	7790	2014	1/20/14	20	ARP	4959.5
707	UT	Bonanza	7790	2014	2/28/14	12	ARP	4959.5
708	UT	Bonanza	7790	2014	3/21/14	20	ARP	4959
709	UT	Bonanza	7790	2014	3/25/14	20	ARP	4958.7
710	UT	Bonanza	7790	2014	3/26/14	5	ARP	4958.7
711	UT	Bonanza	7790	2014	2/28/14	7	ARP	4958.2
712	UT	Bonanza	7790	2014	2/14/14	9	ARP	4958
713	UT	Bonanza	7790	2014	2/16/14	9	ARP	4957.4

	A	B	C	D	E	F	G	H
714	UT	Bonanza	7790	2014	3/31/14	5	ARP	4957.4
715	UT	Bonanza	7790	2014	1/22/14	7	ARP	4957.1
716	UT	Bonanza	7790	2014	1/29/14	10	ARP	4956.7
717	UT	Bonanza	7790	2014	2/17/14	10	ARP	4956.3
718	UT	Bonanza	7790	2014	1/19/14	1	ARP	4956
719	UT	Bonanza	7790	2014	2/14/14	20	ARP	4955.2
720	UT	Bonanza	7790	2014	1/1/14	19	ARP	4954.7
721	UT	Bonanza	7790	2014	1/2/14	10	ARP	4954.7
722	UT	Bonanza	7790	2014	1/2/14	22	ARP	4954.7
723	UT	Bonanza	7790	2014	3/15/14	6	ARP	4954.7
724	UT	Bonanza	7790	2014	3/21/14	22	ARP	4953.9
725	UT	Bonanza	7790	2014	3/22/14	1	ARP	4953.9
726	UT	Bonanza	7790	2014	1/28/14	6	ARP	4953.8
727	UT	Bonanza	7790	2014	1/28/14	2	ARP	4953.7
728	UT	Bonanza	7790	2014	2/14/14	21	ARP	4953.5
729	UT	Bonanza	7790	2014	2/26/14	1	ARP	4953.2
730	UT	Bonanza	7790	2014	1/15/14	8	ARP	4952.9
731	UT	Bonanza	7790	2014	2/16/14	10	ARP	4952.7
732	UT	Bonanza	7790	2014	2/13/14	12	ARP	4951.9
733	UT	Bonanza	7790	2014	2/16/14	11	ARP	4951.8
734	UT	Bonanza	7790	2014	2/14/14	11	ARP	4951.5
735	UT	Bonanza	7790	2014	2/17/14	19	ARP	4950.2
736	UT	Bonanza	7790	2014	3/4/14	14	ARP	4950.1
737	UT	Bonanza	7790	2014	2/16/14	16	ARP	4950
738	UT	Bonanza	7790	2014	1/1/14	14	ARP	4949.9
739	UT	Bonanza	7790	2014	3/18/14	17	ARP	4949.9
740	UT	Bonanza	7790	2014	1/6/14	1	ARP	4949.7
741	UT	Bonanza	7790	2014	1/2/14	9	ARP	4949
742	UT	Bonanza	7790	2014	2/13/14	3	ARP	4948.5
743	UT	Bonanza	7790	2014	3/1/14	5	ARP	4948.5
744	UT	Bonanza	7790	2014	1/22/14	2	ARP	4948.4
745	UT	Bonanza	7790	2014	2/17/14	17	ARP	4948.4
746	UT	Bonanza	7790	2014	3/1/14	8	ARP	4948.4
747	UT	Bonanza	7790	2014	1/21/14	16	ARP	4947.9

	A	B	C	D	E	F	G	H
748	UT	Bonanza	7790	2014	1/15/14	9	ARP	4947.7
749	UT	Bonanza	7790	2014	3/1/14	20	ARP	4947.6
750	UT	Bonanza	7790	2014	3/1/14	10	ARP	4947.5
751	UT	Bonanza	7790	2014	3/17/14	19	ARP	4947.5
752	UT	Bonanza	7790	2014	1/1/14	16	ARP	4947.2
753	UT	Bonanza	7790	2014	1/22/14	9	ARP	4947.1
754	UT	Bonanza	7790	2014	1/1/14	11	ARP	4946.8
755	UT	Bonanza	7790	2014	1/22/14	8	ARP	4946.7
756	UT	Bonanza	7790	2014	3/3/14	3	ARP	4946.7
757	UT	Bonanza	7790	2014	2/14/14	22	ARP	4946.3
758	UT	Bonanza	7790	2014	3/1/14	9	ARP	4945.8
759	UT	Bonanza	7790	2014	1/20/14	17	ARP	4945.5
760	UT	Bonanza	7790	2014	2/12/14	17	ARP	4945.3
761	UT	Bonanza	7790	2014	2/15/14	12	ARP	4945.3
762	UT	Bonanza	7790	2014	3/25/14	13	ARP	4945.2
763	UT	Bonanza	7790	2014	1/6/14	7	ARP	4945
764	UT	Bonanza	7790	2014	2/16/14	13	ARP	4944.9
765	UT	Bonanza	7790	2014	2/16/14	14	ARP	4943.7
766	UT	Bonanza	7790	2014	1/19/14	13	ARP	4943.6
767	UT	Bonanza	7790	2014	2/8/14	16	ARP	4943.6
768	UT	Bonanza	7790	2014	1/20/14	16	ARP	4943.3
769	UT	Bonanza	7790	2014	3/21/14	14	ARP	4943.1
770	UT	Bonanza	7790	2014	2/16/14	12	ARP	4942.8
771	UT	Bonanza	7790	2014	2/26/14	3	ARP	4942.8
772	UT	Bonanza	7790	2014	2/26/14	0	ARP	4942.7
773	UT	Bonanza	7790	2014	1/1/14	17	ARP	4942.4
774	UT	Bonanza	7790	2014	1/20/14	18	ARP	4942.4
775	UT	Bonanza	7790	2014	2/28/14	21	ARP	4941.9
776	UT	Bonanza	7790	2014	1/22/14	10	ARP	4941.4
777	UT	Bonanza	7790	2014	2/8/14	19	ARP	4941.1
778	UT	Bonanza	7790	2014	2/8/14	18	ARP	4941
779	UT	Bonanza	7790	2014	3/19/14	9	ARP	4940.9
780	UT	Bonanza	7790	2014	1/27/14	1	ARP	4940.7
781	UT	Bonanza	7790	2014	1/18/14	10	ARP	4940.6

	A	B	C	D	E	F	G	H
782	UT	Bonanza	7790	2014	1/18/14	15	ARP	4940.5
783	UT	Bonanza	7790	2014	1/21/14	0	ARP	4940.5
784	UT	Bonanza	7790	2014	1/1/14	18	ARP	4940.2
785	UT	Bonanza	7790	2014	3/17/14	7	ARP	4940.2
786	UT	Bonanza	7790	2014	3/1/14	21	ARP	4939.4
787	UT	Bonanza	7790	2014	1/1/14	15	ARP	4938.9
788	UT	Bonanza	7790	2014	3/4/14	8	ARP	4938.8
789	UT	Bonanza	7790	2014	3/17/14	17	ARP	4938.5
790	UT	Bonanza	7790	2014	3/31/14	22	ARP	4938.4
791	UT	Bonanza	7790	2014	3/17/14	11	ARP	4938.1
792	UT	Bonanza	7790	2014	1/20/14	8	ARP	4938
793	UT	Bonanza	7790	2014	3/21/14	16	ARP	4937.6
794	UT	Bonanza	7790	2014	2/28/14	14	ARP	4937.5
795	UT	Bonanza	7790	2014	1/1/14	8	ARP	4937.1
796	UT	Bonanza	7790	2014	3/22/14	7	ARP	4936.9
797	UT	Bonanza	7790	2014	3/29/14	23	ARP	4936.8
798	UT	Bonanza	7790	2014	1/18/14	5	ARP	4936.2
799	UT	Bonanza	7790	2014	3/1/14	22	ARP	4935.9
800	UT	Bonanza	7790	2014	1/22/14	11	ARP	4935.7
801	UT	Bonanza	7790	2014	2/28/14	13	ARP	4935.7
802	UT	Bonanza	7790	2014	1/22/14	21	ARP	4935.3
803	UT	Bonanza	7790	2014	3/25/14	21	ARP	4935.1
804	UT	Bonanza	7790	2014	2/13/14	23	ARP	4935
805	UT	Bonanza	7790	2014	1/29/14	12	ARP	4934.6
806	UT	Bonanza	7790	2014	1/1/14	7	ARP	4934.4
807	UT	Bonanza	7790	2014	1/22/14	20	ARP	4934.4
808	UT	Bonanza	7790	2014	1/15/14	7	ARP	4934
809	UT	Bonanza	7790	2014	2/26/14	5	ARP	4933.9
810	UT	Bonanza	7790	2014	2/13/14	9	ARP	4933.7
811	UT	Bonanza	7790	2014	1/19/14	5	ARP	4933.5
812	UT	Bonanza	7790	2014	2/13/14	11	ARP	4933.3
813	UT	Bonanza	7790	2014	1/1/14	10	ARP	4933.1
814	UT	Bonanza	7790	2014	2/14/14	2	ARP	4932.9
815	UT	Bonanza	7790	2014	2/8/14	15	ARP	4932.8

	A	B	C	D	E	F	G	H
816	UT	Bonanza	7790	2014	3/26/14	8	ARP	4931.7
817	UT	Bonanza	7790	2014	1/20/14	22	ARP	4930.5
818	UT	Bonanza	7790	2014	3/30/14	22	ARP	4929.9
819	UT	Bonanza	7790	2014	3/21/14	15	ARP	4929.6
820	UT	Bonanza	7790	2014	3/21/14	17	ARP	4929.6
821	UT	Bonanza	7790	2014	1/22/14	1	ARP	4929.2
822	UT	Bonanza	7790	2014	1/26/14	23	ARP	4928.7
823	UT	Bonanza	7790	2014	2/28/14	20	ARP	4928.7
824	UT	Bonanza	7790	2014	3/14/14	16	ARP	4928.7
825	UT	Bonanza	7790	2014	1/6/14	8	ARP	4928.2
826	UT	Bonanza	7790	2014	2/14/14	10	ARP	4928.1
827	UT	Bonanza	7790	2014	3/21/14	6	ARP	4928.1
828	UT	Bonanza	7790	2014	1/29/14	9	ARP	4927.9
829	UT	Bonanza	7790	2014	2/13/14	16	ARP	4927.6
830	UT	Bonanza	7790	2014	2/13/14	19	ARP	4927.6
831	UT	Bonanza	7790	2014	3/19/14	6	ARP	4926.9
832	UT	Bonanza	7790	2014	1/18/14	12	ARP	4926.5
833	UT	Bonanza	7790	2014	2/14/14	3	ARP	4926
834	UT	Bonanza	7790	2014	2/13/14	18	ARP	4925.5
835	UT	Bonanza	7790	2014	3/26/14	16	ARP	4925.3
836	UT	Bonanza	7790	2014	1/29/14	14	ARP	4924.7
837	UT	Bonanza	7790	2014	1/6/14	0	ARP	4924.4
838	UT	Bonanza	7790	2014	1/6/14	2	ARP	4924.4
839	UT	Bonanza	7790	2014	1/1/14	9	ARP	4924.3
840	UT	Bonanza	7790	2014	2/17/14	18	ARP	4923.8
841	UT	Bonanza	7790	2014	1/19/14	14	ARP	4923.5
842	UT	Bonanza	7790	2014	3/31/14	13	ARP	4923.2
843	UT	Bonanza	7790	2014	1/1/14	4	ARP	4923.1
844	UT	Bonanza	7790	2014	1/29/14	11	ARP	4922.9
845	UT	Bonanza	7790	2014	1/27/14	5	ARP	4922.5
846	UT	Bonanza	7790	2014	2/13/14	5	ARP	4921.6
847	UT	Bonanza	7790	2014	2/14/14	4	ARP	4921.6
848	UT	Bonanza	7790	2014	1/29/14	17	ARP	4921.1
849	UT	Bonanza	7790	2014	3/4/14	9	ARP	4920.9

	A	B	C	D	E	F	G	H
850	UT	Bonanza	7790	2014	2/8/14	20	ARP	4920.8
851	UT	Bonanza	7790	2014	1/8/14	2	ARP	4920.3
852	UT	Bonanza	7790	2014	1/27/14	4	ARP	4919.9
853	UT	Bonanza	7790	2014	1/8/14	1	ARP	4919.4
854	UT	Bonanza	7790	2014	1/20/14	12	ARP	4919.4
855	UT	Bonanza	7790	2014	2/14/14	1	ARP	4919.4
856	UT	Bonanza	7790	2014	3/19/14	22	ARP	4919.4
857	UT	Bonanza	7790	2014	3/25/14	19	ARP	4919.2
858	UT	Bonanza	7790	2014	1/28/14	1	ARP	4919
859	UT	Bonanza	7790	2014	2/14/14	5	ARP	4919
860	UT	Bonanza	7790	2014	3/21/14	2	ARP	4918.9
861	UT	Bonanza	7790	2014	2/11/14	17	ARP	4918.7
862	UT	Bonanza	7790	2014	1/19/14	12	ARP	4918.6
863	UT	Bonanza	7790	2014	3/31/14	12	ARP	4918.5
864	UT	Bonanza	7790	2014	2/26/14	7	ARP	4917.8
865	UT	Bonanza	7790	2014	2/28/14	16	ARP	4917.8
866	UT	Bonanza	7790	2014	1/5/14	21	ARP	4917.3
867	UT	Bonanza	7790	2014	1/18/14	11	ARP	4917.2
868	UT	Bonanza	7790	2014	1/12/14	23	ARP	4916.9
869	UT	Bonanza	7790	2014	1/20/14	11	ARP	4916.9
870	UT	Bonanza	7790	2014	2/5/14	12	ARP	4916.5
871	UT	Bonanza	7790	2014	2/13/14	21	ARP	4916.1
872	UT	Bonanza	7790	2014	1/18/14	9	ARP	4915.9
873	UT	Bonanza	7790	2014	2/16/14	6	ARP	4915.6
874	UT	Bonanza	7790	2014	1/29/14	18	ARP	4915.5
875	UT	Bonanza	7790	2014	2/28/14	15	ARP	4913.9
876	UT	Bonanza	7790	2014	2/25/14	23	ARP	4913.3
877	UT	Bonanza	7790	2014	3/25/14	14	ARP	4913
878	UT	Bonanza	7790	2014	2/8/14	14	ARP	4912.7
879	UT	Bonanza	7790	2014	3/14/14	4	ARP	4912.6
880	UT	Bonanza	7790	2014	2/27/14	20	ARP	4912.5
881	UT	Bonanza	7790	2014	1/18/14	7	ARP	4912.4
882	UT	Bonanza	7790	2014	1/1/14	21	ARP	4912.1
883	UT	Bonanza	7790	2014	1/26/14	22	ARP	4912.1

	A	B	C	D	E	F	G	H
884	UT	Bonanza	7790	2014	2/13/14	10	ARP	4912.1
885	UT	Bonanza	7790	2014	1/6/14	6	ARP	4912
886	UT	Bonanza	7790	2014	1/19/14	15	ARP	4911.7
887	UT	Bonanza	7790	2014	2/25/14	21	ARP	4911.7
888	UT	Bonanza	7790	2014	2/14/14	0	ARP	4911.4
889	UT	Bonanza	7790	2014	1/12/14	21	ARP	4910.8
890	UT	Bonanza	7790	2014	1/18/14	14	ARP	4910.8
891	UT	Bonanza	7790	2014	2/28/14	5	ARP	4910.8
892	UT	Bonanza	7790	2014	3/31/14	23	ARP	4910.8
893	UT	Bonanza	7790	2014	2/26/14	18	ARP	4910.3
894	UT	Bonanza	7790	2014	3/1/14	6	ARP	4910.2
895	UT	Bonanza	7790	2014	2/28/14	19	ARP	4910
896	UT	Bonanza	7790	2014	3/21/14	18	ARP	4909.7
897	UT	Bonanza	7790	2014	2/8/14	9	ARP	4909.2
898	UT	Bonanza	7790	2014	3/12/14	13	ARP	4909.2
899	UT	Bonanza	7790	2014	1/29/14	16	ARP	4909.1
900	UT	Bonanza	7790	2014	1/3/14	6	ARP	4909
901	UT	Bonanza	7790	2014	2/13/14	22	ARP	4908.8
902	UT	Bonanza	7790	2014	3/31/14	21	ARP	4908.3
903	UT	Bonanza	7790	2014	1/27/14	9	ARP	4908.2
904	UT	Bonanza	7790	2014	1/27/14	2	ARP	4907.7
905	UT	Bonanza	7790	2014	1/2/14	20	ARP	4907.3
906	UT	Bonanza	7790	2014	1/8/14	3	ARP	4907.3
907	UT	Bonanza	7790	2014	3/3/14	4	ARP	4907.3
908	UT	Bonanza	7790	2014	1/6/14	9	ARP	4906.7
909	UT	Bonanza	7790	2014	1/8/14	5	ARP	4906.4
910	UT	Bonanza	7790	2014	3/20/14	21	ARP	4905.8
911	UT	Bonanza	7790	2014	1/6/14	3	ARP	4905.6
912	UT	Bonanza	7790	2014	1/27/14	0	ARP	4905.6
913	UT	Bonanza	7790	2014	1/29/14	4	ARP	4905.6
914	UT	Bonanza	7790	2014	3/21/14	5	ARP	4905.4
915	UT	Bonanza	7790	2014	3/22/14	2	ARP	4905.4
916	UT	Bonanza	7790	2014	1/21/14	6	ARP	4905.3
917	UT	Bonanza	7790	2014	1/22/14	12	ARP	4905.1

	A	B	C	D	E	F	G	H
918	UT	Bonanza	7790	2014	2/13/14	17	ARP	4905.1
919	UT	Bonanza	7790	2014	1/5/14	22	ARP	4904.3
920	UT	Bonanza	7790	2014	1/27/14	3	ARP	4904.3
921	UT	Bonanza	7790	2014	2/11/14	18	ARP	4904.3
922	UT	Bonanza	7790	2014	2/13/14	20	ARP	4904.1
923	UT	Bonanza	7790	2014	1/20/14	3	ARP	4904
924	UT	Bonanza	7790	2014	1/27/14	10	ARP	4903.9
925	UT	Bonanza	7790	2014	1/18/14	8	ARP	4903.6
926	UT	Bonanza	7790	2014	3/30/14	21	ARP	4903.6
927	UT	Bonanza	7790	2014	3/1/14	18	ARP	4903.4
928	UT	Bonanza	7790	2014	3/1/14	19	ARP	4903.2
929	UT	Bonanza	7790	2014	1/2/14	21	ARP	4901.6
930	UT	Bonanza	7790	2014	2/13/14	6	ARP	4901.4
931	UT	Bonanza	7790	2014	2/28/14	4	ARP	4901.2
932	UT	Bonanza	7790	2014	3/1/14	11	ARP	4901.2
933	UT	Bonanza	7790	2014	1/20/14	13	ARP	4901
934	UT	Bonanza	7790	2014	3/21/14	3	ARP	4900
935	UT	Bonanza	7790	2014	1/22/14	22	ARP	4899.9
936	UT	Bonanza	7790	2014	2/26/14	15	ARP	4899.9
937	UT	Bonanza	7790	2014	1/28/14	0	ARP	4899.5
938	UT	Bonanza	7790	2014	3/21/14	19	ARP	4899.5
939	UT	Bonanza	7790	2014	3/25/14	22	ARP	4899.5
940	UT	Bonanza	7790	2014	3/31/14	18	ARP	4899.5
941	UT	Bonanza	7790	2014	2/26/14	17	ARP	4899
942	UT	Bonanza	7790	2014	1/1/14	5	ARP	4898.5
943	UT	Bonanza	7790	2014	1/22/14	18	ARP	4898.5
944	UT	Bonanza	7790	2014	1/29/14	7	ARP	4898.5
945	UT	Bonanza	7790	2014	1/20/14	15	ARP	4898.3
946	UT	Bonanza	7790	2014	2/6/14	12	ARP	4898.2
947	UT	Bonanza	7790	2014	1/14/14	10	ARP	4897.8
948	UT	Bonanza	7790	2014	1/20/14	23	ARP	4897.7
949	UT	Bonanza	7790	2014	2/28/14	18	ARP	4897.7
950	UT	Bonanza	7790	2014	2/8/14	23	ARP	4897.6
951	UT	Bonanza	7790	2014	2/8/14	4	ARP	4896.9

	A	B	C	D	E	F	G	H
952	UT	Bonanza	7790	2014	1/27/14	22	ARP	4896.5
953	UT	Bonanza	7790	2014	3/19/14	21	ARP	4896.1
954	UT	Bonanza	7790	2014	1/1/14	20	ARP	4895.9
955	UT	Bonanza	7790	2014	1/14/14	11	ARP	4895.7
956	UT	Bonanza	7790	2014	1/22/14	6	ARP	4895.2
957	UT	Bonanza	7790	2014	1/29/14	19	ARP	4895.1
958	UT	Bonanza	7790	2014	1/6/14	22	ARP	4894.8
959	UT	Bonanza	7790	2014	2/25/14	22	ARP	4894.3
960	UT	Bonanza	7790	2014	1/5/14	20	ARP	4893.8
961	UT	Bonanza	7790	2014	1/8/14	0	ARP	4893.8
962	UT	Bonanza	7790	2014	2/9/14	2	ARP	4892.8
963	UT	Bonanza	7790	2014	1/29/14	22	ARP	4892.5
964	UT	Bonanza	7790	2014	2/8/14	11	ARP	4892.4
965	UT	Bonanza	7790	2014	1/22/14	13	ARP	4892.1
966	UT	Bonanza	7790	2014	2/14/14	6	ARP	4892.1
967	UT	Bonanza	7790	2014	3/1/14	17	ARP	4892.1
968	UT	Bonanza	7790	2014	2/8/14	21	ARP	4892
969	UT	Bonanza	7790	2014	1/14/14	9	ARP	4891.7
970	UT	Bonanza	7790	2014	1/14/14	14	ARP	4891.7
971	UT	Bonanza	7790	2014	1/22/14	14	ARP	4891.7
972	UT	Bonanza	7790	2014	2/26/14	14	ARP	4891.3
973	UT	Bonanza	7790	2014	1/15/14	14	ARP	4890.3
974	UT	Bonanza	7790	2014	2/5/14	11	ARP	4890.3
975	UT	Bonanza	7790	2014	2/28/14	17	ARP	4890.3
976	UT	Bonanza	7790	2014	2/11/14	21	ARP	4890
977	UT	Bonanza	7790	2014	2/4/14	16	ARP	4889.9
978	UT	Bonanza	7790	2014	3/31/14	14	ARP	4889.4
979	UT	Bonanza	7790	2014	2/26/14	19	ARP	4889.1
980	UT	Bonanza	7790	2014	1/14/14	17	ARP	4889
981	UT	Bonanza	7790	2014	2/27/14	14	ARP	4888.7
982	UT	Bonanza	7790	2014	2/8/14	13	ARP	4888.6
983	UT	Bonanza	7790	2014	1/15/14	16	ARP	4888.5
984	UT	Bonanza	7790	2014	2/9/14	0	ARP	4888.1
985	UT	Bonanza	7790	2014	1/6/14	21	ARP	4887.7

	A	B	C	D	E	F	G	H
986	UT	Bonanza	7790	2014	1/20/14	9	ARP	4887.7
987	UT	Bonanza	7790	2014	3/30/14	20	ARP	4887.4
988	UT	Bonanza	7790	2014	1/19/14	8	ARP	4887.3
989	UT	Bonanza	7790	2014	3/21/14	23	ARP	4887.3
990	UT	Bonanza	7790	2014	1/14/14	18	ARP	4887.2
991	UT	Bonanza	7790	2014	2/12/14	14	ARP	4886.9
992	UT	Bonanza	7790	2014	2/4/14	12	ARP	4886.8
993	UT	Bonanza	7790	2014	2/5/14	4	ARP	4886.8
994	UT	Bonanza	7790	2014	1/27/14	23	ARP	4886.5
995	UT	Bonanza	7790	2014	1/30/14	7	ARP	4885.7
996	UT	Bonanza	7790	2014	1/29/14	8	ARP	4885.4
997	UT	Bonanza	7790	2014	2/7/14	9	ARP	4885.2
998	UT	Bonanza	7790	2014	1/14/14	12	ARP	4885
999	UT	Bonanza	7790	2014	1/8/14	4	ARP	4884.7
1000	UT	Bonanza	7790	2014	2/7/14	8	ARP	4884.7
1001	UT	Bonanza	7790	2014	1/2/14	11	ARP	4884.6
1002	UT	Bonanza	7790	2014	1/19/14	9	ARP	4884.6
1003	UT	Bonanza	7790	2014	1/1/14	1	ARP	4884.3
1004	UT	Bonanza	7790	2014	1/1/14	2	ARP	4884.3
1005	UT	Bonanza	7790	2014	3/19/14	10	ARP	4884.3
1006	UT	Bonanza	7790	2014	1/17/14	3	ARP	4884.2
1007	UT	Bonanza	7790	2014	3/28/14	12	ARP	4884.2
1008	UT	Bonanza	7790	2014	1/30/14	8	ARP	4884
1009	UT	Bonanza	7790	2014	2/25/14	17	ARP	4884
1010	UT	Bonanza	7790	2014	1/3/14	11	ARP	4883.7
1011	UT	Bonanza	7790	2014	1/18/14	4	ARP	4883.7
1012	UT	Bonanza	7790	2014	2/28/14	2	ARP	4883.7
1013	UT	Bonanza	7790	2014	2/8/14	22	ARP	4883.4
1014	UT	Bonanza	7790	2014	1/14/14	16	ARP	4883.3
1015	UT	Bonanza	7790	2014	2/28/14	3	ARP	4883.3
1016	UT	Bonanza	7790	2014	2/8/14	12	ARP	4882.7
1017	UT	Bonanza	7790	2014	2/17/14	20	ARP	4882.6
1018	UT	Bonanza	7790	2014	3/22/14	5	ARP	4882.3
1019	UT	Bonanza	7790	2014	1/27/14	19	ARP	4882.2

	A	B	C	D	E	F	G	H
1020	UT	Bonanza	7790	2014	2/8/14	3	ARP	4882.2
1021	UT	Bonanza	7790	2014	3/31/14	19	ARP	4881.8
1022	UT	Bonanza	7790	2014	2/1/14	12	ARP	4881.7
1023	UT	Bonanza	7790	2014	3/22/14	4	ARP	4881.3
1024	UT	Bonanza	7790	2014	2/9/14	19	ARP	4881
1025	UT	Bonanza	7790	2014	3/4/14	6	ARP	4880.6
1026	UT	Bonanza	7790	2014	1/18/14	3	ARP	4880.2
1027	UT	Bonanza	7790	2014	1/19/14	10	ARP	4880.2
1028	UT	Bonanza	7790	2014	1/30/14	4	ARP	4879.3
1029	UT	Bonanza	7790	2014	1/26/14	21	ARP	4879.1
1030	UT	Bonanza	7790	2014	2/9/14	3	ARP	4879.1
1031	UT	Bonanza	7790	2014	2/26/14	13	ARP	4879.1
1032	UT	Bonanza	7790	2014	2/26/14	16	ARP	4879.1
1033	UT	Bonanza	7790	2014	2/27/14	19	ARP	4879.1
1034	UT	Bonanza	7790	2014	2/27/14	10	ARP	4878.7
1035	UT	Bonanza	7790	2014	1/18/14	13	ARP	4878.5
1036	UT	Bonanza	7790	2014	2/9/14	21	ARP	4878
1037	UT	Bonanza	7790	2014	1/1/14	0	ARP	4877.8
1038	UT	Bonanza	7790	2014	1/14/14	8	ARP	4877.6
1039	UT	Bonanza	7790	2014	1/22/14	17	ARP	4877.4
1040	UT	Bonanza	7790	2014	2/1/14	13	ARP	4877.4
1041	UT	Bonanza	7790	2014	2/27/14	15	ARP	4877.4
1042	UT	Bonanza	7790	2014	1/6/14	10	ARP	4877.1
1043	UT	Bonanza	7790	2014	3/1/14	12	ARP	4877
1044	UT	Bonanza	7790	2014	1/1/14	3	ARP	4876.5
1045	UT	Bonanza	7790	2014	2/6/14	19	ARP	4876.5
1046	UT	Bonanza	7790	2014	1/19/14	11	ARP	4876.3
1047	UT	Bonanza	7790	2014	2/8/14	8	ARP	4876.1
1048	UT	Bonanza	7790	2014	2/26/14	8	ARP	4876.1
1049	UT	Bonanza	7790	2014	2/26/14	11	ARP	4876.1
1050	UT	Bonanza	7790	2014	1/14/14	15	ARP	4875.9
1051	UT	Bonanza	7790	2014	2/5/14	10	ARP	4875.9
1052	UT	Bonanza	7790	2014	2/8/14	5	ARP	4875.2
1053	UT	Bonanza	7790	2014	2/27/14	16	ARP	4875.2

	A	B	C	D	E	F	G	H
1054	UT	Bonanza	7790	2014	3/30/14	0	ARP	4875.2
1055	UT	Bonanza	7790	2014	1/29/14	20	ARP	4875
1056	UT	Bonanza	7790	2014	2/25/14	16	ARP	4874.6
1057	UT	Bonanza	7790	2014	1/17/14	4	ARP	4874.5
1058	UT	Bonanza	7790	2014	1/21/14	5	ARP	4874.5
1059	UT	Bonanza	7790	2014	1/22/14	15	ARP	4874.4
1060	UT	Bonanza	7790	2014	1/22/14	16	ARP	4874.4
1061	UT	Bonanza	7790	2014	1/5/14	19	ARP	4873.7
1062	UT	Bonanza	7790	2014	1/29/14	15	ARP	4873.7
1063	UT	Bonanza	7790	2014	2/6/14	17	ARP	4873.5
1064	UT	Bonanza	7790	2014	2/9/14	17	ARP	4873.1
1065	UT	Bonanza	7790	2014	1/3/14	8	ARP	4872.8
1066	UT	Bonanza	7790	2014	1/15/14	15	ARP	4872.7
1067	UT	Bonanza	7790	2014	2/9/14	13	ARP	4872.7
1068	UT	Bonanza	7790	2014	2/27/14	8	ARP	4872.2
1069	UT	Bonanza	7790	2014	3/30/14	19	ARP	4872.1
1070	UT	Bonanza	7790	2014	1/17/14	14	ARP	4871.9
1071	UT	Bonanza	7790	2014	1/20/14	14	ARP	4871.4
1072	UT	Bonanza	7790	2014	1/30/14	9	ARP	4871.2
1073	UT	Bonanza	7790	2014	1/5/14	23	ARP	4869.6
1074	UT	Bonanza	7790	2014	2/9/14	22	ARP	4869.5
1075	UT	Bonanza	7790	2014	2/28/14	6	ARP	4869.4
1076	UT	Bonanza	7790	2014	1/3/14	9	ARP	4869.3
1077	UT	Bonanza	7790	2014	1/17/14	9	ARP	4868.8
1078	UT	Bonanza	7790	2014	2/9/14	7	ARP	4868.4
1079	UT	Bonanza	7790	2014	2/9/14	4	ARP	4868
1080	UT	Bonanza	7790	2014	3/26/14	23	ARP	4867.4
1081	UT	Bonanza	7790	2014	2/9/14	16	ARP	4867.3
1082	UT	Bonanza	7790	2014	1/14/14	20	ARP	4867.1
1083	UT	Bonanza	7790	2014	2/11/14	20	ARP	4867
1084	UT	Bonanza	7790	2014	1/14/14	19	ARP	4866.6
1085	UT	Bonanza	7790	2014	1/8/14	7	ARP	4866.5
1086	UT	Bonanza	7790	2014	1/31/14	12	ARP	4866.5
1087	UT	Bonanza	7790	2014	2/4/14	15	ARP	4866.2

	A	B	C	D	E	F	G	H
1088	UT	Bonanza	7790	2014	2/11/14	16	ARP	4866.2
1089	UT	Bonanza	7790	2014	2/2/14	1	ARP	4866.1
1090	UT	Bonanza	7790	2014	2/9/14	20	ARP	4866.1
1091	UT	Bonanza	7790	2014	2/27/14	12	ARP	4865.8
1092	UT	Bonanza	7790	2014	3/28/14	14	ARP	4865.8
1093	UT	Bonanza	7790	2014	2/9/14	18	ARP	4865.7
1094	UT	Bonanza	7790	2014	1/17/14	7	ARP	4865.3
1095	UT	Bonanza	7790	2014	2/8/14	10	ARP	4865.3
1096	UT	Bonanza	7790	2014	2/9/14	9	ARP	4865.3
1097	UT	Bonanza	7790	2014	1/15/14	5	ARP	4864.9
1098	UT	Bonanza	7790	2014	1/14/14	7	ARP	4864.8
1099	UT	Bonanza	7790	2014	1/17/14	5	ARP	4864.8
1100	UT	Bonanza	7790	2014	2/2/14	7	ARP	4864.4
1101	UT	Bonanza	7790	2014	1/2/14	19	ARP	4863.6
1102	UT	Bonanza	7790	2014	1/22/14	23	ARP	4863.5
1103	UT	Bonanza	7790	2014	1/29/14	2	ARP	4863.5
1104	UT	Bonanza	7790	2014	2/1/14	19	ARP	4863.5
1105	UT	Bonanza	7790	2014	3/1/14	13	ARP	4863.5
1106	UT	Bonanza	7790	2014	2/11/14	23	ARP	4863.1
1107	UT	Bonanza	7790	2014	3/28/14	16	ARP	4863.1
1108	UT	Bonanza	7790	2014	1/12/14	22	ARP	4862.7
1109	UT	Bonanza	7790	2014	2/26/14	12	ARP	4862.6
1110	UT	Bonanza	7790	2014	2/8/14	7	ARP	4862.3
1111	UT	Bonanza	7790	2014	2/27/14	2	ARP	4861.8
1112	UT	Bonanza	7790	2014	2/27/14	21	ARP	4861.8
1113	UT	Bonanza	7790	2014	1/17/14	15	ARP	4861.7
1114	UT	Bonanza	7790	2014	1/27/14	11	ARP	4861.5
1115	UT	Bonanza	7790	2014	2/6/14	18	ARP	4861.4
1116	UT	Bonanza	7790	2014	2/28/14	0	ARP	4861.4
1117	UT	Bonanza	7790	2014	3/16/14	3	ARP	4861.4
1118	UT	Bonanza	7790	2014	2/2/14	8	ARP	4861
1119	UT	Bonanza	7790	2014	2/27/14	0	ARP	4860.9
1120	UT	Bonanza	7790	2014	3/21/14	4	ARP	4860.4
1121	UT	Bonanza	7790	2014	2/1/14	16	ARP	4860.2

	A	B	C	D	E	F	G	H
1122	UT	Bonanza	7790	2014	2/11/14	19	ARP	4860.2
1123	UT	Bonanza	7790	2014	2/27/14	7	ARP	4860.2
1124	UT	Bonanza	7790	2014	1/17/14	10	ARP	4860
1125	UT	Bonanza	7790	2014	3/19/14	11	ARP	4860
1126	UT	Bonanza	7790	2014	2/26/14	10	ARP	4859.6
1127	UT	Bonanza	7790	2014	2/26/14	22	ARP	4859.2
1128	UT	Bonanza	7790	2014	2/6/14	13	ARP	4858.9
1129	UT	Bonanza	7790	2014	3/1/14	16	ARP	4858.9
1130	UT	Bonanza	7790	2014	1/13/14	9	ARP	4858.8
1131	UT	Bonanza	7790	2014	1/13/14	10	ARP	4858.8
1132	UT	Bonanza	7790	2014	3/9/14	14	ARP	4858.8
1133	UT	Bonanza	7790	2014	2/26/14	9	ARP	4858.7
1134	UT	Bonanza	7790	2014	1/2/14	18	ARP	4858.4
1135	UT	Bonanza	7790	2014	1/17/14	17	ARP	4858.4
1136	UT	Bonanza	7790	2014	2/5/14	5	ARP	4858.4
1137	UT	Bonanza	7790	2014	2/5/14	9	ARP	4858.4
1138	UT	Bonanza	7790	2014	2/26/14	23	ARP	4858.3
1139	UT	Bonanza	7790	2014	3/10/14	13	ARP	4858.3
1140	UT	Bonanza	7790	2014	2/26/14	20	ARP	4858
1141	UT	Bonanza	7790	2014	2/2/14	2	ARP	4857.4
1142	UT	Bonanza	7790	2014	2/26/14	6	ARP	4857.4
1143	UT	Bonanza	7790	2014	1/14/14	13	ARP	4857.1
1144	UT	Bonanza	7790	2014	1/1/14	6	ARP	4856.9
1145	UT	Bonanza	7790	2014	1/13/14	7	ARP	4855.8
1146	UT	Bonanza	7790	2014	1/7/14	23	ARP	4855.7
1147	UT	Bonanza	7790	2014	2/1/14	14	ARP	4855.5
1148	UT	Bonanza	7790	2014	1/29/14	21	ARP	4855.4
1149	UT	Bonanza	7790	2014	1/27/14	21	ARP	4855.1
1150	UT	Bonanza	7790	2014	3/22/14	3	ARP	4855.1
1151	UT	Bonanza	7790	2014	1/14/14	21	ARP	4854.9
1152	UT	Bonanza	7790	2014	2/1/14	21	ARP	4854.9
1153	UT	Bonanza	7790	2014	2/3/14	22	ARP	4854.4
1154	UT	Bonanza	7790	2014	2/12/14	7	ARP	4854.4
1155	UT	Bonanza	7790	2014	1/17/14	13	ARP	4854.3

	A	B	C	D	E	F	G	H
1156	UT	Bonanza	7790	2014	2/28/14	1	ARP	4854
1157	UT	Bonanza	7790	2014	2/12/14	0	ARP	4853.6
1158	UT	Bonanza	7790	2014	2/9/14	1	ARP	4852.9
1159	UT	Bonanza	7790	2014	2/27/14	17	ARP	4852.4
1160	UT	Bonanza	7790	2014	1/18/14	2	ARP	4852.2
1161	UT	Bonanza	7790	2014	2/6/14	8	ARP	4852.2
1162	UT	Bonanza	7790	2014	2/7/14	12	ARP	4852
1163	UT	Bonanza	7790	2014	2/9/14	8	ARP	4852
1164	UT	Bonanza	7790	2014	3/29/14	22	ARP	4852
1165	UT	Bonanza	7790	2014	2/12/14	15	ARP	4851.6
1166	UT	Bonanza	7790	2014	2/4/14	11	ARP	4851.2
1167	UT	Bonanza	7790	2014	2/26/14	21	ARP	4851.2
1168	UT	Bonanza	7790	2014	2/9/14	10	ARP	4851.1
1169	UT	Bonanza	7790	2014	2/6/14	10	ARP	4850.9
1170	UT	Bonanza	7790	2014	1/7/14	22	ARP	4850.8
1171	UT	Bonanza	7790	2014	1/18/14	6	ARP	4850.8
1172	UT	Bonanza	7790	2014	3/30/14	18	ARP	4850.7
1173	UT	Bonanza	7790	2014	1/22/14	19	ARP	4850.5
1174	UT	Bonanza	7790	2014	1/30/14	10	ARP	4850.5
1175	UT	Bonanza	7790	2014	3/31/14	20	ARP	4850.4
1176	UT	Bonanza	7790	2014	1/27/14	18	ARP	4850.3
1177	UT	Bonanza	7790	2014	3/1/14	14	ARP	4849.9
1178	UT	Bonanza	7790	2014	2/13/14	14	ARP	4849
1179	UT	Bonanza	7790	2014	3/1/14	15	ARP	4848.6
1180	UT	Bonanza	7790	2014	3/28/14	13	ARP	4848.3
1181	UT	Bonanza	7790	2014	2/1/14	11	ARP	4848.1
1182	UT	Bonanza	7790	2014	1/17/14	16	ARP	4847.9
1183	UT	Bonanza	7790	2014	1/30/14	23	ARP	4847.7
1184	UT	Bonanza	7790	2014	2/27/14	9	ARP	4847.7
1185	UT	Bonanza	7790	2014	2/7/14	7	ARP	4847.1
1186	UT	Bonanza	7790	2014	1/7/14	3	ARP	4847
1187	UT	Bonanza	7790	2014	2/6/14	23	ARP	4846.5
1188	UT	Bonanza	7790	2014	2/6/14	9	ARP	4845.7
1189	UT	Bonanza	7790	2014	2/2/14	10	ARP	4845.3

	A	B	C	D	E	F	G	H
1190	UT	Bonanza	7790	2014	2/5/14	8	ARP	4845.2
1191	UT	Bonanza	7790	2014	2/3/14	15	ARP	4844.9
1192	UT	Bonanza	7790	2014	1/13/14	8	ARP	4844.4
1193	UT	Bonanza	7790	2014	2/12/14	13	ARP	4844.4
1194	UT	Bonanza	7790	2014	2/3/14	14	ARP	4844
1195	UT	Bonanza	7790	2014	2/25/14	20	ARP	4843.9
1196	UT	Bonanza	7790	2014	2/12/14	1	ARP	4843.6
1197	UT	Bonanza	7790	2014	2/9/14	12	ARP	4843.5
1198	UT	Bonanza	7790	2014	1/7/14	1	ARP	4843.1
1199	UT	Bonanza	7790	2014	1/27/14	6	ARP	4843.1
1200	UT	Bonanza	7790	2014	2/12/14	12	ARP	4842.7
1201	UT	Bonanza	7790	2014	1/18/14	0	ARP	4842.6
1202	UT	Bonanza	7790	2014	1/27/14	20	ARP	4842.6
1203	UT	Bonanza	7790	2014	2/1/14	18	ARP	4842.6
1204	UT	Bonanza	7790	2014	3/31/14	16	ARP	4842.4
1205	UT	Bonanza	7790	2014	1/13/14	11	ARP	4842.2
1206	UT	Bonanza	7790	2014	2/27/14	22	ARP	4842.2
1207	UT	Bonanza	7790	2014	2/27/14	18	ARP	4841.7
1208	UT	Bonanza	7790	2014	1/12/14	19	ARP	4841.3
1209	UT	Bonanza	7790	2014	2/1/14	17	ARP	4840.9
1210	UT	Bonanza	7790	2014	2/2/14	3	ARP	4840.6
1211	UT	Bonanza	7790	2014	1/27/14	12	ARP	4840.1
1212	UT	Bonanza	7790	2014	1/17/14	12	ARP	4840
1213	UT	Bonanza	7790	2014	2/7/14	13	ARP	4840
1214	UT	Bonanza	7790	2014	2/9/14	5	ARP	4840
1215	UT	Bonanza	7790	2014	1/30/14	19	ARP	4839.9
1216	UT	Bonanza	7790	2014	1/15/14	4	ARP	4839.6
1217	UT	Bonanza	7790	2014	2/27/14	1	ARP	4839.5
1218	UT	Bonanza	7790	2014	1/6/14	12	ARP	4838.3
1219	UT	Bonanza	7790	2014	1/6/14	18	ARP	4838.3
1220	UT	Bonanza	7790	2014	1/17/14	21	ARP	4838.3
1221	UT	Bonanza	7790	2014	2/4/14	13	ARP	4838.3
1222	UT	Bonanza	7790	2014	2/7/14	10	ARP	4838.3
1223	UT	Bonanza	7790	2014	2/11/14	22	ARP	4838.3

	A	B	C	D	E	F	G	H
1224	UT	Bonanza	7790	2014	2/6/14	21	ARP	4837.8
1225	UT	Bonanza	7790	2014	2/2/14	5	ARP	4837.1
1226	UT	Bonanza	7790	2014	3/16/14	2	ARP	4837.1
1227	UT	Bonanza	7790	2014	1/6/14	13	ARP	4837
1228	UT	Bonanza	7790	2014	1/17/14	20	ARP	4837
1229	UT	Bonanza	7790	2014	2/9/14	14	ARP	4836.7
1230	UT	Bonanza	7790	2014	3/31/14	15	ARP	4836.6
1231	UT	Bonanza	7790	2014	2/9/14	11	ARP	4836.2
1232	UT	Bonanza	7790	2014	1/18/14	1	ARP	4836.1
1233	UT	Bonanza	7790	2014	2/27/14	3	ARP	4836.1
1234	UT	Bonanza	7790	2014	1/6/14	19	ARP	4835.2
1235	UT	Bonanza	7790	2014	1/30/14	20	ARP	4834.8
1236	UT	Bonanza	7790	2014	2/5/14	13	ARP	4834.5
1237	UT	Bonanza	7790	2014	2/3/14	20	ARP	4834
1238	UT	Bonanza	7790	2014	2/7/14	11	ARP	4834
1239	UT	Bonanza	7790	2014	1/12/14	20	ARP	4833.9
1240	UT	Bonanza	7790	2014	2/9/14	15	ARP	4833.7
1241	UT	Bonanza	7790	2014	2/5/14	22	ARP	4833.6
1242	UT	Bonanza	7790	2014	3/22/14	6	ARP	4833.5
1243	UT	Bonanza	7790	2014	1/17/14	11	ARP	4833.4
1244	UT	Bonanza	7790	2014	2/1/14	5	ARP	4833.1
1245	UT	Bonanza	7790	2014	2/6/14	22	ARP	4832.7
1246	UT	Bonanza	7790	2014	1/15/14	6	ARP	4832.5
1247	UT	Bonanza	7790	2014	1/19/14	6	ARP	4832.5
1248	UT	Bonanza	7790	2014	1/6/14	14	ARP	4832.1
1249	UT	Bonanza	7790	2014	1/7/14	0	ARP	4832.1
1250	UT	Bonanza	7790	2014	1/30/14	11	ARP	4831.9
1251	UT	Bonanza	7790	2014	2/8/14	1	ARP	4831.8
1252	UT	Bonanza	7790	2014	1/17/14	2	ARP	4831.7
1253	UT	Bonanza	7790	2014	1/30/14	3	ARP	4831.5
1254	UT	Bonanza	7790	2014	3/17/14	8	ARP	4831.5
1255	UT	Bonanza	7790	2014	1/8/14	8	ARP	4831.4
1256	UT	Bonanza	7790	2014	1/7/14	2	ARP	4831.2
1257	UT	Bonanza	7790	2014	1/29/14	23	ARP	4831

	A	B	C	D	E	F	G	H
1258	UT	Bonanza	7790	2014	1/31/14	14	ARP	4830.9
1259	UT	Bonanza	7790	2014	2/1/14	15	ARP	4830.9
1260	UT	Bonanza	7790	2014	2/6/14	14	ARP	4830.9
1261	UT	Bonanza	7790	2014	2/25/14	18	ARP	4830.6
1262	UT	Bonanza	7790	2014	1/30/14	2	ARP	4830.3
1263	UT	Bonanza	7790	2014	2/7/14	1	ARP	4830.1
1264	UT	Bonanza	7790	2014	1/8/14	9	ARP	4829.7
1265	UT	Bonanza	7790	2014	2/3/14	17	ARP	4829.6
1266	UT	Bonanza	7790	2014	1/6/14	15	ARP	4829
1267	UT	Bonanza	7790	2014	1/13/14	21	ARP	4829
1268	UT	Bonanza	7790	2014	1/30/14	21	ARP	4828.9
1269	UT	Bonanza	7790	2014	2/7/14	0	ARP	4828.8
1270	UT	Bonanza	7790	2014	1/7/14	4	ARP	4828.6
1271	UT	Bonanza	7790	2014	1/30/14	14	ARP	4828.5
1272	UT	Bonanza	7790	2014	2/27/14	23	ARP	4828.4
1273	UT	Bonanza	7790	2014	1/17/14	6	ARP	4828.2
1274	UT	Bonanza	7790	2014	3/26/14	18	ARP	4828
1275	UT	Bonanza	7790	2014	1/13/14	15	ARP	4827.5
1276	UT	Bonanza	7790	2014	1/16/14	18	ARP	4827.3
1277	UT	Bonanza	7790	2014	1/17/14	1	ARP	4827.3
1278	UT	Bonanza	7790	2014	3/28/14	15	ARP	4827.2
1279	UT	Bonanza	7790	2014	1/29/14	5	ARP	4826.7
1280	UT	Bonanza	7790	2014	2/27/14	11	ARP	4826.6
1281	UT	Bonanza	7790	2014	1/17/14	0	ARP	4826.5
1282	UT	Bonanza	7790	2014	2/2/14	0	ARP	4826.3
1283	UT	Bonanza	7790	2014	3/16/14	1	ARP	4826.3
1284	UT	Bonanza	7790	2014	2/5/14	7	ARP	4826
1285	UT	Bonanza	7790	2014	2/12/14	8	ARP	4825.6
1286	UT	Bonanza	7790	2014	1/30/14	5	ARP	4825.1
1287	UT	Bonanza	7790	2014	1/3/14	12	ARP	4824.9
1288	UT	Bonanza	7790	2014	2/4/14	10	ARP	4824.7
1289	UT	Bonanza	7790	2014	2/7/14	3	ARP	4824.5
1290	UT	Bonanza	7790	2014	2/8/14	2	ARP	4824.5
1291	UT	Bonanza	7790	2014	1/6/14	11	ARP	4824.3

	A	B	C	D	E	F	G	H
1292	UT	Bonanza	7790	2014	2/3/14	18	ARP	4824.1
1293	UT	Bonanza	7790	2014	2/6/14	2	ARP	4824.1
1294	UT	Bonanza	7790	2014	3/31/14	17	ARP	4823.6
1295	UT	Bonanza	7790	2014	1/6/14	23	ARP	4823.4
1296	UT	Bonanza	7790	2014	3/19/14	12	ARP	4823.4
1297	UT	Bonanza	7790	2014	2/12/14	3	ARP	4822.8
1298	UT	Bonanza	7790	2014	2/2/14	4	ARP	4822.3
1299	UT	Bonanza	7790	2014	1/5/14	4	ARP	4821.9
1300	UT	Bonanza	7790	2014	2/4/14	14	ARP	4821.9
1301	UT	Bonanza	7790	2014	2/12/14	4	ARP	4821.9
1302	UT	Bonanza	7790	2014	1/6/14	20	ARP	4821.7
1303	UT	Bonanza	7790	2014	1/3/14	10	ARP	4821.4
1304	UT	Bonanza	7790	2014	2/12/14	11	ARP	4821.4
1305	UT	Bonanza	7790	2014	1/30/14	16	ARP	4821.3
1306	UT	Bonanza	7790	2014	2/4/14	9	ARP	4819.5
1307	UT	Bonanza	7790	2014	2/4/14	5	ARP	4819.4
1308	UT	Bonanza	7790	2014	2/7/14	2	ARP	4819.4
1309	UT	Bonanza	7790	2014	2/6/14	20	ARP	4818.9
1310	UT	Bonanza	7790	2014	1/30/14	12	ARP	4818.3
1311	UT	Bonanza	7790	2014	2/1/14	9	ARP	4818.1
1312	UT	Bonanza	7790	2014	2/1/14	10	ARP	4817.6
1313	UT	Bonanza	7790	2014	1/30/14	18	ARP	4817.5
1314	UT	Bonanza	7790	2014	2/25/14	19	ARP	4817.5
1315	UT	Bonanza	7790	2014	1/13/14	14	ARP	4817.1
1316	UT	Bonanza	7790	2014	1/30/14	13	ARP	4817.1
1317	UT	Bonanza	7790	2014	1/30/14	6	ARP	4816.3
1318	UT	Bonanza	7790	2014	1/16/14	7	ARP	4816
1319	UT	Bonanza	7790	2014	1/17/14	8	ARP	4816
1320	UT	Bonanza	7790	2014	1/31/14	0	ARP	4815.4
1321	UT	Bonanza	7790	2014	1/13/14	22	ARP	4815.1
1322	UT	Bonanza	7790	2014	1/31/14	2	ARP	4814.5
1323	UT	Bonanza	7790	2014	1/13/14	13	ARP	4814.1
1324	UT	Bonanza	7790	2014	2/12/14	5	ARP	4814.1
1325	UT	Bonanza	7790	2014	1/30/14	1	ARP	4813.7

	A	B	C	D	E	F	G	H
1326	UT	Bonanza	7790	2014	1/3/14	13	ARP	4813.6
1327	UT	Bonanza	7790	2014	3/19/14	13	ARP	4813.3
1328	UT	Bonanza	7790	2014	1/31/14	1	ARP	4813.2
1329	UT	Bonanza	7790	2014	2/4/14	17	ARP	4813.2
1330	UT	Bonanza	7790	2014	1/13/14	23	ARP	4812.9
1331	UT	Bonanza	7790	2014	1/13/14	16	ARP	4812.8
1332	UT	Bonanza	7790	2014	1/30/14	0	ARP	4812.4
1333	UT	Bonanza	7790	2014	2/1/14	4	ARP	4812.4
1334	UT	Bonanza	7790	2014	2/1/14	20	ARP	4812.4
1335	UT	Bonanza	7790	2014	2/4/14	4	ARP	4811.2
1336	UT	Bonanza	7790	2014	2/6/14	11	ARP	4811.2
1337	UT	Bonanza	7790	2014	1/13/14	19	ARP	4811.1
1338	UT	Bonanza	7790	2014	1/16/14	9	ARP	4811.1
1339	UT	Bonanza	7790	2014	2/2/14	9	ARP	4811.1
1340	UT	Bonanza	7790	2014	2/2/14	11	ARP	4811.1
1341	UT	Bonanza	7790	2014	1/6/14	16	ARP	4810.7
1342	UT	Bonanza	7790	2014	2/12/14	9	ARP	4810.6
1343	UT	Bonanza	7790	2014	1/5/14	10	ARP	4810.2
1344	UT	Bonanza	7790	2014	2/27/14	5	ARP	4809.8
1345	UT	Bonanza	7790	2014	2/4/14	21	ARP	4809.3
1346	UT	Bonanza	7790	2014	1/16/14	17	ARP	4809
1347	UT	Bonanza	7790	2014	2/3/14	12	ARP	4809
1348	UT	Bonanza	7790	2014	2/7/14	16	ARP	4808.6
1349	UT	Bonanza	7790	2014	3/28/14	4	ARP	4808.5
1350	UT	Bonanza	7790	2014	1/16/14	12	ARP	4808.1
1351	UT	Bonanza	7790	2014	1/16/14	8	ARP	4807.7
1352	UT	Bonanza	7790	2014	1/16/14	10	ARP	4807.3
1353	UT	Bonanza	7790	2014	1/30/14	22	ARP	4807.3
1354	UT	Bonanza	7790	2014	3/27/14	23	ARP	4807.1
1355	UT	Bonanza	7790	2014	2/7/14	14	ARP	4806.8
1356	UT	Bonanza	7790	2014	1/10/14	20	ARP	4806.7
1357	UT	Bonanza	7790	2014	1/29/14	3	ARP	4806.5
1358	UT	Bonanza	7790	2014	2/1/14	7	ARP	4806
1359	UT	Bonanza	7790	2014	2/7/14	4	ARP	4806

	A	B	C	D	E	F	G	H
1360	UT	Bonanza	7790	2014	2/2/14	12	ARP	4805.9
1361	UT	Bonanza	7790	2014	2/12/14	2	ARP	4805.6
1362	UT	Bonanza	7790	2014	2/4/14	22	ARP	4805.4
1363	UT	Bonanza	7790	2014	1/30/14	15	ARP	4804.8
1364	UT	Bonanza	7790	2014	1/8/14	6	ARP	4803.7
1365	UT	Bonanza	7790	2014	2/4/14	19	ARP	4803.7
1366	UT	Bonanza	7790	2014	2/12/14	10	ARP	4803.7
1367	UT	Bonanza	7790	2014	2/3/14	19	ARP	4803.4
1368	UT	Bonanza	7790	2014	2/4/14	18	ARP	4803.3
1369	UT	Bonanza	7790	2014	2/1/14	0	ARP	4802.5
1370	UT	Bonanza	7790	2014	3/15/14	23	ARP	4801.9
1371	UT	Bonanza	7790	2014	1/7/14	21	ARP	4800.9
1372	UT	Bonanza	7790	2014	1/27/14	16	ARP	4800.9
1373	UT	Bonanza	7790	2014	2/7/14	20	ARP	4800.4
1374	UT	Bonanza	7790	2014	1/13/14	17	ARP	4800.2
1375	UT	Bonanza	7790	2014	1/17/14	23	ARP	4800.2
1376	UT	Bonanza	7790	2014	1/27/14	13	ARP	4800
1377	UT	Bonanza	7790	2014	2/5/14	1	ARP	4799.8
1378	UT	Bonanza	7790	2014	2/8/14	0	ARP	4799.6
1379	UT	Bonanza	7790	2014	3/31/14	3	ARP	4799.5
1380	UT	Bonanza	7790	2014	2/2/14	17	ARP	4799.1
1381	UT	Bonanza	7790	2014	2/2/14	23	ARP	4799.1
1382	UT	Bonanza	7790	2014	3/30/14	23	ARP	4799.1
1383	UT	Bonanza	7790	2014	2/2/14	13	ARP	4798.5
1384	UT	Bonanza	7790	2014	2/27/14	4	ARP	4797.9
1385	UT	Bonanza	7790	2014	2/3/14	13	ARP	4797.4
1386	UT	Bonanza	7790	2014	2/3/14	16	ARP	4797.4
1387	UT	Bonanza	7790	2014	2/5/14	2	ARP	4797.2
1388	UT	Bonanza	7790	2014	1/5/14	9	ARP	4796.3
1389	UT	Bonanza	7790	2014	1/8/14	10	ARP	4796.3
1390	UT	Bonanza	7790	2014	1/10/14	21	ARP	4796.3
1391	UT	Bonanza	7790	2014	2/6/14	7	ARP	4796.1
1392	UT	Bonanza	7790	2014	2/7/14	23	ARP	4796.1
1393	UT	Bonanza	7790	2014	2/5/14	3	ARP	4795.9

	A	B	C	D	E	F	G	H
1394	UT	Bonanza	7790	2014	2/4/14	20	ARP	4795.5
1395	UT	Bonanza	7790	2014	1/5/14	7	ARP	4795
1396	UT	Bonanza	7790	2014	1/16/14	11	ARP	4795
1397	UT	Bonanza	7790	2014	2/8/14	6	ARP	4795
1398	UT	Bonanza	7790	2014	1/5/14	1	ARP	4794
1399	UT	Bonanza	7790	2014	2/1/14	23	ARP	4793.5
1400	UT	Bonanza	7790	2014	2/5/14	14	ARP	4793.5
1401	UT	Bonanza	7790	2014	2/1/14	2	ARP	4792.7
1402	UT	Bonanza	7790	2014	3/6/14	8	ARP	4792.4
1403	UT	Bonanza	7790	2014	2/3/14	4	ARP	4792.3
1404	UT	Bonanza	7790	2014	2/1/14	22	ARP	4791.8
1405	UT	Bonanza	7790	2014	3/19/14	20	ARP	4791.3
1406	UT	Bonanza	7790	2014	1/7/14	5	ARP	4791.1
1407	UT	Bonanza	7790	2014	2/3/14	8	ARP	4791
1408	UT	Bonanza	7790	2014	2/7/14	22	ARP	4791
1409	UT	Bonanza	7790	2014	1/13/14	6	ARP	4789.9
1410	UT	Bonanza	7790	2014	1/5/14	8	ARP	4789.8
1411	UT	Bonanza	7790	2014	1/15/14	3	ARP	4789.3
1412	UT	Bonanza	7790	2014	1/15/14	18	ARP	4789
1413	UT	Bonanza	7790	2014	2/1/14	1	ARP	4788.9
1414	UT	Bonanza	7790	2014	2/6/14	5	ARP	4788.8
1415	UT	Bonanza	7790	2014	1/5/14	11	ARP	4788.5
1416	UT	Bonanza	7790	2014	1/17/14	22	ARP	4788.5
1417	UT	Bonanza	7790	2014	1/5/14	18	ARP	4788.1
1418	UT	Bonanza	7790	2014	2/2/14	19	ARP	4788
1419	UT	Bonanza	7790	2014	2/7/14	17	ARP	4787.6
1420	UT	Bonanza	7790	2014	2/6/14	3	ARP	4787.5
1421	UT	Bonanza	7790	2014	1/5/14	17	ARP	4787.2
1422	UT	Bonanza	7790	2014	1/13/14	12	ARP	4787.2
1423	UT	Bonanza	7790	2014	1/13/14	18	ARP	4787.2
1424	UT	Bonanza	7790	2014	1/13/14	20	ARP	4787.2
1425	UT	Bonanza	7790	2014	1/27/14	14	ARP	4787.2
1426	UT	Bonanza	7790	2014	1/14/14	6	ARP	4786.3
1427	UT	Bonanza	7790	2014	2/3/14	23	ARP	4785.3

	A	B	C	D	E	F	G	H
1428	UT	Bonanza	7790	2014	1/6/14	17	ARP	4785
1429	UT	Bonanza	7790	2014	2/1/14	8	ARP	4784.9
1430	UT	Bonanza	7790	2014	2/6/14	1	ARP	4784.9
1431	UT	Bonanza	7790	2014	1/10/14	19	ARP	4784.6
1432	UT	Bonanza	7790	2014	1/8/14	11	ARP	4784.5
1433	UT	Bonanza	7790	2014	1/16/14	19	ARP	4784.2
1434	UT	Bonanza	7790	2014	1/7/14	7	ARP	4782.9
1435	UT	Bonanza	7790	2014	1/5/14	16	ARP	4782
1436	UT	Bonanza	7790	2014	2/27/14	13	ARP	4781.6
1437	UT	Bonanza	7790	2014	2/2/14	20	ARP	4781.5
1438	UT	Bonanza	7790	2014	1/16/14	20	ARP	4781.1
1439	UT	Bonanza	7790	2014	1/16/14	15	ARP	4780.7
1440	UT	Bonanza	7790	2014	2/2/14	18	ARP	4780.6
1441	UT	Bonanza	7790	2014	1/29/14	6	ARP	4780.2
1442	UT	Bonanza	7790	2014	2/2/14	21	ARP	4780.2
1443	UT	Bonanza	7790	2014	2/4/14	7	ARP	4780.2
1444	UT	Bonanza	7790	2014	1/12/14	18	ARP	4779.4
1445	UT	Bonanza	7790	2014	2/5/14	16	ARP	4779.4
1446	UT	Bonanza	7790	2014	1/27/14	15	ARP	4779.1
1447	UT	Bonanza	7790	2014	2/7/14	21	ARP	4778.5
1448	UT	Bonanza	7790	2014	3/29/14	2	ARP	4778.4
1449	UT	Bonanza	7790	2014	1/31/14	3	ARP	4777.8
1450	UT	Bonanza	7790	2014	1/7/14	18	ARP	4777.2
1451	UT	Bonanza	7790	2014	2/3/14	9	ARP	4777.2
1452	UT	Bonanza	7790	2014	2/7/14	15	ARP	4776.9
1453	UT	Bonanza	7790	2014	2/4/14	2	ARP	4776.8
1454	UT	Bonanza	7790	2014	2/5/14	0	ARP	4776.8
1455	UT	Bonanza	7790	2014	2/7/14	5	ARP	4776.8
1456	UT	Bonanza	7790	2014	2/12/14	6	ARP	4776.3
1457	UT	Bonanza	7790	2014	1/27/14	17	ARP	4775.7
1458	UT	Bonanza	7790	2014	2/27/14	6	ARP	4774.7
1459	UT	Bonanza	7790	2014	2/2/14	15	ARP	4774.2
1460	UT	Bonanza	7790	2014	1/17/14	19	ARP	4774
1461	UT	Bonanza	7790	2014	1/7/14	20	ARP	4773.8

	A	B	C	D	E	F	G	H
1462	UT	Bonanza	7790	2014	1/31/14	23	ARP	4773.5
1463	UT	Bonanza	7790	2014	2/1/14	3	ARP	4773.1
1464	UT	Bonanza	7790	2014	2/4/14	3	ARP	4772.9
1465	UT	Bonanza	7790	2014	3/14/14	0	ARP	4772.9
1466	UT	Bonanza	7790	2014	1/31/14	4	ARP	4772.7
1467	UT	Bonanza	7790	2014	1/16/14	23	ARP	4772.5
1468	UT	Bonanza	7790	2014	1/10/14	11	ARP	4771.6
1469	UT	Bonanza	7790	2014	2/3/14	21	ARP	4771.6
1470	UT	Bonanza	7790	2014	1/16/14	16	ARP	4770.7
1471	UT	Bonanza	7790	2014	1/5/14	3	ARP	4769.9
1472	UT	Bonanza	7790	2014	2/6/14	0	ARP	4769.9
1473	UT	Bonanza	7790	2014	2/9/14	6	ARP	4769.5
1474	UT	Bonanza	7790	2014	2/7/14	18	ARP	4769.3
1475	UT	Bonanza	7790	2014	2/7/14	19	ARP	4769
1476	UT	Bonanza	7790	2014	3/14/14	19	ARP	4768.6
1477	UT	Bonanza	7790	2014	1/16/14	5	ARP	4767.7
1478	UT	Bonanza	7790	2014	1/16/14	14	ARP	4767.7
1479	UT	Bonanza	7790	2014	1/4/14	7	ARP	4767.3
1480	UT	Bonanza	7790	2014	2/5/14	20	ARP	4766.9
1481	UT	Bonanza	7790	2014	1/11/14	14	ARP	4766.3
1482	UT	Bonanza	7790	2014	2/4/14	23	ARP	4765.6
1483	UT	Bonanza	7790	2014	2/2/14	16	ARP	4765
1484	UT	Bonanza	7790	2014	1/5/14	2	ARP	4764.7
1485	UT	Bonanza	7790	2014	2/6/14	4	ARP	4764.7
1486	UT	Bonanza	7790	2014	1/7/14	19	ARP	4764.2
1487	UT	Bonanza	7790	2014	1/10/14	12	ARP	4763.9
1488	UT	Bonanza	7790	2014	2/5/14	17	ARP	4763.9
1489	UT	Bonanza	7790	2014	2/4/14	1	ARP	4763.4
1490	UT	Bonanza	7790	2014	2/4/14	8	ARP	4763.4
1491	UT	Bonanza	7790	2014	2/6/14	15	ARP	4762.5
1492	UT	Bonanza	7790	2014	2/2/14	14	ARP	4762.2
1493	UT	Bonanza	7790	2014	1/5/14	12	ARP	4761.3
1494	UT	Bonanza	7790	2014	2/5/14	21	ARP	4761.3
1495	UT	Bonanza	7790	2014	1/5/14	13	ARP	4760.9

	A	B	C	D	E	F	G	H
1496	UT	Bonanza	7790	2014	1/8/14	12	ARP	4760.9
1497	UT	Bonanza	7790	2014	1/7/14	17	ARP	4760.3
1498	UT	Bonanza	7790	2014	1/31/14	5	ARP	4760.3
1499	UT	Bonanza	7790	2014	2/4/14	0	ARP	4760.3
1500	UT	Bonanza	7790	2014	2/3/14	0	ARP	4759.6
1501	UT	Bonanza	7790	2014	2/5/14	23	ARP	4759.6
1502	UT	Bonanza	7790	2014	2/5/14	6	ARP	4759.1
1503	UT	Bonanza	7790	2014	1/5/14	5	ARP	4758.7
1504	UT	Bonanza	7790	2014	1/10/14	7	ARP	4758.7
1505	UT	Bonanza	7790	2014	1/31/14	22	ARP	4758.3
1506	UT	Bonanza	7790	2014	3/14/14	3	ARP	4758.1
1507	UT	Bonanza	7790	2014	1/7/14	16	ARP	4757.7
1508	UT	Bonanza	7790	2014	2/3/14	1	ARP	4757
1509	UT	Bonanza	7790	2014	2/3/14	7	ARP	4756.6
1510	UT	Bonanza	7790	2014	1/16/14	13	ARP	4754.3
1511	UT	Bonanza	7790	2014	2/2/14	22	ARP	4753.9
1512	UT	Bonanza	7790	2014	1/7/14	12	ARP	4753
1513	UT	Bonanza	7790	2014	1/3/14	22	ARP	4748.4
1514	UT	Bonanza	7790	2014	1/15/14	20	ARP	4747.6
1515	UT	Bonanza	7790	2014	2/5/14	19	ARP	4746.7
1516	UT	Bonanza	7790	2014	2/2/14	6	ARP	4746.5
1517	UT	Bonanza	7790	2014	1/12/14	17	ARP	4745.4
1518	UT	Bonanza	7790	2014	1/15/14	19	ARP	4745.4
1519	UT	Bonanza	7790	2014	1/8/14	13	ARP	4744.9
1520	UT	Bonanza	7790	2014	1/10/14	10	ARP	4744.5
1521	UT	Bonanza	7790	2014	1/5/14	14	ARP	4744.1
1522	UT	Bonanza	7790	2014	3/15/14	18	ARP	4744.1
1523	UT	Bonanza	7790	2014	1/7/14	8	ARP	4743.8
1524	UT	Bonanza	7790	2014	2/1/14	6	ARP	4741.7
1525	UT	Bonanza	7790	2014	1/15/14	21	ARP	4741.1
1526	UT	Bonanza	7790	2014	1/7/14	14	ARP	4740.9
1527	UT	Bonanza	7790	2014	1/7/14	6	ARP	4739.7
1528	UT	Bonanza	7790	2014	1/3/14	18	ARP	4739.4
1529	UT	Bonanza	7790	2014	1/5/14	15	ARP	4739

	A	B	C	D	E	F	G	H
1530	UT	Bonanza	7790	2014	1/4/14	21	ARP	4737.2
1531	UT	Bonanza	7790	2014	1/15/14	17	ARP	4735.2
1532	UT	Bonanza	7790	2014	1/12/14	16	ARP	4735.1
1533	UT	Bonanza	7790	2014	1/3/14	14	ARP	4734.7
1534	UT	Bonanza	7790	2014	1/31/14	20	ARP	4734.6
1535	UT	Bonanza	7790	2014	1/7/14	15	ARP	4734.3
1536	UT	Bonanza	7790	2014	2/3/14	11	ARP	4733.9
1537	UT	Bonanza	7790	2014	1/4/14	3	ARP	4733.5
1538	UT	Bonanza	7790	2014	3/11/14	1	ARP	4733.5
1539	UT	Bonanza	7790	2014	1/3/14	15	ARP	4732.9
1540	UT	Bonanza	7790	2014	1/7/14	10	ARP	4732.6
1541	UT	Bonanza	7790	2014	1/11/14	13	ARP	4732.6
1542	UT	Bonanza	7790	2014	1/4/14	8	ARP	4729.5
1543	UT	Bonanza	7790	2014	1/31/14	21	ARP	4729.1
1544	UT	Bonanza	7790	2014	1/4/14	11	ARP	4728.2
1545	UT	Bonanza	7790	2014	1/31/14	19	ARP	4727.9
1546	UT	Bonanza	7790	2014	1/3/14	19	ARP	4727.7
1547	UT	Bonanza	7790	2014	1/16/14	6	ARP	4726.9
1548	UT	Bonanza	7790	2014	3/26/14	4	ARP	4726.7
1549	UT	Bonanza	7790	2014	2/3/14	5	ARP	4726.2
1550	UT	Bonanza	7790	2014	3/14/14	20	ARP	4726.1
1551	UT	Bonanza	7790	2014	3/10/14	15	ARP	4725.6
1552	UT	Bonanza	7790	2014	1/31/14	7	ARP	4725.3
1553	UT	Bonanza	7790	2014	3/6/14	15	ARP	4723
1554	UT	Bonanza	7790	2014	1/31/14	8	ARP	4722.8
1555	UT	Bonanza	7790	2014	3/16/14	0	ARP	4722.6
1556	UT	Bonanza	7790	2014	3/6/14	6	ARP	4721.6
1557	UT	Bonanza	7790	2014	1/3/14	16	ARP	4720.9
1558	UT	Bonanza	7790	2014	1/4/14	10	ARP	4720
1559	UT	Bonanza	7790	2014	3/12/14	17	ARP	4719
1560	UT	Bonanza	7790	2014	1/12/14	7	ARP	4718.5
1561	UT	Bonanza	7790	2014	2/3/14	3	ARP	4718.1
1562	UT	Bonanza	7790	2014	1/3/14	20	ARP	4717.1
1563	UT	Bonanza	7790	2014	2/4/14	6	ARP	4716.5

	A	B	C	D	E	F	G	H
1564	UT	Bonanza	7790	2014	2/7/14	6	ARP	4716.5
1565	UT	Bonanza	7790	2014	1/14/14	1	ARP	4715.9
1566	UT	Bonanza	7790	2014	1/4/14	0	ARP	4714.7
1567	UT	Bonanza	7790	2014	1/4/14	22	ARP	4713.9
1568	UT	Bonanza	7790	2014	1/31/14	15	ARP	4713.9
1569	UT	Bonanza	7790	2014	1/4/14	9	ARP	4713.2
1570	UT	Bonanza	7790	2014	1/7/14	13	ARP	4713.2
1571	UT	Bonanza	7790	2014	1/11/14	19	ARP	4712.7
1572	UT	Bonanza	7790	2014	1/5/14	6	ARP	4712.4
1573	UT	Bonanza	7790	2014	1/5/14	0	ARP	4711.3
1574	UT	Bonanza	7790	2014	1/8/14	21	ARP	4711.3
1575	UT	Bonanza	7790	2014	1/14/14	0	ARP	4710.9
1576	UT	Bonanza	7790	2014	1/4/14	13	ARP	4710.1
1577	UT	Bonanza	7790	2014	1/4/14	23	ARP	4710
1578	UT	Bonanza	7790	2014	1/4/14	4	ARP	4709.6
1579	UT	Bonanza	7790	2014	2/6/14	6	ARP	4709.2
1580	UT	Bonanza	7790	2014	1/4/14	12	ARP	4708.8
1581	UT	Bonanza	7790	2014	1/4/14	19	ARP	4707.9
1582	UT	Bonanza	7790	2014	1/31/14	10	ARP	4707.9
1583	UT	Bonanza	7790	2014	1/4/14	5	ARP	4706.6
1584	UT	Bonanza	7790	2014	1/4/14	16	ARP	4706.3
1585	UT	Bonanza	7790	2014	1/4/14	2	ARP	4706.2
1586	UT	Bonanza	7790	2014	1/4/14	18	ARP	4705.7
1587	UT	Bonanza	7790	2014	2/3/14	2	ARP	4704.9
1588	UT	Bonanza	7790	2014	1/12/14	15	ARP	4703.6
1589	UT	Bonanza	7790	2014	1/7/14	11	ARP	4703.3
1590	UT	Bonanza	7790	2014	1/4/14	17	ARP	4702.7
1591	UT	Bonanza	7790	2014	1/4/14	20	ARP	4702.7
1592	UT	Bonanza	7790	2014	1/8/14	14	ARP	4702.3
1593	UT	Bonanza	7790	2014	1/30/14	17	ARP	4702.3
1594	UT	Bonanza	7790	2014	1/16/14	4	ARP	4700.9
1595	UT	Bonanza	7790	2014	2/5/14	15	ARP	4700.8
1596	UT	Bonanza	7790	2014	1/31/14	11	ARP	4700.2
1597	UT	Bonanza	7790	2014	1/31/14	9	ARP	4699.8

	A	B	C	D	E	F	G	H
1598	UT	Bonanza	7790	2014	1/12/14	8	ARP	4698.5
1599	UT	Bonanza	7790	2014	1/3/14	21	ARP	4698.1
1600	UT	Bonanza	7790	2014	1/31/14	6	ARP	4697.9
1601	UT	Bonanza	7790	2014	1/11/14	18	ARP	4695.5
1602	UT	Bonanza	7790	2014	1/31/14	18	ARP	4695.3
1603	UT	Bonanza	7790	2014	3/17/14	10	ARP	4695.3
1604	UT	Bonanza	7790	2014	1/8/14	15	ARP	4694.7
1605	UT	Bonanza	7790	2014	1/10/14	8	ARP	4694.7
1606	UT	Bonanza	7790	2014	1/12/14	13	ARP	4694.7
1607	UT	Bonanza	7790	2014	2/15/14	8	ARP	4694
1608	UT	Bonanza	7790	2014	1/7/14	9	ARP	4693.4
1609	UT	Bonanza	7790	2014	1/12/14	10	ARP	4693.4
1610	UT	Bonanza	7790	2014	2/5/14	18	ARP	4692.5
1611	UT	Bonanza	7790	2014	2/12/14	16	ARP	4692.3
1612	UT	Bonanza	7790	2014	1/12/14	9	ARP	4692.1
1613	UT	Bonanza	7790	2014	1/12/14	14	ARP	4690.8
1614	UT	Bonanza	7790	2014	1/21/14	4	ARP	4690.8
1615	UT	Bonanza	7790	2014	3/10/14	16	ARP	4690.4
1616	UT	Bonanza	7790	2014	1/4/14	6	ARP	4688.8
1617	UT	Bonanza	7790	2014	1/12/14	12	ARP	4688.7
1618	UT	Bonanza	7790	2014	1/15/14	2	ARP	4688.4
1619	UT	Bonanza	7790	2014	1/8/14	16	ARP	4688.3
1620	UT	Bonanza	7790	2014	1/8/14	18	ARP	4686.1
1621	UT	Bonanza	7790	2014	1/3/14	17	ARP	4685.7
1622	UT	Bonanza	7790	2014	1/4/14	1	ARP	4685.7
1623	UT	Bonanza	7790	2014	1/12/14	11	ARP	4685.7
1624	UT	Bonanza	7790	2014	3/15/14	11	ARP	4685.3
1625	UT	Bonanza	7790	2014	2/13/14	15	ARP	4684.9
1626	UT	Bonanza	7790	2014	1/21/14	2	ARP	4681.8
1627	UT	Bonanza	7790	2014	1/4/14	14	ARP	4679.7
1628	UT	Bonanza	7790	2014	1/9/14	3	ARP	4679.7
1629	UT	Bonanza	7790	2014	2/3/14	6	ARP	4678.4
1630	UT	Bonanza	7790	2014	1/9/14	4	ARP	4678.1
1631	UT	Bonanza	7790	2014	3/25/14	18	ARP	4677.6

	A	B	C	D	E	F	G	H
1632	UT	Bonanza	7790	2014	1/8/14	22	ARP	4676.3
1633	UT	Bonanza	7790	2014	1/4/14	15	ARP	4674.6
1634	UT	Bonanza	7790	2014	1/8/14	20	ARP	4674.6
1635	UT	Bonanza	7790	2014	1/3/14	23	ARP	4674.2
1636	UT	Bonanza	7790	2014	1/31/14	17	ARP	4673.7
1637	UT	Bonanza	7790	2014	1/8/14	19	ARP	4673.3
1638	UT	Bonanza	7790	2014	1/9/14	1	ARP	4671.2
1639	UT	Bonanza	7790	2014	1/9/14	2	ARP	4670.3
1640	UT	Bonanza	7790	2014	1/9/14	7	ARP	4670.3
1641	UT	Bonanza	7790	2014	2/6/14	16	ARP	4670
1642	UT	Bonanza	7790	2014	3/12/14	18	ARP	4668.3
1643	UT	Bonanza	7790	2014	3/13/14	19	ARP	4668.2
1644	UT	Bonanza	7790	2014	1/8/14	17	ARP	4667.8
1645	UT	Bonanza	7790	2014	1/20/14	4	ARP	4665.6
1646	UT	Bonanza	7790	2014	1/8/14	23	ARP	4661.8
1647	UT	Bonanza	7790	2014	1/31/14	16	ARP	4660.6
1648	UT	Bonanza	7790	2014	2/3/14	10	ARP	4658.5
1649	UT	Bonanza	7790	2014	1/9/14	9	ARP	4654.1
1650	UT	Bonanza	7790	2014	3/14/14	14	ARP	4653.3
1651	UT	Bonanza	7790	2014	1/21/14	3	ARP	4651.2
1652	UT	Bonanza	7790	2014	1/9/14	21	ARP	4648.6
1653	UT	Bonanza	7790	2014	1/10/14	6	ARP	4645.9
1654	UT	Bonanza	7790	2014	1/9/14	5	ARP	4643.9
1655	UT	Bonanza	7790	2014	1/9/14	0	ARP	4642.7
1656	UT	Bonanza	7790	2014	1/9/14	20	ARP	4641.3
1657	UT	Bonanza	7790	2014	1/9/14	23	ARP	4640.1
1658	UT	Bonanza	7790	2014	1/9/14	19	ARP	4639.7
1659	UT	Bonanza	7790	2014	1/14/14	23	ARP	4634.6
1660	UT	Bonanza	7790	2014	3/12/14	14	ARP	4631.7
1661	UT	Bonanza	7790	2014	2/20/14	14	ARP	4629.9
1662	UT	Bonanza	7790	2014	1/9/14	8	ARP	4624.7
1663	UT	Bonanza	7790	2014	3/16/14	12	ARP	4623.6
1664	UT	Bonanza	7790	2014	3/13/14	20	ARP	4618.6
1665	UT	Bonanza	7790	2014	2/20/14	12	ARP	4617.8

	A	B	C	D	E	F	G	H
1666	UT	Bonanza	7790	2014	2/23/14	7	ARP	4616.7
1667	UT	Bonanza	7790	2014	1/10/14	18	ARP	4616.4
1668	UT	Bonanza	7790	2014	1/9/14	11	ARP	4615.3
1669	UT	Bonanza	7790	2014	2/23/14	2	ARP	4614.5
1670	UT	Bonanza	7790	2014	1/9/14	10	ARP	4612
1671	UT	Bonanza	7790	2014	3/14/14	15	ARP	4611
1672	UT	Bonanza	7790	2014	1/9/14	12	ARP	4610.3
1673	UT	Bonanza	7790	2014	2/22/14	23	ARP	4610.1
1674	UT	Bonanza	7790	2014	2/20/14	10	ARP	4609.3
1675	UT	Bonanza	7790	2014	3/11/14	5	ARP	4608.6
1676	UT	Bonanza	7790	2014	2/22/14	20	ARP	4608.3
1677	UT	Bonanza	7790	2014	1/16/14	21	ARP	4605.6
1678	UT	Bonanza	7790	2014	2/23/14	1	ARP	4605.3
1679	UT	Bonanza	7790	2014	1/25/14	7	ARP	4604
1680	UT	Bonanza	7790	2014	1/9/14	13	ARP	4603.1
1681	UT	Bonanza	7790	2014	2/20/14	13	ARP	4602.4
1682	UT	Bonanza	7790	2014	2/20/14	21	ARP	4601.1
1683	UT	Bonanza	7790	2014	3/29/14	5	ARP	4600.7
1684	UT	Bonanza	7790	2014	1/9/14	18	ARP	4598.9
1685	UT	Bonanza	7790	2014	1/15/14	22	ARP	4598.9
1686	UT	Bonanza	7790	2014	3/30/14	17	ARP	4598.5
1687	UT	Bonanza	7790	2014	2/22/14	22	ARP	4596.9
1688	UT	Bonanza	7790	2014	2/19/14	23	ARP	4596.5
1689	UT	Bonanza	7790	2014	2/20/14	17	ARP	4596.3
1690	UT	Bonanza	7790	2014	2/23/14	5	ARP	4596.1
1691	UT	Bonanza	7790	2014	2/20/14	9	ARP	4595.8
1692	UT	Bonanza	7790	2014	2/20/14	1	ARP	4595.3
1693	UT	Bonanza	7790	2014	3/17/14	6	ARP	4593.4
1694	UT	Bonanza	7790	2014	2/20/14	20	ARP	4591.3
1695	UT	Bonanza	7790	2014	2/22/14	21	ARP	4591.2
1696	UT	Bonanza	7790	2014	1/10/14	0	ARP	4591.1
1697	UT	Bonanza	7790	2014	2/23/14	10	ARP	4590.8
1698	UT	Bonanza	7790	2014	3/17/14	15	ARP	4589.3
1699	UT	Bonanza	7790	2014	2/20/14	11	ARP	4588.2

	A	B	C	D	E	F	G	H
1700	UT	Bonanza	7790	2014	1/13/14	0	ARP	4587.8
1701	UT	Bonanza	7790	2014	1/9/14	16	ARP	4586.6
1702	UT	Bonanza	7790	2014	1/10/14	9	ARP	4585.5
1703	UT	Bonanza	7790	2014	2/20/14	2	ARP	4583.8
1704	UT	Bonanza	7790	2014	1/9/14	14	ARP	4583.2
1705	UT	Bonanza	7790	2014	1/9/14	15	ARP	4583.2
1706	UT	Bonanza	7790	2014	3/29/14	4	ARP	4583.1
1707	UT	Bonanza	7790	2014	1/16/14	22	ARP	4580.9
1708	UT	Bonanza	7790	2014	2/23/14	3	ARP	4580.1
1709	UT	Bonanza	7790	2014	2/23/14	12	ARP	4580.1
1710	UT	Bonanza	7790	2014	2/23/14	11	ARP	4579.3
1711	UT	Bonanza	7790	2014	2/20/14	19	ARP	4578.5
1712	UT	Bonanza	7790	2014	1/9/14	17	ARP	4578.1
1713	UT	Bonanza	7790	2014	1/25/14	5	ARP	4577.3
1714	UT	Bonanza	7790	2014	2/20/14	22	ARP	4577.1
1715	UT	Bonanza	7790	2014	1/10/14	17	ARP	4576
1716	UT	Bonanza	7790	2014	2/24/14	23	ARP	4574.8
1717	UT	Bonanza	7790	2014	2/23/14	13	ARP	4574.7
1718	UT	Bonanza	7790	2014	2/25/14	14	ARP	4574.4
1719	UT	Bonanza	7790	2014	2/24/14	22	ARP	4573.9
1720	UT	Bonanza	7790	2014	2/20/14	7	ARP	4573.5
1721	UT	Bonanza	7790	2014	2/20/14	15	ARP	4573.1
1722	UT	Bonanza	7790	2014	2/20/14	0	ARP	4572.2
1723	UT	Bonanza	7790	2014	3/19/14	15	ARP	4572.2
1724	UT	Bonanza	7790	2014	2/23/14	9	ARP	4571.8
1725	UT	Bonanza	7790	2014	2/23/14	0	ARP	4571.2
1726	UT	Bonanza	7790	2014	2/23/14	8	ARP	4570.9
1727	UT	Bonanza	7790	2014	1/2/14	15	ARP	4568.7
1728	UT	Bonanza	7790	2014	1/12/14	6	ARP	4568.4
1729	UT	Bonanza	7790	2014	1/25/14	4	ARP	4567.7
1730	UT	Bonanza	7790	2014	3/4/14	2	ARP	4567.3
1731	UT	Bonanza	7790	2014	1/9/14	6	ARP	4566.7
1732	UT	Bonanza	7790	2014	1/25/14	2	ARP	4565.6
1733	UT	Bonanza	7790	2014	3/7/14	6	ARP	4564.8

	A	B	C	D	E	F	G	H
1734	UT	Bonanza	7790	2014	3/4/14	3	ARP	4561.6
1735	UT	Bonanza	7790	2014	1/25/14	3	ARP	4560.3
1736	UT	Bonanza	7790	2014	1/14/14	2	ARP	4556.2
1737	UT	Bonanza	7790	2014	2/23/14	20	ARP	4555.5
1738	UT	Bonanza	7790	2014	2/20/14	3	ARP	4554.9
1739	UT	Bonanza	7790	2014	3/21/14	1	ARP	4554.9
1740	UT	Bonanza	7790	2014	2/20/14	8	ARP	4552.5
1741	UT	Bonanza	7790	2014	2/22/14	19	ARP	4551.6
1742	UT	Bonanza	7790	2014	1/10/14	13	ARP	4551
1743	UT	Bonanza	7790	2014	2/20/14	18	ARP	4550.9
1744	UT	Bonanza	7790	2014	2/23/14	4	ARP	4550.2
1745	UT	Bonanza	7790	2014	2/24/14	18	ARP	4550.1
1746	UT	Bonanza	7790	2014	2/20/14	4	ARP	4548.7
1747	UT	Bonanza	7790	2014	2/19/14	21	ARP	4548.5
1748	UT	Bonanza	7790	2014	2/20/14	23	ARP	4547.1
1749	UT	Bonanza	7790	2014	2/22/14	17	ARP	4547.1
1750	UT	Bonanza	7790	2014	2/23/14	14	ARP	4545.4
1751	UT	Bonanza	7790	2014	3/30/14	1	ARP	4545.4
1752	UT	Bonanza	7790	2014	2/21/14	1	ARP	4543.2
1753	UT	Bonanza	7790	2014	2/22/14	18	ARP	4542.7
1754	UT	Bonanza	7790	2014	3/17/14	16	ARP	4542.5
1755	UT	Bonanza	7790	2014	2/20/14	5	ARP	4542
1756	UT	Bonanza	7790	2014	1/9/14	22	ARP	4541.6
1757	UT	Bonanza	7790	2014	1/24/14	7	ARP	4539.6
1758	UT	Bonanza	7790	2014	1/11/14	3	ARP	4539
1759	UT	Bonanza	7790	2014	1/25/14	1	ARP	4538.8
1760	UT	Bonanza	7790	2014	2/24/14	20	ARP	4538.6
1761	UT	Bonanza	7790	2014	1/11/14	9	ARP	4538.4
1762	UT	Bonanza	7790	2014	3/21/14	0	ARP	4537.5
1763	UT	Bonanza	7790	2014	2/23/14	6	ARP	4536.7
1764	UT	Bonanza	7790	2014	1/24/14	4	ARP	4536.2
1765	UT	Bonanza	7790	2014	2/19/14	19	ARP	4536.1
1766	UT	Bonanza	7790	2014	2/19/14	22	ARP	4535.6
1767	UT	Bonanza	7790	2014	1/26/14	7	ARP	4534.9

	A	B	C	D	E	F	G	H
1768	UT	Bonanza	7790	2014	1/25/14	9	ARP	4534.5
1769	UT	Bonanza	7790	2014	2/23/14	15	ARP	4533.6
1770	UT	Bonanza	7790	2014	1/26/14	4	ARP	4533
1771	UT	Bonanza	7790	2014	1/10/14	2	ARP	4532.1
1772	UT	Bonanza	7790	2014	2/19/14	20	ARP	4531.7
1773	UT	Bonanza	7790	2014	1/11/14	4	ARP	4531.2
1774	UT	Bonanza	7790	2014	1/14/14	5	ARP	4530.6
1775	UT	Bonanza	7790	2014	2/23/14	18	ARP	4530.6
1776	UT	Bonanza	7790	2014	1/26/14	0	ARP	4530
1777	UT	Bonanza	7790	2014	1/25/14	8	ARP	4528.4
1778	UT	Bonanza	7790	2014	2/23/14	19	ARP	4528.4
1779	UT	Bonanza	7790	2014	2/24/14	7	ARP	4528.4
1780	UT	Bonanza	7790	2014	1/13/14	5	ARP	4528
1781	UT	Bonanza	7790	2014	1/26/14	20	ARP	4528
1782	UT	Bonanza	7790	2014	2/25/14	0	ARP	4527.8
1783	UT	Bonanza	7790	2014	2/25/14	2	ARP	4527.8
1784	UT	Bonanza	7790	2014	2/24/14	21	ARP	4526.7
1785	UT	Bonanza	7790	2014	2/23/14	22	ARP	4525.4
1786	UT	Bonanza	7790	2014	1/24/14	22	ARP	4524.9
1787	UT	Bonanza	7790	2014	1/26/14	9	ARP	4524.9
1788	UT	Bonanza	7790	2014	1/26/14	5	ARP	4521.8
1789	UT	Bonanza	7790	2014	2/24/14	3	ARP	4521.8
1790	UT	Bonanza	7790	2014	2/23/14	21	ARP	4519.8
1791	UT	Bonanza	7790	2014	2/21/14	15	ARP	4518.9
1792	UT	Bonanza	7790	2014	1/25/14	21	ARP	4518.8
1793	UT	Bonanza	7790	2014	2/23/14	16	ARP	4518.3
1794	UT	Bonanza	7790	2014	1/26/14	1	ARP	4517.5
1795	UT	Bonanza	7790	2014	2/21/14	19	ARP	4517
1796	UT	Bonanza	7790	2014	1/10/14	1	ARP	4516.4
1797	UT	Bonanza	7790	2014	2/21/14	2	ARP	4515.9
1798	UT	Bonanza	7790	2014	1/24/14	5	ARP	4515.7
1799	UT	Bonanza	7790	2014	1/2/14	17	ARP	4515.4
1800	UT	Bonanza	7790	2014	2/24/14	0	ARP	4514.9
1801	UT	Bonanza	7790	2014	2/23/14	23	ARP	4514.5

	A	B	C	D	E	F	G	H
1802	UT	Bonanza	7790	2014	3/31/14	4	ARP	4514.1
1803	UT	Bonanza	7790	2014	1/26/14	8	ARP	4513.3
1804	UT	Bonanza	7790	2014	3/20/14	22	ARP	4513.1
1805	UT	Bonanza	7790	2014	1/24/14	23	ARP	4512.4
1806	UT	Bonanza	7790	2014	2/21/14	14	ARP	4512.3
1807	UT	Bonanza	7790	2014	3/25/14	23	ARP	4511.6
1808	UT	Bonanza	7790	2014	1/2/14	16	ARP	4511.1
1809	UT	Bonanza	7790	2014	2/24/14	4	ARP	4510.6
1810	UT	Bonanza	7790	2014	2/25/14	3	ARP	4510.2
1811	UT	Bonanza	7790	2014	2/25/14	9	ARP	4509.8
1812	UT	Bonanza	7790	2014	2/22/14	16	ARP	4508.7
1813	UT	Bonanza	7790	2014	2/24/14	2	ARP	4508
1814	UT	Bonanza	7790	2014	2/22/14	15	ARP	4507
1815	UT	Bonanza	7790	2014	1/10/14	4	ARP	4506.8
1816	UT	Bonanza	7790	2014	2/24/14	10	ARP	4505.9
1817	UT	Bonanza	7790	2014	2/24/14	19	ARP	4505.9
1818	UT	Bonanza	7790	2014	2/24/14	16	ARP	4505.5
1819	UT	Bonanza	7790	2014	3/17/14	12	ARP	4504.1
1820	UT	Bonanza	7790	2014	2/21/14	0	ARP	4503
1821	UT	Bonanza	7790	2014	1/26/14	6	ARP	4502.6
1822	UT	Bonanza	7790	2014	1/26/14	3	ARP	4502.5
1823	UT	Bonanza	7790	2014	2/21/14	16	ARP	4500
1824	UT	Bonanza	7790	2014	1/26/14	2	ARP	4499.5
1825	UT	Bonanza	7790	2014	1/24/14	1	ARP	4499.1
1826	UT	Bonanza	7790	2014	1/11/14	12	ARP	4498.9
1827	UT	Bonanza	7790	2014	2/21/14	3	ARP	4498.2
1828	UT	Bonanza	7790	2014	1/25/14	0	ARP	4497.7
1829	UT	Bonanza	7790	2014	1/24/14	21	ARP	4496.8
1830	UT	Bonanza	7790	2014	2/25/14	7	ARP	4496.8
1831	UT	Bonanza	7790	2014	2/25/14	5	ARP	4496.4
1832	UT	Bonanza	7790	2014	2/24/14	14	ARP	4496
1833	UT	Bonanza	7790	2014	2/23/14	17	ARP	4495.6
1834	UT	Bonanza	7790	2014	2/24/14	5	ARP	4495.5
1835	UT	Bonanza	7790	2014	1/13/14	3	ARP	4495.2

	A	B	C	D	E	F	G	H
1836	UT	Bonanza	7790	2014	2/25/14	4	ARP	4495.2
1837	UT	Bonanza	7790	2014	2/24/14	15	ARP	4493.9
1838	UT	Bonanza	7790	2014	2/21/14	7	ARP	4493.8
1839	UT	Bonanza	7790	2014	2/21/14	11	ARP	4493.3
1840	UT	Bonanza	7790	2014	2/22/14	12	ARP	4493
1841	UT	Bonanza	7790	2014	3/29/14	3	ARP	4492.9
1842	UT	Bonanza	7790	2014	2/19/14	18	ARP	4492.5
1843	UT	Bonanza	7790	2014	1/24/14	9	ARP	4491.7
1844	UT	Bonanza	7790	2014	1/24/14	0	ARP	4490.8
1845	UT	Bonanza	7790	2014	1/13/14	4	ARP	4490.7
1846	UT	Bonanza	7790	2014	2/24/14	9	ARP	4489.8
1847	UT	Bonanza	7790	2014	2/25/14	1	ARP	4488.7
1848	UT	Bonanza	7790	2014	2/21/14	18	ARP	4488.6
1849	UT	Bonanza	7790	2014	2/24/14	8	ARP	4488.5
1850	UT	Bonanza	7790	2014	2/24/14	12	ARP	4487.3
1851	UT	Bonanza	7790	2014	2/22/14	14	ARP	4486.8
1852	UT	Bonanza	7790	2014	3/17/14	22	ARP	4484.7
1853	UT	Bonanza	7790	2014	2/21/14	12	ARP	4484.6
1854	UT	Bonanza	7790	2014	2/21/14	13	ARP	4484.6
1855	UT	Bonanza	7790	2014	1/25/14	22	ARP	4483.5
1856	UT	Bonanza	7790	2014	2/25/14	11	ARP	4483.1
1857	UT	Bonanza	7790	2014	2/21/14	17	ARP	4481.6
1858	UT	Bonanza	7790	2014	2/22/14	13	ARP	4481.6
1859	UT	Bonanza	7790	2014	1/25/14	20	ARP	4481.4
1860	UT	Bonanza	7790	2014	2/22/14	4	ARP	4481.2
1861	UT	Bonanza	7790	2014	2/22/14	5	ARP	4481.2
1862	UT	Bonanza	7790	2014	2/20/14	6	ARP	4480.8
1863	UT	Bonanza	7790	2014	2/22/14	8	ARP	4480.3
1864	UT	Bonanza	7790	2014	2/24/14	1	ARP	4480.3
1865	UT	Bonanza	7790	2014	1/25/14	19	ARP	4479.7
1866	UT	Bonanza	7790	2014	1/23/14	5	ARP	4479.4
1867	UT	Bonanza	7790	2014	1/11/14	6	ARP	4478.1
1868	UT	Bonanza	7790	2014	2/25/14	8	ARP	4477.9
1869	UT	Bonanza	7790	2014	2/21/14	23	ARP	4477.7

	A	B	C	D	E	F	G	H
1870	UT	Bonanza	7790	2014	1/25/14	23	ARP	4476.3
1871	UT	Bonanza	7790	2014	2/21/14	5	ARP	4475.8
1872	UT	Bonanza	7790	2014	2/25/14	12	ARP	4475.5
1873	UT	Bonanza	7790	2014	1/24/14	19	ARP	4474.7
1874	UT	Bonanza	7790	2014	1/10/14	22	ARP	4474.1
1875	UT	Bonanza	7790	2014	1/25/14	11	ARP	4473.8
1876	UT	Bonanza	7790	2014	1/24/14	20	ARP	4472.9
1877	UT	Bonanza	7790	2014	1/10/14	3	ARP	4472.8
1878	UT	Bonanza	7790	2014	1/24/14	8	ARP	4472.4
1879	UT	Bonanza	7790	2014	3/29/14	21	ARP	4471.6
1880	UT	Bonanza	7790	2014	2/25/14	10	ARP	4471.1
1881	UT	Bonanza	7790	2014	1/25/14	10	ARP	4470.4
1882	UT	Bonanza	7790	2014	2/24/14	13	ARP	4469.8
1883	UT	Bonanza	7790	2014	1/25/14	6	ARP	4469.2
1884	UT	Bonanza	7790	2014	2/24/14	17	ARP	4468.9
1885	UT	Bonanza	7790	2014	2/24/14	6	ARP	4467.8
1886	UT	Bonanza	7790	2014	1/24/14	2	ARP	4467.2
1887	UT	Bonanza	7790	2014	1/11/14	15	ARP	4465.7
1888	UT	Bonanza	7790	2014	2/25/14	6	ARP	4465
1889	UT	Bonanza	7790	2014	2/19/14	16	ARP	4464.1
1890	UT	Bonanza	7790	2014	2/22/14	11	ARP	4463.4
1891	UT	Bonanza	7790	2014	1/24/14	10	ARP	4462.9
1892	UT	Bonanza	7790	2014	1/24/14	3	ARP	4462
1893	UT	Bonanza	7790	2014	1/15/14	0	ARP	4460.3
1894	UT	Bonanza	7790	2014	2/25/14	13	ARP	4459.7
1895	UT	Bonanza	7790	2014	1/10/14	23	ARP	4459.1
1896	UT	Bonanza	7790	2014	2/21/14	4	ARP	4457.7
1897	UT	Bonanza	7790	2014	1/25/14	12	ARP	4457.3
1898	UT	Bonanza	7790	2014	2/22/14	7	ARP	4457.1
1899	UT	Bonanza	7790	2014	1/11/14	2	ARP	4455.5
1900	UT	Bonanza	7790	2014	1/23/14	2	ARP	4453.5
1901	UT	Bonanza	7790	2014	2/22/14	10	ARP	4453.4
1902	UT	Bonanza	7790	2014	3/19/14	19	ARP	4450.4
1903	UT	Bonanza	7790	2014	3/20/14	23	ARP	4449.2

	A	B	C	D	E	F	G	H
1904	UT	Bonanza	7790	2014	2/22/14	9	ARP	4448.2
1905	UT	Bonanza	7790	2014	1/11/14	5	ARP	4446.5
1906	UT	Bonanza	7790	2014	1/24/14	17	ARP	4445.6
1907	UT	Bonanza	7790	2014	1/24/14	18	ARP	4445.2
1908	UT	Bonanza	7790	2014	2/21/14	8	ARP	4443.1
1909	UT	Bonanza	7790	2014	1/24/14	11	ARP	4442.3
1910	UT	Bonanza	7790	2014	2/20/14	16	ARP	4441
1911	UT	Bonanza	7790	2014	1/10/14	14	ARP	4440.1
1912	UT	Bonanza	7790	2014	1/25/14	15	ARP	4439.7
1913	UT	Bonanza	7790	2014	1/24/14	6	ARP	4439.6
1914	UT	Bonanza	7790	2014	3/29/14	20	ARP	4439.5
1915	UT	Bonanza	7790	2014	1/23/14	21	ARP	4437.3
1916	UT	Bonanza	7790	2014	1/24/14	14	ARP	4436.5
1917	UT	Bonanza	7790	2014	1/23/14	1	ARP	4435.4
1918	UT	Bonanza	7790	2014	1/23/14	3	ARP	4433.2
1919	UT	Bonanza	7790	2014	1/24/14	15	ARP	4432.2
1920	UT	Bonanza	7790	2014	1/23/14	4	ARP	4428.9
1921	UT	Bonanza	7790	2014	2/19/14	15	ARP	4428.9
1922	UT	Bonanza	7790	2014	1/23/14	22	ARP	4428.7
1923	UT	Bonanza	7790	2014	1/23/14	20	ARP	4427.9
1924	UT	Bonanza	7790	2014	1/23/14	9	ARP	4427
1925	UT	Bonanza	7790	2014	1/23/14	19	ARP	4425.7
1926	UT	Bonanza	7790	2014	2/19/14	11	ARP	4424.2
1927	UT	Bonanza	7790	2014	1/23/14	0	ARP	4423.4
1928	UT	Bonanza	7790	2014	2/21/14	6	ARP	4422.2
1929	UT	Bonanza	7790	2014	2/21/14	22	ARP	4421.3
1930	UT	Bonanza	7790	2014	1/26/14	12	ARP	4420.8
1931	UT	Bonanza	7790	2014	1/25/14	18	ARP	4418.3
1932	UT	Bonanza	7790	2014	1/11/14	8	ARP	4416.5
1933	UT	Bonanza	7790	2014	1/14/14	22	ARP	4416
1934	UT	Bonanza	7790	2014	1/25/14	17	ARP	4415.8
1935	UT	Bonanza	7790	2014	1/26/14	11	ARP	4415.6
1936	UT	Bonanza	7790	2014	1/24/14	16	ARP	4414.4
1937	UT	Bonanza	7790	2014	1/25/14	13	ARP	4414.3

	A	B	C	D	E	F	G	H
1938	UT	Bonanza	7790	2014	2/19/14	17	ARP	4412.7
1939	UT	Bonanza	7790	2014	3/15/14	12	ARP	4410.4
1940	UT	Bonanza	7790	2014	2/19/14	13	ARP	4409.8
1941	UT	Bonanza	7790	2014	1/23/14	18	ARP	4409.6
1942	UT	Bonanza	7790	2014	1/24/14	13	ARP	4409.6
1943	UT	Bonanza	7790	2014	1/23/14	8	ARP	4409.2
1944	UT	Bonanza	7790	2014	1/16/14	3	ARP	4408.3
1945	UT	Bonanza	7790	2014	1/25/14	14	ARP	4404.9
1946	UT	Bonanza	7790	2014	1/26/14	10	ARP	4404.5
1947	UT	Bonanza	7790	2014	1/14/14	3	ARP	4401.8
1948	UT	Bonanza	7790	2014	1/23/14	13	ARP	4400.9
1949	UT	Bonanza	7790	2014	1/23/14	23	ARP	4399.3
1950	UT	Bonanza	7790	2014	2/21/14	9	ARP	4396.9
1951	UT	Bonanza	7790	2014	1/23/14	10	ARP	4395.7
1952	UT	Bonanza	7790	2014	1/23/14	7	ARP	4394.9
1953	UT	Bonanza	7790	2014	1/15/14	1	ARP	4393.7
1954	UT	Bonanza	7790	2014	1/14/14	4	ARP	4392.3
1955	UT	Bonanza	7790	2014	3/27/14	0	ARP	4391.5
1956	UT	Bonanza	7790	2014	1/23/14	15	ARP	4391.4
1957	UT	Bonanza	7790	2014	1/11/14	17	ARP	4391.1
1958	UT	Bonanza	7790	2014	3/17/14	9	ARP	4390.8
1959	UT	Bonanza	7790	2014	1/25/14	16	ARP	4386.8
1960	UT	Bonanza	7790	2014	1/23/14	17	ARP	4386.6
1961	UT	Bonanza	7790	2014	2/22/14	3	ARP	4385.4
1962	UT	Bonanza	7790	2014	1/11/14	1	ARP	4384.7
1963	UT	Bonanza	7790	2014	2/19/14	12	ARP	4384.7
1964	UT	Bonanza	7790	2014	1/11/14	10	ARP	4384.2
1965	UT	Bonanza	7790	2014	2/19/14	14	ARP	4384.1
1966	UT	Bonanza	7790	2014	1/17/14	18	ARP	4382.5
1967	UT	Bonanza	7790	2014	2/21/14	21	ARP	4382.4
1968	UT	Bonanza	7790	2014	1/16/14	2	ARP	4381.3
1969	UT	Bonanza	7790	2014	3/29/14	9	ARP	4381
1970	UT	Bonanza	7790	2014	1/24/14	12	ARP	4380.1
1971	UT	Bonanza	7790	2014	1/26/14	13	ARP	4379.1

	A	B	C	D	E	F	G	H
1972	UT	Bonanza	7790	2014	1/23/14	11	ARP	4378.4
1973	UT	Bonanza	7790	2014	1/11/14	16	ARP	4377.9
1974	UT	Bonanza	7790	2014	1/23/14	16	ARP	4374.9
1975	UT	Bonanza	7790	2014	1/28/14	8	ARP	4368.3
1976	UT	Bonanza	7790	2014	1/16/14	1	ARP	4367.2
1977	UT	Bonanza	7790	2014	2/22/14	6	ARP	4367.1
1978	UT	Bonanza	7790	2014	3/6/14	1	ARP	4366.2
1979	UT	Bonanza	7790	2014	2/21/14	20	ARP	4361.2
1980	UT	Bonanza	7790	2014	1/15/14	23	ARP	4357.4
1981	UT	Bonanza	7790	2014	1/10/14	15	ARP	4354.8
1982	UT	Bonanza	7790	2014	3/6/14	5	ARP	4354.8
1983	UT	Bonanza	7790	2014	1/11/14	7	ARP	4353.7
1984	UT	Bonanza	7790	2014	1/16/14	0	ARP	4352.4
1985	UT	Bonanza	7790	2014	3/28/14	0	ARP	4351.4
1986	UT	Bonanza	7790	2014	1/23/14	6	ARP	4350
1987	UT	Bonanza	7790	2014	3/28/14	3	ARP	4347.5
1988	UT	Bonanza	7790	2014	1/26/14	17	ARP	4345.7
1989	UT	Bonanza	7790	2014	1/10/14	16	ARP	4345.5
1990	UT	Bonanza	7790	2014	3/29/14	7	ARP	4342.6
1991	UT	Bonanza	7790	2014	1/10/14	5	ARP	4342.2
1992	UT	Bonanza	7790	2014	1/26/14	18	ARP	4341.2
1993	UT	Bonanza	7790	2014	3/29/14	10	ARP	4339.9
1994	UT	Bonanza	7790	2014	1/23/14	12	ARP	4337.4
1995	UT	Bonanza	7790	2014	2/24/14	11	ARP	4337
1996	UT	Bonanza	7790	2014	3/29/14	6	ARP	4334.5
1997	UT	Bonanza	7790	2014	3/16/14	13	ARP	4334
1998	UT	Bonanza	7790	2014	1/26/14	19	ARP	4333.4
1999	UT	Bonanza	7790	2014	1/11/14	11	ARP	4330.5
2000	UT	Bonanza	7790	2014	1/11/14	20	ARP	4322.3
2001	UT	Bonanza	7790	2014	3/18/14	3	ARP	4316.4
2002	UT	Bonanza	7790	2014	1/12/14	5	ARP	4310
2003	UT	Bonanza	7790	2014	3/15/14	14	ARP	4307.4
2004	UT	Bonanza	7790	2014	3/19/14	16	ARP	4302
2005	UT	Bonanza	7790	2014	1/26/14	14	ARP	4298.2

	A	B	C	D	E	F	G	H
2006	UT	Bonanza	7790	2014	3/27/14	1	ARP	4290.2
2007	UT	Bonanza	7790	2014	1/26/14	15	ARP	4276.7
2008	UT	Bonanza	7790	2014	3/17/14	21	ARP	4271.1
2009	UT	Bonanza	7790	2014	3/15/14	17	ARP	4266.1
2010	UT	Bonanza	7790	2014	3/20/14	3	ARP	4257.6
2011	UT	Bonanza	7790	2014	1/26/14	16	ARP	4247.1
2012	UT	Bonanza	7790	2014	2/22/14	0	ARP	4241.7
2013	UT	Bonanza	7790	2014	3/29/14	19	ARP	4241
2014	UT	Bonanza	7790	2014	3/7/14	1	ARP	4220
2015	UT	Bonanza	7790	2014	3/29/14	8	ARP	4219.3
2016	UT	Bonanza	7790	2014	3/14/14	1	ARP	4215.8
2017	UT	Bonanza	7790	2014	3/29/14	11	ARP	4215.2
2018	UT	Bonanza	7790	2014	3/12/14	16	ARP	4214.4
2019	UT	Bonanza	7790	2014	2/22/14	1	ARP	4212.8
2020	UT	Bonanza	7790	2014	3/28/14	2	ARP	4212.7
2021	UT	Bonanza	7790	2014	3/26/14	0	ARP	4210
2022	UT	Bonanza	7790	2014	3/16/14	19	ARP	4208.2
2023	UT	Bonanza	7790	2014	3/16/14	20	ARP	4207.8
2024	UT	Bonanza	7790	2014	3/14/14	2	ARP	4204.3
2025	UT	Bonanza	7790	2014	1/23/14	14	ARP	4191.9
2026	UT	Bonanza	7790	2014	3/20/14	0	ARP	4183.3
2027	UT	Bonanza	7790	2014	2/21/14	10	ARP	4178.3
2028	UT	Bonanza	7790	2014	3/19/14	17	ARP	4178.2
2029	UT	Bonanza	7790	2014	3/16/14	18	ARP	4175.6
2030	UT	Bonanza	7790	2014	3/7/14	5	ARP	4166.3
2031	UT	Bonanza	7790	2014	1/11/14	21	ARP	4159.5
2032	UT	Bonanza	7790	2014	2/22/14	2	ARP	4158.2
2033	UT	Bonanza	7790	2014	3/15/14	5	ARP	4154.4
2034	UT	Bonanza	7790	2014	3/28/14	1	ARP	4152.5
2035	UT	Bonanza	7790	2014	3/27/14	3	ARP	4151.9
2036	UT	Bonanza	7790	2014	3/15/14	15	ARP	4151.8
2037	UT	Bonanza	7790	2014	1/28/14	9	ARP	4151.4
2038	UT	Bonanza	7790	2014	3/15/14	16	ARP	4138.9
2039	UT	Bonanza	7790	2014	3/17/14	23	ARP	4134.1

	A	B	C	D	E	F	G	H
2040	UT	Bonanza	7790	2014	3/14/14	21	ARP	4128.2
2041	UT	Bonanza	7790	2014	1/13/14	2	ARP	4117.2
2042	UT	Bonanza	7790	2014	1/13/14	1	ARP	4113.5
2043	UT	Bonanza	7790	2014	3/11/14	2	ARP	4107.5
2044	UT	Bonanza	7790	2014	3/14/14	23	ARP	4095.6
2045	UT	Bonanza	7790	2014	2/19/14	9	ARP	4083.7
2046	UT	Bonanza	7790	2014	3/27/14	2	ARP	4079.7
2047	UT	Bonanza	7790	2014	2/19/14	10	ARP	4075.5
2048	UT	Bonanza	7790	2014	3/30/14	2	ARP	4063.4
2049	UT	Bonanza	7790	2014	3/16/14	16	ARP	4055.9
2050	UT	Bonanza	7790	2014	2/15/14	9	ARP	4055.1
2051	UT	Bonanza	7790	2014	3/12/14	15	ARP	4051
2052	UT	Bonanza	7790	2014	2/15/14	11	ARP	4049.5
2053	UT	Bonanza	7790	2014	2/19/14	8	ARP	4044.6
2054	UT	Bonanza	7790	2014	2/11/14	15	ARP	4043.9
2055	UT	Bonanza	7790	2014	3/19/14	18	ARP	4036
2056	UT	Bonanza	7790	2014	3/26/14	1	ARP	4015.6
2057	UT	Bonanza	7790	2014	2/15/14	10	ARP	4007.3
2058	UT	Bonanza	7790	2014	3/11/14	4	ARP	3993.7
2059	UT	Bonanza	7790	2014	3/31/14	0	ARP	3981.2
2060	UT	Bonanza	7790	2014	3/17/14	20	ARP	3978.3
2061	UT	Bonanza	7790	2014	3/31/14	2	ARP	3975.3
2062	UT	Bonanza	7790	2014	3/17/14	13	ARP	3966
2063	UT	Bonanza	7790	2014	3/29/14	12	ARP	3959.1
2064	UT	Bonanza	7790	2014	3/26/14	3	ARP	3954.7
2065	UT	Bonanza	7790	2014	3/15/14	13	ARP	3947.8
2066	UT	Bonanza	7790	2014	3/7/14	4	ARP	3941.8
2067	UT	Bonanza	7790	2014	3/14/14	22	ARP	3932
2068	UT	Bonanza	7790	2014	3/7/14	2	ARP	3929.2
2069	UT	Bonanza	7790	2014	1/11/14	23	ARP	3919.6
2070	UT	Bonanza	7790	2014	1/11/14	0	ARP	3913.3
2071	UT	Bonanza	7790	2014	3/16/14	15	ARP	3908
2072	UT	Bonanza	7790	2014	3/7/14	3	ARP	3907.8
2073	UT	Bonanza	7790	2014	3/16/14	17	ARP	3905

	A	B	C	D	E	F	G	H
2074	UT	Bonanza	7790	2014	1/2/14	14	ARP	3893
2075	UT	Bonanza	7790	2014	3/16/14	14	ARP	3885.5
2076	UT	Bonanza	7790	2014	1/2/14	12	ARP	3838.1
2077	UT	Bonanza	7790	2014	3/17/14	5	ARP	3837.9
2078	UT	Bonanza	7790	2014	3/29/14	13	ARP	3821.3
2079	UT	Bonanza	7790	2014	1/12/14	2	ARP	3821
2080	UT	Bonanza	7790	2014	3/18/14	0	ARP	3814.3
2081	UT	Bonanza	7790	2014	3/20/14	2	ARP	3810.2
2082	UT	Bonanza	7790	2014	1/11/14	22	ARP	3780.7
2083	UT	Bonanza	7790	2014	3/30/14	10	ARP	3769.5
2084	UT	Bonanza	7790	2014	3/20/14	1	ARP	3746.7
2085	UT	Bonanza	7790	2014	3/29/14	18	ARP	3743.4
2086	UT	Bonanza	7790	2014	3/11/14	3	ARP	3740.1
2087	UT	Bonanza	7790	2014	1/12/14	3	ARP	3739
2088	UT	Bonanza	7790	2014	3/26/14	2	ARP	3731.2
2089	UT	Bonanza	7790	2014	1/12/14	1	ARP	3724.7
2090	UT	Bonanza	7790	2014	3/16/14	21	ARP	3717.9
2091	UT	Bonanza	7790	2014	3/17/14	14	ARP	3716.1
2092	UT	Bonanza	7790	2014	3/15/14	0	ARP	3705.4
2093	UT	Bonanza	7790	2014	2/17/14	21	ARP	3700.4
2094	UT	Bonanza	7790	2014	3/30/14	16	ARP	3668.7
2095	UT	Bonanza	7790	2014	3/29/14	17	ARP	3653.2
2096	UT	Bonanza	7790	2014	3/30/14	11	ARP	3643.1
2097	UT	Bonanza	7790	2014	1/12/14	4	ARP	3636.4
2098	UT	Bonanza	7790	2014	3/6/14	2	ARP	3622.6
2099	UT	Bonanza	7790	2014	3/6/14	4	ARP	3617.3
2100	UT	Bonanza	7790	2014	3/30/14	12	ARP	3604.2
2101	UT	Bonanza	7790	2014	1/12/14	0	ARP	3600.8
2102	UT	Bonanza	7790	2014	3/30/14	13	ARP	3589
2103	UT	Bonanza	7790	2014	3/15/14	4	ARP	3565.8
2104	UT	Bonanza	7790	2014	3/6/14	3	ARP	3555.5
2105	UT	Bonanza	7790	2014	3/29/14	16	ARP	3542.3
2106	UT	Bonanza	7790	2014	3/29/14	15	ARP	3497.9
2107	UT	Bonanza	7790	2014	3/29/14	14	ARP	3479.1

	A	B	C	D	E	F	G	H
2108	UT	Bonanza	7790	2014	3/30/14	3	ARP	3478
2109	UT	Bonanza	7790	2014	3/30/14	8	ARP	3456.7
2110	UT	Bonanza	7790	2014	3/30/14	9	ARP	3437.1
2111	UT	Bonanza	7790	2014	3/30/14	14	ARP	3411
2112	UT	Bonanza	7790	2014	3/30/14	15	ARP	3405.3
2113	UT	Bonanza	7790	2014	3/18/14	2	ARP	3375.1
2114	UT	Bonanza	7790	2014	2/18/14	17	ARP	3353.4
2115	UT	Bonanza	7790	2014	3/31/14	1	ARP	3331.4
2116	UT	Bonanza	7790	2014	3/16/14	22	ARP	3293.7
2117	UT	Bonanza	7790	2014	2/18/14	18	ARP	3279.4
2118	UT	Bonanza	7790	2014	3/30/14	6	ARP	3259.7
2119	UT	Bonanza	7790	2014	2/18/14	19	ARP	3251.4
2120	UT	Bonanza	7790	2014	3/30/14	7	ARP	3241.5
2121	UT	Bonanza	7790	2014	2/19/14	1	ARP	3204.5
2122	UT	Bonanza	7790	2014	3/15/14	1	ARP	3198.3
2123	UT	Bonanza	7790	2014	2/19/14	7	ARP	3198.2
2124	UT	Bonanza	7790	2014	3/30/14	4	ARP	3197.3
2125	UT	Bonanza	7790	2014	2/19/14	2	ARP	3195.9
2126	UT	Bonanza	7790	2014	1/2/14	13	ARP	3194.9
2127	UT	Bonanza	7790	2014	2/19/14	6	ARP	3192.9
2128	UT	Bonanza	7790	2014	2/18/14	20	ARP	3173.9
2129	UT	Bonanza	7790	2014	2/19/14	3	ARP	3160
2130	UT	Bonanza	7790	2014	2/19/14	5	ARP	3157.6
2131	UT	Bonanza	7790	2014	2/19/14	0	ARP	3139.4
2132	UT	Bonanza	7790	2014	2/19/14	4	ARP	3136.5
2133	UT	Bonanza	7790	2014	2/18/14	22	ARP	3126.8
2134	UT	Bonanza	7790	2014	3/15/14	2	ARP	3124.8
2135	UT	Bonanza	7790	2014	2/18/14	21	ARP	3119.5
2136	UT	Bonanza	7790	2014	2/18/14	23	ARP	3110.2
2137	UT	Bonanza	7790	2014	3/18/14	1	ARP	3098.9
2138	UT	Bonanza	7790	2014	3/16/14	23	ARP	3078.8
2139	UT	Bonanza	7790	2014	3/15/14	3	ARP	3073.8
2140	UT	Bonanza	7790	2014	3/17/14	0	ARP	3060.5
2141	UT	Bonanza	7790	2014	2/17/14	22	ARP	3030.3

	A	B	C	D	E	F	G	H
2142	UT	Bonanza	7790	2014	3/17/14	4	ARP	2993.3
2143	UT	Bonanza	7790	2014	3/30/14	5	ARP	2974.5
2144	UT	Bonanza	7790	2014	2/18/14	16	ARP	2967.3
2145	UT	Bonanza	7790	2014	2/18/14	15	ARP	2919.1
2146	UT	Bonanza	7790	2014	2/18/14	0	ARP	2673.4
2147	UT	Bonanza	7790	2014	3/17/14	1	ARP	2644.4
2148	UT	Bonanza	7790	2014	3/17/14	3	ARP	2613.1
2149	UT	Bonanza	7790	2014	2/17/14	23	ARP	2609.4
2150	UT	Bonanza	7790	2014	3/17/14	2	ARP	2590.7
2151	UT	Bonanza	7790	2014	2/18/14	4	ARP	2522.9
2152	UT	Bonanza	7790	2014	2/18/14	1	ARP	2515
2153	UT	Bonanza	7790	2014	2/18/14	5	ARP	2509.3
2154	UT	Bonanza	7790	2014	2/18/14	12	ARP	2509.2
2155	UT	Bonanza	7790	2014	2/18/14	10	ARP	2499.2
2156	UT	Bonanza	7790	2014	2/18/14	2	ARP	2493.5
2157	UT	Bonanza	7790	2014	2/18/14	9	ARP	2489.2
2158	UT	Bonanza	7790	2014	2/18/14	13	ARP	2488.9
2159	UT	Bonanza	7790	2014	2/18/14	8	ARP	2483.6
2160	UT	Bonanza	7790	2014	2/18/14	14	ARP	2482.6
2161	UT	Bonanza	7790	2014	2/18/14	3	ARP	2478.9
2162	UT	Bonanza	7790	2014	2/18/14	7	ARP	2478.1
2163	UT	Bonanza	7790	2014	2/18/14	11	ARP	2475.9
2164	UT	Bonanza	7790	2014	2/18/14	6	ARP	2469.7