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June 16, 2014

Via E-Mail

Michael B. Owens
Air Program (8P-AR)
U.S. Environmental Protection Agency, Region 8
1595 Wynkoop Street
Denver, CO 80202-1129
Email: owens.mike@epa.gov

Re: Comments of Deseret Generation & Transmission Co-operative on Draft Title V Permit No. V-UO-000004-00.00

Dear Mr. Owens:

The enclosed comments are filed on behalf of Deseret Generation & Transmission Co-operative ("Deseret") in response to the Environmental Protection Agency's ("EPA") draft Title V operating permit for the Bonanza Power Plant. EPA's draft permit contains a number of significant legal defects and factual errors that are discussed in Deseret's comments.

In particular, EPA has no authority to impose a schedule of compliance in a Title V permit for a requirement absent a final determination that the requirement applies to the source and a certification by the responsible official that the facility will not be in compliance with that purported "applicable requirement." Further, the premise underlying EPA's proposed "compliance plan"—that the Agency may undertake a PSD permit revision proceeding to correct a purported error in the Bonanza plant's PSD permit—is fundamentally incorrect, as EPA has no authority to reopen or revise a final PSD permit. EPA's draft permit also raises numerous jurisdictional issues regarding whether the Bonanza plant is located on Indian lands. Due to these and other deficiencies, it would be arbitrary, capricious, and unlawful for EPA to finalize the draft Title V permit in its current form.

Deseret appreciates the opportunity to comment on the draft Title V permit and looks forward to reviewing EPA's response. Please contact me if you have any questions concerning these comments.

HUNTON& WILLIAMS

Sincerely,

/ADK

Makram B. Jaber
William L. Wehrum
Andrew D. Knudsen
Counsel for Deseret Generation
& Transmission Co-operative

Copy to: David Crabtree

Enclosures (2):
Deseret Generation & Transmission Co-operative Comments on Draft Title V Permit for Bonanza Power Plant
Exhibits A Through E to Comments of Deseret Generation & Transmission Co-operative

BEFORE THE UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY
REGION 8

DRAFT TITLE V PERMIT TO OPERATE BONANZA POWER PLANT	**Draft Permit No. V-UO-000004-00.00**

COMMENTS OF DESERET GENERATION & TRANSMISSION CO-OPERATIVE

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June 16, 2014

DESERET GENERATION & TRANSMISSION CO-OPERATIVE COMMENTS ON DRAFT TITLE V PERMIT FOR BONANZA POWER PLANT

I. Factual/Regulatory Background

The factual background and regulatory history of Deseret Generation & Transmission Co-operative's ("Deseret" or "DG&T") Bonanza plant that EPA recites in the Draft Statement of Basis[1] is inaccurate and incomplete. At the outset, it is important to note that since the early 1980s, both the U.S. Environmental Protection Agency ("EPA" or "the Agency") Region 8 and the Utah Division of Air Quality ("UDAQ") have issued parallel and overlapping permits, and permit modifications, authorizing every significant activity at Bonanza. Indeed, EPA itself issued the original Prevention of Significant Deterioration ("PSD") permit on February 4, 1981, authorizing construction of the plant. On April 29, 1981, UDAQ issued a parallel approval order for construction of the Plant. This UDAQ approval order was followed on July 11, 1984 with a modified approval order that consolidated the permit conditions contained in the 1981 UDAQ and EPA permits. The UDAQ approval order for Bonanza was modified again on May 19, 1987 and July 2, 1987 to correct typographical errors and replace the prior approval orders. This, in turn, was followed on June 14, 1995 with a modified approval order modifying certain emission limits and subjecting Bonanza to a new round of PSD permitting analysis, including dispersion modeling and top-down BACT analysis. On March 16, 1998, UDAQ issued an approval order specifically authorizing the ruggedized rotor project (the "project") at the Bonanza plant. In 1999, EPA reasserted PSD permitting authority over Bonanza. On September 12, 2000, EPA issued a Fact Sheet providing a detailed permitting history of Bonanza and stating its intent to reissue the 1981 PSD permit, including specific authorization for installation of the ruggedized rotor. On February 2, 2001, EPA Region 8 reissued PSD permit no. PSD-UO-0001-2001 to Deseret for Bonanza (the "2001 PSD Permit"). Thus, all new source construction and subsequent modification activities at Bonanza were authorized by permits issued both by EPA and UDAQ.

EPA omits four key facts relating to the project, the state's 1998 permit authorizing the project's construction, and EPA's February 2001 analysis and reissuance of the plant's PSD permit again authorizing the project's construction.

First, and most importantly, the Draft Statement of Basis does not acknowledge that Deseret installed low nitrogen-oxide ("NOx") burners at the plant in 1997, just months before submitting its application for approval of the ruggedized rotor project. In its December 24, 1997 Notice of Intent for the project, Deseret informed the UDAQ that it had installed low-NOx burners during its May 1997 outage.[2] Because of these new burners, the post-project NOx emissions rate was expected to be (and, in fact, was) *lower* than the NOx baseline rate, both on a

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[1] EPA Region 8, Air Pollution Control, Title V Permit to Operate, Draft Permit No. V-UO-000004-00.00: Statement of Basis, Draft (Apr. 28, 2014) ("Draft Statement of Basis").

[2] Letter from Stan Gordon, Plant Manager, Deseret Generation & Transmission Coop., to Ursula Trueman, UDAQ (Dec. 24, 1997) (Request for Approval Order for DG&T Bonanza Unit (1) Power Plant Revised Emission Limits, Change in Coal Pile Parameters and Ruggedized Rotor Project, Uintah County) ("Notice of Intent"), Attachment 5 (attached as Exhibit A hereto).

pounds per million British thermal units ("lb/mmbtu") basis and at full capacity.[3] Consequently, the ruggedized rotor project—though it resulted in an increase in the maximum hourly heat input rate at the boiler—did not result (and could not have resulted) in an increase in the plant's annual NOx emissions for that reason, much less a significant increase. Moreover, nothing in the record suggests that the unit's utilization after the project was expected to increase, much less that such increase, if any, would be due to the project.

UDAQ recognized the significance of the plant's new burners: their installation provided the fundamental basis for UDAQ's March 1998 pre-construction approval order (the "1998 Approval Order") authorizing the ruggedized rotor project. UDAQ's engineering review for the project noted that "DG&T also recently installed improved low-NOx burner technology at the boiler which allows DG&T to voluntarily significantly reduce NOx emissions. The *net effect* of the proposed emission changes will be to significantly reduce overall plant wide emissions as a result of lower NOx limits."[4] Based on this decrease in NOx emissions (and the insignificant increases in other emissions), UDAQ concluded that the project "is not a PSD major modification."[5]

EPA agreed with the UDAQ's analysis, which placed emphasis on the low-NOx burner replacement as part of the ruggedized rotor project. In the Fact Sheet supporting the 2001 PSD Permit, EPA specifically stated that it "relied on" the UDAQ's engineering review.[6] EPA made no correction to the UDAQ engineering analysis, nor did EPA question the basis for approving the rotor project with the inclusion of the new low-NOx burners, a very prominent feature of the UDAQ's analysis. EPA chose, rather, to rely on the analysis in reaching its own independent determination to issue a second approval for the integrated rotor project.

It was well understood and widely accepted, at the time the 2001 PSD Permit was finalized, that low-NOx burners had formed a part of the overall rotor project, and that the project had been approved for the 2001 PSD permit on the basis of reductions in NOx to be derived from the addition of the low-NOx burner portion of the project. As an example, shortly after the 2001 PSD Permit was finalized, the National Park Service ("NPS") attempted to object, albeit belatedly, to that permit. NPS's 2002 comments demonstrate the widely held understanding that the project had been approved on the basis of the low-NOx burners, stating that "[w]e understand that Deseret proposed to install Low-NOx burners."[7] EPA can neither deny nor ignore the essential role of the low-NOx burner replacement in the context of the overall changes to Bonanza as approved in the PSD permits issued for the ruggedized rotor project.

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[3] *Id.*

[4] UDAQ Modified Source Plan Review at 5 (Jan. 2, 1998) ("MSPR"), Doc. No. 01 (emphasis added).

[5] *Id*. at 13.

[6] EPA Region 8, Ref: 8P-AR, Fact Sheet, Prevention of Significant Deterioration (PSD) Permit, PSD-70-00001-00 to Deseret Generation and Transmission Co-Operative at 18 (Sept. 12, 2000), Doc. No. 09.

[7] Letter from John Bunyak, Chief, NPS, to Michael B. Owens, EPA Region 8 (Sept. 19, 2002), Doc. No. 12.

Second, contrary to EPA's narrative in the Statement of Basis, the Agency did indeed review the ruggedized rotor project during the 2001 permit proceeding and made an independent finding that the project did not trigger PSD. In February 2001, EPA reissued a PSD permit for the Bonanza plant.[8] The 2001 PSD Permit specifically approved the ruggedized rotor project and associated changes to the distributed control system, burners, and scrubber trays.[9] In the current Draft Statement of Basis, EPA suggests that its 2001 PSD Permit merely adopted the conclusions contained in UDAQ's March 1998 Approval Order for the project without conducting further independent analysis of whether the project triggered PSD requirements.[10] To the contrary, EPA did not accept UDAQ's analyses and reissue the 1998 Approval Order as a matter of course. EPA conducted its own review of the information and analyses submitted to UDAQ in order to reach an independent conclusion as to what provisions to include in the 2001 PSD Permit. EPA took special efforts to obtain all "documentation, letters, reports, engineering plans, evaluations, or comments" exchanged between Deseret and UDAQ to support its own analysis because EPA "deem[ed] it necessary to review this background documentation to develop a PSD permit."[11] Although the 2001 PSD Permit relied on the same information and analyses developed for UDAQ's 1998 Approval Order and other administrative decisions involving the plant,[12] this is only because EPA never requested any new information from Deseret, presumably because it found "the analyses of information made available to the State of Utah in issuing Approval Orders" sufficient to rely upon in reissuing its own PSD permit.[13]

Third, EPA had no authority to change the provisions of Deseret's pre-construction approval for the ruggedized rotor project in 2001 because Utah's permit was valid when it was issued, as discussed below under Section IV (Jurisdiction).[14] In any event, even if EPA had this authority, it did not exercise it. Based on its review of the information submitted, EPA

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[8] EPA Region 8, Re-issuance of Prevention of Significant Deterioration (PSD) Permit to Deseret Generation & Transmission Co-Operative, Bonanza Power Plant Unit Number 1, PSD-UO-0001-2001: 00 (Feb. 2, 2001) ("2001 PSD Permit"), Doc. No. 10.

[9] *Id*. at 3 ("This PSD Permit . . . approves the proposed ruggedized rotor and associated plant equipment to be added in 2000.").

[10] *See* Draft Statement of Basis at 35 ("EPA's 2001 PSD action erred in not conducting a full independent review of the rationale for the MSPR."). Even if true, EPA's suggestion that it apparently now believes that it shirked its responsibilities in 2001 is no excuse for EPA to attempt to second-guess the State of Utah's and EPA's own permits more than a decade later.

[11] Letter from Richard R. Long, Dir., EPA Region 8, to Howard L. Vickers, DG&T (Sept. 22, 1999), Doc. No. 4.

[12] 2001 PSD Permit at 4.

[13] *Id.* at 2 ("The Permittee has not been requested to provide any new substantive information or data for this PSD permit that was not given to the State of Utah.").

[14] In addition, EPA had no authority to alter Deseret's pre-construction authorization because the ruggedized rotor project was completed in December 2000, several months before EPA issued the 2001 PSD Permit on February 2, 2001. Letter from David Crabtree, Vice President & Gen. Counsel, DG&T, to Richard R. Long, Dir., EPA Region 8 (Dec. 29, 2003) (PSD Applicability Determination for the Turbine Rotor Upgrade Project), Doc. No. 19, at 4 (stating that ruggedized rotor project was completed in December 2000). As discussed below, a permitting authority cannot revise a PSD pre-construction permit after construction is complete.

determined that the project "was below significance levels for SO_2, NOx, PM, and PM_{10}."[15] On that basis, the 2001 PSD Permit "approve[d] the proposed ruggedized rotor and associated plant equipment" and adopted emission limits for those pollutants that were substantially equivalent to those in UDAQ's 1998 Approval Order.[16]

Fourth, emissions associated with increased demand on the Bonanza plant that occurred after the ruggedized rotor project are clearly not attributable to that project. As discussed above, UDAQ's 1998 Approval Order (and, therefore, the 2001 EPA PSD permit) recognized that the installation of low-NOx burners shortly before the project resulted in a reduction in NOx emission rate per unit of generation that was much larger in percentage terms than the expected increase in maximum capacity. This means that NOx emissions after the ruggedized rotor project that could be attributed to generation levels above the previous maximum levels could not possibly result in increased emissions, because they would be more than offset by lower NOx emission rate. After the project was complete, increasing demand for electricity due to a sudden and fundamental change in market conditions led to greater output from the Bonanza plant. Specifically, the demand for output from the Bonanza plant increased significantly in response to the California electric power crisis that happened to coincide with the completion of the ruggedized rotor project. Any post-project increase in overall emissions from the plant was the result of this increased utilization, which was due to demand growth unrelated to the project. That increased demand, moreover, could have been easily accommodated in the baseline period, as the unit had ample, unused availability.

II. EPA Has No Authority to Include the Proposed Compliance Schedule in the Title V Permit.

EPA's Draft Title V Permit includes a "Compliance Schedule" and a proposed requirement for Deseret to request an administrative permit amendment within 60 days after EPA issues any final revised PSD permit applicable to the plant.[17] That proposed requirement, if finalized, would be arbitrary, capricious, and unlawful. EPA has no authority to impose a schedule of compliance in the Title V permit absent both (1) a final determination that a given applicable requirement applies to the source and (2) a certification by the responsible official that the facility will not be in compliance with that applicable requirement at permit issuance. In this case, not only has there been no final finding of applicability, but Deseret disputes EPA's suggestion that any additional applicable requirement applies and has made no certification of noncompliance.

Under the Clean Air Act ("CAA") and Part 71, an applicant is required to submit "a compliance plan describing how the source will comply with all *applicable requirements* under

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[15] 2001 PSD Permit at 3.

[16] *Id.* ("The Permit has conditions as stringent for SO_2, NOx, PM, and PM_{10}, as those contained in the State of Utah's of March 16, 1998.").

[17] EPA Region 8, Air Pollution Control Permit to Operate, Bonanza Power Plant, Deseret Power Electric Cooperative, Permit Number: V-UO-000004-00.00, Draft (Apr. 28, 2014) ("Draft Title V Permit"), § III.D.1, p. 81; Draft Statement of Basis at 19, 36, 50.

this chapter."[18] The Part 71 rules break this requirement down into three parts, *see* 40 C.F.R. § 71.5(c)(8), and require the permit to include a "schedule of compliance consistent with § 71.5(c)(8)."[19]

First, for applicable requirements with which the permittee is in compliance, the schedule of compliance must include a statement that the permittee is in compliance and will remain in compliance. Deseret here has certified that it is in compliance with all applicable requirements, including the PSD requirements embodied in its 2001 PSD Permit, and the proposed permit recognizes as much.

Second, for applicable requirements that will become effective during the permit term, the schedule of compliance should state that the permittee will comply when the applicable requirement becomes effective. For an applicable requirement to fall into this category, it must be applicable at the time of the permit issuance, but with a compliance date sometime in the future.[20] For example, the National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Steam Generating Units[21] ("EGU NESHAP") have already been promulgated and are an applicable requirement for Bonanza, but their compliance date is in the future (namely, April 16, 2015), so the permit should (and does) contain conditions requiring Bonanza to comply with them as of that date. The possibility that, in the future, EPA might revise the current PSD permit (assuming it had the authority to do so, which it does not)—or, for that matter, that the source might undertake a project that will require new permitting and new conditions—does not make it an applicable requirement with a future compliance date. The *current* applicable requirements for PSD are in the duly-issued 2001 PSD Permit for Bonanza.[22] That EPA says it intends to "revise" that permit in the future is no different than if EPA opined in the Draft Statement of Basis that it has "discovered" that the EGU NESHAP currently on the books was issued in "error," and therefore EPA now intends to revise it in a new rulemaking. The schedule of compliance would not—indeed could not—include a provision stating that *if* EPA revises the NESHAP (or, for that matter, any other applicable requirement), the source must revise its permit to include compliance with the revised rule.

An obligation to submit a request for a permit amendment at the end of a planned future permit proceeding is not within the scope of EPA's authority here. Such a provision would be nonsensical, and in any event superfluous. Part 71 already provides procedures for incorporating new requirements that *become applicable* to the source during the term of an existing Title V permit (as opposed to requirements that *are already applicable* to the source when the permit is issued, but for which the effective date for compliance is in the future). A permittee may request

[18] CAA § 503(b)(1) (emphasis added); *see also* 40 C.F.R. § 71.5(c)(8).

[19] 40 C.F.R. § 71.6(c)(3).

[20] *See* 40 C.F.R. § 71.2 (defining applicable requirement to include a list of requirements "including requirements that have been promulgated or approved by EPA through rulemaking *at the time of issuance* but have future compliance dates") (emphasis added).

[21] 40 C.F.R. pt. 63, subpt. UUUUU.

[22] In relation to PSD, the *only* type of applicable requirement is "[a]ny term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D, of the Act"). 40 C.F.R. § 71.2.

certain changes through administrative permit amendments, including revisions to incorporate requirements from preconstruction review permits.[23] For other changes, EPA may amend a Title V permit using procedures for minor or significant permit modifications.[24] In addition, EPA may completely reopen portions of a Title V permit prior to its expiration if, *inter alia*, additional requirements become applicable while the remaining term of the permit is 3 years or more, or where EPA determines that the permit must be revised or revoked to assure compliance with applicable requirements.[25] Each of these avenues is already provided for in the Draft Title V Permit for the Bonanza plant.[26] Thus, EPA's inclusion of a "compliance schedule" that would require Bonanza to seek to revise the permit *if* the PSD permit is "revised" in the future is unlawful.

Third, for applicable requirements for which the permittee is in noncompliance, the compliance schedule submitted by the applicant under § 71.5(c)(8) must include the details of how compliance will be achieved.[27] This is inapplicable here, however, because Deseret has not identified any noncompliance at Bonanza (including with PSD requirements)—quite the opposite, Deseret has certified compliance with PSD requirements in its 2001 PSD Permit. Nothing in § 71.5(c)(8) or § 71.6(c)(3) authorizes EPA to use the Title V permitting process to impose a compliance schedule that is inconsistent with the facility's own certified Title V compliance plan. The CAA and Part 71 both assign to the *permittee* (not EPA) the responsibility to develop a compliance plan and schedule describing how the source will comply with applicable requirements.[28]

Indeed, it is hard to imagine how Deseret can be in *noncompliance* with PSD requirements where, as the record abundantly shows, Deseret did everything it is required to do, and more. Deseret obtained not one, but two preconstruction permits authorizing the project. And there is no claim that Deseret violated any of the requirements of those permits, including a PSD permit duly issued by EPA itself in 2001. Apparently EPA thinks now that *it*—i.e., EPA—issued that permit in "error." If there is any noncompliance, it is EPA's noncompliance, not Deseret's.

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[23] 40 C.F.R. § 71.7(d).

[24] *Id.* § 71.7(e).

[25] *Id.* § 71.7(f).

[26] Draft Title V Permit § IV.H-K, pp. 89-92.

[27] It is worth noting that Title V does not displace or supplement the statute's enforcement provision for the applicable requirement itself. Even if a source's Title V permit omits an applicable requirement, EPA may still enforce violations of that requirement through other provisions of the Act. *See* CAA § 113(a)(1), (a)(3) (authorizing EPA to require compliance with "any requirement or prohibition of an applicable implementation plan or permit" independently of authority to enforce violations of Title V); *cf. id.* § 504(f) (absent explicit permit shield, compliance with Title V permit does not necessarily constitute compliance with applicable requirements).

[28] CAA § 503(b)(1) (applicant must submit compliance plan); 40 C.F.R. § 71.5(c)(4), (c)(8) (applicant must identify all applicable requirements and submit a compliance plan); *id.* § 71.6(c)(3) (EPA permit must contain schedule of compliance consistent with that submitted by applicant).

In any event, EPA does not purport to have made a final determination of PSD applicability or to have established in a PSD proceeding any applicable requirements for the ruggedized rotor project that are different from the 2001 PSD Permit authorizing the project, assuming that the Agency even has the authority to make such a determination now (which it does not, *see infra* Section III). EPA only refers to a purported "*preliminary* PSD applicability determination" as its basis for incorporating a compliance schedule into the Draft Title V Permit.[29] The Agency explains that it will "undertake a separate error correction PSD permitting action in the near future that will undergo its own public notice and comment period."[30] Thus, it is clear that no final PSD applicability determination has been made in this proposed permit proceeding, and that no new applicable requirements have been identified that could require a compliance schedule. Even a final determination of PSD applicability does not itself result in any applicable requirement, and EPA lacks authority to unilaterally create new PSD permit requirements in a Title V permit proceeding.[31] EPA appears to recognize these limits on its authority in the Draft Statement of Basis, stating that "[e]mission limits originating in a previously-issued PSD permit cannot be revised in a Title V permit without first (or simultaneously) revising the PSD permit under the applicable PSD regulations."[32] The same is true for whether that permit was "deficient." Such a decision must be made (if at all) in a PSD permit proceeding, not here. The "pre-existing requirements" applicable here and with which Deseret certified compliance are found in a duly issued PSD permit.

In short, EPA has not yet established PSD applicability for the ruggedized rotor project. If and when any new applicable requirements (i.e., permit conditions) are established in a PSD proceeding, those requirements may be incorporated into the permit according to the procedures already specified in Part 71. EPA's attempt to unilaterally impose a compliance schedule in the absence of such requirements and a certification of noncompliance by Deseret is both inappropriate and unlawful.

III. EPA Cannot Seek to Revise the 2001 PSD Permit Based on a Purported "Error" that EPA "Discovered" More than a Decade After the Permit Became Final.

A. EPA Has No Authority To Revise the 2001 PSD Permit.

The PSD permitting process is, at the most fundamental level, concerned with *pre-construction* review of the construction and modification of major sources.[33] Unlike a Title V permit, a PSD permit does not authorize a source's continuing operations: it is a one-time

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[29] *E.g.*, Draft Statement of Basis at 28 (emphasis added).

[30] *Id.* at 36.

[31] *See, e.g., Ohio Pub. Interest Research Grp. v. Whitman*, 386 F.3d 792, 794 (6th Cir. 2004); *New York Pub. Interest Research Grp. v. Whitman*, 321 F.3d 316, 320 (2d Cir. 2003) ("Title V permits do not impose additional requirements on sources"); *United States v. Duke Energy Corp.*, 278 F. Supp. 2d 619, 651-52 (M.D.N.C. 2003) ("Title V does not establish additional substantive requirements, but merely brings together applicable requirements").

[32] Draft Statement of Basis at 27.

[33] *See* CAA § 165 (titled "Preconstruction requirements").

authorization to perform the discrete act of constructing or modifying a source.[34] It is used to set forth the requirements on which the permitting authority will condition the source's construction or modification. In this way, the CAA ensures that all appropriate emission control technology will be identified at the earliest phases of the project, so that the technology can be incorporated into the source's design and installed in the most efficient way possible. Once construction is complete, any further PSD permit revisions would be untimely because the preconstruction period has passed. In other words, once construction is complete, any further PSD permit proceedings would be beyond EPA's authority, as the source would no longer need permission to construct something that has already been constructed.

Reflecting that pre-construction review must necessarily be limited to the pre-construction period, the CAA and the PSD regulations do not authorize EPA to reopen or revise final PSD permits.[35] In the Draft Statement of Basis, EPA acknowledges that "[t]he applicable federal PSD regulations, 40 CFR 52.21, do not include provisions for amending or revising permits."[36] The Agency also recognizes that "under the rules applicability of the major NSR program must be determined in advance of construction."[37] Thus by EPA's own admission, the premise underlying its proposed "compliance plan"—that the Agency may undertake an "error correction PSD permitting action" to make an applicability determination and revise the Bonanza plant's PSD permit—is fundamentally incorrect.[38]

Indeed, the PSD regulations specify that the *only* mechanism available to alter a PSD permit after it has been issued is for the source's *owner* to request its rescission.[39] Under the regulations, a source owner may request that the Administrator rescind a permit, and the Administrator must grant the request if specific criteria are met.[40] While certain permits "*other than* PSD permits" may be "modified, revoked and reissued, or terminated . . . upon the [permitting authority's] initiative," a PSD permit "may be terminated *only* by rescission under

[34] *See Sierra Club v. Otter Tail Power Co.*, 615 F.3d 1008, 1014 (8th Cir. 2010) (CAA language "unambiguously indicates that the PSD requirements are conditions of construction, not operation"); *United States v. EME Homer City Generation, L.P.*, 727 F.3d 274, 284 (3d Cir. 2013) (holding "unanimous view" is that "failure to comply with the PSD program is a one-time violation that occurs only at the time of construction or modification").

[35] *See* 40 C.F.R. § 52.21.

[36] Draft Statement of Basis at 27.

[37] *Id.* at 28.

[38] *Id*. at 36.

[39] 40 C.F.R. § 52.21(w)(2).

[40] *Id.* § 52.21(w)(2), (3) ("The Administrator *shall* grant an application for rescission if the application shows that this section would not apply to the source or modification.") (emphasis added).

§ 52.21(w) or by automatic expiration."[41] Thus, absent a request for rescission, the PSD regulations are clear that a permit "*shall* remain in effect" until it expires.[42]

EPA suggests that, despite this lack of statutory and regulatory authority, EPA guidance documents may provide a path for the Agency to revise PSD permits. Putting aside the fact that "guidance" does not trump the authority (or lack thereof) provided in statutes and regulations, the "guidance" that EPA cites is inapposite. That guidance merely addresses revising BACT limits *at the request of the source*, presumably shortly after construction, when it turns out that the source, as constructed, simply cannot meet the limits set in the permit.[43] That guidance did not address a situation in which the Agency "discovered" that a PSD permit it issued was "deficient," much less one where the Agency made such a "discovery" more than a decade after construction was complete, and now retroactively seeks to impose new and more stringent requirements on the source.[44] The relevant EPA guidance that exists actually demonstrates that the Agency's options are extremely limited, even where EPA "discovers" the deficiency shortly after the permit authorizing construction was issued, and clearly do not extend to the circumstances here, where the Agency "discovers" the purported "deficiency" after construction ended, much less more than a decade after construction.

In a July 15, 1988 memorandum, EPA directly addressed what options are available in circumstances where the Agency "discovers" that an EPA-issued permit is "deficient."[45] The 1988 Guidance is clear that any authority EPA has to revise a permit depends heavily on whether the Agency timely discovers the purported deficiency before construction of the source is complete. EPA concluded that its "ability to influence the terms of a permit, both informally and through legal procedures, *diminishes markedly* the longer EPA waits after a permit is issued before objecting" to it because courts are "less likely to require new sources to accept more stringent permit conditions the farther planning and construction have progressed."[46] Notably, EPA's list of its "only available options" in the 1988 Guidance does not include the novel approach that EPA has apparently chosen here—namely, to simply undertake a proceeding to issue a revised PSD permit years after the project in question has been completed.[47] In other

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[41] *Id.* § 124.5(a), (g)(2) (emphases added). Notably, § 124.5(g)(1) of those regulations is "Reserved for PSD Modification Provisions" that remain conspicuously absent from the Code of Federal Regulations.

[42] *Id.* § 52.21(w)(1) (emphasis added).

[43] Draft Statement of Basis at 27 (citing Memorandum from Gary McCutchen, Chief, EPA, & Michael Trutna, Chief, EPA, to J. David Sullivan, EPA Region 6 (Nov. 19, 1987) (Request for Determination on Best Available Control Technology (BACT) Issues – Ogden Martin Tulsa Municipal Waste Incinerator Facility) ("Ogden BACT Guidance")).

[44]Ogden BACT Guidance at 2 ("This guidance does not apply to any other type of noncompliance scenario.").

[45] Memorandum from Michael S. Alushin, Associate Enforcement Counsel for Air Office of Enforcement & Compliance Monitoring, EPA, & John S. Seitz, Dir., EPA, at 7 (July 15, 1988) (Procedures for EPA to Address Deficient New Source Permits Under the Clean Air Act) ("1988 Guidance") (attached as Exhibit B hereto).

[46] *Id.* at 2 (emphasis added).

[47] *Id.* at 7.

words, EPA is apparently planning to take an action here that its own longstanding policy affirms it has no authority to undertake. Indeed, the Supreme Court itself cited the 1988 Guidance in *Alaska Department of Environmental Conservation v. EPA* when it held that the Agency cannot "indulge in the inequitable conduct" of revising a PSD permit "months, even years, after a permit has been issued."[48]

Even where EPA acts quickly in response to a potentially deficient permit (rather than waiting over 13 years after the permit was issued, not to mention after construction was completed), the Agency has recognized that "if EPA cannot get the source to accept new permit conditions, [its] *only options* are review under [40 C.F.R.] Section 124.19(b) [since recodified to § 124.19(p)], revocation of the permit, and/or enforcement action."[49] As to the first option, review under § 124.19 must be brought within 30 days of permit issuance and is unavailable over 13 years after construction has been completed.[50]

As for the other two methods EPA identified as its "only available options," the 1988 Guidance warns that the regulations "are unclear about EPA's authority to revoke PSD permits."[51] In fact, the regulations provide EPA with *no* authority to revoke PSD permits, as discussed above.[52] Even if such authority did exist, unclear or not, the potential enforcement action EPA discusses—issuing an order under § 167 or § 113(a)(5) of the CAA to prevent commencement or require immediate cessation of construction—would be a meaningless exercise where, as here, construction is already complete.[53] Those provisions only authorize EPA to take action to *prevent* construction, not to impose new requirements after a project has been finished.[54] Where construction is complete, the CAA provides no mechanism for enforcement against an EPA-issued pre-construction permit.

Should EPA attempt to pursue such measures under section 167 or section 113, it would face yet another obstacle: any enforcement action related to the ruggedized rotor project is time-barred. EPA's ability to enforce alleged violations of the CAA's PSD requirements is constrained by a five-year statute of limitations.[55] This time limit applies equally to enforcement actions pursued through judicial suits and through administrative adjudication.[56] It bars any

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[48] 540 U.S. 461, 495 (2004) ("*Alaska DEC*").

[49] 1988 Guidance at 2 (emphasis added).

[50] *Id.* at 7; 40 C.F.R. § 124.19(p).

[51] 1988 Guidance at 7.

[52] *See* 40 C.F.R. § 52.21(w) (permit "shall remain in effect" unless it expires or source owner requests rescission); *id.* § 124.19(j) (allowing for permit withdrawal only during timely appeal to Environmental Appeals Board).

[53] 1988 Guidance at 7.

[54] *See* CAA § 167 (EPA may take enforcement measures "as necessary to *prevent the construction or modification* of a major emitting facility which does not conform to the requirements of this part") (emphasis added); *id.* § 113(a)(5) (EPA may "issue an order *prohibiting the construction or modification* of any major stationary source") (emphasis added).

[55] 28 U.S.C. § 2462; *see EME Homer City Generation, L.P.*, 727 F.3d at 282 n.9 (applying § 2462 in PSD enforcement proceeding).

[56] *3M Co. (Minn. Mining & Manuf.) v. Browner*, 17 F.3d 1453 (D.C. Cir. 1994).

untimely proceeding seeking civil penalties, as well as any action for injunctive relief.[57] Under the prevailing view in the federal courts, the statute of limitations begins to run once a source is constructed, which is considered a single occurrence rather than a "continuing violation."[58] Thus, any EPA enforcement action based on a project at Bonanza that was completed over 13 years ago is long since time barred.[59]

In any event, the 1988 Guidance also states that the drastic step of revoking a permit and taking enforcement action "should only be taken if *extremely strong equities* in favor of enforcement exist."[60] Needless to say, EPA faces particularly acute—if not insurmountable—"equitable problems associated with enforcing against [its] own permits."[61] In other words, EPA cannot take enforcement action against itself.

Indeed, since the 1988 Guidance was issued, several courts have confirmed that EPA cannot even collaterally attack duly-issued state CAA permits years after they are issued.[62] In light of these serious limitations, if a source submits adequate information and EPA simply issues a faulty permit (which, of course, is not the case here, but is suggested by EPA's self-

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[57] 28 U.S.C. § 2462 (barring proceeding for enforcement of "any civil fine, penalty, or forfeiture"); *see United States v. Midwest Generation, LLC*, 720 F.3d 644, 648 (7th Cir. 2013) (rejecting claims for injunctive relief because "[o]nce the statute of limitations expired, Commonwealth Edison was entitled to proceed as if it possessed all required construction permits *United States v. U.S. Steel Corp.*, No. 2:12-cv-00304, 2014 WL 1577837, at *5 (N.D. Ind. Apr. 18, 2014) (*Midwest Generation* held that "the government cannot seek injunctive relief for alleged permitting violations that were committed and completed many years ago."); *see also EME Homer City Generation, L.P.*, 727 F.3d at 292 (rejecting claims for injunctive relief because CAA "cannot be read so broadly as to authorize an injunction for completed violations").

[58] *E.g.*, *Midwest Generation*, 720 F.3d at 647; *Otter Tail Power Co.*, 615 F.3d at 1014-15; *Nat'l Parks & Conservation Ass'n v. Tenn. Valley Auth.*, 502 F.3d 1316, 1322 (11th Cir. 2007).

[59] That the statute of limitations bars any enforcement proceeding based on the ruggedized rotor project further proves that any attempt by EPA to alter the 2001 PSD Permit through *regulatory* action would also be inequitable. It would be legally inappropriate for EPA to do through a "permit modification" proceeding what it is statutorily barred from doing through an enforcement proceeding.

[60] 1988 Guidance at 5-6 (emphasis added).

[61] *Id.* at 7.

[62] *See United States v. EME Homer City Generation L.P.*, 823 F. Supp. 2d 274, 287 (W.D. Penn. 2011), *aff'd*, 727 F.3d 274 (3d Cir. 2013); *United States v. AM Gen. Corp.*, 34 F.3d 472, 475 (7th Cir. 1994) ("[W]e cannot find in the text of the Clean Air Act, or elsewhere, any indication that Congress expressly or by implication meant to authorize the EPA to mount a collateral attack on a permit by bringing a civil penalty action as many as five years after the permit had been granted and the modification implemented, . . . [and the source] had been operating under a permit valid on its face and never before challenged.").

serving *mea culpa*), the 1988 Guidance advises that EPA should "accept the permit" as it stands.[63]

Regarding the Bonanza plant, an order under CAA § 167 to "prevent the construction or modification" of the plant would have no effect here, where the project in question was completed over a decade ago. There is no activity currently proposed for construction or modification at the plant. Further, EPA has not suggested that it is making any finding that "extremely strong equities" favor revoking the 2001 PSD Permit. Nor can it, as described in Section III.B below.

B. Even If EPA Had Some Limited Authority To Revise A PSD Permit, The Due Process Clause And Fundamental Equity Concerns Preclude Its Exercise Here, Where The Project In Question Was Completed Over A Decade Ago.

To the extent that EPA has *any* authority to reopen or revise a PSD permit, it does not extend to the present circumstances. EPA is attempting to revise a *pre-construction* permit more than 13 years after it was first issued and the project was completed, apparently in order to impose for the first time new and drastically different PSD requirements. Retroactively imposing costly regulatory requirements as a condition to a source's construction—where the construction was completed long ago—would be fundamentally inequitable and impermissible, as EPA itself and the Supreme Court have recognized. Such action also would violate due process because it would impose substantial costs on Deseret without fair notice of the project's potential regulatory consequences and would constitute an impermissible retroactive rulemaking.

At the outset, it bears noting again that EPA itself states in its 1988 Guidance that its purported ability to revoke a PSD permit and issue a §167 stop-construction order should only be exercised "if extremely strong equities in favor of enforcement" exist.[64] In this regard, putting aside the nonsensical notion that a pre-construction permit could be revoked and a "stop-construction" order can be issued well after the construction ended, EPA's 13-year delay in addressing a permit it now claims was "deficient" disqualifies it from taking any action allegedly to remedy the purported deficiency. The Agency acknowledges the inequity of altering a pre-construction permit after construction has commenced, noting that "equitable considerations . . . make courts less likely to require new sources to accept more stringent permit conditions the farther planning and construction have progressed."[65] For that reason, EPA's "ability to influence the terms of a permit, both informally and through legal procedures, diminishes markedly the longer EPA waits after a permit is issued before objecting to a specific term."[66]

In contrast to the 1988 Guidance, which expressed concern over the equity of revising a PSD permit shortly after it has been issued but where "planning and construction have progressed" beyond the point at which it could be reasonable for the source to alter its design, here, construction has not only progressed; EPA has waited *over 13 years* after construction on

[63] 1988 Guidance at 7.
[64] *Id.* at 5-6.
[65] *Id.* at 2 (cited in *Alaska DEC*, 540 U.S. at 495).
[66] *Id.*

the project was *completed* before expressing its intent to correct its own purported "mistake." EPA's own guidance, as well as fundamental fairness and equity, preclude EPA's proposed action here.

Even more important, the Supreme Court also recognizes that equity concerns bar EPA from altering a PSD permit in circumstances such as this. In *Alaska DEC*, the Court held that the CAA authorizes EPA to conduct some limited review of the BACT determinations in a state-issued PSD permit shortly after it is issued but before significant construction had commenced.[67] However, the Court was careful to emphasize that EPA's authority does not extend to the "inequitable conduct" of invalidating a PSD permit "months, even years, after a permit has been issued."[68] The Court was "confident" that such "postconstruction federal Agency directives" affecting PSD permits could not survive judicial review.[69] EPA's action is even more inequitable here than the situation the Court described in *Alaska DEC*. Here, EPA is apparently planning to second-guess its own permit, one that specifically authorized the project at issue, more than a decade after the fact.

In addition, any revision to Bonanza's PSD permit well after construction has been completed would violate the Due Process clause of the U.S. Constitution by subjecting Deseret to harsh economic consequences without fair notice that its conduct would trigger such requirements. "Due process requires that parties receive fair notice before being deprived of property," whether that deprivation involves levying fines or requiring actions that "entail[] the

[67] 540 U.S. at 481, 501.

[68] *Id.* at 495 (internal quotation marks omitted).

[69] *Id.* (citing *United States v. AM General Corp.*, 34 F.3d 472, 475 (7th Cir. 1994), *aff'g* 808 F. Supp. 1353 (N.D. Ind. 1992)). In support of this conclusion, the Supreme Court cited *AM General*, a Seventh Circuit case affirming a lower court's rejection of EPA's attempt to collaterally attack a facially valid state PSD permit through enforcement action filed 4 months after the permit was issued and after the source's modification had been completed. In *AM General*, EPA had participated in the state permit proceeding and recommended that the permit be denied, but the state authority issued the permit anyway. 808 F. Supp. at 1359. Rather than immediately challenge the permit directly, EPA waited 4 months until after the source had already completed its modification to initiate an enforcement action against the source claiming that it was operating pursuant to an invalid PSD permit. *Id.* Citing the 1988 Guidance, the district court rejected EPA's enforcement action, holding that "[n]o enforcement authority is provided by the statute's plain language when, as here, a source is modified in reliance on a state-issued permit and the EPA later finds that the permit should not have been issued by the state permitting authority." *Id.* at 1365; *see also id.* at 1367 ("Nothing in § 113 authorizes the EPA to retroactively invalidate a permit issued by a duly authorized state authority and then institute enforcement proceedings against a permit holder for modifying a facility without a valid permit."). A unanimous Seventh Circuit affirmed. 34 F.3d at 475 ("[W]e cannot find in the text of the Clean Air Act, or elsewhere, any indication that Congress expressly or by implication meant to authorize the EPA to mount a collateral attack on a permit . . . after the permit had been granted and the modification implemented . . . .") (Posner, J.). Given that EPA cannot challenge a facially valid state-issued PSD permit 4 months after it was issued, it certainly cannot collaterally attack its own permit over 13 years after it was issued.

expenditure of significant amounts of money."[70] The requirement that an agency give fair notice of a regulation's applicability and consequences is "basic hornbook law in the administrative context."[71]

This fundamental notion embodies the principle that individuals should be able to ascertain the meaning of the law—and the consequences that flow from their conduct—before they engage in that conduct, so they can avoid triggering those consequences. Numerous factors are relevant to the question of whether a source had fair notice of regulatory requirements, most relevant here the Agency's own statements.[72] Here, EPA is seeking to undermine its own pre-construction permit after construction has already been completed. There can hardly be a more stark example of a lack of fair notice for Deseret.

The PSD permit revision proceeding that EPA contemplates in the Draft Statement of Basis would substantially deprive Deseret of its property without due process by potentially requiring costly pollution control retrofits. EPA cannot claim that Deseret had "fair notice" that the ruggedized rotor project would trigger PSD requirements in light of the Agency's own long-standing contrary interpretation—enshrined in a duly issued permit, no less—and its current confusion on the subject. At the time of the pre-construction review, EPA explicitly determined that the project was *not* a major modification. This position was embodied in two separate permits by EPA and UDAQ *approving* the project. The principles of fair notice would be meaningless if EPA could issue a permit specifically authorizing a project, only to completely reverse course after the project has already been completed and the source can no longer decide to pursue alternative action, including potentially not pursuing the project at all.

This kind of bait-and-switch is also precluded as a retroactive rulemaking. Courts have firmly established that retroactivity is not favored in the law and, as such, an agency may not promulgate retroactive rules absent express congressional authority.[73] An agency action is impermissibly retroactive if it "'creates a new obligation, imposes a new duty, or attaches a new

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[70] *General Elec. Co. v. EPA*, 53 F.3d 1324, 1328 (D.C. Cir. 1995) (citing *Mullane v. Central Hanover Bank & Trust Co.*, 339 U.S. 306, 314 (1950)); *id.* at 1329 ("In the absence of notice . . . an agency may not deprive a party of property . . . ."); *United States v Chrysler Corp.*, 158 F.3d 1350, 1354-55 (D.C. Cir. 1998) (fair notice required before imposing recall of cars already produced and sold).

[71] *General Elec. Co.*, 53 F.3d at 1329 (citing *Rollins Envtl. Servs.(NJ) Inc. v. EPA*, 937 F.2d 649, 654 n.1 (D.C. Cir. 1991) (Edwards, J., dissenting in part and concurring in part)).

[72] *See United States v. Hoechst Celanese Corp.*, 128 F.3d 216, 229 (4th Cir. 1997) (fair notice would be lacking if EPA issued conflicting interpretations of regulation).

[73] *Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208 (1988); *Nat'l Mining Ass'n v. Dep't of Labor*, 292 F.3d 849, 859 (D.C. Cir. 2002). As Justice Scalia noted in *Bowen*, a rule is "an agency statement of general or *particular* applicability *and future effect* designed to implement, interpret, or prescribe law or policy." *Bowen*, 488 U.S. at 216 (Scalia, J., concurring) (citing 5 U.S.C. § 551(4)) (first emphasis added). By this definition, a PSD permit condition is a rule, and given the notice requirements of the PSD program, even a notice-and-comment rule.

disability in respect to transactions or considerations already past.'"[74] The PSD permit revision EPA describes for the Bonanza plant would unquestionably impose new duties in connection with the ruggedized rotor project, a past transaction that Deseret began planning in 1997 and completed over 13 years ago.

The fundamental unfairness of this proposition—assigning new and unexpected legal implications to past actions—demonstrates why the CAA and its implementing regulations do not allow EPA to revise pre-construction permits once they are issued. One of the most basic goals of pre-construction review under the PSD program is to ensure that all applicable control technology will be incorporated into a source at the time it is first constructed or modified.[75] In part, this goal is motivated by efficiency: it is generally less expensive to install pollution controls as part of a source's initial design or modification rather than as a separate project.[76] But it is also motivated by a desire to ensure that source owners and operators can make fully informed decisions about whether or not to construct or modify a source. Especially in the context of a proposed project at an existing unit, the source owner must be able to accurately determine whether the project, as proposed, is a "major modification" and, if so, whether going forward with the project would require installation of additional controls. In other words, the source owner must be able to evaluate the full cost of controlling its emissions before commencing work on a project so that it can act accordingly.

For example, if the project, as proposed, would be a major modification, the source may choose to go forward with the project and install any additional controls that may be required as part of pre-construction permitting, but a rational source will do so only where it makes economic sense. That decision necessarily would be influenced by the controls that would be required as part of obtaining a pre-construction permit for the proposed project. Conversely, a rational source may choose not to undertake the project at all where the pollution control costs outweigh the potential economic benefits. Or the source may decide to go forward with the project, but to limit its future emissions so as to ensure that the project would not result in significant emissions increase, and thus would not be a "major modification" possibly requiring additional controls.

In short, pre-construction review ensures that the only projects that go forward are those for which the economic benefits justify the costs of preserving the existing air quality in the area. In this way, pre-construction review advances the statutory goal of "insur[ing] that economic growth will occur in a manner consistent with the preservation of existing clean air resources."[77]

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[74] *Nat'l Mining Ass'n*, 292 F.3d at 859 (quoting *Nat'l Mining Ass'n v. U.S. Dep't of Interior*, 177 F.3d 1, 8 (D.C. Cir. 1999)).

[75] *Wisc. Elec. Power Co. v. Reilly,* 893 F.2d 901, 909 (7th Cir. 1990) ("*WEPCO* ") (citing H.R. REP. NO. 95-294, at 185 (1977), *reprinted in* 1977 U.S.C.C.A.N. 1077, 1264).

[76] *Id.* ("The purpose of the 'modification' rule is to ensure that pollution control measures are undertaken when they can be most effective, at the time of new or modified construction.") (internal quotation marks and citation omitted); *see also United States v. DTE Energy Co.*, 711 F.3d 643, 651 (6th Cir. 2013).

[77] CAA § 160(3).

In contrast, imposing new pollution control requirements *after* construction is complete would fundamentally change the basis upon which the project proceeded. This risks stranding resources that could have been allocated to other beneficial purposes at the outset with better warning. It also denies source owners the opportunity to determine, before construction, what course of action makes sense, such as not undertaking projects that will later subject them to costly control requirements, or altering the project to avoid such requirements. Here, Deseret obtained two preconstruction permits for the ruggedized projects—one from the State of Utah and one from EPA—and both agencies agreed that the project required no additional controls.

If Deseret had been informed before starting the ruggedized rotor project that the project could subject the Bonanza plant to additional BACT controls, Deseret may have chosen to go forward with the project if the cost of these controls were economically rational; or it may have chosen not to conduct the project at all if the benefits of the new rotor would not allow it to recover the costs of installing and operating additional controls; or it may have obtained a synthetic minor permit to proceed with the project. Now that the project has already been completed, if EPA revises the PSD permit purportedly to include new BACT limits, and if these new BACT limits would require expensive new controls, Deseret will not have the option of simply foregoing the project as it could have done if it had been given fair notice of these consequences during the pre-construction review.[78]

Moreover, Deseret would suffer these unforeseeable consequences as a result of a project that was authorized by not one, but *two* facially valid preconstruction permits. The CAA cannot be read to allow such a deprivation of fundamental due process. Deseret is confident, as the Supreme Court was in *Alaska DEC*, that EPA "could not indulge in the inequitable conduct" of revising a PSD permit "months, even years" after the fact "while the federal courts sit to review EPA's actions."[79]

C. The Ruggedized Rotor Project Did Not Result In A Significant Emissions Increase.

As noted above, EPA has not proposed to make a finding of PSD applicability in this proceeding.[80] Deseret supports EPA's decision not to make such a finding in this Title V permit proceeding, and reiterates that EPA has no authority to modify, revise, or revoke the Bonanza plant's PSD permit here or in *any* future proceeding.[81] In any event, the Agency's "preliminary determination" in the Draft Statement of Basis that "the 2000 ruggedized rotor project should have undergone PSD review for NOx, including a BACT analysis," is wrong.[82] If EPA commences an administrative process to "revise" the 2001 PSD Permit, the Agency will bear the burden of proving that its determination in that permit that the ruggedized rotor project would

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[78] Of course, in any such proceeding Deseret must be afforded other options, including obtaining a "synthetic minor" permit.

[79] *Alaska DEC*, 540 U.S. at 495.

[80] *E.g.*, Draft Statement of Basis at 28 ("[W]e intend to propose—in a *separate permitting action* in the near future—a PSD correction permit for this facility.") (emphasis added).

[81] *See supra* Section III.A-B.

[82] Draft Statement of Basis at 49.

not cause a significant emissions increase was incorrect. EPA did not make such a showing in the record of this permit proceeding. Indeed, based on the information EPA currently in the record, it cannot make such a showing. At EPA's request, Deseret previously provided an informal, preliminary analysis in 2005 addressing some of the reasons why the project did not result in a significant emissions increase.[83] EPA did not inform Deseret at the time that it disagreed with the conclusions of that preliminary analysis or that it needed additional information or analysis. If EPA undertakes a PSD permit "revision" proceeding in the future (which, EPA legally cannot, as discussed earlier), Deseret will submit a comprehensive analysis in that proceeding demonstrating that the project did not trigger PSD requirements. That analysis would demonstrate two key points.

First, the project was authorized in two separate preconstruction permits by the State of Utah and by EPA. Using data that satisfied the requirements of the applicable PSD regulations, both of these permitting authorities concluded that the project would not result in significant emissions increases, and that NOx emissions would actually decrease as a result of the contemporaneous installation of low-NOx burners.[84] Both PSD permits contained enforceable emission limits based on the operation of these low-NOx burners.[85] Thus, regardless of the plant's post-project utilization and emissions, the project did not trigger PSD requirements because it was affirmatively authorized by both Utah and EPA in PSD permits.

Second, the project was not expected to and did not cause a significant increase in NOx emissions because the NOx emission rate—both on a lb/mmBtu basis and at full capacity—*decreased* as a result of the contemporaneous installation of low-NOx burners, and the project was not expected to and did not increase the unit's utilization. NOx reductions resulting from these low-NOx burners were appropriately accounted for in the pre-project emissions calculations that formed the basis of Utah's and EPA's PSD permits; and they must be accounted for in any "retrospective" analysis that would have to be undertaken in any proceeding to "revise" the Bonanza PSD permit.[86]

Specifically, even though the MW rating (and maximum hourly heat input) of the unit increased as a result of the project, because the NOx emission rate at maximum MW rating after the project was lower than the NOx rate at maximum MW rating before the project, the project itself could not cause any increase in NOx emissions. It could only decrease them. Moreover,

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[83] Letter from Howard Vickers, Envtl. Supervisor, DG&T, to Michael Owens, EPA Region 8 (Sept. 27, 2005) (Ruggedized Rotor Spreadsheet for the Bonanza Plant), Doc. No. 21.

[84] Utah Dep't of Envtl. Quality, Approval Order for Modification of Bonanza One Power Plant Emission Limits, Change in Coal Pile Parameters, and Ruggedized Rotor Project, Approval Order No. DAQE-186-98 at 3 (Mar. 16, 1998), Doc. No. 02 ("1998 Approval Order"); 2001 PSD Permit at 3.

[85] 1998 Approval Order at 3; *see* 2001 PSD Permit at 3 ("The Permit has conditions as stringent for SO_2, NOx, PM, and PM_{10} as those contained in" the 1998 Approval Order).

[86] *See* Order Responding to Petitioners' Requests That the Administrator Object to Issuance of State Operating Permits at 20-26, *In re Scherer Steam-Electric Generating Plant Juliette, Georgia*, Petition No. IV-2012-1 (EPA Adm'r Apr. 14, 2014) (attached as Exhibit C hereto).

there was no reason to expect, before the project was undertaken, that the unit's utilization would increase as a result of the project. The increase in utilization of the Bonanza plant that did occur upon completion of the project was clearly and demonstrably the result of independent factors – mainly, the California energy crisis, which happened to coincide with the project. In the wake of the collapse in the California energy market, the more limited supply of electricity generation led to spectacular wholesale price spikes and (as it did at power plants across the West) fuller utilization of the Bonanza plant to satisfy consumer demand. But the plant could have accommodated the increased emissions associated with this increased utilization because its pre-project equivalent availability factor was extremely high, and using a baseline that includes the period before the low-NOx burner upgrades, could have emitted substantially more than it actually did emit. In short, any increase that did occur in the overall post-project emissions from the Bonanza plant was caused by demand growth and not by the project.

Deseret will comment on these PSD applicability issues in more detail in the appropriate proceeding if EPA proposes administrative action to revise the 2001 PSD Permit.

IV. Jurisdiction

For years prior to EPA asserting Indian Country jurisdiction over the Bonanza plant site, the status of the site and related factual and legal issues pertaining to Indian Country boundaries in the surrounding areas remained in question and open to ongoing judicial proceedings. EPA first made its determination that that Bonanza is situated within Indian Country no sooner than July 19, 1999.[87]

One of the most important elements of the proposed Title V Permit is EPA's attempt to assert that, *even prior to its determination of Indian Country jurisdiction,* EPA should be recognized as the sole jurisdictional regulatory authority—that the State of Utah's regulatory actions undertaken with respect to Bonanza prior to the EPA asserting jurisdiction were and are a legal nullity. This claim is contrary to well-established law and cannot form any part of the basis on which EPA may proceed in this permitting action.

For years, parties have disputed whether the site on which the Bonanza Plant is situated lies within the exterior boundaries of what is now known as the Uintah and Ouray Indian Reservation ("Reservation"). At the outset, it is important to note that neither the United States, nor EPA, nor Deseret has ever appeared as a party in any portion of the decades-long legal battles (state and federal) pertaining to the boundaries of the Reservation. EPA (and the United States) have therefore never sought nor obtained a court order, judgment, declaratory decree or similar binding decision in their favor granting to EPA permitting authority over the area encompassing the Bonanza Plant site.

EPA is incorrect in its conclusion, in the Draft Statement of Basis, that Utah was "not the correct permitting authority" when it issued the pre-construction permit to approve the rotor

[87] Letter from Monica S. Morales, EPA Region 8, to Ed Kurip, Dir., Ute Indian Tribe Air Quality Mgmt., & Rusty Ruby, Manager, UDAQ at Table 1 (July 19, 1999) (Regarding 40 C.F.R. Part 71 Sources on Uintah and Ouray Reservation) (attached as Exhibit D hereto).

project in 1998. Courts have conclusively held that Congress intended state regulatory agencies to retain primary jurisdiction under state permitting programs in all instances where continuing legal or factual uncertainty exists as to the status of any given source and its possible location within "Indian Country."

As the D.C. Circuit has explained:

> [U]nlike typical political boundaries, the jurisdictional boundaries of Indian tribes are not always clearly delineated, and often are determined through adjudication or other administrative proceedings. . . . EPA's only authority under the Clean Air Act to operate a federal permitting program arises from 42 U.S.C. §§ 7601(d) and 7661a, and . . . these provisions require that EPA make a determination as to whether a state or a tribe has jurisdiction [before the Agency may assume permitting jurisdiction].[88]

The State of Utah issued its notice of intent to approve the ruggedized rotor project on January 30, 1998.[89] EPA was copied by UDAQ on this notice, which stated that the proposed modification was based on air quality analysis available from UDAQ and that comments would be considered for 30 days following publication of the notice.[90] EPA never objected to the UDAQ's proposed issuance of the 1998 Approval Order.

A few months later, on March 16, 1998, UDAQ issued the final 1998 Approval Order authorizing the completion of the ruggedized rotor project, which entailed, among other things, the installation of low NOx burners, modification of the emission limits to lower permitted levels of NOx from Bonanza, and installation of redesigned turbine blading, pulverizers, control equipment, etc.[91]

It makes no difference for this permitting action whether, in retrospect, Bonanza was located on Indian Country as of the date that the State of Utah issued the 1998 Approval Order and approved the project. What matters, as the court in *Michigan* clearly instructs, is that EPA had not yet made a determination that the site was within Indian Country as of that date.[92]

EPA could not have made a determination on jurisdiction prior to UDAQ's publication of the notice of intent to approve the project or its issuance of the 1998 Approval Order. Such a determination at that date would have been premature, given that the issue remained *sub judice* before the Utah federal district court in *Ute Indian Tribe v. Utah*. It was not until March 2000 that the federal district court in Utah finally dismissed the lawsuit which had raised the boundary

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[88] *Michigan v. EPA*, 268 F.3d 1075, 1079, 1087 (D.C. Cir. 2001) (internal citations omitted).

[89] UDAQ, Intent to Approve Modification of Bonanza Unit (1) Power Plant Emission Limits, Change in Coal Pile Parameters, and Ruggedized Rotor Project, No. DAQE-086-98 (Jan. 30, 1998) (attached as Exhibit E hereto).

[90] *Id.* at 2.

[91] 1998 Approval Order at 3.

[92] *See Michigan*, 268 F.3d at 1087.

issues.[93] EPA first asserted primary jurisdiction in CAA permitting matters concerning the Bonanza Plant and the PSD permit approximately *one year after* the 1998 Approval Order was final and binding. There was never any notice or rulemaking, and EPA afforded no opportunity for comment with respect to its determination in 2000 that the boundary/jurisdictional issues were to be resolved in favor of EPA exercising direct permitting authority.[94]

Deseret does not need to contend (nor is it necessary to resolve at this point) whether the boundaries of the Reservation were diminished by Congressional Act on that portion of the Reservation where the Bonanza plant site is located. Therefore, Deseret does not here exhaust the issue concerning the extent to which the Bonanza plant is excluded from jurisdiction under the EPA's Indian Country authority.[95] Deseret continues to expressly reserve on that issue, but raises it here to place EPA on notice that it may indeed be raised and litigated in any subsequent PSD revocation or modification proceeding.

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[93] Stipulated Order Vacating Preliminary Injunction and Dismissing the Suit with Prejudice, *Ute Indian Tribe v. Utah*, No. 2:75-cv-00408-BSJ (D. Utah Mar. 28, 2000), Docket No. 145. The lawsuit has since been reopened in 2013 to consider, among other things, further issues of tribal authority over non-Tribe member activities.

[94] Throughout the record of EPA's 2001 PSD Permit, and of UDAQ's 1998 Approval Order, EPA made and acted upon numerous statements, positions, and determinations that preclude the Agency from now attempting to reverse itself with respect to the project's pre-construction review and authorization. Deseret does not present a detailed discussion of these issues, including equitable estoppel and similar doctrines related to EPA's past conduct: that analysis would be presented, and Deseret's position thereon will be pressed, at such time, if any, as EPA may attempt to proceed with any future PSD modification.

[95] As a non-party to the *Ute Tribe* litigation which led to the Tenth Circuit's 1985 *en banc* decision known as "*Ute III*," 773 F.2d 1087 (10th Cir. 1985), Deseret believes itself entitled to an opportunity to raise the issue of the U.S. Supreme Court's subsequent contrary statutory interpretation found in *Hagen v. Utah*, 510 U.S. 399 (1995), which was not, nor could not have been, presented by the parties to the litigation that ended ten years earlier. As a non-party to the litigation, EPA and/or the United States would have difficulty asserting issue preclusion against another non-litigant in that case. Moreover, the subsequent Supreme Court precedent in *Hagen* has not been addressed by the courts in the context of a lawsuit commenced after the final mandate of *Ute III* involving facts specifically pertaining to Indian country jurisdiction within the Uncompahgre portion of the Reservation. The Tenth Circuit has subsequently recognized the error in its own statutory interpretation in *Ute III*, *see Ute Tribe V*, 114 F.3d 1513 (10th Cir. 1997), and presumably would now decide that the portion of the Reservation once known as the Uncompahgre, on which Bonanza is located, has been diminished or disestablished. The appellate court was prevented from altering its earlier mandate only by virtue of the fact that no present case or controversy was presented to the Court in *Hagen* concerning the Uncompahgre portion of the Reservation. In any event, EPA has not properly undertaken, through public comment and rulemaking, to support its determination of Indian country jurisdiction over Bonanza; it would be odd indeed for EPA to assert that Deseret is collaterally estopped from challenging a jurisdictional determination that EPA never correctly made in the first instance.

Deseret does assert that EPA is factually and legally incorrect in its conclusion in the Draft Statement of Basis that "Utah was not the correct permitting authority" when it acted to grant Deseret the 1998 Approval Order.[96] As the D.C. Circuit held,

> Where a valid state program exists, EPA may implement a federal program only for Indian country itself, not for lands the status of which EPA deems 'in question.' Thus, prior to implementing any federal operating permits program EPA must determine the scope of state and tribal jurisdiction. In making such determinations EPA *must use notice and comment proceedings*. . . . This includes determinations of 'adequate authority,' and thus determinations of jurisdiction under the Act.[97]

Having failed to make a determination of the scope of state and tribal jurisdiction on the Bonanza plant site, prior to March 1998, when the State of Utah issued the 1998 Approval Order to Deseret, EPA cannot claim jurisdiction as of that date on behalf of the Tribe. Likewise, as the D.C. Circuit explained in *Michigan*, there is no "vacuum" of jurisdiction that deprives the State of legitimate regulatory authority during the period when the status is in doubt – the State has legitimate jurisdiction until such time that EPA, on behalf of the Tribe, properly exercises Indian Country jurisdiction.

EPA cannot ignore or dismiss the State of Utah's authoritative Approval Order issued in March 1998. EPA cannot dismiss or diminish its own issuance of the 2001 PSD Permit by disavowing any reliance that it may have placed, in issuing that permit, on duplicating the analysis performed by the State of Utah in issuing the 1998 Approval Order. In its Draft Statement of Basis, EPA attempts to discredit its own PSD permitting decision, arguing that it was "improper" to have relied in part on the State's pre-construction permit analysis because, as EPA now asserts for the first time, the State lacked authority to issue the 1998 Approval Order. As demonstrated above, this latest contention of the EPA is erroneous. Utah *did* have jurisdiction, and therefore the Utah State Permit must be accepted. So too, EPA's decision and its action, to the extent it may have relied on the same or similar PSD analysis as was performed by the State, *was* appropriate and must continue to be recognized and accepted. In fact, it was required, because the project was authorized by a valid state PSD permit and EPA has no authority to second-guess such a state action—at least not years after the fact.[98] Where EPA has no authority to act for the Tribe, the State retains jurisdiction and has plenary permitting authority under the CAA.[99]

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[96] Draft Statement of Basis at 43.

[97] *Michigan*, 268 F.3d at 1088-89 (emphasis added) (internal citations omitted).

[98] *See supra*, Section III.

[99] *Michigan*, 268 F.3d at 1086 ("Jurisdiction as between states and tribes is binary, it must either lie with the state or with the tribe—one or the other—and EPA does not have a third option . . . .").

V. Comments on Specific Proposed Conditions in Draft Title V Permit

Deseret offers the following comments on specific sections of the proposed Draft Title V Permit, with insertions indicated by underlined text.

Section I.A: Potential to Emit

Comment: The potential to emit for the overall plant, shown on page 9 of the Draft Title V Permit, states that it is "based on an estimate by Deseret Power that approximately 99.5% of the coal is burned while the pollution control equipment is in service."[100] The values listed on page 9 reflect values derived based on an estimate assuming that 100% of the coal is burned while pollution control equipment is in service, not 99.5%.

Section I.B: Facility Emission Points

Comment: Table 2, page 9 of the Draft Title V Permit lists "BOILER: Foster-Wheeler steam generator; heat input capacity of 4,578 MMBtu/hr." The Emission Unit 1-1 is in fact a Foster-Wheeler design boiler, with heat input capacity that has previously been permitted and described, for all permitting purposes as "about 4578 MMBTU/hr."[101] The description of the boiler in the Draft Title V Permit should reflect accurately the description provided by Deseret and incorporated into the relevant PSD Permit, and should read: "BOILER: Foster-Wheeler steam generator; heat input capacity of about 4,578 MMBtu/hr . . . ."

Comment: Table 3, page 10 of the Draft Title V Permit lists Activity/Emission Unit ID 1-2 as "AUXILIARY BOILER * (184 MMBTU/hr, pre-1984, fired on fuel oil or natural gas)." The description should read: "AUXILIARY BOILER * (168 MMBtu/hr, pre-1984, fired on fuel oil or natural gas)."

Section II.A.3: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Steam Generating Units

Comment: Subsection (d), pages 52-55, "Notification, Reports and Records." This section pertains to requirements of 40 C.F.R. Subpart UUUUU, the compliance date of which will not commence until sometime in the future. This Subpart, and all requirements under the Draft Title V Permit, should be conditioned on the effective beginning date on which such reports, notifications, and records will be required to be made/kept. Each paragraph ((d)(i), (d)(ii), and (d)(iii)) and all other relevant provisions of the Draft Title V Permit pertaining to compliance under subpart UUUUU should include specific dates for the beginning effective date of mandatory compliance as set forth in the MATS regulations. Deseret believes that no Subpart UUUUU requirement will impose mandatory obligations regarding the Bonanza Unit before April 16, 2015.[102]

[100] Draft Title V Permit at 9.
[101] *See* 2001 PSD Permit at 2.
[102] *See* 40 C.F.R. § 63.9984(b).

Section II.A.4: National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [40 CFR Part 63, Subpart ZZZZ]

<u>Comment</u>: Subsection (a), pages 55-58, "Existing emergency diesel fire pump (498 hp, started up mid-1980's)." This entire paragraph should be deleted. Part 63, Subpart ZZZZ is no longer applicable for the new emergency diesel fire pump engine that Deseret is purchasing to replace the older failed one referenced in the Draft Title V Permit. 40 C.F.R. § 63.6590(c)(6)

Section II.A.5: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 C.F.R. Part 60, Subpart IIII]

<u>Comment</u>: Deseret is replacing an emergency diesel fire pump engine with a new model, which will require additional changes to the Draft Title V Permit, including the following:

1. Description, page 59, should read: "These requirements apply to the 1,220-horsepower emergency diesel generator which started up on January 8, 2013 <u>and the 494-horsepower emergency diesel fire pump engine which is anticipated to start up by the end of 2014</u>."

2. Subsection (a), page 59, "Emission standards," should reference the following: 40 C.F.R. § 60.4205(b) <u>– emergency diesel generator; 40 C.F.R. § 60.4205(c) - emergency diesel fire pump engine</u>.

3. Subsection (b), "Compliance requirements." The top of page 60 should read:

   If the permittee does not install, configure, operate and maintain the engine according to the manufacturer's emission-related written instructions, or changes the emission-related settings in a way that is not permitted by the manufacturer, the permit shall demonstrate compliance in accordance with 40 C.F.R. § 60.4211(g)(3) <u>for the emergency diesel generator and 40 C.F.R. § 60.4211(g)(2) for the emergency diesel fire pump engine</u>.

4. Subsection (d), page 60, "Testing requirements." This should read: "Performance tests conducted pursuant to Subpart IIII, <u>if required by 40 C.F.R. § 60.4211(g),</u> shall be done in accordance with § 60.4212(a) through (e)." 40 C.F.R. § 60.4212.

5. Subsection (e), page 60, "Notifications, reports and records." This should read:

   <u>An initial notification is not required for the emergency diesel generator and the emergency diesel fire pump engine.</u> The permittee shall keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The permittee shall record the time of operation of the engine and the reason the engine was in operation during that time. 40 C.F.R. § 60.4214(b).

Section II.A.6: Federal PSD Permit Issued February 2, 2001

<u>Comment</u>: Paragraph (a), pages 60-65, "Particulate matter emission limitations, testing and monitoring." The Draft Title V Permit sets forth particulate matter emissions limits from the

main boiler stack not to exceed "0.0297 lb/MMBtu of heat input" (in subsection (a)(i)) and "0.0286 lb/MMBtu of heat input" (in subsection (a)(ii)).[103] Both of these limits should be clarified to include only total filterable particulate matter.

Comment: Paragraph (a)(viii)(A), pages 62-63, "Compliance Assurance Monitoring (CAM), Indicator #1." The definition of excursion for the CAM plan should be clarified so that, at times when the unit is completely shut down (as for extended maintenance outages), the parameter of "less than four of the 24 baghouse compartments are in service" can be disregarded. Deseret suggests adding the following language at the end of the provision:

> Definition of excursion: An excursion shall be defined as any time that less than four of the 24 baghouse compartments are in service at any one time while combustion is occurring within the boiler or while stack exit temperature remains significantly above ambient air temperature following shutdown of the unit.

Comment: Paragraph (a)(viii)(B), pages 63-64, "Compliance Assurance Monitoring (CAM), Indicator #2." Deseret has proposed an alternative indicator for CAM assurance, which entails Deseret's intention to install Particulate Matter Continuous Emissions Monitoring System ("PM CEMS") for the limited purpose of providing an additional CAM indicator. The sole purpose of installing PM CEMS as set forth in the CAM plan will be to provide another indicator, and PM CEMS is not required to be installed or maintained under any relevant provision of law or regulation. The Title V Permit cannot be deemed, and should not be read to imply, that any such requirement to install or operate PM CEMS for compliance or other monitoring purpose exists, and no reporting, calibrating, or other maintenance requirement can be derived by virtue of Deseret proposing this second CAM indicator, beyond the express conditions contained in the Draft Title V Permit CAM provision.

Section II.B: Fugitive Emission Sources

Comment: Section II.B.1(g), pages 75-76. The second complete sentence on the top of page 76 should include the following provision to allow for consistent, practical fugitive control treatment, especially given long periods during winter months when surface areas are covered by snow or ice: "Treatment shall be of sufficient frequency and quantity to maintain the surface material in a damp/moist condition during times of use and when it is reasonably applicable relative to weather conditions."

Comment: Section II.B.2(c), page 77. The provision requiring Method 9 testing "no less frequently than monthly" should be modified with the following: "except for months when the monthly average outside temperature is below freezing (generally November through February)." It is not practical nor needed to perform a Method 9 during typical winter months for roads and storage piles. Similar language is in our Fugitive Emission Dust Control Plan,

[103] Draft Title V Permit at 60-61.

included as Attachment 2 to the Draft Title V Permit.[104] The 2001 PSD Permit also states, "The opacity must not exceed 20% during all times the areas are in use or the outside temperature is below freezing."[105] Deseret interprets this condition to require that during the summer, opacity must not exceed 20% when the areas are in use.

Attachment 1: Bonanza Plant Process Description

Comment: Page 1, "General plant description." The third paragraph of this description is incorrect and should be revised to read as follows:

> 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.

Deseret makes no sales of electricity from the Bonanza plant to southern California.

Comment: Page 1, "Fuel systems." The last paragraph of this section is incorrect because there are no underground storage tanks at the plant. The paragraph should be revised to read as follows:

> 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.

Comment: Page 2, "Baghouse." The last sentence, last paragraph of the description should be corrected to read: "From the hopper, the ash is transported to a silo where it is mixed with scrubber waste streams for landfill." Bottom ash is not mixed with the fly ash.

Comment: Page 2, "Scrubber." The second sentence, first paragraph of the description should be corrected to read: "It consists of three identical countercurrent absorber modules, of which at least two are on line any time the plant is in service." There are times when three absorbers are in service.

Comment: Page 2, "Scrubber." The second sentence, second paragraph of the description should be corrected to read: "The slurry is mixed into the absorber modules to

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[104] Draft Title V Permit, Attachment 2, at 2 ¶ 5 ("Deseret recognizes that there are periods of unusual weather events such as strong winds or periods of extreme cold when reasonable methods to control fugitive dust would not be successful.").

[105] 2001 PSD Permit at 19, ¶ 34.

maintain the module percent solids between 13% and 17% with a pH between 5.5 and 6.0."

Comment: Page 3, "Emission monitoring equipment." The first sentence, first paragraph of the description should be corrected to read that the samples are taken at 334.5' not 320' from grade.

BEFORE THE UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY
REGION 8

DRAFT TITLE V PERMIT TO OPERATE BONANZA POWER PLANT	**Draft Permit No. V-UO-000004-00.00**

EXHIBITS A THROUGH E TO COMMENTS OF DESERET GENERATION & TRANSMISSION CO-OPERATIVE

William L. Wehrum
Makram B. Jaber
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Counsel for Deseret Generation & Transmission Co-operative

June 16, 2014

EXHIBIT A

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

COPY

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 Revised Emission Limits, Change in Coal Pile Parameters and Ruggedized Rotor Project, Uintah County

Dear Ms. Trueman:

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

The Ruggedized Rotor Project will increase the overall 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. DG&T proposes to increase its PTE for other emissions as follows: particulate emissions 22.60, PM_{10} 14.11 TPY, SO_2 38.21 TPY, CO 91.60 TPY, VOC 10.68 TPY.

DG&T also proposes a change in its Coal Pile parameters to allow the area of the pile to increase to 22 acres and the active reclaim area to increase to 11 acres. The total emission increase from this change will be 3.08 TPY of particulate emissions. The additional emissions will be offset by a reduction in the emission limit for particulate emissions from the tall stack.

The new Coal Pile parameters and Bonanza 1 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 for which DG&T plans to submit applications for applicable sales tax credits.

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

Sincerely,

Stan Gordon
Plant Manager

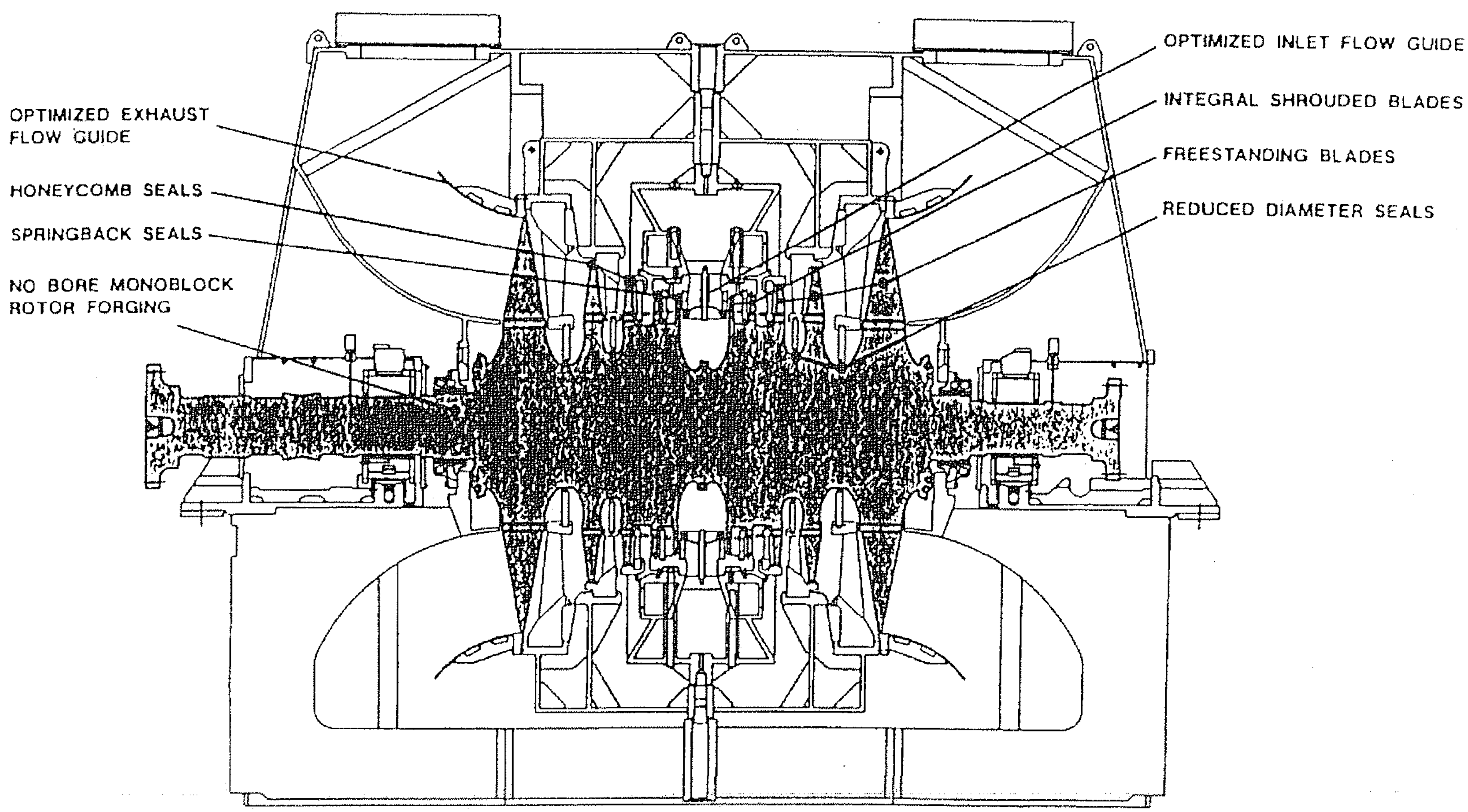
Attachment 1

Ruggedized Rotor Project Description

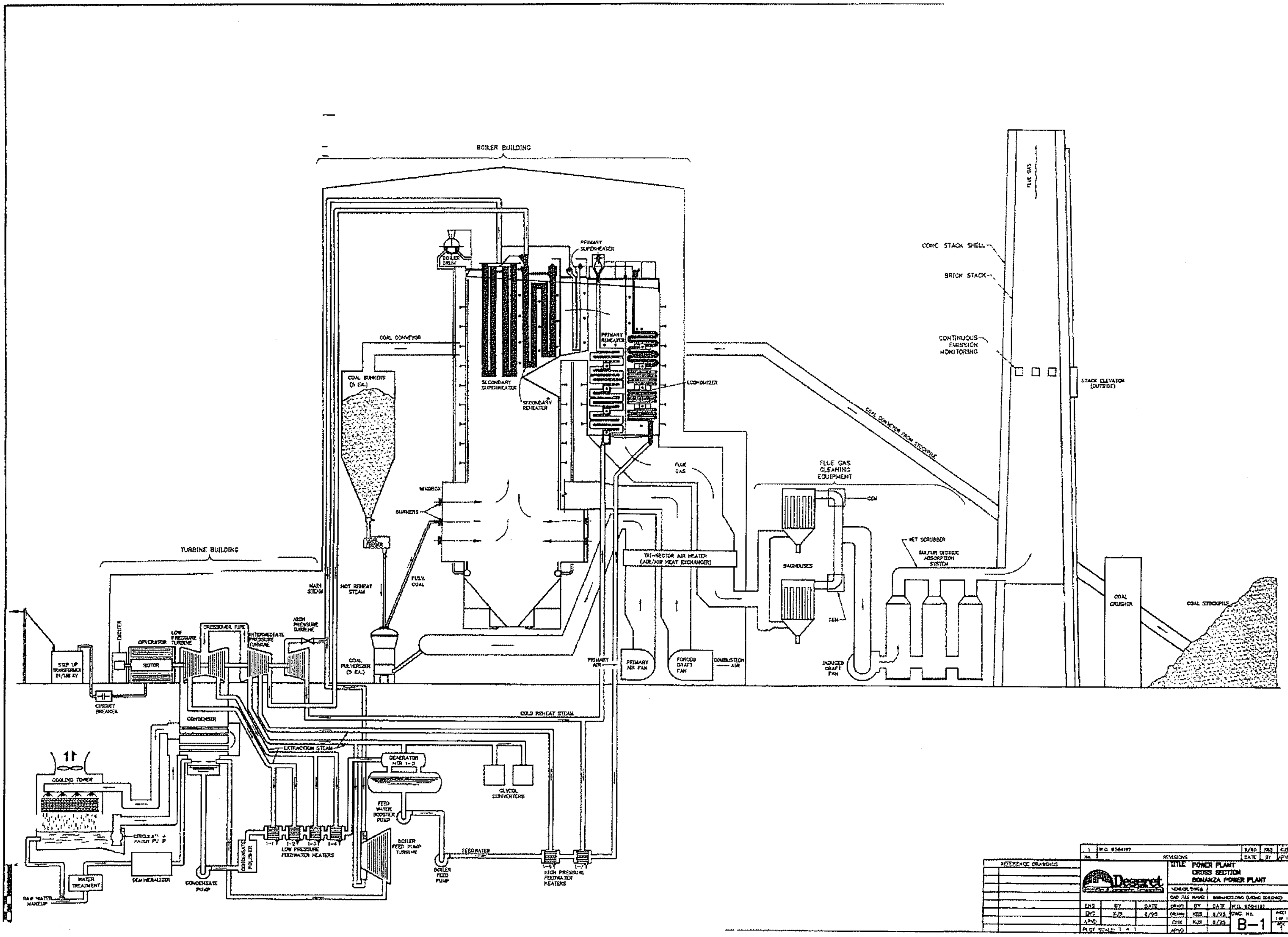
DG&T plans to upgrade the Turbine Generator at Bonanza 1 during the year 2000 or 2001 Unit Outage (A cross section diagram of Bonanza 1 indicating the location of the turbine is attached hereto). The upgrade–referred to as the "Ruggedized Rotor Project"–involves the replacement of the HP/IP and LP rotating 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 time frame and is expected to take about 6 weeks. The Project will increase Bonanza 1's generating capacity by at least 28 MW (per vendor representations). DG&T believes that the gross rating of Bonanza 1 could be as much as 500 MW or more (referred to as 500 est. MW) after the upgrade.

Approximately 20 MW from the upgrade will result from an increase in the 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 in Bonanza 1's emissions, the increased capacity of the Turbine Generator to handle the Boiler's peak capacity will increase Bonanza 1's overall potential to emit (PTE).

DG&T has prepared this NOI to provide for necessary increases in Bonanza 1's overall PTE to allow operation of the Boiler and Turbine Generator at their full capacity. DG&T also recently installed improved low-NO_x burner technology at the boiler which allows DG&T to voluntarily significantly reduce NO_x emissions. The net effect of the proposed emission changes will be to significantly reduce overall plant wide emissions as a result of lower NO_x limits.



RUGGEDIZED LP ROTOR


BOILER BUILDING
TURBINE BUILDING
PRIMARY SUPERHEATER
BOILER DRUM
COAL CONVEYOR
COAL BUNKERS (5 EA.)
SECONDARY SUPERHEATER
SECONDARY REHEATER
PRIMARY REHEATER
ECONOMIZER
COAL CONVEYOR FROM STOCKPILE
CONC STACK SHELL
BRICK STACK
CONTINUOUS EMISSION MONITORING
FLUE GAS
STACK ELEVATOR (OUTSIDE)
WINDBOX
BURNERS
COAL FEEDER
PULV. COAL
HOT REHEAT STEAM
MAIN STEAM
HIGH PRESSURE TURBINE
INTERMEDIATE PRESSURE TURBINE
CROSSOVER PIPE
LOW PRESSURE TURBINE
GENERATOR
ROTOR
EXCITER
STEP UP TRANSFORMER
CIRCUIT BREAKER
COAL PULVERIZER (5 EA.)
FLUE GAS CLEANING EQUIPMENT
BAGHOUSES
CEM
TRI-SECTOR AIR HEATER (AIR/AIR HEAT EXCHANGER)
WET SCRUBBER
SULFUR DIOXIDE ABSORPTION SYSTEM
COAL CRUSHER
COAL STOCKPILE
PRIMARY AIR
PRIMARY AIR FAN
FORCED DRAFT FAN
COMBUSTION AIR
INDUCED DRAFT FAN
COLD REHEAT STEAM
CONDENSER
EXTRACTION STEAM
DEAERATOR
GLYCOL CONVERTERS
COOLING TOWER
CIRCULATING WATER PUMP
FEED WATER BOOSTER PUMP
BOILER FEED PUMP TURBINE
FEEDWATER
BOILER FEED PUMP
HIGH PRESSURE FEEDWATER HEATERS
LOW PRESSURE FEEDWATER HEATERS
CONDENSATE POLISHER
CONDENSATE PUMP
DEMINERALIZER
WATER TREATMENT
RAW WATER MAKEUP
REFERENCE DRAWINGS
1 W.O. 9564197
No. REVISIONS DATE BY APVD
Deseret
TITLE POWER PLANT
CROSS SECTION
BONANZA POWER PLANT
VENDOR DWG#
CAD FILE NAME
ENG BY DATE
CHK KJS
APVD
DRAFT BY DATE
DRAWN KBS
CHK KJS
APVD
DWG. NO.
B-1
SHEET 1 OF 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 rolling 12-month average. On the first day of each month a new 12-month average shall be 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 discharge to the atmosphere nitrogen oxide (NO_x) at a rate exceeding 0.50 lb/MM BTU heat input on an annual average. Compliance with this emission limitation shall be based on CEM data and fuel heat input. Compliance shall be determined in accordance with 40 CFR 76.5(b).

3. **Revise condition 9.A to read as follows:**

9. Particulate and PM_{10} Emission Control

A. Unit No. 1 shall not discharge to the atmosphere particulate matter at a rate exceeding 0.0297 lbs/MMBTU heat input as determined by 40 CFR 60, Appendix 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, 4,5-5e 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. A log of operation shall be kept. The log shall include:

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

Attachment 3

Net Emission Changes

Pollutant	Pre-Change Emissions TPY		Post-Change Emissions TPY		Net Change TPY	
CO	510.85		602.45		91.60	
VOC	60.21		70.89		10.68	
NO_x	10558.00		10029.83		**<528.17>**	
SO_2	1929.90		1968.11		38.21	
PM	939.96		962.56		22.60	
PM_{10}	911.65		925.76		14.11	
HAPS	55.77	6.19	60.46	10.84	4.69	4.65
Totals	14966.34		14,620.06		**<346.28>**	346.32
	14916.83		14,570.44			
Net Emissions Decrease	16				**<346.28>**	346.32

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	0.03	0.00
Emergency Generator	0.06	0.06	0.00
Fire Pump	0.02	0.02	0.00
Construction Heaters	0.00	0.00	0.00
Access Road	1.77	1.77	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]	0.04	0.04	0.00
Coal Pile wind Erosion	0.02	0.02	0.00
Limestone Conveyors 1&2 [a]	0.00	0.00	0.00
Dozers on the Limestone Piles	0.01	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 Pile	0.09	0.11	0.02
Sludge Pile Wind Erosion	12.01	12.01	0.00
Cooling Tower Drift	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	10	7,000	M	8	60	2	10.00
				6,120	A				

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	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	(EPRI) 75.00	5.6234		AP-42	3.60	1.12	4.92
PM10	Watering	Chemical	75.00	2.0244		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 EPRI for gravel roads

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 for loaded and unloaded 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 truck capacity of 10 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

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)
30500833	5.00	25	1	2,000	M	4	60	2
				1,500	A			

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	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			(EPRI) 0.00	0.7934		AP-42	0.60	0.18	0.79
PM10			0.00	0.2856		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 for gravel roads

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 for loaded and unloaded hauling wts)

w = mean number of wheels; Estimated to be 6

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 truck capacity of 10 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: 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 HT (%)	MAXIMUM & ACTUAL PILE SIZE (ACRES)		SCC UNITS	NO. DAYS WITH >= 0.01" PRECIP PER YEAR
	0.01	29.50	22.00	M	TON	80
		(Estimated)	22.00	A		

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	Chemical	Compaction	(EPRI) 50.00	0.0289		AP-42	0.06	0.01	0.06
PM10	Chemical	Compaction	50.00	0.0145		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 and EPRI for western coal.

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

f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to be 29.5% based on 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 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: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: DOZER RECLAIM (p.1 of 8)
rev. 2

PROCESS DATA

YEAR: 1997 SCC CODE		SILT CONTENT (%)	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS	MOISTURE CONTENT (%)
30501040		0.01	10.00	2,000,000	M	TON	12.00
			(Average)	1,100,000	A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL 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			0.00	0.01234		AP-42	6.79	2.82	12.34
PM10			0.00	0.00043		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 airport

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 continuous drop operations.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on 100% fuel delivery by truck, full load unlimited operation of combustion units, and a coal heat content of 8,200 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) 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	PROCESS DATA			
SCC CODE	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS	MOISTURE CONTENT (%)
	10.00 (Estimated)	2,008,000 1,700,000 A	TON	12.00 (Recieved)

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL 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	Dust Suppression		(Estimated) 95.00	0.00064		AP-42	0.027	0.007	0.032
PM10	Dust Suppression		(Estimated) 95.00	0.00022		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 operations.

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 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: Benanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: CONV. 1 AND 2 TO STORAGE, (p. 3 of 8)
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	3	10.00	2,006,000	TON	12.00
		(Estimated)	1,700,000	A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL 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	Fabric Filter	Dust Suppression	(EPRI: EPA) 99.70	0.00064		AP-42	0.00	0.00	0.01
PM10	Fabric Filter	Dust Suppression	(Calculated) 99.27	0.00022		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 operations.

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 6)
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	3	10.00 (Estimated)	2,006,000 / 1,700,000 A	TON	12.00

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL 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	Fabric Filter		(EPRI: EPA) 99.70	0.00064		AP-42	0.00	0.00	0.00
PM10	Fabric Filter		(Calculated) 99.27	0.00022		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 operations.

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	SCC CODE	PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS
1997		2,008,000	TON
		1,700,000 A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL 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	Fabric Filter		(EPRI: EPA) 99.70	0.1600		EPRI	0.46	0.12	0.54
PM10	Fabric Filter		(Calculated) 99.49	0.0900		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, as noted for each pollutant.

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 emissions factor published in EPRI and engineering judgement, as noted for each pollutant.

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 8)
rev.2

YEAR: 1997			PROCESS DATA			
SCC CODE		MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS	MOISTURE CONTENT (%)	
		10.00	1,500,000	TON	12.00	
		(Estimated)	550,000	A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL 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	Dust Suppression		(AWMA) 75.00	0.00064		AP-42	0.04	0.03	0.12
PM10	Dust Suppression		75.00	0.00022		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 operations.

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

PROCESS DATA

YEAR: 1997 / SCC CODE	NUMBER OF TRANSFER POINTS	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS	MOISTURE CONTENT (%)
30501011	3	10.00 (Estimated)	60,000 / 40,000 A	TON	3.00

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	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: EPA) 99.70	0.00447		AP-42	0.00	0.00	0.00
PM10	Fabric Filter		(Calculated) 99.43	0.00156		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 operations.

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	10	300	TON	4	80
				150	A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	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			(EPRI) 0.00	0.2366		AP-42	0.02	0.01	0.04
PM10			0.00	0.0659		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 and EPRI for western 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	6.00	TON	60
		(Estimated)	2.00	A	

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	4.3392		AP-42	1.58	1.08	4.75
PM10			0.00	2.1696		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 for western coal.
p = number of days with >= 0.01 inch of precipitation per year; Estimated to be 85 based on AP-42 weather chart.
f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to 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 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: SLUDGE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: CONVa, 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	10.00	245,000		TON	15.00
		(Estimated)	145,000	A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL 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			0.00	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 operations.

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	10	1,200 600 A	TON	4	80

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	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		(EPRI) 50.00	1.0338		AP-42	0.21	0.07	0.31
PM10	Watering		50.00	0.3722		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 and EPRI for western 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	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	Watering		(EPRI) 50.00	18.8033		AP-42	24.02	5.48	24.02
PM10	Watering		50.00	9.4016		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 for western coal.

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

f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to 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 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 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 for western coal.
p = number of days with >= 0.01 inch of precipitation per year; Estimated to be 65 based on AP-42 weather chart.
f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to 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 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: 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 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 for western coal.

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

f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to 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 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: FUEL OIL STORAGE TANK 1- 268,000 GALLONS
SOURCE DESCRIPT: No. 2 Fuel Oil Evaporation

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

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL 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			0.00	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. Actual plant 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 burned by the combustion units.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions. Actual plant 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	OVERALL 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			0.00	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 emissions. Actual plant 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 burned by the combustion units.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions. Actual plant 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: 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	23	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 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)
PM10	Drift Eliminators		(CALCULATED) 76.93	0.0126		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 recirculation water.
2) Actual chlorine emissions calculated based on a continuous Cl2 level of 0.0 ppm and a daily shock chlorination level of 0.05 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 0.05 ppm for three 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: 1995 / SCC CODE	PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS
	20,000		GAL
	17,000	A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL 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			0.00	SEE NOTES (1) & (4)		AP-42	0.11	0.03	0.13
HAPs			0.00	SEE NOTES (1) & (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 emissions.
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 gasoline), based on EPA information. HAPs may include benzene, toluene, hexane, ethylbenzene, napthalene, cumene, xylenes, n-hexane, 2,2,4-trimethylpentane, MBTE, and others.

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 EPA information. 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	OVERALL 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			0.00	SEE NOTES (1) & (4)		AP-42	0.11	0.03	0.13
HAPs			0.00	SEE NOTES (1) & (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 emissions.
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 gasoline), based on EPA information. HAPs may include benzene, toluene, hexane, ethylbenzene, napthalene, cumene, xylenes, n-hexane, 2,2,4-trimethylpentane, MBTE, and others.

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 EPA information. 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- 268,000 GALLONS
SOURCE DESCRIPT: No. 2 Fuel Oil Evaporation

YEAR	SCC CODE	PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS
1995	40400413	293,000		GAL
		166,809	A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL 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			0.00	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. Actual plant 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 burned by the combustion units.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions. Actual plant 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	OVERALL 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			0.00	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 emissions. Actual plant 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 burned by the combustion units.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions. Actual plant 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.

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 existing filter bags. There are 450 Bags in each compartment, 24 compartments, for a total of 10,800 Bags.

3. Grasshopper Conveyors:

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

4. New Bull Gear on the Ball Mill:

D G & T is replacing the Bull Gear with a redesigned model on a Ball Mill to improve efficiency of the Grinding unit.

5. New Absorber Inlet Damper Seals:

During the May 1997 Outage, D G & T upgraded the Absorber Inlet Damper seals. This new Seal design reduces 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 B

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 15 1988

MEMORANDUM

SUBJECT: Procedures for EPA to Address Deficient New Source Permits Under the Clean Air Act

FROM: Michael S. Alushin
Associate Enforcement Counsel for Air Office of Enforcement and Compliance Monitoring

John S. Seitz, Director
Stationary Source Compliance Division
Office of Air Quality Planning and standards

TO: Addressees

INTRODUCTION

This memorandum transmits the final guidance for your use in addressing deficient new source permits. After we distributed the draft guidance for comment on December 16, 1987, several Regional Offices took action on deficient new source permits. The events surrounding those permit actions, as well as your thoughtful comments on the draft guidance, have shaped the final policy.

RESPONSE TO COMMENTS

We have incorporated most of your comments into the final guidance. As you requested, we have included examples of forms showing a request for permit review under 40 C.F.R. Section 124.19, a Section 167 order, and a Section 113(a) (5) finding of violation.

Some commenters suggested that we include a section on actions that can be taken, not against the source, but against the state issuing the deficient permit. We agree that this topic should be included in the guidance because it surfaces repeatedly in individual cases. Therefore, we have added a section on possible actions against states for issuing deficient permits. We have also clarified the guidance to indicate that EPA should send a state written comments at both the draft and final permit stage when a state is issuing what EPA considers a deficient permit.

Some reviewers requested further elaboration of when to use alternative enforcement responses. We have indicated relevant considerations in determining which action to take. One commenter pointed out that the guidance did not define what was meant by a "deficient permit." This involves a determination that requires the exercise of judgment. However, we have tried to list most of the criteria that will support a finding of deficiency. We realize, however, that we may not have anticipated every deficiency that may present itself to every Regional Office in the future.

Concern was expressed over the requirement to respond to a deficient permit within thirty days. We realize that this is an ambitious objective, but it is a legal requirement for permit review under 40 C.F.R Section 124, and greatly enhances EPA's equitable position in challenges under Section 167 and Section 113(a) (5). It will be easier to meet this deadline if Regional Offices have routine procedures in place for prompt receipt of all permits from their states and for thorough review of permits as they are received.

A few commenters wanted the guidance expanded to apply to "netting" actions and "synthetic minor" sources. We agree that guidance in this area would be useful, but the topic is too broad to be folded into the same document as the guidance on deficient permits. We have begun work to address appropriate enforcement action for improper "synthetic minors" in the context of the Federal Register notice announcing the program for federally enforceable state operating permits. If you think that separate enforcement guidance is needed on this subject, please let us know.

Finally a few reviewers questioned the guidance regarding EPA directly- issued permits. We agree that, in all cases where we find a deficiency, it is preferable to change the permit by modifying its terms. If the source is amenable, we should do so. However, if EPA cannot get the source to accept new permit conditions, our only options are review under Section 124.19(b), revocation of the permit, and/or enforcement action. A Section 124.19 (b) review must be taken within 30 days after the permit was issued. The regulations are unclear on EPA's authority to revoke PSD permits. In an enforcement action to force a source, involuntarily, to accept a permit change when the source has not requested the change or made any modification to its facility or operations, EPA must always keep in mind the litigation practicalities and equities. These make enforcing against a permit we have issued when we are not basing our action on any new information a difficult proposition.

CONCLUSION

We hope that this guidance will help EPA Regions act to challenge deficient new source permits. Many of the practices advocated in this document may be litigated in pending or future cases. We will amend the guidance as necessary in light of judicial developments. If you have any questions, please contact attorney Judith Katz at FTS 382-2843.

Attachment

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Air Management Division Directors
Regions I, III, and IX

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 15 1988

MEMORANDUM

SUBJECT: Procedures for EPA to Address Deficient New Source Permits Under the Clean Air Act

FROM: Michael S. Alushin
Associate Enforcement Counsel for Air Office of Enforcement and Compliance Monitoring

John S. Seitz, Director
Stationary Source Compliance Division
Office of Air Quality Planning and Standards

TO: Addressees

I. Introduction

This guidance applies to permits issued for major new sources and major modifications under both the prevention of significant deterioration (PSD) program and the nonattainment new source review (NSR) program. It contains three sets of procedures -- one for permits issued pursuant to EPA-approved state programs (NSR permits and PSD permits in more than half the states) one for permits issued by states pursuant to delegations of authority from EPA, and one for instances where EPA issues the permit directly. An appendix of model forms appears at the end.

The need for this guidance has become increasingly evident in the last two years. Before then, EPA had attempted only once, in 1981, to enforce against sources constructing or operating with new source permits the Agency determined to be deficient. In 1986, EPA litigated Greater Detroit Recovery Facility v. Adamkus et al. No. 86-CU-72910-DT (October 21, 1986). In that case, EPA wanted to enforce against a major stationary source constructing with a PSD permit issued by Michigan under a delegation agreement with EPA. The Agency had first determined that the best available control technology (BACT) determination for SO2 in the permit was inadequate. Before EPA started formal enforcement action, the source filed suit against the Agency, arguing that EPA had no authority to "second guess" the BACT determination and that, in any event, we should be equitably foreclosed from challenging the permit because we had remained silent during the two years since we had failed to comment on the permit. The court agreed and granted the source's motion for summary judgement.

The Detroit case was an example of the need for prompt and thorough EPA review of and written comments on new source permits. Our ability to influence the terms of a permit, both informally and through legal procedures, diminishes markedly the longer EPA waits after a permit is issued before objecting to a specific term. This is due both to legal constraints, that is, tight time limits for comments provided in the regulations, and to equitable considerations that make courts less likely to require new sources to accept more stringent permit conditions the farther planning and construction have progressed. Accordingly, as a prerequisite to successful enforcement action, it is imperative that EPA review all major source permit packages on a timely basis and provide detailed comments on deficiencies. If EPA does not obtain adequate consideration of those comments, it is also important for EPA to protect air quality by prompt and consistent enforcement action against sources whose permits are found lacking. Because PSD permits are issued on a case-by-case basis, taking into consideration individual source factors, permitting decisions involve the exercise of judgment. However, although not an exhaustive list, any one of the following factors will normally be sufficient for EPA to find a permit "deficient" and consider enforcement action:

1. BACT determination not using the "top-down" approach.

2. BACT determination not based on a reasoned analysis.

3. No consideration of unregulated toxic pollutants in BACT determination.

4. Public notice problems - no public notice & comment period or deficiencies in the public notice.

5. Inadequate air quality modeling demonstrations.

6. Inadequate air quality analysis or impact analysis.

7. Unenforceable permit conditions.

8. For sources that impact Class I areas, inadequate notification of Federal Land Manager or inadequate consideration of impacts on air quality related values of Class I areas.

In NSR permitting, each of the following factors, while not necessarily an exhaustive list, are grounds for a deficient permit:

1. Incorrect LAER determination, i.e., failure to be at least as stringent as the most stringent level achieved in practice or required under any SIP or federally enforceable permit.

2. No finding of state-wide compliance.

3. No emissions offsets or incorrect offsets.

4. Public notice problems - no public notice and comment or deficiencies in public notice.

5. Unenforceable permit conditions.

II. Timing of EPA Response

A. Comment

Although EPA should know about every permit, at least by the time it is published as a proposal, the Agency sometimes does not learn about a permit during its development prior to the time the final permit is issued. If we do become aware of the permit and have objections to any of its terms, we should comment during the developmental stage before the permit becomes final.

State agencies should send copies of all draft permit public notice packages and all final permits to EPA immediately upon issuance. (The requirements for contents of public notice packages are set forth at 40 C.F.R. Section 51.166(q)(2](iii).) The Regional Office should review all draft permit public notice packages and final permits during the 30 day comment periods provided for in the federal regulations. It should write detailed comments whenever Agency staff does not agree with the terms of a draft or final permit. To make sure they get permits in time for review, Regional Offices should consider requiring states with approved new source programs, through Section 105 Grant Conditions, to notify them of the receipt of all major new source permit applications. They should also require states to send them copies of their draft permits at the beginning of the public comment period.

Final permits should be required to be sent to EPA immediately upon issuance. (Note that the requirement for Regions to review draft and final permits is contained in guidance issued by Craig Potter on December 1, 1987.) Regions should carefully check their agreements with delegated states. These agreements require states to send draft permits to EPA during the comment period. In addition, 40 C.F.R. Section 52.21(u)(2)(ii) requires delegated agencies to send a copy of any public comment notice to the appropriate regional office. Pursuant to 40 C.F.R. Section 124.15, a final permit does not become effective until 30 days after issuance, unless there are no comments received during the comment period, in which case it becomes effective immediately. Regions should make sure that delegated states know about permit appeal procedures at 40 C.F.R. Section 124 and, if necessary, issue advisory memoranda notifying them that EPA will use these procedures if the Agency determines a permit is deficient.

B. Formal Enforcement Action

If the permit was issued under a delegated program, it is important to initiate formal review or appeal within 30 days after the final permit is issued. (This response is set forth in Section IV below. The 30 day period is required by the regulations at 40 C.F.R. Section 124.19). When enforcing against permits issued under state programs, the same legal requirement to initiate enforcement within 30 days does not exist, but it is still extremely important to act expeditiously.

III. Enforcement Against the Source v. Enforcement Against the State

If a state has demonstrated a pattern of repeatedly issuing deficient permits, EPA may consider revoking the delegation for a delegated state or acting under Section 113(a) (2) of the Act to assume federal enforcement for an approved state. It is not appropriate to issue a Section 167 order to a state. Revocations of delegated authority as to individual permits and revocations of actual permits are theoretically possible, but they are unnecessary where EPA can act under Part 124 (i.e. within 30 days of issuance). Revocation may be appropriate where Part 124 appeals are unavailable, but likely will be subject to legal challenge.

IV. Procedures to Follow When Enforcing Against Deficient Permits in
Delegated Programs

A. If possible, the following actions before construction commences:

1. Take action under 40 C.F.R. Section 124.19(a) or (b) within 30 days of the date the final permit was issued to review deficient provisions of the permit.

    a. Section 124.19(a) is an appeal, which may be taken by any person who commented during the public comment period.

b. Section 124.19(b) is a review of the terms of the permit by the Administrator under his own initiative. Regional Offices informally request the Administrator to take this action. They need not have commented during the public comment period. The Administrator has demonstrated a preference for using Section 124.19(b) over Section 124.19(a). In the four instances thus far when he was given the choice of acting under (a) or (b), he chose (b). However, the Administrator may not have sufficient time to act within 30 days in every situation in the future.

2. In the majority of situations, it is more appropriate for the Agency to act as one body to initiate review under Section 124.19(b). In some instances, however, the third party role for a Regional Office, through 40 C.F.R. Section 124.19(a) may be preferable. Regions should pick (a) or (b). However, if both provisions are legally available, they should request, in the alternative, that the Administrator act under the provision other than the one chosen by the Region should he deem it more appropriate. In particular, if a Region requests the Administrator to act under Section 124.19(b), it should ask that its memorandum be considered as a petition for review under Section 124.19(a) should review under Section 124.19(b) not be granted within 30 days. This is to protect the Regions' right to appeal a permit if the Administrator does not have sufficient time to act. Therefore, all memoranda requesting review should be written to withstand public scrutiny if considered as petitions under Section 124.19(a).

3. If the 30 day period for appeal has run and strong equities in favor of enforcement exist, issue a Section 167 order and be prepared to file a civil action to prohibit commencement of construction until the source secures a valid permit. (See Section IV B(2)) below.

B. For sources where construction has already commenced:

1. If the permit was issued less than 30 days previously take action under 40 CFR Section 124.19.

2. If the permit was issued more than 30 days previously, issue a Section 167 order requiring immediate cessation of construction until a valid permit is obtained. This

step should only be taken if extremely strong equities in favor of enforcement exist. Regions should be keeping state and source informed of all informal efforts to change permit terms before the Section 167 order is issued. Section 167 orders may be used both for sources which have and have not commenced construction. However, because the Section 124.19 administrative appeal and review process is available in delegated programs, it is greatly preferred for challenging deficient permits in states where it can be used.

3. If EPA determines that penalties are appropriate, issue a NOV under Section 113(a) (1) of the Act for commencement of construction of a major source or major modification without a valid permit. This is necessary because Section 167 contains no penalty authority. Note that strong equities for enforcement must exist before taking this step. EPA can issue both a Section 167 order requiring immediate injunctive relief and a NOV if we decide that both are appropriate.

4. Follow up with judicial action under Section 167 and Section 113(b) (2) if construction continues without a new permit.

C. Note that the appeal provisions of 40 C.F.R. Section 124.19 apply to all delegated PSD programs even if Section 124.19 is not specifically referenced in the delegation.

V. Procedures to Follow When Enforcing Against Permits in EPA-Approved State Programs (All NSR and More Than Half of the PSD Programs)

A. Issue Section 113(a) (5) order (for NSR) or 167 order (for PSD) as expeditiously as possible, preferably within 30 days after the permit is issued, requiring the source not to commence construction, or if already started, to cease construction (on the basis that it would be constructing with an invalid permit), and to apply for a new permit. Note that EPA should issue a Section 167 order if it has determined that there is a reasonable chance the source will comply. Otherwise, the Region should move directly to section V.D below.

B. From the outset of EPA's involvement, keep the source informed of all EPA's attempts to convince the permitting agency to change the permit.

C. Issue an NOV (113(a)) as soon as construction commences if EPA determines penalties are appropriate.

D. If source does not comply with order, follow up with judicial action under Section 167, Section 113(b) (5), or, if NOV issued, Section 113(b) (2). If penalties are appropriate, issue NOV and later amend complaint to add a Section 113 count when 30 day statutory waiting period has run after initial action is filed under Section 167.

VI. For EPA-issued Permits (Non-delegated)

A. If source submitted inadequate information (e.g., misleading, not identifying all options) and EPA recently found out about it,

1. If within 30 days of permit issuance, request review by the Administrator under 40 C.F.R. Section 124.19(b).

2. If permit has been issued for more than 30 days, issue Section 167 or Section 113(a) (5) order preventing startup or, if appropriate, immediate cessation of construction.

3. Issue NOV if construction has commenced and EPA determines penalties to be appropriate.

4. If necessary, request additional information from source; if source cooperates, issue new permit.

5. Consider taking judicial action if appropriate.

EPA recognizes the distinction between permits based on faulty and correct information only for EPA directly-issued permits. This distinction is necessary for EPA permits due to equitable considerations.

B. If source submitted adequate information and EPA issued faulty permit, we should attempt to get source to agree to necessary changes and accept modification of its permit. However, if source will not agree, only available options are revoking the permit and enforcing. Consolidated permit regulations are unclear about EPA's authority to revoke PSD permits. Because of this and the equitable problems associated with enforcing against our own permits, unless new information about health effects or other significant findings is available, we may choose to accept the permit. If faulty permit produces unacceptable environmental risk, act under 40 C.F.R. Section 124.19, if possible. If action under 40 C.F.R. Section 124.19 not possible, first revoke permit and then act as set forth in Section IV.

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Appendix

1. Request for Review under 40 C.F.R. Section 124.19

2. Section 167 Order

3. Section 113(a)(5) finding of violation and accompanying Section 113(a) (1)
Notice of violation

EXHIBIT C

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF SCHERER STEAM-ELECTRIC GENERATING PLANT JULIETTE, GEORGIA PERMIT NO. 4911-207-0008-V-03-0 HAMMOND STEAM-ELECTRIC GENERATING PLANT COOSA, GEORGIA PERMIT NO. 4911-115-0003-V-03-0 WANSLEY STEAM-ELECTRIC GENERATING PLANT CARROLLTON, GEORGIA PERMIT NO. 4911-149-0001-V-03-0 KRAFT STEAM-ELECTRIC GENERATING PLANT PORT WENTWORTH, GEORGIA PERMIT NO. 4911-051-0006-V-03-0 MCINTOSH STEAM-ELECTRIC GENERATING PLANT RINCON, GEORGIA PERMIT NO. 4911-103-0003-V-03-0 ISSUED BY THE GEORGIA ENVIRONMENTAL PROTECTION DIVISION	ORDER RESPONDING TO PETITIONERS' REQUESTS THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF STATE OPERATING PERMITS PETITION NOS. IV-2012-1, IV-2012-2 IV-2012-3, IV-2012-4 AND IV-2012-5

ORDER GRANTING IN PART AND DENYING IN PART FIVE PETITIONS FOR OBJECTION TO PERMITS

I. INTRODUCTION

This Order responds to issues raised in five related petitions submitted to the U.S. Environmental Protection Agency by GreenLaw on behalf of the Sierra Club and several other environmental organizations[1] (the Petitioners) pursuant to Section 505(b)(2) of the Clean Air Act ("CAA" or "Act"), 42 United States Code (U.S.C.) § 7661d(b)(2). The petitions seek the EPA's objection to operating permits issued by the Georgia Environmental Protection Division (Georgia EPD) to Georgia Power/Southern Company for five existing coal-fired electricity and steam generating plants located in the state of Georgia. Petition IV-2012-1, received on June 13, 2012, addresses the operating permit for the Scherer Steam-Electric Generating Plant (Plant Scherer). Petition IV-2012-2, received by the EPA on June 15, 2012, addresses the operating permit for the Hammond Steam-Electric Generating Plant (Plant

[1] Southern Alliance for Clean Energy, Fall-line Alliance for a Clean Environment, and Ogeechee Riverkeeper joined the Sierra Club in the Plant Wansley Petition (Petition No. IV-2012-3). Southern Alliance for Clean Energy also joined Sierra Club in the Plant Kraft Petition (Petition No. IV-2012-4).

Hammond). Petition IV-2012-3, received on September 5, 2012, addresses the operating permit for Wansley Steam-Electric Generating Plant (Plant Wansley). Petition IV-2012-4, received on October 23, 2012, addresses the operating permit for Kraft Steam-Electric Generating Plant (Plant Kraft). Finally, Petition IV-2012-5, received on November 13, 2012, addresses the operating permit for McIntosh Steam-Electric Generating Plant (Plant McIntosh). These permits are state operating permits issued by Georgia EPD pursuant to title V of the CAA, CAA §§ 501-507, 42 U.S.C. §§ 7661-7661f, the EPA's implementing regulations at 40 Code of Federal Regulations (C.F.R.) Part 70, and Georgia's EPA-approved state operating program regulations at Georgia Air Quality Rule 391-3-1-.03(10). The Petitioners timely filed all five petitions within 60 days after the expiration of the relevant EPA review period for each permit, consistent with CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2). Due to significant overlap in the issues raised in the Petitions and the similarity of the relevant permit conditions in each of the five permits, the EPA is responding to all five petitions in this Order.

The Petitioners requested that the EPA object to the five Georgia Power title V permits on several different grounds. The Petitioners did not raise all of their claims in every Petition. In total, the Petitioners raise five claims, which are described in detail in Section IV of this Order, below. In summary, the issues raised are:

(1) The permits lack sufficiently detailed information regarding the facilities' compliance obligations related to hazardous air pollutant (HAP) emissions under the National Emission Standards for Hazardous Air Pollutants (NESHAP) for electric utility steam generating units at 40 C.F.R. 63 Subpart UUUUU. (Raised in the petitions on Plants Hammond, Kraft, McIntosh, Wansley and Scherer).
(2) The permits do not assure compliance at all times with the sulfur dioxide (SO_2) emission limit derived from Georgia Rule 391-3-1-.02(2)(uuu) because they appear to authorize the facilities to not operate their continuous emissions monitoring system (CEMS) for SO_2 during startup, shutdown, malfunction and other periods. (Raised in the petitions on Plants Hammond, Wansley and Scherer).
(3) The permits' particulate matter (PM) monitoring requirements are insufficient to assure compliance with PM emission limits. (Raised in the petitions on Plants Hammond, McIntosh, Wansley and Scherer).
(4) The permit conditions governing fugitive dust control do not comply with the state implementation plan (SIP), do not assure compliance with the applicable 20 percent opacity standard, and are vague and unenforceable. (Raised in the petitions on Plants Hammond, Kraft, McIntosh, Wansley and Scherer).
(5) The permit for Plant Scherer should include preconstruction requirements under the CAA's Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) programs due to recent and planned upgrades to the facility's steam turbines. (Raised in the petition on Plant Scherer).

For the reasons provided below, based on a review of the Petitions and other relevant materials, including the permits, permit records, and applicable statutory and regulatory authorities, I grant in part and deny in part the five petitions requesting that the EPA object to the five Georgia Power permits. Specifically, as explained in Section IV.D of this order, I grant the five petitions on Claim 4, regarding permit conditions governing fugitive dust, which the Petitioners raised with respect to all five permits. In addition, as described in the EPA's response to Claim 2 in Section IV of this Order, I am also notifying the state and the permittees of the EPA's determination that cause exists to reopen the Hammond, Scherer and Wansley permits, pursuant to 42 U.S.C. § 7661d(e) and 40 C.F.R. § 70.7(g).

II. STATUTORY AND REGULATORY FRAMEWORK

Section 502(d)(l) of the CAA, 42 U.S.C. § 766la(d)(l), requires each state to develop and submit to the EPA an operating permit program to meet the requirements of title V of the CAA. The EPA granted interim approval of Georgia's title V operating permit program on November 22, 1995 (60 *Fed. Reg.* 57836) and full approval on June 8, 2000 (65 *Fed. Reg.* 36358). 40 C.F.R. Part 70, Appendix A. This program is codified in Georgia Air Quality Rule 391-3-1-.03(10).

All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions as necessary to assure compliance with applicable requirements of the CAA, including the requirements of the applicable SIP. CAA §§ 502(a) and 504(a), 42 U.S.C. §§ 7661a(a) and 7661c(a). The title V operating permit program generally does not impose new substantive air quality control requirements, but does require permits to contain adequate monitoring, recordkeeping, reporting and other requirements to assure sources' compliance with applicable requirements. 57 *Fed. Reg.* 32250, 32251 (July 21, 1992). One purpose of the title V program is to "enable the source, States, the EPA, and the public to understand better the requirements to which the source is subject, and whether the source is meeting those requirements." *Id.* Thus, the title V operating permit program is a vehicle for ensuring that air quality control requirements are appropriately applied to facility emission units and for assuring compliance with such requirements.

Applicable requirements for a new major stationary source or for a major modification to a major stationary source include the requirement to obtain a preconstruction permit that complies with applicable new source review (NSR) requirements. For major sources, the NSR program is comprised of two core types of preconstruction permit programs. Part C of Title I of the CAA establishes the PSD program, which applies to areas of the country that are designated as attainment or unclassifiable for the national ambient air quality-standards (NAAQS). CAA §§ 160-169, 42 U.S.C. §§ 7470-7479. Part D of Title I of the Act establishes the NNSR program, which applies to areas that are designated as nonattainment with the NAAQS. The EPA has two largely identical sets of regulations implementing the PSD program, one set, found at 40 C.F.R. § 51.166, contains the requirements that state PSD programs must meet to be approved as part of a SIP. The other set of regulations, found at 40 C.F.R. § 52.21, contains the EPA's federal PSD program, which applies in areas without a SIP-approved PSD program. The EPA has approved Georgia's PSD SIP, which is codified in Georgia Rule 391-3-1-.02(7). *See* 40 C.F.R. § 52.570(b). The EPA's regulations implementing the NNSR program are codified at 40 C.F.R. §§ 51.160-51.165, and Georgia's SIP-approved NNSR regulations are codified at Georgia Rule 391-3-1-.03(8). *See* 40 C.F.R. § 52.570(b). The applicable requirements of the Act for new major sources or major modifications include the requirement to comply with PSD and NNSR requirements. *See, e.g.,* 40 C.F.R. § 70.2.[2] At issue in this order, among other things, is whether Plant Scherer's Turbine Upgrade Project qualified as a "major modification" that should have been subject to PSD and NNSR requirements.

[2] Under 40 C.F.R. § 70.1(b), "[a]ll sources subject to [the title V regulations] shall have a permit to operate that assures compliance by the source with all applicable requirements." "Applicable requirements" are defined in 40 C.F.R. § 70.2 to include "(1) [a]ny standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the [Clean Air] Act that implements the relevant requirements of the Act, including any revisions to that plan promulgated in [40 C.F.R.] part 52; (2) [a]ny term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D, of the Act."

A. Review of Issues in a Petition

State and local permitting authorities issue title V permits pursuant to the EPA-approved title V programs. Under CAA § 505(a), 42 U.S.C. § 766ld(a), and the relevant implementing regulations found at 40 C.F.R. § 70.8(a), states are required to submit each proposed title V operating permit to the EPA for review. Upon receipt of a proposed permit, the EPA has 45 days to object to final issuance of the permit if the EPA determines that the permit is not in compliance with applicable requirements of the Act. CAA §§ 505(b)(1), 42 U.S.C. § 7661d(b)(1); *see also* 40 C.F.R. § 70.8(c) (providing that the EPA will object if the EPA determines that a permit is not in compliance with applicable requirements or requirements under 40 C.F.R. Part 70). If the EPA does not object to a permit on its own initiative, § 505(b)(2) of the Act and 40 C.F.R. § 70.8(d), provide that any person may petition the Administrator, within 60 days of the expiration of the EPA's 45-day review period, to object to the permit. The petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period). CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(d). In response to such a petition, the Act requires the Administrator to issue an objection if a petitioner demonstrates to the Administrator that a permit is not in compliance with the requirements of the Act. CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(c)(1); *see also New York Public Interest Research Group, Inc. (NYPIRG) v. Whitman,* 321 F.3d 316, 333 n.11 (2nd Cir. 2003). Under § 505(b)(2) of the Act, the burden is on the petitioner to make the required demonstration to the EPA. *MacClarence v. EPA,* 596 F.3d 1123, 1130-33 (9th Cir. 2010); *Sierra Club v. Johnson,* 541 F.3d 1257, 1266-1267 (11th Cir. 2008); *Citizens Against Ruining the Environment v. EPA,* 535 F.3d 670, 677-78 (7th Cir. 2008); *WildEarth Guardians v. EPA*, 728 F.3d 1075, 1081-1082 (10th Cir. 2013); *Sierra Club v. EPA,* 557 F.3d 401, 406 (6th Cir. 2009) (discussing the burden of proof in title V petitions); *see also NYPIRG,* 321 F.3d at 333 n.11. In evaluating a petitioner's claims, the EPA considers, as appropriate, the adequacy of the permitting authority's rationale in the permitting record, including the response to comments (RTC), among other things.

The petitioner's demonstration burden is a critical component of CAA § 505(b)(2). As courts have recognized, CAA § 505(b)(2) contains both a "discretionary component," to determine whether a petition demonstrates to the Administrator that a permit is not in compliance with the requirements of the Act, and a nondiscretionary duty to object where such a demonstration is made. *NYPIRG*, 321 F.3d at 333; *Sierra Club v. Johnson*, 541 F.3d at 1265-66 ("it is undeniable [CAA § 505(b)(2)] also contains a discretionary component: it requires the Administrator to make a judgment of whether a petition demonstrates a permit does not comply with clean air requirements"). Courts have also made clear that the Administrator is only obligated to grant a petition to object under CAA § 505(b)(2) if the Administrator determines that the petitioners have demonstrated that the permit is not in compliance with requirements of the Act. *See, e.g., Citizens Against Ruining the Environment*, 535 F.3d at 667 (§ 505(b)(2) "clearly obligates the Administrator to (1) determine whether the petition demonstrates noncompliance and (2) object <u>if</u> such a demonstration is made") (emphasis added); *NYPIRG*, 321 F.3d at 334 ("§ 505(b)[2] of the CAA provides a step-by-step procedure by which objections to draft permits may be raised and directs the EPA to grant or deny them, *depending on* whether non-compliance has been demonstrated.") (emphasis added); *Sierra Club v. Johnson*, 541 F.3d at 1265 ("Congress's use of the word 'shall' ... plainly mandates an objection *whenever* a petitioner demonstrates noncompliance") (emphasis added). When courts review the EPA's interpretation of the ambiguous term "demonstrates" and its determination as to whether the demonstration has been made, they have applied a deferential standard of review. *See, e.g., Sierra Club v. Johnson*, 541 F.3d at 1265-66; *Citizens Against Ruining the Environment*, 535 F.3d at 678; *MacClarence*, 596 F.3d at 1130-31. This order addresses certain aspects of the petitioner demonstration burden below; however, a fuller discussion can be found in *In the Matter of Consolidated Environmental Management, Inc. – Nucor Steel Louisiana*, Order on Petition Numbers VI-2011-06 and VI-2012-07 (June 19, 2013) (*Nucor II Order*) at 4-7.

The EPA examines a number of criteria in determining whether a petitioner has demonstrated noncompliance with the Act. *See generally Nucor II Order* at 7. For example, one such criterion is whether the petitioner has addressed the state or local permitting authority's decision and reasoning. The EPA expects the petitioner to address the permitting authority's decision, and reasoning (including the RTC, where available). *See MacClarence*, 596 F.3d at 1132-33; *see also, e.g., In the Matter of Noranda Alumina, LLC*, Order on Petition No. VI-2011-04 (December 14, 2012) (*Noranda Order*) at 20 (denying title V petition issue where petitioners did not respond to state's explanation in response to comments or explain why the state erred or the permit was deficient); *In the Matter of Kentucky Syngas, LLC*, Order on Petition No. IV-2010-9 (June 22, 2012) at 41 (*2012 Kentucky Syngas Order*) (denying title V petition issue where petitioners did not acknowledge or reply to state's response to comments or provide a particularized rationale for why the state erred or the permit was deficient). Another factor the EPA examines is whether the petitioner has provided the relevant analyses and citations to support its claims. If the petitioner does not, the EPA is left to work out the basis for petitioner's objection, contrary to Congress' express allocation of the burden of demonstration to the petitioner in CAA § 505(b)(2). *See MacClarence*, 596 F.3d at 1131 ("the Administrator's requirement that [a title V petitioner] support his allegations with legal reasoning, evidence, and references is reasonable and persuasive"); *In the Matter of Murphy Oil USA, Inc.*, Order on Petition No. VI-2011-02 (Sept. 21, 2011) (hereafter "*Murphy Oil Order*") at 12 (denying a title V petition claim where the petitioner claimed that the permit lacked sufficient monitoring, but failed to identify any permit term or condition for which monitoring was lacking). Relatedly, the EPA has pointed out in numerous orders that, in particular cases, general assertions or allegations did not meet the demonstration standard. *See, e.g., In the Matter of Luminant Generation Co. – Sandow 5 Generating Plant*, Order on Petition Number VI-2011-05 (Jan. 15, 2013) at 9; *In the Matter of BP Exploration (Alaska) Inc., Gathering Center #1*, Order on Petition Number VII-2004-02 (Apr. 20, 2007) at 8; *In the Matter of Chevron Products Co., Richmond, Calif. Facility*, Order on Petition No. IX-2004-10 (Mar. 15, 2005) (hereafter "*Chevron Order*") at 12, 24. Also, if the petitioner fails to address a key element of a particular issue, the EPA has denied the petition. *See, e.g., In the Matter of Public Service Company of Colorado, dba Xcel Energy, Pawnee Station,* Order on Petition Number: VIII-2010-XX (June 30, 2011) at 7–10; *See, e.g., In the Matter of Georgia Pacific Consumer Products LP Plant,* Order on Petition No. V-2011-1 at 6-7, 10-11 (July 23, 2012) at 10–11, 13–14.

B. Raising NSR Issues in a Petition

Where a petitioner's request that the Administrator object to the issuance of a title V permit is based in whole, or in part, on a permitting authority's alleged failure to comply with the requirements of its approved PSD or NNSR program (as with other allegations of inconsistency with the Act), the burden is on the petitioners to demonstrate to the Administrator that the permitting decision was not in compliance with the requirements of the Act, including the requirements of the SIP. Such requirements, as the EPA has explained in describing its authority to oversee the implementation of the PSD program in states with approved programs, include the requirements that the permitting authority, if applicable: (1) follow the required procedures in the SIP; (2) make PSD determinations on reasonable grounds properly supported on the record; and (3) describe the determinations in enforceable terms. *See, e.g., In the*

Matter of Wisconsin Power and Light, Columbia Generating Station, Order on Petition No. V-2008-01 (October 8, 2009) (*Columbia Generating Order*) at 8.[3]

Georgia EPD has substantial discretion in carrying out its responsibilities under Georgia's SIP-approved PSD and NNSR programs. Given this discretion, in reviewing a PSD or NNSR permitting decision, the EPA will not substitute its own judgment for that of Georgia. Rather, consistent with the decision in *Alaska Dep't of Envt'l Conservation v. EPA*, 540 U.S. 461 (2004), in reviewing a petition to object to a title V permit raising concerns regarding a state's PSD or NNSR permitting decision, the EPA generally will look to see whether the petitioner has shown that the state did not comply with its SIP-approved regulations governing PSD permitting or whether the state's exercise of discretion under such regulations was unreasonable or arbitrary. *See, e.g., In re Louisville Gas and Electric Company*, Order on Petition No. IV-2008-3 (Aug. 12, 2009) (hereafter "*LG&E Order*"); *In re East Kentucky Power Cooperative, Inc. Hugh L. Spurlock Generating Station*, Order on Petition No. IV-2006-4 (Aug. 30, 2007) (hereafter "*Spurlock Order*"); *In re Pacific Coast Building Products, Inc.* (Order on Petition) (Dec. 10, 1999); *In re Roosevelt Regional Landfill Regional Disposal Company* (Order on Petition) (May 4, 1999).

III. BACKGROUND

Plant Hammond is located in northwest Georgia near Coosa in Floyd County. The facility, which commenced operation in June 1954, currently consists of four wall-fired steam generating units (designated as Units SG01 through 04) with maximum heat input capacities ranging from 1,313 to 5,972 million British thermal units per hour (MMBtu/hr). Bituminous coal is the primary fuel for these units with limited use of wood, biomass, and #2 fuel oil. Also present are associated coal, ash and materials handling systems. Add-on controls include a flue gas desulfurization (FGD) scrubber system and electrostatic precipitators (ESPs) on Units SG01 through 04 and a selective catalytic reduction (SCR) scrubber on Unit SG04. The initial title V permit (#4911-115-0003-V-01-0) was issued January 1, 2000; the renewal permit (#4911-115-0003-V-03-0), on which the petition is based, was issued May 8, 2012.

Plant Kraft is located in north coastal Georgia near Port Wentworth in Chatham County. The facility, which commenced operation in 1958, currently consists of one wall-fired steam generating unit (Unit SG04)and three tangentially-fired steam generating units (Units SG01 through 03 and SG04) with maximum heat input capacities ranging from 647 to 1,493 MMBtu/hr. Bituminous coal is the primary fuel for Units SG01 through 03 with natural gas as backup. Natural gas is the primary fuel for Unit SG04 with #6 fuel oil as backup. Also present are: a simple cycle combustion turbine rated at 17 megawatts (MW) using natural gas as primary fuel with #2 fuel oil as backup, associated coal and ash handling systems, and a barge-to-railcar unloading system (for transport of coal to other facilities). Add-on controls include ESPs on Units SG01 through 03 and a dust control system on the barge-to-railcar transfer system. The initial title V permit (#4911-015-0006-V-01-0) was issued November 9, 1999; the renewal permit (#4911-015-0006-V-03-0), on which the petition is based, was issued September 24, 2012.

[3] In reviewing PSD permit determinations in the context of a petition to object to a title V permit, the standard of review applied by the Environmental Appeals Board (EAB) in reviewing the appeals of federal PSD permits provides a useful analogy. *In the Matter of Louisville Gas and Electric Company*, Order on Petition No. IV-2008-3 (Aug. 12, 2009) at 5 n.6; *see also In the Matter of East Kentucky Power Cooperative, Inc., Hugh L. Spurlock Generating Station*, Order on Petition No. IV-2006-4 (Aug. 30, 2007) at 5. The standard of review applied by the EAB in its review of federal PSD permits is discussed in numerous EAB orders as the "clearly erroneous" standard. *See, e.g., In re Prairie State Generation Company*, 13 E.A.D. 1, 10 (EAB, Aug. 24, 2006) (*Prairie State*); *In re Kawaihae Cogeneration*, 7 E.A.D. 107, 114 (EAB, April 28, 1997). In short, in such appeals, the EAB has explained that the burden is on a petitioner to demonstrate that review is warranted.

Plant McIntosh is located in east Georgia near Rincon in Effingham County. The facility, which commenced operation in 1979, currently consists of one wall-fired steam generating unit (designated as Unit SG01) with a maximum heat input of 1,862 MMBtu/hr. Bituminous coal is the primary fuel with limited use of wood, biomass and #2 fuel oil. Also present are: eight simple cycle combustion turbines rated at 103.5 MW each using natural gas as the primary fuel with #2 fuel oil, biodiesel and biodiesel blends as backup; one startup boiler; and associated coal and ash handling systems. Add-on controls include an ESP on SG01. The initial title V permit (#4911-103-0003-V-01-0) was issued November 9, 1999; the renewal permit (#4911-103-0003-V-03-0), on which the petition is based, was issued September 25, 2012.

Plant Scherer is located in middle Georgia near Juliette in Monroe County. The facility, which commenced operation in March 1982, currently consists of four tangentially-fired steam generating units (designated as Units SG01 through 04). Georgia Power is in the process of upgrading its four steam turbines and installing pollution control equipment; following completion of all steam turbine upgrades the maximum heat input capacities for the generating units will range from 9,653 to a projected 10,070 MMBtu/hr. Bituminous coal is the primary fuel with limited use of wood and #2 fuel oil. Also present are: two startup boilers and associated coal, ash and materials handling systems. Add-on controls include (or will include) FGD and SCR scrubber systems, ESPs and baghouses on Units SG01 through 04; wet suppression system on the coal handling system; and baghouses on the limestone silos of the materials handling system. The initial title V permit (#4911-207-0008-V-01-0) was issued January 1, 2000; the renewal permit (#4911-207-0008-V-03-0), on which the petition is based, was issued May 8, 2012.

Plant Scherer's title V permit was revised to address the recent steam turbine upgrades: the Unit SG03 steam turbine upgrade was addressed in permit revision #4911-207-0008-V-02-7, issued on November 16, 2009; the Unit SG01, 02 and 04 steam turbine upgrades were addressed in permit revision #4911-207-0008-V-02-A issued on February 23, 2010. According to the permit record, the purpose of the turbine upgrades is two-fold: (1) to improve the efficiency of the high-pressure section of the turbine, *i.e.*, the turbine will be able to generate more electricity from a unit of coal; and (2) to increase the maximum steam flow capacity (and, thus, increase heat input capacity) of the turbine, *i.e.*, the turbine will be able to generate more electricity due to increased capacity to burn coal.[4] This combined effect is to increase the maximum generating capacity of Scherer by 140 MW (or 35 MW from each turbine).[5] According to the respective statements of basis for the relevant permit revisions, the turbine upgrades were not projected to result in a significant emissions increase and, therefore, did not trigger PSD or NNSR review. The planned timing of the turbine upgrades was as follows: October 2010 for Unit SG03, January 2012 for Unit SG04, April 2013 for Unit SG02 and October 2013 for Unit SG01.

Concurrent with the steam turbine upgrades and as part of the same project, *i.e.*, during the same shutdown period for each electric utility steam generating unit (boiler/turbine or EUSGU)[6], Georgia Power received authorization from Georgia EPD to install pollution controls (FGDs and SCRs) on Units SG01 through 04 to comply with Georgia Rule 391-3-1-.02(2)(sss). Georgia EPD addressed Georgia

[4] *See, e.g.*, Georgia Power's SIP Air Permit Application #18-835 for Unit SG03, dated March 10, 2009, at 4 (Plant Scherer Petition Exhibit E).

[5] *Id.*

[6] "Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility. *See* 40 C.F.R. § 52.21(b)(31) and Georgia Rule 391-3-1.02(7)(a)2.(i), which in this case are identical.

Power's request to install the pollution controls in a significant modification to their title V permit issued on May 12, 2010 (#4911-207-0008-V-02-B).[7] The controls will be installed and operating when the source resumes regular operation after the project's completion.[8]

Plant Wansley is located in west Georgia near Carrollton in Heard County. The facility, which commenced operation in December 1976, currently consists of two tangentially-fired steam generating units (designated as Units SG01 and 02) with maximum heat input capacities of 9,420 MMBtu/her each. Bituminous coal is the primary fuel with limited use of wood, biomass, biodiesel, biodiesel blends and #2 fuel oil. Also present are: a simple cycle combustion turbine rated at 54 MW using #2 fuel oil, biodiesel and biodiesel blends; two startup boilers; and associated coal, ash and materials handling systems. Add-on controls include FGD and SCR scrubber systems and ESPs on Units SG01 and 02. The initial title V permit (#4911-149-0001-V-01-0) was issued January 1, 2000; the renewal permit (#4911-149-0001-V-03-0), on which the petition is based, was issued July 26, 2012.

IV. ISSUES RAISED BY THE PETITIONERS AND THE EPA'S RESPONSES[9]

Claim 1: Petitioners' Claim that the Permits Should Include Detailed Requirements for Hazardous Air Pollutant ("HAP") Standards.

Petitioners' Claim.[10] In their petitions of the permits for Plants Hammond, Kraft, McIntosh, Wansley and Scherer, the Petitioners claim that the permits are deficient because they lack sufficient detail regarding the facilities' obligation to control hazardous air pollutants under the NESHAP applicable to coal- and oil-fired electric utility steam generating units, which the Petitioners refer to as the "EGU MACT." The Petitioners observe that each of the five permits includes a condition that "makes a generic reference to the EGU MACT." The Petitioners note that this condition was not included in two of the permits when they were released for public comment, but that Georgia EPD added the condition to those two permits. The Petitioners assert that this generic condition is insufficient. Specifically, the Petitioners contend that all five permits are deficient because they do not include "the specific requirements of the

[7] The narrative accompanying the permit revision addressing the turbine upgrades for Units SG01, SG0, and SG04 explained: "A flue gas desulfurization (scrubber) system and a selective catalytic reduction (SCR) system will be installed simultaneously with the project as required in accordance with Georgia Rule (sss)." Narrative, Permit Amendment #4911-207-0008-V-02-A, at 3. *See also* Narrative, Permit Amendment #4911-207-0008-V-7, at 3 (stating the same with respect to the relationship between the turbine upgrade for Unit SG03 and the installation of controls required by Georgia Rule (sss)).

[8] The footnotes for the "projected actual emissions" table in the narrative accompanying the permit revision addressing the turbine upgrades for Units SG01, SG02, and SG04 indicate that the emissions projections included consideration of the effect of controls. *See* Narrative, Permit Amendment #4911-207-0008-V-02-A, at 6. While the narrative accompanying the permit revision for Unit SG03 does not include the footnotes cited above, the EPA concludes the "projected actual emissions" for Unit SG03 also include operation of the controls for this unit, since the permit narrative describe identical controls (scrubber and SCR) installed simultaneously to the turbine upgrade projects to comply with the same requirements (Rule sss) at Unit SG01, Unit SG02 and Unit SG04. Narrative, Permit Amendment #4911-207-0008-V-02-7, at 3. Additionally, the associated permit application for the upgrade to Unit SG03 explained: "Actual emissions estimates based on ozone season only operation of the SCR...". Finally, Permit Condition 6.2.21 specifies for all four units that the Permittee must calculate and maintain a record of annual emissions for a period of ten years "following resumption of regular operations <u>after installation of the upgraded high pressure steam turbines, and control equipment for each unit</u>." (emphasis added). Therefore, for all four units, it is clear that the applicant and Georgia EPD envisioned that the controls would be installed and operating when the units resumed regular operations following completion of the Turbine Upgrade Project.

[9] Headings summarizing Petitioners' claims are taken verbatim from the Petition.

[10] Petitioners' claims regarding the inadequacy of the permits with respect to HAP standards appear in the Plant Hammond Petition at 10-11, the Plant Kraft Petition at 3-4, the Plant McIntosh Petition at 8-9, the Plant Wansley Petition at 11-12, and the Plant Scherer Petition at 19.

EGU MACT" and also do not include "provisions to add any additional monitoring required by 40 C.F.R. § 70.6(c)(1)."

EPA's Response. For the reasons provided below, I deny the Petitioners' request for an objection to the permits on this claim. The Petitioners did not demonstrate that the permits lack sufficient specificity regarding applicable EGU NESHAP requirements and associated monitoring.

The EGU NESHAP, published at 40 C.F.R. 63 Subpart UUUUU, was promulgated on February 16, 2012 and became effective on April 16, 2012. 77 *Fed. Reg*. 9304. The date by which sources must be in compliance is April 16, 2015, 40 C.F.R. § 63.9984(b), unless the source seeks and is granted a one year extension, 40 C.F.R. 63.6(i). The EGU NESHAP establishes numerical emission limits and allows facilities to select from a range of widely available and economically feasible technologies, practices and compliance strategies to meet these limits. The rule also provides an alternative compliance option for sources that plan to comply by averaging across multiple units.

Georgia EPD issued all five of the title V permits addressed by the Petitions more than two years prior to the EGU NESHAP compliance date.[11] Each of the five permits includes the following condition (or the equivalent) with respect to the EGU NESHAP:

> The Permittee shall comply with all applicable provisions of the "National Emission Standards for Hazardous Air Pollutants" as found in 40 CFR Subpart A, "General Provisions" and 40 CFR 63, Subpart UUUUU, "National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units" for operation of steam generating units.
> [40 CFR 63, Subparts A and UUUUU][12]

Absent a specific requirement in the applicable NESHAP, a source is not required to have determined which of the available compliance approaches it will use to comply with the rule prior to the compliance date. The Petitioners have not identified any provision of the EGU MACT that requires such action. Selection of the particular compliance options for an affected source from among the available options in a NESHAP can be a complex determination.[13] Thus, when a permit is issued prior to the NESHAP compliance date, a source may not have yet determined the provisions that will describe NESHAP applicability beyond the subpart level. EPA has previously stated that:

> When a permit is issued prior to the MACT compliance date, the EPA believes that it is acceptable for the initial permit to describe MACT applicability at the Subpart level, and for all other compliance requirements (including compliance options and parameter ranges) of the MACT that apply below the Subpart level to be added at a later time as a significant permit modification.

In re ConocoPhillips Company, Order on Petition, Petition No. IX-2004-09 (March 15, 2005), at 24-25; see also *In re Chevron Products Company*, Order on Petition, Petition No. IX-2004-08 (March 15, 2005), at 39; Letter from John Seitz, EPA, to Robert Hodanbosi, STAPPA/ALAPCO (May 20, 1999),

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[11] Georgia EPD issued the Plants Scherer and Hammond permits on May 8, 2012, the Plant Wansley permit on July 26, 2012, the Plant Kraft permit on September 24, 2012, and the Plant McIntosh permit on September 25, 2012.

[12] Plant Hammond Permit Condition 3.3.1, Plant Kraft Permit Condition 3.3.2, Plant McIntosh Permit at 3.3.9, Plant Wansley Permit Condition 3.3.6, Plant Scherer Permit Condition 3.3.8.

[13] *See* for example, 77 *Fed. Reg*. 9494-9498.

Enclosure B. Consistent with this approach, Georgia EPD explained in its response to comments on several of the draft permits that it "will add any necessary conditions for EGU MACT in a permit amendment in the future." Plant Kraft RTC at 2, Plant McIntosh RTC at 10, Plant Wansley RTC at 8. In light the above, the Petitioners have not demonstrated that it is necessary for the five permits addressed in their petitions to include additional detail regarding the specific EGU NESHAP requirements and associated monitoring prior to the MACT compliance date.

Claim 2: Petitioners' Claim that the Permits Should Clearly Require SO_2 CEMS Operation During All Periods of Operation Except CEMS Breakdown and Repair.

Petitioners' Claim.[14] In the Hammond, Scherer and Wansley petitions, the Petitioners contend that the monitoring included in the relevant permits is insufficient to assure compliance with the 95 percent SO_2 reduction requirement in Georgia Rule 391-3-1-.02(2)(uuu) ("Rule (uuu)").[15] The Petitioners assert that "it is unclear in the Permit[s] whether operation of SO_2 CEMS is required during startup, shutdown, and malfunction."[16] The Petitioners assert further that allowing the facilities to cease operation of the SO_2 CEMS during startup, shutdown and malfunction periods makes the CEMS insufficient to assure compliance with the SO_2 emission limitation set forth in permit conditions based on Rule (uuu). The Petitioners contend that Georgia EPD should revise the permit to clearly require CEMS operation at all times, including during startup, shutdown and malfunction.

EPA's response. For the reasons provided below, I am hereby notifying the state and the permittees of the EPA's determination that cause exists to reopen the Hammond, Scherer and Wansley permits. Pursuant to 42 U.S.C. § 7661d(e) and 40 C.F.R. §§ 70.7(f) and (g), the EPA has determined that the three permits identified in the Petitioners' claim contain material mistakes that require correction and are related to the Petitioners' claim. Specifically, the permits erroneously identify as federally enforceable permit conditions that cite to Georgia Rule 391-3-1-.02(2)(uuu) as their legal basis. Additionally, the EPA has determined that the permit for Scherer erroneously incorporates state-only exemptions from SO_2 CEMS operation contained in Georgia Rule 391-3-1-.02(2)(uuu)4 into federally enforceable conditions addressing monitoring for the SO_2 limit from the EPA's New Source Performance Standard (NSPS) at 40 C.F.R. part 60, Subpart D, 40 C.F.R. § 60.43(a)(2). *See* Scherer Permit Condition 5.2.21.[17]

Under 40 C.F.R. § 70.6(b)(2), "the permitting authority shall specifically designate as not being federally enforceable under the Act any terms and conditions included in the permit that are not required under the Act or under any of its applicable requirements." Several conditions in each of the three permits cite Georgia Rule 391-3-1-.02(2)(uuu) as their legal basis.[18] Georgia EPD submitted Georgia

[14] Petitioners' claims regarding operation of the SO_2 CEMS appear in the Hammond Petition at 9-10, the Scherer Petition at 17-18, and the Wansley Petition at 9-11.

[15] The SO_2 emission limitations cited by Petitioner are: Hammond Permit at conditions 3.4.9; Scherer Permit at conditions 3.4.15-3.4.18; and Wansley Permit at conditions 3.4.13-3.4.14. These permit conditions cite Rule (uuu) as their legal basis.

[16] Hammond Petition at 9; Scherer Petition at 17; Wansley Petition at 9-10. The monitoring language that the Petitioner claims may exempt the source from the requirement to operate SO_2 CEMS during startup, shutdown, and malfunction periods also derives from Rule (uuu). Hammond Permit at conditions 5.2.11, 3.4.10; Scherer Permit at conditions 5.2.21, 3.4.19; Wansley Permit at conditions 5.2.14.

[17] The NSPS SO_2 limit is in Condition 3.3.4. Condition 5.2.4 specifies that the source must use SO_2 CEMS to assure compliance with the NSPS limit, and references the SO_2 CEMS requirement in Condition 5.2.1f. Condition 5.2.21 exempts the source from having to operate the SO_2 CEMS required by Condition 5.2.1f during any period allowed under Condition 3.4.19. Condition 3.4.19 contains the state-only CEMS exemptions provided in Georgia Rule 391-3-1-.02(d)(uuu)4.

[18] The Rule (uuu) SO_2 limit appears in the Hammond Permit at condition 3.4.9, in the Scherer Permit at conditions 3.4.15-3.4.18, and in the Wansley Permit at conditions 3.4.13-3.4.14. The associated CEMS requirements appear in the Hammond Permit at conditions 5.2.11, and 3.4.10, in the Scherer Permit at conditions 5.2.21 and 3.4.19, and in the Wansley Permit at

Rule 391-3-1-.02(2)(uuu) to the EPA for incorporation into the Georgia SIP, but the EPA has neither proposed approval nor taken final action on this submittal. Absent approval by the EPA, Georgia Rule 391-3-1-.02(2)(uuu) is not part of the Georgia SIP, and therefore is not a federally enforceable "applicable requirement," as defined by 40 C.F.R. § 70.2. The title V permits for Plants Hammond, Scherer and Wansley include numerous conditions labeled as "State Only Enforceable," but do not label the conditions related to Georgia Rule 391-3-1-.02(2)(uuu) as such, and Georgia EPD did not label these permit requirements based on Rule (uuu) as "not being federally enforceable" anywhere else. Also, the Scherer permit erroneously applies the state-only CEMS exemptions contained in Georgia Rule 391-3-1-.02(2)(uuu)4 to monitoring conditions for the federally enforceable SO_2 limit from 40 C.F.R. § 60.43(a)(2). Based on these findings, the EPA concludes that cause exists to reopen the three permits to correct these mistakes. In accordance with 42 U.S.C. § 7661d(e) and 40 CFR § 70.7(g), the EPA hereby notifies the Georgia EPD and the permittees of EPA's determination. In response to this notification, Georgia EPD must take action to: (1) ensure that any permit condition that cites to Georgia Rule 391-3-1-.02(2)(uuu) as its legal basis is designated as not being federally enforceable; (2) ensure that the CEMS exemptions from Georgia Rule 391-3-1-.02(2)(uuu)4 are not incorporated into permit conditions addressing monitoring for federal requirements; and (3) ensure and clarify that the federal portion of the permits contains the necessary monitoring requirements for the permits' federal SO_2 limits (e.g., Condition 5.2.4 from the Scherer Permit).

Accordingly, I am neither granting nor denying this claim. Clean Air Act section 505(b)(2) indicates the Administrator "shall grant or deny [a] petition within 60 days after the petition is filed." This provision does not direct how the Administrator must address the individual issues in each petition, thus providing the EPA with discretion in determining the best approach. The EPA may consider the complexity of the issues, the inter-relatedness of the issues, agency resources, public participation opportunities, source-specific considerations and other relevant factors in deciding the most appropriate approach for addressing the issues in each petition. *See also In the Consolidated Environmental Management, Inc. – Nucor Steel Louisiana*, Petition Nos. VI-201002 and VI-2011-03 at 11 (March 23, 2012) (*Nucor I Order*) ("Section 505(b)(2) does not specify whether the EPA must respond initially to all of the issues raised in a petition."). In this instance, the EPA has initiated a process to reopen the permits on which Petitioners' Claim 2 is based. Further, the questions underlying Petitioners' claims could be moot or could be substantively different depending on Georgia EPD's response to the EPA's determinations described above and the reopening for cause process.

Claim 3: Petitioners' Claim that the Permits' PM Monitoring Provisions Must be Strengthened.

Petitioners' Claim.[19] The Petitioners contend in their petitions on the Plant Hammond, McIntosh, Wansley and Scherer permits that the PM stack testing frequency required in the permits is insufficient to assure continuous compliance with the applicable hourly PM limitations.[20] Citing to *In re U.S. Steel*

condition 5.2.14.

[19] Petitioners' claims regarding PM monitoring appear in the Plant Scherer Petition at 14-17, the Plant Hammond Petition at 6-9, the Plant McIntosh Petition at 3-8 and the Plant Wansley Petition at 6-9.

[20] Plant McIntosh's one steam generating unit is subject to a PM limit of 0.18 lb/MMBtu heat input under Georgia Rules 391-3-1-.02(2)(c) and .02(2)(d)1(ii). Plant McIntosh Permit Condition 3.4.1. Plant Scherer's four steam generating units are subject to a PM limit of 0.10 lb/MMBtu heat input under 40 C.F.R. § 60.42(a)(1) and Georgia Rule 391-3-1-.02(2)(d)2(iii). Plant Scherer Permit Condition 3.3.2. Plant Hammond's four steam generating units are subject to a PM limit of 0.24 lb/MMBtu heat input under Georgia Rule 391-3-1-.02(2)(d)1(iii). Hammond Permit Condition 3.4.1. Plant Wansley's two steam generating units are subject to a PM limit of 0.24 lb/MMBtu heat input under Georgia Rule 391-3-1-.02(2)(d)1(iii). Plant Wansley Permit Condition 3.4.1.

Corporation—Granite City Works, Order on Petition, Petition No. V-2009-03 (Jan. 31, 2011), the Petitioners contend that the EPA has already found "that PM compliance testing once every permit cycle (5 years) was facially insufficient to assure compliance with continuous limitations." The Petitioners acknowledge that the permits also require the facilities to monitor opacity using continuous opacity monitoring systems (COMS), but state that Georgia EPD does not discuss or try to establish a correlation between opacity limits and PM limits.[21] The Petitioners further contend that neither the permits nor Georgia EPD's responses to comments provide a detailed rationale as to why the chosen monitoring method is sufficient to assure compliance. The Petitioners claim that the permits should require a continuous emissions monitoring system (CEMS) for PM, or at a minimum, must include more frequent PM stack tests, e.g. quarterly, and the use of continuous parametric or surrogate monitoring with site specific correlations established during each stack test.[22] According to the Petitioners, "the variability of emissions, especially as they relate to the add-on controls," strongly indicates the necessity for continuous monitoring. The Petitioners contend that companies arrange diagnostic tests prior to official stack tests to ensure that their facility passes the stack tests, "even though particulate matter emissions may be much greater" during the rest of the five-to-ten-year period. The Petitioners note that PM CEMS "are increasingly employed at other coal-fired power plants," and that the EPA has "secured commitments from up to 30 existing coal-fired utility installations to install PM CEMS within the next few years." The Petitioners state that "[g]iven the use, reliability, and accuracy of monitoring requirements for similar emission units at other facilities, the EPA should object to the Permit and require the use of PM CEMS."

EPA's Response. For the reasons provided below, I deny the Petitioners' request for an objection to the permits on this claim. The Petitioners fail to demonstrate that the permits' monitoring requirements, viewed as a whole, are insufficient to assure compliance with the applicable PM limits. As discussed below, in addition to requiring stack testing, each permit includes parametric monitoring requirements designed to assure compliance with the applicable PM limits. Furthermore, contrary to Petitioners' assertion, the compliance assurance monitoring (CAM) plan attached to each of the facilities' permit applications, which is part of the title V permit record, shows a source-specific correlation between opacity levels and compliance with the applicable PM limits. Therefore, the Petitioners did not meet their burden of demonstrating that the permits are not in compliance with the requirements of the Act.

Further, although CEMS may be the preferred type of monitoring in some instances, CEMS are not always necessary to assure compliance with applicable requirements. Section 504(b) of the Act provides that "continuous emissions monitoring need not be required if alternative methods are available that provide sufficiently reliable and timely information for determining compliance." 42 U.S.C. § 7661c(b). *See also In re Alliant Energy WPL-Edgewater Generating Station,* Order on Petition, Petition Number V -2009-02 (August 17, 2010), at 11. The Petitioners neither identify an applicable requirement that compels the use of CEMS nor demonstrate that a CEM is the only monitoring method that can assure compliance with the applicable requirements.

As described in detail below, the Georgia Power permits at issue utilize a three-pronged approach for assuring compliance with the applicable PM limits: (1) performance testing to demonstrate that the

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[21] Regarding Plant McIntosh, the petition notes that EPD "attempt[s] to correlate between opacity and PM," but contends that EPD's explanation was inadequate because the relationship between opacity and PM can differ based on load and EPD did not explain whether the stack tests were across a range of loads, and also because it is unclear whether EPD repeats the correlation analysis during every stack test.

[22] In the Plant Scherer petition, the Petitioner insisted that PM CEMS are necessary and did not suggest that parametric monitoring as a potentially acceptable substitute.

specified limit is being met; (2) continuous monitoring of the operation and maintenance of the applicable control devices to ensure continued proper operation (including monitoring operational parameters such as ESP indicator levels, opacity levels from COMs, number of recycling pumps in operation or sparger tube submergence levels for continuous monitoring of scrubbers/FGD); and (3) CAM plan requirements, including ranges of opacity along with additional secondary indicator monitoring in some cases.

The Petitioners have not demonstrated that Georgia EPD failed to provide a rationale for why the selected monitoring is sufficient to assure compliance with the applicable PM limits. To satisfy Part 70 requirements, "[t]he rationale for the selected monitoring requirements must be clear and documented in the permit record." *In re Public Service Company of Colorado, Pawnee Station*, Order on Petition, Petition No. VIII-2010-XX (June 30, 2011), at 12 (citing 40 C.F.R. 70.7(a)(5)). The permit record includes, among other things, the response to comments, the permit narrative, the permit application, and, for these permits, a CAM plan (or plans).[23] As discussed below, I find that, for each of the permits, the permit record sufficiently documents the rationale for the monitoring requirements selected to assure compliance with applicable PM emission limits.

Source-Specific PM Monitoring Requirements and Associated Rationale

Plant Hammond.
In response to comments, Georgia EPD explained that there is no requirement to install PM CEMS on Plant Hammond's four steam generating units (Units SG01-SG04), and that "PM testing requirements in Condition 4.2.1 and the operation of the Continuous Opacity Monitoring Systems (COMS) are sufficient monitoring requirements to ensure this facility will be able to comply with the PM and opacity emissions limits." Plant Hammond Permit RTC at 10. In addition, Georgia EPD's response points to Conditions 5.2.3 through 5.2.10 which explicitly list the CAM Plan requirements under 40 C.F.R. part 64 for SG01-SG04. *Id.* at 11. Georgia's EPD's response guides the commenter to the State's website where the CAM Plan electronic documents can be found (Application No. 19763). *Id.* Plant Hammond Permit Condition 4.2.1.b requires PM testing of SG01-SG04 stack (ST03) annually, unless previous test results were less than 50 percent of the limit of 0.24 lb/MMBtu, in which case the testing can be delayed no more than 12 months. Hammond Permit Condition 4.2.1a also requires PM testing of SG01, SG02 & SG03 scrubber bypass stack (ST01) and SG04 (ST02) after 8760 hrs of bypass operation or five years to show compliance with the limit of 0.24 lb/MMBtu. Consistent with the CAM plan, between stack tests compliance is assured through the use of parametric monitoring. Specifically, the permit requires continuous opacity monitoring upstream of the FGD scrubbers with dedicated COMS. Permit Condition 5.2.1a. The permit identifies as an exceedance "[a]ny six-minute period during which the average opacity, as measured by the COMS...exceeds 40 percent." Permit Condition 6.1.7.b.i. The permit identifies as an excursion requiring corrective action for Source 1 (comprised of steam generating units 1, 2 and 3) as "any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 40 percent." Permit Condition 6.1.7.c.i. For Source 2 (comprised of steam generating unit 4), an excursion occurs whenever the three-hour block average opacity exceeds 37 percent. Permit Condition 6.1.7.c.ii. The permit also requires continuous monitoring of ESP power and continuous monitoring of the number of recycle pumps to maintain performance of the Flue Gas Desulfurization ("FGD") unit. Permit Condition 5.2.10.

[23] CAM plans for these facilities are available on Georgia EPD's website at *http://airpermit.dnr.state.ga.us/GATV/GATV/TitleV.asp*.

The rationale for the selected opacity level, ESP power level, and FGD number of recycle pumps running is provided in the permit narrative and in the CAM plans attached to Georgia Power's permit applications and included in the permit record. Specifically, Plant Hammond's CAM plan dated 4/27/04 explains that when opacity is below 40 percent for Source 1, or below 37 percent for Source 2, "test data indicates a reasonable assurance that the PM emissions will be significantly less than the permit limit." Hammond CAM Plan at 4, 8. The plan confirms that if the three-hour opacity average for either source approaches the specified level, "action will be taken to reduce the average as soon as possible." *Id.* The CAM plan further states: "The CAM opacity cap was established by measuring the particulate emissions at different opacity levels in the combined ESP exhausts … no changes have taken place that could result in a significant change in the precipitator performance or the selected indicator ranges since the compliance or performance test was conducted." *Id.* Regarding monitoring of the ESP power level and the FGD number of recycle pumps running, the permit itself explains that the ESP power and the number of FGD1 recycle pumps running and minimum rotations per minute (RPM) detected are indicators of particulate matter collection and equipment performance. Hammond Permit Condition 5.2.10. The permit narrative explains: "If the ESP power falls below the established threshold, then the number of pumps operating and the RPM for each of the pumps at the time will be verified. An excursion will be reported if the ESP power falls and the number of pumps is less than the minimum and the RPMs are below the threshold." Permit narrative at 15. The narrative further explains: "The scrubber is a secondary control device and compliance has been routinely demonstrated during the annual performance testing prior to installation of the scrubber." *Id.*

Plant Scherer.

In response to comments, Georgia EPD explained that there is no requirement to install PM CEMS on these units, and that "PM testing requirements in Condition 4.2.1 and the operation of the Continuous Opacity Monitoring Systems (COMS) are sufficient monitoring requirements to ensure this facility will be able to comply with the PM and opacity emissions limits." Plant Scherer Permit RTC at 7. The Plant Scherer permit requires PM testing of SG01, SG02, SG03 and SG04 scrubber stacks (ST05, ST06, ST07 & ST08) once every 5 years (Permit Condition 4.2.1b) for a limit of 0.10 lb/MMBtu (Permit Condition 3.3.3). The permit also requires PM testing of SG01, SG02, SG03 and SG04 scrubber bypass stacks (ST01, ST02, ST03 & ST04) after 8760 hours of bypass operation or 5 years unless previous results were 50 percent or less of limit of 0.10 lb/MMBtu. Permit Condition 4.2.1a. Between PM stack tests, the permit assures compliance with PM limits using parametric monitoring. Specifically, the permit requires continuous opacity monitoring upstream of the FGD scrubbers with dedicated COMS. Permit Condition 5.2.1b. For each of the steam generator units, Permit Condition 6.1.7 defines as an excursion (i.e., a departure from an indicator range) "any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 20 percent." For SG03 and SG04, the permit supplements opacity monitoring with a second compliance indicator: the number of FGD recycle pumps running. Conditions 5.2.8 and 5.2.9.

The rationale for the monitoring selected to assure compliance with applicable PM limits is provided in the permit, the permit narrative, and in Plant Scherer's CAM plan (attached to the permit application and included in the permit record). As the permit narrative explains, SG01, SG02, SG03 and SG04 and the associated FGD Scrubber and ESP are subject to the CAM plan requirements of 40 CFR part 64 for control of PM. Plant Scherer Permit Narrative at 14. The parametric monitoring requirements included in the permit to assure compliance with the PM limit are taken from the plant's CAM plan dated 4/27/04. Regarding the required opacity monitoring, the CAM plan explains that for each of the units, when opacity is below 20 percent, "test data indicates a reasonable assurance that the PM emissions will be less than the permit limit." CAM plan at 4 (SG01), at 8 (SG02), at 12 (SG03), at 16 (SG04). The plan further states: "If the three-hour opacity average approaches 20%, action will be taken to reduce the average as soon as possible." *Id.* According to the plan, the opacity cap "was established by measuring the particulate emissions at different opacity levels in the ESP exhaust." *Id.* The plan explains: "No changes have taken place that could result in a significant change in the precipitator performance or the selected indicator since the compliance or performance test was conducted." *Id.* The requirement to monitor the number of FGD recycle pumps running at Units SG03 and SG04 is based on a CAM plan modification submitted on June 22, 2011. As the permit explains: "The number of FGD pumps running is an indicator of particulate matter collection and equipment performance of the FGD." Plant Scherer Permit Conditions 5.2.8 and 5.2.9. The 2011 CAM plan modification summarizes test data indicating the correlation between the number of FGD recycle pumps running and particulate matter emissions. 2011 CAM Plan at 3.

Plant Wansley.

In response to comments, Georgia EPD explained that there is no requirement to install PM CEMS on these units and that "PM testing requirements in Condition 4.2.1 and the operation of the Continuous Opacity Monitoring Systems (COMS) are sufficient monitoring requirements to ensure this facility will be able to comply with the PM and opacity emissions limits." Plant Wansley Permit RTC at 6. The Plant Wansley permit requires PM testing of SG01 & SG02 scrubber stacks (ST03 & ST04) every 5 years (Permit Condition 4.2.1b) to show compliance with a limit of 0.24 lb/MMBtu (Permit Condition 3.4.1). The permit also requires PM testing of SG01 & SG02 scrubber bypass stacks (ST01 & ST02) after 8760 hours of bypass operation or 5 years (Permit Condition 4.2.1a) to show compliance with the PM limit of 0.24 lb/MMBtu (Permit Condition 3.4.1). Between PM stack tests, the permit assures compliance with PM limits using parametric monitoring. The permit narrative explains that PM emissions from Steam Generating Units 1 and 2 are each controlled by an ESP (Source Codes EP01 and EP02) on the bypass stack liner and controlled by a FGD system (Source Codes FGD1 and FGD2) on the main stack liners. Plant Wansley Permit Narrative at 26. Permit Condition 5.2.1 requires the Permittee to install and operate a COMS on SG01 and SG02 located in each liner of the scrubber bypass stacks. Performance criteria for the COMS are established in Permit Conditions 5.2.6 and 5.2.7. Under Permit Condition 6.1.7.b, any six-minute period during which the average opacity, as measured by the COMs for Units SG01 and SG02, exceeds 40 percent shall be reported as an exceedance. In addition, for Units SG01 and SG02, the permit defines as an excursion requiring corrective action any 3-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 40 percent. Permit Condition 6.1.7.c. For parametric monitoring of the main stacks, the permit requires the Permittee to install and operate a continuous monitoring system (CMS) for the measurement of the sparger tube liquid submergence level in the scrubber vessels for Units SG01 and SG02. Permit Condition 5.2.2. Performance criteria pertaining to the sparger tube liquid submergence level are provided in Permit Conditions 5.2.6 and 5.2.7. The permit defines an excursion requiring corrective action for the FGDs as a 3-hour-average scrubber vessel sparger tube liquid submergence level less than 5.0. Permit Condition 6.1.7.c.iv).

The rationale for the monitoring selected to assure compliance with applicable PM limits is provided in the permit, the permit narrative, and in Plant Wansley's CAM plan (attached to the permit application and included in the permit record). For the bypass stacks, the permit narrative explains that COMS are the primary indicator that the ESP is operating properly. Plant Wansley Permit Narrative at 26. The narrative reports: "It has been determined that the opacity cap levels indicating unacceptable performance are: for Unit 1, a three-hour average of 40% opacity and for Unit 2, a three-hour average of 40% opacity." *Id.* For the main stacks, the permit narrative explains that the FGD scrubber is designated as the primary control device to achieve compliance with the PM standard. The narrative further explains that the primary indicator that the FGD scrubber is working properly is the sparger tube liquid submergence level in the FGD vessel for each unit. *Id.* According to Plant Wansley's CAM plan dated 1/26/2009: "Test data indicates particulate matter emissions will be well below the permit limit even with the ESP out of service if the JBR sparger tubes submergence level is maintained at or above 5.0 inches of liquid." Wansley CAM Plan at 4. The CAM plan includes a table summarizing test data showing the relationship between particulate matter emissions and the JBR sparger tube submergence level. *Id.* at 7.

Plant McIntosh.

In response to comments, Georgia EPD explained that there is no requirement to install PM CEMS on Plant McIntosh's steam generating unit (unit SG01), and that "PM testing requirements in Condition 4.2.1 and the operation of the Continuous Opacity Monitoring Systems (COMS) are sufficient monitoring requirements to ensure this facility will be able to comply with the PM and opacity emissions limits." Plant McIntosh RTC at 9. The Plant McIntosh permit requires PM testing of SG01 annually unless previous test results were less than 50 percent of the limit of 0.18 lb/MMBtu, in which case the testing can be delayed no more than 12 months. Permit Condition 4.2.1a. The Permittee must monitor opacity continuously with a dedicated COMS. Permit Condition 5.2.1.a. Performance criteria for the COMS are identified in Permit Condition 5.2.12. The permit identifies as an exceedance "[a]ny six-minute period during which the average opacity, as measured by the COMS for the steam generating unit (Emission Unit ID SG01) exceeds 40 percent." Permit Condition 6.1.7.b.iv. The permit explains that an excursion requiring corrective action occurs when "any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 28 percent (for combustion of fuel which does not include Pine Branch coal) or 22.5 percent (for combustion of fuel which includes Pine Branch coal)." Permit Condition 6.1.7.c.i.

The rationale for COMS as a PM monitoring approach is provided in the permit, the permit narrative, and in Plant McIntosh's CAM plan (attached to the permit application and included in the permit record). The permit narrative explains that the steam generating unit is controlled by an ESP, and the primary indicator of proper control device operation for particulate matter is a COMS. Permit Narrative at 25. Thus, the narrative explains that a COMS will be used to assure compliance with the opacity standard as well as the PM standard. McIntosh Permit Narrative at 22. More specifically, the permit narrative explains: "To assure compliance with the particulate standard, an Opacity Index Value was established for SG01. The Opacity Index Value is the opacity level at which particulate matter emissions would be expected to be at or near the allowable limit (0.18 pounds per million Btu) and was established by correlating test data from previous PM emissions tests with the corresponding opacity levels during the testing." *Id.* at 22. The narrative further explains: "It has been determined that the opacity cap level indicating unacceptable performance is a three-hour average of 28% opacity." Narrative at 25. The Plant McIntosh CAM plan dated 7/30/2004 explains that when opacity is below 28%, "test data indicates a reasonable assurance that the PM emissions will be less than the permit limit." CAM Plan at 4. The plan further explains: "If the three-hour opacity average approaches 28%, action will be taken to reduce the average as soon as possible. If the 3-hour opacity average exceeds 28%, a CAM excursion has occurred." [24] *Id.* According to the plan: "The CAM opacity cap was established by measuring the particulate emissions at different opacity levels in the ESP exhaust … No changes have taken place that

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[24] The permit narrative for the 2007 Plant McIntosh title V permit renewal (Permit No. 4911-103-0003-V-02-0) explains that the more stringent CAM excursion opacity level applicable when the plant is using Pine Branch coal is in accordance with Consent Order No. EPD-AQC-1596 executed on April 28, 2000. 2007 Renewal Permit Narrative at 16. The narrative for the 2012 Plant McIntosh renewal permit at issue in this order includes a table referencing the 2007 title V permit renewal action. Plant McIntosh Narrative at 3.

could result in a significant change in the precipitator performance or the selected indicator since the compliance or performance test was conducted." *Id.*

Correlation Between PM and Opacity

Regarding the Petitioners' claim that the permit records lacked a source-specific correlation between opacity and PM emissions—or, in the case of Plant McIntosh, that the record lacked an adequate correlation that would be reconfirmed in future stack tests—this claim was not raised with reasonable specificity in comments to Georgia EPD on the draft permits. Nor is there any demonstration in the petitions that it was impracticable to do so or evidence that the grounds arose after the comment period. As discussed above, under CAA § 505(b)(2): "The petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period)." Accordingly, I deny the Petitioners' correlation claim on procedural grounds. However, as noted above, Georgia Power's CAM plan for each plant does show the correlation between opacity and PM emissions.

PM Monitoring Adequacy

Regarding the Petitioners' claim that the overall approach to PM monitoring set forth in the permits is insufficient to assure compliance with applicable PM limitations, the Petitioners have not met their burden of demonstrating that the PM monitoring is insufficient. The suite of monitoring requirements included in each permit as described above, including PM stack testing and parametric monitoring (continuous opacity monitoring, and where appropriate and necessary, other parametric monitoring of control equipment) is consistent with the monitoring approach we reviewed in a number of orders. *See In re Wisconsin Public Service Corporation's JP Pulliam Power Plant*, Petition V-2012-01 (Jan. 7, 2013); *In re Public Service Company of Colorado, dba Xcel Energy, Hayden Station*, Petition VIII-2009-01 (March 24, 2010), at 5. *In re Public Service Company of Colorado, dba Xcel Energy,Pawnee Station*, Petition VIII-2010-XX (June 30, 2011), at 12; *In re Public Service Company of Colorado, dba Xcel Energy, Cherokee* Station, Petition VIII-2010-XX (September 29, 2011), at 11; *In re Public Service Company of Colorado, dba Xcel Energy, Valmont Station*, Petition VIII-2010-XX (September 29, 2011), at 10. While the Petitioners insist that the permits' stack testing requirements are insufficient to assure compliance with short-term PM limits, the Petitioners fail to demonstrate the inadequacy of the associated parametric monitoring described in the CAM plans and included in the permits as part of the broader suite of PM monitoring. Likewise, the Petitioners' contention that the COMS monitoring is ineffective due to the lack of a source-specific correlation between opacity and PM emissions is not supported by the record; as discussed above, the CAM plan for each facility provides this source-specific correlation. These plans were included in the permit records and were available for public review during the public comment period.[25]

As mentioned above, under title V a petitioner has the burden to demonstrate to the EPA that a permit is not in compliance with the requirements of the Act. *Sierra Club v. Johnson, 541 F.3d 1257, 1266-1267*

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[25] As explained above, the correlation issue was not raised with reasonable specificity in comments to the Georgia EPD on the draft permits, and therefore, the EPA is denying the correlation claims on procedural grounds. Alternatively, even if the correlation claims had been raised with reasonable specificity in comments on the draft permits, the EPA denies the correlation claims on the basis that the Petitioners did not demonstrate the inadequacy of the correlations provided in the CAM plans, which were available in the permit records.

(11th Cir. 2008); Citizens Against Ruining the Environment v. EPA, 535 F.3d 670, 677-678 (7th Cir. 2008); Sierra Club v. EPA, 557 F.3d 401, 406 (6th Cir. 2009); McClarence v. EPA, 596 F.3d 1123, 130-31 (9th Cir. 2010) (discussing the burden of proof in title V petitions). Because the Petitioners simply challenge the lack of CEMS and the frequency of stack testing without addressing the overall monitoring scheme for the PM limits in the permits, the Petitioner failed to demonstrate that the monitoring requirements in the permit are insufficient to assure compliance with the PM limits. Furthermore, contrary to the Petitioners' contention, the permit record for each of the permits provides the rationale for the selected monitoring regime. Therefore, I deny the Petitioners' request for an objection to the permits based on alleged deficiencies in the permits' PM monitoring requirements and the purported lack of an explanation in the permit record for the selected PM monitoring approach.

Claim 4: Petitioners' Claim that Permits Must Include Provisions to Control Fugitive Dust from the Coal, Ash and Material Handling Systems.

Petitioners' Claims. In their petitions on the Plants Hammond, Kraft, McIntosh, Wansley and Scherer permits, the Petitioners claim that the permits lack "the specific, enforceable best management practices necessary to eliminate or minimize fugitive dust" generated from the facilities' various coal, ash and material handling operations (the specific operations vary depending upon the facility). The Petitioners allege three deficiencies related to this issue. The Petitioners allege that this lack of specificity contravenes Georgia SIP Rule 391-3-1-.02(2)(n)1, which "includes a non-exhaustive list of specific control devices and practices that should be applied to the facility and detailed in its Title V permit as enforceable conditions." The Petitioners also state that the condition in each permit requiring the facilities to take "reasonable precautions" is vague and unenforceable. According to the Petitioners, the permits should specify "[t]he required frequency, quantity and duration of dust suppression techniques." Finally, the Petitioners contend that the permits do not include monitoring and reporting of control devices and practices to demonstrate compliance with the twenty percent opacity limit in Georgia SIP Rule 391-3-1-.02(2)(n)2. *See* Plant Scherer Petition at 20-21, Plant Hammond Petition at 11-12, Plant Kraft Petition at 4-5, Plant McIntosh Petition at 9-10, Plant Wansley Petition at 12-13.

EPA's Response. For the reasons provided below, I grant the Petitioners' request for an objection to the permits based on deficiencies in the permit conditions implementing the fugitive dust control requirements of Georgia SIP Rule 391-3-1-.02(2)(n).

The permits' fugitive dust control requirements are taken directly from Georgia SIP Rule 391-3-1-.02(2)(n). This SIP provision requires source operations which may generate fugitive dust to "take all reasonable precautions to prevent such dust from becoming airborne." This provision identifies "[s]ome reasonable precautions which could be taken to prevent dust from becoming airborne," (Georgia SIP Rule 391-3-1-.02(2)(n)1 (emphasis added)), but the SIP does not specifically require that a source take a specific action. Thus, the lack of a condition in the permits requiring that the sources take the precautions identified in the rule does not contravene the SIP. However, the EPA determines that the Petitioners met their burden of demonstrating that without details regarding what type of actions qualify as "reasonable precautions" to control fugitive dust at these facilities, the permits do not assure compliance with Georgia SIP Rule 391-3-1-.02(2)(n)1.

Under CAA § 504(a), "[e]ach permit issued under this subchapter shall include enforceable emission limitations and standards...and such other conditions as are necessary to assure compliance with the applicable requirements of this chapter, including the requirements of the applicable implementation plan." Likewise, the EPA's regulations specify that each Title V permit must include "[e]missions limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance." 40 C.F.R. § 70.6(a)(1) (emphasis added). *See also* 40 C.F.R. § 70.6(c)(1).

The "reasonable precautions" requirement at Georgia SIP Rule 391-3-1-.02(2)(n)1 is an "applicable requirement" for title V purposes. While the SIP regulation identifies various fugitive dust control methods that may constitute "reasonable precautions," it does not mandate the use of any of these methods. For a title V permit to assure a particular source's compliance with this requirement, consistent with 40 C.F.R. § 70.6(a)(1) and the approved Georgia title V program at Georgia Air Quality Rule 391-3-1-.03(10), the permit terms must specify the emissions limitations and standards, including those operational requirements and limitations that assure compliance with the applicable requirement in Georgia SIP Rule 391-3-1-.02(2)(n)1. I find that the Petitioners demonstrated a flaw in the permit.

Because there can be many different interpretations of what constitutes "reasonable precautions" to control fugitive dust, the State's contention that the Petitioners' concerns are addressed by a permit condition requiring that the facility record steps taken to control fugitive emissions is inapposite in light of the permit's lack of specificity.[26] Likewise, while the State points out that the permits also require compliance with the SIP's 20 percent opacity limit, the State fails to explain how the existence of the opacity limit assures compliance with the "reasonable precautions" standard and there is no such explanation in the permit records.

In response to this Order, the EPA directs Georgia EPD to take action to include in the title V permits for Plants Hammond, Kraft, McIntosh, Wansley and Scherer emissions limitations and standards, including those operational requirements and limitations that assure compliance with Georgia SIP Rule 391-3-1-.02(2)(n)1.[27] In addition, Georgia EPD must provide a rationale in the permit record explaining why the permit conditions are sufficient to assure compliance with Georgia SIP Rule 391-3-1-.02(2)(n)1,including necessary monitoring, recordkeeping and reporting. The EPA notes that the Plant Scherer permit includes a wet suppression requirement under the applicable NSPS (Scherer Permit Condition 6.2.5) that potentially could be construed as sufficient to assure compliance with the reasonable precautions standard at Plant Scherer's railcar unloading area. If Georgia EPD concludes that this requirement is sufficient to assure compliance with Georgia SIP Rule 391-3-1-.02(2)(n)1 at Plant Scherer's railcar unloading area, Georgia EPD must provide the basis for such determination in a rationale included in the permit record.

Finally, regarding whether the permit conditions are sufficient to assure compliance with the 20% opacity limit in Georgia SIP Rule 391-3-1-.02(2)(n)2, I find that the Petitioners have demonstrated that neither the permits nor the permit records indicate how the permits assure compliance with the limit, as required by 40 CFR §§ 70.6(a)(3)(i)(B) and 70.6(c)(1). Though the Petitioners commented to the Georgia EPD that the draft permits "should be subject to monitoring and reporting to demonstrate compliance with a 20 percent opacity limit,"[28] Georgia EPD's response lacks any explanation as to how

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[26] Plant Scherer Permit RTC at 9; Plant Wansley Permit RTC at 7; Plant Kraft Permit RTC at 3; Plant Hammond Permit RTC at 12; Plant McIntosh RTC at 10.

[27] For Plants Hammond, Wansley and Scherer, the affected units are the Coal Handling System (CHS), the Ash Handling System (AHS) and the Materials Handling System (MHS). For Plant Kraft, the affected units are the Coal Handling System (CHS), the Transfer and Loading Equipment, Including the Transloader System (TLS) and the Ash Handling System (AHS). For Plant McIntosh, the affected units are the Coal Handling System (CHS) and the Ash Handling System (AHS).

[28] GreenLaw Comments on draft Wansley Permit dated May 18, 2012, at 21-22; GreenLaw Comments on draft Hammond Permit dated November 14, 2011, at 24; GreenLaw Comments on draft McIntosh Permit dated July 5, 2012, at 15; GreenLaw Comments on draft Scherer Permit dated October 21, 2011, at 21. *See also* Comments by Kurt Ebersbach, et al. on draft Kraft

the permit assures compliance with the opacity limit. While Georgia EPD's response refers to the condition in each of the facilities' permits "to maintain a record of all actions taken ... to suppress fugitive dust," Georgia EPD does not explain how that permit condition might relate to assuring compliance with the 20 percent opacity limit. Furthermore, nothing in the permit record indicates that the permit contains monitoring, recordkeeping and reporting obligations sufficient to assure compliance with the 20 percent opacity limit. Therefore, I also grant the petitions on this aspect of the Petitioners' claim. In response to this Order, the EPA directs the Georgia EPD to identify the specific methods and the monitoring to be used by Georgia Power to assure compliance with the 20 percent opacity limit for the fugitive dust sources at Plants Hammond, Kraft, McIntosh, Wansley and Scherer consistent with 40 CFR §§ 70.6(a)(3)(i)(B) and 70.6(c)(1), and provide an adequate rationale for the chosen methods in the permit record.

Claim 5: Petitioners' Claim that the Plant Scherer Permit Must Include Limitations to Comply with both PSD and NNSR.

The Petitioners claim that recent and planned upgrades to Plant Scherer's four steam turbines constitute a "modification" that should have triggered applicability of PSD and NNSR requirements; therefore, the Petitioners claim the Plant Scherer permit is deficient because it omits PSD and NNSR limitations. Scherer Petition at 3-11. The Petitioners further claim that Georgia EPD failed to provide a reasoned analysis of why PSD and NNSR are not applicable to this project. *Id.* According to the Petitioners, Georgia EPD's responses to Sierra Club's comments on the draft permit did not address Sierra Club's concerns, "but rather improperly required additional reporting on the emissions once the project is complete, which is irrelevant to the preconstruction analysis." Scherer Petition at 8. The Petitioners claim that the PSD/NNSR applicability analysis performed by Georgia Power and relied upon by Georgia EPD was flawed because it improperly accounted for emission reductions resulting from installation of pollution controls required by Georgia Rules 391-3-1-.02(2)(sss) and the accompanying SO_2 emission reductions required under Georgia Rule 391-3-1-.02(2)(uuu). Scherer Petition at 3-11. The Petitioners also state that "the required applicability review for PM and SO_2, which contribute to PM2.5 emissions, is properly termed 'new source nonattainment review'" and that the analysis for nonattainment NSR is the same as PSD. Petition at 11. The Petitioners' specific allegations regarding deficiencies in the PSD/NNSR applicability analysis are described in detail below.

1. **Georgia Power Incorrectly Considered Emission Reductions Anticipated from the Facility's Installation of SO_2 Controls Required by Georgia Rules in Determining that the Turbine Project Will Not Cause a Significant Emissions Increase Under Step One of the PSD/NNSR Applicability Analysis.**

Petitioners' Claim: The Petitioners contend that under Step One of the PSD/NNSR applicability analysis,[29] Georgia Power's calculation of whether the turbine upgrade project would result in a "significant emissions increase" improperly considered emission reductions anticipated from Georgia Power's installation of SO_2 controls (simultaneous with the Turbine Upgrade Project) required by Georgia Rule 391-3-1-.02(2)(sss) and accompanying reductions in SO_2 required under Georgia Rule 391-3-1-.02(2)(uuu). Scherer Petition at 7-9. In particular, the Petitioners argue that in applying the

Permit dated June 6, 2012, at 8-10 (noting that the permit applies the 20 percent opacity standard to the facility's coal handling operations "but does not include the specific, enforceable best management practices necessary to eliminate or minimize fugitive dust from this component of the plant.").

[29] *See* page 23, *infra*, for an explanation of the two-step analysis for determining PSD and NNSR applicability.

"actual-to-projected-actual" methodology for determining whether the Turbine Upgrade Project would result in a "significant emissions increase," Georgia Power incorrectly subtracted the emission reductions anticipated to be achieved by the installation of emission controls from the Turbine Upgrade Project's "projected actual emissions."[30] Scherer Petition at 9.

According to the Petitioners, Georgia Power should not have considered the emission reductions obtained from anticipated compliance with Georgia Rules 391-3-1-.02(2)(uuu) and (sss) in calculating the project's "projected actual emissions" because these emission reductions are "unenforceable." Scherer Petition at 9. Specifically, the Petitioners contend that "the reductions are not enforceable as a practical matter, because neither rule is enforceable during periods of allowable excess emissions (broadly defined periods of startup, shutdown and malfunction), and there is no requirement for continuous monitoring during such episodes." Scherer Petition at 10.

The Petitioners also contend that if the emission reductions resulting from Georgia Power's installation of SO_2 controls to comply with state regulatory requirements are in fact enforceable, Georgia Power should have adjusted the "baseline actual emissions"[31] used in the "actual-to-projected actual" calculation downward to reflect the required emission reductions. Scherer Petition at 9. Citing to 40 C.F.R. § 52.21(b)(48)(ii)(c)[32] and Georgia's PSD Guidance, the Petitioners contend that "baseline actual emissions" must be adjusted downward to account for any "new emissions limitations with which the source must currently comply."[33] *Id.* The Petitioners state that if Georgia Rules (uuu) and (sss) are enforceable, then they constitute "emission limitations with which the source must currently comply" and therefore must be accounted for in the facility's "baseline actual emissions." *Id.*

In sum, regarding consideration of the emission reductions anticipated from compliance with Georgia Rules (uuu) and (sss), the Petitioners contend that "either the limits were enforceable and should have been subtracted from the baseline emissions rate; or the emissions [reductions] were not enforceable and should not have been subtracted from the final actual annual emissions post-project." Scherer Petition at 9. According to the Petitioners, "either result would have made the baseline actual emissions and the

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[30] Under Georgia's SIP-approved PSD rules at Georgia Rule 391-3-1.02(7)(a)2.(ii)(I), the term "Projected actual emissions" is defined as "the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the five years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source." This definition also is incorporated into Georgia's SIP-approved NNSR rules at Georgia Rule 391-3-1-.03(8)(g)1.

[31] Georgia's SIP-approved PSD rules (at Georgia Rule 391-3-1.02(7)(a)2.(i)(I)) define "Baseline actual emissions" for an existing electric utility steam generating unit as "the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project." This definition also is incorporated into Georgia's SIP-approved NNSR rules at Georgia Rule 391-3-1-.03(8)(g)1.

[32] 40 C.F.R. § 52.21(b)(48)(ii)(c) applies to "existing emissions units (other than an electric utility steam generating unit)" and requires that in calculating "baseline actual emissions," the "average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply."

[33] It should be noted that 40 C.F.R. § 52.21(b)(48)(i), which applies to existing electric utility steam generating units, does not require that "baseline actual emissions" be adjusted downward to account for new emission limitations with which the source must "currently comply;" but Georgia's PSD and NNSR regulations for existing electric utility steam generating units do require this adjustment. *See* Georgia Rule 391-3-1.02(7)(a)2.(i)(I).VI. ("The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major source been required to comply with such limitations during the consecutive 24-month period."); *see also* Georgia Rule 391-3-1-.03(8)(g)1 (incorporating this language in Georgia's NNSR regulations).

projected annual emissions or potential to emit much closer, and would likely have resulted in a finding of significant emissions increase." *Id.*

Finally, the Petitioners contend that by counting the emission reductions obtained from anticipated compliance with Georgia Rules 391-3-1-.02(2)(uuu) and (sss) in Step One of the PSD/NNSR applicability analysis, "Georgia Power incorrectly collapsed both the significant emissions increase and significant net emissions increase steps into one step." Scherer Petition at 8. The Petitioners state that "because it appears that Georgia Power incorporated incorrect emissions reductions into its collapsed version, it is likely that a more-detailed analysis would uncover that Georgia Power's changes have resulted in triggering PSD and limitations related to that program must be incorporated into the Permit." *Id.*

EPA's Response. For the reasons provided below, I deny the Petitioners' request for an objection to the permit on this claim. The Petitioners failed to demonstrate that in determining that Plant Scherer's Turbine Upgrade Project did not trigger PSD/NNSR requirements, Georgia EPD did not comply with its SIP-approved regulations governing PSD/NNSR permitting or that Georgia EPD's exercise of discretion under such regulations was unreasonable or arbitrary.

First, regarding the Petitioners' claim that the emission reductions associated with compliance with Georgia Rules (uuu) and (sss) cannot be considered in the "projected actual emissions" determination because these reductions are (allegedly) unenforceable, neither the Petitioners nor any other commenter raised this issue with reasonable specificity in their comments to Georgia EPD on the draft permit. Nor do the Petitioners demonstrate that it was impracticable to raise this argument, and there is no basis for finding that grounds for such argument arose after the comment period. Thus, I deny this aspect of the Petitioners' claim on procedural grounds. CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2). However, the issue of whether controls or their effect on emissions must be "enforceable" to be considered in determining a unit's "projected actual emissions" is relevant to the EPA's response to the Petitioners' claim that Georgia Power's consideration of emission reductions resulting from the installation of controls improperly collapsed Steps One and Two of the PSD/NNSR applicability analysis. Therefore, the EPA addresses this issue below.

Second, neither the Petitioners nor any other commenter raised with reasonable specificity in their comments to Georgia EPD on the draft permit the argument that the project's "baseline emissions" should have been lowered to account for emission reductions attributable to compliance with Georgia Rules (uuu) and (sss). While comments to Georgia EPD on the draft Plant Scherer permit generally alleged that Georgia Power "took into account the effect of such other projects as the installation and operation of the SCR and scrubber systems required to be installed under Rule (sss), and the accompanying reductions in SO_2 emissions required under rule (uuu)," (GreenLaw comments at 10), the Petitioners did not specifically allege that the baseline should have been lowered. Rather, the Petitioners' comments focused on the argument that in Step One of the applicability analysis, emission decreases associated with pollution control projects and accompanying limits cannot be considered. *See* GreenLaw Comments at 12. The Petitioners did not demonstrate that it was impracticable to raise its concern regarding the "baseline emissions" calculation in its comments on the draft permit, and there is no basis for finding that grounds for this argument arose after the comment period. Accordingly, I also deny this aspect of the Petitioners' claim on procedural grounds. CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2).

The EPA has noted the importance of the requirement that petitioners raise issues with reasonable specificity to the state permitting authority:

As the EPA stated in the proposal to the original title V regulations:

> The EPA believes that Congress did not intend for Petitioners to be allowed to create an entirely new record before the Administrator that the State has had no opportunity to address. Accordingly, the Agency believes that the requirement to raise issues 'with reasonable specificity' places a burden on the Petitioner, absent unusual circumstances, to adduce before the State the evidence that would support a finding of noncompliance with the Act.

56 Fed. Reg. 21712, 21750 (1991). Thus, a title V petition should not be used to raise issues to the EPA that the State has had no opportunity to address, and the requirement to raise issues 'with reasonable specificity' places a burden on the petitioner, absent unusual circumstances, to adduce before the State the evidence that would support a finding of noncompliance with the Act. *Id.*

In the Matter of Luminant Generating Station, Petition No. VI-2011-05, Order on Petition, August 28, 2011 at 5.

Finally, regarding the Petitioners' more general claim that Georgia Power's consideration of the emission reductions expected from the installation of controls pursuant to Georgia Rules (uuu) and (sss) incorrectly collapsed Step One (the significant emissions increase) and Step Two (significant net emissions increase) steps into one step, I find that the Petitioners did not make the demonstration necessary to support that claim. As explained below, based on the EPA's review of the permit record and the applicable legal requirements, I find that the Petitioners have not demonstrated that it was inappropriate for Georgia Power to consider the effect of the pollution controls installed pursuant to Georgia Rules (uuu) and (sss) in Step One of the PSD/NNSR applicability analysis for Plant Scherer's Turbine Upgrade Project.[34]

When determining if a project at an existing major source is a "major modification"[35] that triggers PSD or NNSR requirements, it is necessary to first evaluate whether the project will result in a "significant emissions increase" (Step One). One option for making this determination is to apply the "actual-to-projected-actual" test.[36] This is the option used by Georgia Power to determining whether PSD and

[34] The basis for Georgia Power's determination that the Turbine Upgrade Project did not trigger PSD or NNSR appears in the narratives accompanying the two permit revisions that address the project. *See* Narrative for Permit Revision #4911-207-0008-V-02-A (addressing turbine upgrades for Units SG01, 02 and 04); Narrative for Permit Revision #4911-207-0008-V-02-7 (addressing turbine upgrade for Unit SG03). Both narratives are available on Georgia EPD's website at *http://airpermit.dnr.state.ga.us/gaairpermits/*.

[35] 40 C.F.R. § 52.21(b)(2)(i) [incorporated by reference in Georgia's SIP-approved PSD regulations at Rule 391-3-1.02(7)(a)2] defines "[m]ajor modification" as "any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase (as defined in paragraph (b)(40) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(50) of this section); and a significant net emissions increase of that pollutant from the major stationary source." This definition also is incorporated into Georgia's SIP-approved NNSR rules at Georgia Rule 391-3-1-.03(8)(g)1.(ii), with some adjustments that are not relevant to this order.

[36] Under 40 C.F.R. § 52.21(a)(2)(iv)(c), which is incorporated by reference into Georgia's SIP-approved PSD regulations at Rule 391-3-1.02(7)(a)3 , the "actual-to-projected actual" applicability test for projects that involve existing emissions units is as follows: "A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions . . . and the baseline actual emissions, for each existing emissions unit, equals or exceeds the significant amount for that pollutant." Georgia's SIP-approved NNSR rules at Georgia Rule 391-3-1-.03(8)(g)2. incorporate by reference the same language.

NNSR requirements applied to its Turbine Upgrade Project.[37] Under this test, the "baseline actual emissions" for each emission unit to be modified are subtracted from the unit's "projected actual emissions" (determined based on projected emissions after the unit resumes regular operations following the project's completion). The emissions change from any emission units for which the "actual-to-projected-actual" calculation shows an increase are then summed to determine the project's overall projected emissions increase. This sum is compared to the appropriate "significant emissions rate" for each pollutant. For all pollutants that have a "significant emissions increase," the PSD/NNSR applicability analysis goes forward to Step Two, where the "significant net emissions increase" is determined.

Georgia's SIP-approved PSD and NNSR regulations contain definitions for "baseline actual emissions" and "projected actual emissions," which include a basic definition and several required "adjustments" for each of these calculations. The definition that is most relevant here is that "projected actual emissions" is defined at its base as "the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the five years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity ...."[38]

For Plant Scherer's Turbine Upgrade Projects[39], Georgia Power (and in turn Georgia EPD) based "projected actual emissions" on the maximum annual rate at which the affected emissions unit is projected to emit a regulated NSR pollutant in any one of the 10 years (12-month period) following the date the unit resumes regular operation after the project, consistent with the regulations cited above.[40] As noted above, this emissions projection included consideration of the effect of pollution controls installed pursuant to Georgia Rules (uuu) and (sss).

In determining a unit's "projected actual emissions," the existence of pollution controls on a unit is considered part of the unit's operational capabilities; therefore, the anticipated effect of the controls on the unit's post-project emissions can be considered if the controls will be installed and operating during the time period selected for the emissions calculation. The "projected actual emissions" calculation is a prediction of the unit's future emissions and is not meant to become an enforceable limit. *See* Letter from Stephen Page, EPA, to David Isaacs, Semiconductor Industry Assn., dated August 26, 2011 at 9 ("[W]hen calculating projected actual emissions, in addition to considering legally enforceable restrictions, owners or operators may consider the effect on emissions of design or operational parameters, including air pollution control equipment, that are not enforceable."). This is consistent with the EPA's statement in the preamble to the EPA's 2002 revisions to its NSR regulations, which confirms that the EPA was not requiring that a source's projected actual emissions become an enforceable limit.

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[37] *See* Plant Scherer RTC at 5.

[38] Georgia's SIP-approved PSD regulations define "Baseline actual emissions" at Georgia Rule 391-3-1.02(7)(a)2.(i) and "Projected actual emissions" at Georgia Rule 391-3-1.02(7)(a)2.(ii). Georgia's SIP-approved NNSR regulations at Georgia Rule 391-3-1-.03(8)(g)1 incorporate these same definitions.

[39] *See* page 7-8 of the Background Section of the Order, which describes the dates of the turbine upgrades and the installation of required controls.

[40] *See* Letter from Georgia Power to Georgia EPD dated October 23, 2009 for Unit SG03 (supplement to application for permit amendment # 4911-207-0008-V-02-7, submitted in response to Georgia EPD request for additional information); Letter from Georgia Power to Georgia EPD dated November 17, 2009 for Unit SG02 (supplement to application for permit amendment # 4911-207-0008-V-02-A, submitted in response to Georgia EPD request for additional information); *see also* Permit 4911-207-0008-V-03-0, at 39-40, Conditions 6.2.20 and 6.2.21 (for all four units, requiring Georgia Power to calculate and maintain a record of annual emissions for a period of ten years following resumption of regular operations after installation of the upgraded steam turbines and control equipment, and requiring retention records associated with the initial PSD/NNSR non-applicability determination for 15 years following resumption of regular operations after the changes.).

67 Fed. Reg. 80186, 80197 (Dec. 31, 2002). There, the EPA explained that rather than making the unit's projected actual emissions an enforceable limit, a facility's projected actual emissions must be tracked against the facility's actual post-change emissions for five years following resumption of regular operations (or ten years if one of the effects of the physical or operational change is to increase a unit's design capacity or potential to emit), if there is a reasonable possibility that a project will cause a significant emissions increase. *Id.* at 80192. This directly refutes the Petitioners' assertions that Georgia EPD "improperly required additional reporting on the emissions once the project is complete, which is irrelevant to the pre-construction analysis" (Scherer Petition at 8) and that Georgia EPD's reliance on monitoring to confirm the accuracy of Georgia Power's emissions projection was "incorrect under the PSD regulations" (Scherer Petition at 9).[41] To the contrary, this is the way the EPA's NSR regulations are intended to work. The permit record indicates that Plant Scherer's turbine upgrades and the installation of pollution controls to comply with Georgia Rule (sss) are changes to the same emission unit (*i.e.*, the boiler/steam turbine or EUSGU). The record further indicates that Georgia Power planned to undertake the turbine upgrades and pollution control installation as part of the same renovation project during the same shutdown period, and that the controls will be installed and operating when the source resumes regular operation after the project's completion.[42] The Petitioners offer nothing rebutting information in the permit record indicating that the controls will be installed and operating during the time period selected by Georgia Power for use in its "projected actual emissions" calculation.[43] The Petitioners provided no additional demonstration concerning the NNSR applicability review for PM and SO_2 emissions related to this claim. Thus, I find that the Petitioners did not demonstrate that it was inappropriate for Georgia Power to consider the emission reductions anticipated from the installation of controls in calculating the units' "projected actual emissions" under Step One of the PSD/NNSR applicability analysis.[44] For the foregoing reasons, I deny the petition on these issues.

2. Georgia Power Cannot Take Credit for Emission Decreases Associated with Georgia Rules (sss) and (uuu) in Determining Whether the Project Will Cause a Net Emissions Increase under Step Two of the PSD/NNSR Applicability Analysis.

Petitioners' Claim. The Petitioners contend that if Georgia Power took credit for decreases associated with Rules (sss) and (uuu) in determining the project's net emissions increase under Step Two of the PSD/NNSR applicability analysis, this was improper because neither rule is enforceable during periods of allowable excess emissions and there is no requirement for continuous monitoring during such

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[41] In response to comments on the draft Plant Scherer permit, Georgia EPD explained that to address the commenters' concerns, "the Division has added Conditions 6.2.20, 6.2.21 and 6.2.22 to require record keeping and reporting of actual emissions that are pertinent to this modification (i.e., the turbine upgrade projects for Units 1, 2, 3 and 4) in accordance with Georgia Rule 391-3-1-.02(7)(b)15.(i)." Scherer Response to Comments, Permit Narrative Addendum at 5. Georgia EPD explained: "These conditions will require the facility to record, maintain and report actual emissions that are pertinent to this modification that justify avoidance of NSR/PSD review and document accuracy of the baseline-actual-to-projected-actual emissions calculations and explain any increases reported." *Id.*

[42] *See* pages 7-8 of the Background Section of this Order.

[43] Petitioners argue that it is not clear whether the emission limits (and control requirements) in Georgia Rules (uuu) and (sss) will be in effect at the time that construction begins (Plant Scherer Petition at 10), but do not dispute that the emission controls will be in effect during the time period following resumption of regular operations that Georgia Power selected for use in the "project actual emissions" determination.

[44] In the section of the Scherer Petition addressing the appropriateness of considering the controls in Step Two of the PSD/NNSR analysis, Petitioners contended that "it is not clear that such limits were or will be in effect 'at and after the time that actual construction on the particular change begins.'" Scherer Petition at 10. This argument does not apply to consideration of the controls in Step One of the analysis, which does not depend on an emission limit being in effect at the time that construction begins but instead turns on whether the controls will be installed and operating as of "the date the unit resumes regular operation after the project." *See* Georgia Rule 391-3-1.02(7)(a)2.(ii) (PSD definition of "projected actual emissions") and Georgia Rule 391-3-1-.03(8)(g)1 (NNSR incorporation by reference of PSD definition).

episodes, and it is not clear that such limits were or will be in effect "at and after the time that actual construction on the particular change begins." Scherer Petition at 10.

EPA's Response. Petitioners' claim does not demonstrate that the permit is not in compliance with the Act. Georgia EPD's determination that the turbine upgrades are not subject to PSD/NNSR was based solely on Georgia EPD's conclusion under Step One of the required analysis that the project will not result in a significant emissions increase. Furthermore, as discussed above, I deny the Petitioners' claims regarding deficiencies in Step One of the analysis. Thus, Petitioners' arguments regarding whether it would be appropriate to consider emission reductions associated with compliance with Georgia Rules (uuu) and (sss) under Step Two of the analysis are irrelevant to the applicability determination. The Petitioners provided no additional demonstration concerning the NNSR applicability review for PM and SO_2 emissions related to this claim. Therefore, I deny the Petitioners' request for an objection to the permit on this claim.

V. CONCLUSION

For the reasons set forth above and pursuant to CAA § 505(b)(2) and 40 C.F.R. § 70.8(d), I hereby grant in part and deny in part the Petitioners' five petitions seeking the EPA's objection to the title V operating permits issued by Georgia EPD for Plants Hammond, Kraft, McIntosh, Wansley and Scherer. I further order actions consistent with 42 U.S.C. § 7661d(e) and 40 C.F.R. § 70.7(g), as described in Section IV, Claim 2.

Dated: APR 1 4 2014

Gina McCarthy,
Administrator

EXHIBIT D

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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JUL 19 1999

Ref: 8P-AR

Mr. Ed Kurip, Director
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Ute Indian Tribe
P.O. Box 279
Ft. Duchesne, Utah 84026

Mr. Rusty Ruby, Manager
Operating Permits Section
Utah Division of Air Quality
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Salt Lake City, Utah 84114-4820

Re: 40 CFR Part 71 Sources on Uintah and Ouray Reservation

Dear Mr. Kurip and Mr. Ruby:

This is concerning each of your responses to my June 1999 request for identification of jurisdictional authority (Tribe/EPA or State) for air pollution sources located within the exterior boundaries of the Uintah and Ouray Indian Reservation. Enclosed are the June 23, 1999 response from Rusty Ruby with the State of Utah's conclusions on jurisdictional authority and the July 15, 1999 response from Ed Kurip with the Ute Indian Tribe's conclusions on jurisdictional authority. Also enclosed is a revised Table 1 – Reservation Land Source Summary (dated 7/16/99), that is based on the Tribe's and State's conclusions for jurisdictional authority.

Region VIII intends to use the revised Table 1 in determining which air pollution sources may be subject to the federal operating permits program (part 71), the pre-construction Prevention of Significant Deterioration Program (PSD), and other applicable federal programs.

If either of you have any questions concerning this correspondence, please feel free to contact me at (303) 312-6936.

Sincerely,

Monica S. Morales

Monica S. Morales
Air & Radiation Program

Enclosures (3)

cc: Tod J. Smith (Whiteing & Smith, w/enclosures)
Fred Nelson (UT - AG Office, w/enclosures)
Elaine Willie (Env. Coordinator, Ute Indian Tribe, w/enclosures)

Table 1 -- Reservation Land Source Summary

	Company	Site	Location	TSP tons/yr	PM_{10} tons/yr	NO_x tons/yr	CO tons/yr	SO_2 tons/yr	VOC tons/yr	Title V
Tribe/EPA	American Gilsonite Co	Bonanza Mines	40°01'04" lat 109°10'17" long Zone 12	24.98	16.10	3.00	0.60		241.00	yes
State	ANR Production Co	East Field Compressor Station	40°21'19" lat 110°14'46" long Zone 12			171.41	21.78		0.10	yes
State	ANR Production Co	Main Gas Processing Plant	40°21'28" lat 110°19'38" long Zone 12		0.10	283.88	36.90		0.20	yes
State	ANR Production Co	South Field Compressor Station	40°16'19" lat 110°26'06" long Zone 12			134.27	17.08		0.10	yes
State	ANR Production Co	West Field Compressor Station	40°19'06" lat 110°23'41" long Zone 12			119.98	15.27		0.10	yes
Tribe/EPA	Apache Corp	Compressor Station	39°54'56" lat 109°43'50" long Zone 12	0.04	0.04	12.17	5.41	0.01	2.16	
State	Burdick Paving Co	Madsen Hot Plant	N Airport Road, Roosevelt		6.01	0.48	0.50	3.86	0.37	yes NSPS[2]
Tribe/EPA	Chevron USA Production Co	Red Wash Field	40°15'00" lat 109°20'00" long Zone 12		1.25	255.68	44.54	24.61	85.66	yes NSPS[3]
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Prospect Well #33-3-5	40°15'13" lat 109°33'28" long Zone 12	0.12	0.12	7.5	1.04 CO_2 469.6	0.002	4.02	
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Prospect Well Alta #5-1-B	40°14'45" lat 109°34'36" long Zone 12		0.12	7.5	1.04	0.002	4.02	
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Prospect Well Alta #5-1-B	40°14'45" lat 109°34'36" long Zone 12		0.12	7.5	1.04	0.002	4.02	
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Prospect Well Alta #5-2-C	40°14'46" lat 109°34'55" long Zone 12		0.12	7.5	1.04	0.002	4.02	
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Federal Well #33-7-L	40°15'8" lat 109°33'58" long Zone 12		0.12	7.5	1.04	0.002	4.02	
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Federal Well #33-8-N	40°14'8" lat 109°33'58" long Zone 12		0.12	7.5	1.04	0.002	4.02	
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Prospect Fed. Well #33-6-F	40°15'23" lat 109°33'32" long Zone 12		0.12	7.5	1.04	0.002	4.02	
Tribe/EPA	Deseret Generation & Transmission	Bonanza	T 8 S, R 23 E Section 26 Zone 12	369.88	326.94	6,336.6	44.25	631.81	83.11	yes
Tribe/EPA	Enron Oil & Gas Co	Old Squaw Crossing Compressor Station	39°55'20" lat 109°45'13" long Zone 12							

[2] NSPS = New Source Performance Standards -- 40 CFR Part 60
[3] NSPS = New Source Performance Standards -- 40 CFR Part 60

Table 1 -- Reservation Land Source Summary (con't)

	Company	Site	Location	TSP tons/yr	PM_{10} tons/yr	NO_x tons/yr	CO tons/yr	SO_2 tons/yr	VOC tons/yr	Title V
Tribe/EPA	Exxon Co, USA	Walker Hollow Unit - Tank Battery #1	40°13'10" lat 109°14'33" long Zone 12	0.06	42.05	11.15	1.57	0.26	1.88	no
Tribe/EPA	Exxon Co, USA	Walker Hollow Unit - Tank Battery #2	40°13'08" lat 109°16'19" long Zone 12	0.16	0.14	3.29	0.69	0.56	3.02	no
Tribe/EPA	Exxon Co, USA	Walker Hollow Unit - Tank Battery #3	40°10'41" lat 109°18'41" long Zone 12	0.01	0.01	0.25	0.05		12.70	no
Tribe/EPA	Exxon Co, USA	Walker Hollow Unit Satellite Tank Battery	40°14'06" lat 109°16'49" long Zone 12	0.01	0.01	5.10	0.68	0.00	1.75	no
State	Gary-Williams Energy Corp	Altonah Gas Plant	T 2 S, R 3 W Section 5 Zone 12	0.10	0.10	4.76	1.19	0.02	0.24	yes Part 70[4]
State	Gary-Williams Energy Corp	Bluebell Gas Plant	40°23'00" lat 110°05'00" long Zone 12	125.30	61.30	566.72	101.56	0.14	29.47	yes
State	Koch Hydrocarbon Co*	Cedar Rim Gas Plant	T 3 S, R 6 W Section 21 Zone 12		0.14	108.69	43.46		4.75	yes
State	Pennzoil Products Co	Roosevelt Refinery	40°16'49" lat 110°01'07" long Zone 12	36.03	12.98	233.52	439.28	85.03	653.40	yes
Tribe/EPA	PG&E Resources Co	Riverbend Compressor Station	39°57'07" lat 109°45'11" long Zone 12							
Tribe/EPA	PG&E Resources Co	Riverbend Well Site	40°06'03" lat 109°42'25" long Zone 12							
Tribe/EPA	PG&E Resources Co	Willowcreek Gas Injection Project	40°0'37" lat 109°44'36" long Zone 12			16.2	24.2		8.1	no
Tribe/EPA	CNG Producing Co	Riverbend Field	40°02'00" lat 109°40'00" long Zone 12	1.23	936.00	229.97	8.44	0.07	274.48	yes
Tribe/EPA	Questar Pipeline Co	Fidlar Main Line Station	40°02'02" lat 109°26'49" long Zone 12			164.60	27.89	0.04		yes
Tribe/EPA	Wexpro Co	Wexpro Island Unit	39°54'00" lat 109°42'00" long Zone 12	0.01		0.80	0.16		0.04	no
Tribe/EPA	Williams Field Services	Duck Creek Compressor Station	T 9 S, R 20 E Section 23 Zone 12			30.04	3.80		1.24	no

* Koch Hydrocarbon Co. has been sold. New owner is unknown at this time.

[4] Part 70 = Operating Permits Program -- 40 CFR Part 70

EXHIBIT E

State of Utah
DEPARTMENT OF ENVIRONMENTAL QUALITY
DIVISION OF AIR QUALITY

Michael O. Leavitt
Governor
Dianne R. Nielson, Ph.D.
Executive Director
Ursula K. Trueman
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DAQE-086-98

January 30, 1998

Howard L. Vickers
Deseret Generation & Transmission
12500 East 25500 South
Vernal, Utah 84078

Dear Mr. Vickers:

Re: Intent to Approve Modification of Bonanza One (1) Power Plant Emission Limits, Change in Coal Pile Parameters, and Ruggedized Rotor Project, Uintah County, CDS-A1, NSPS, NESHAP, Title V

The attached document is an Intent to Approve for the above referenced project.

Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. Please direct any technical questions you may have on this project to Mr. Tim Blanchard. He may be reached at (801) 536-4057.

Sincerely,

Lynn R. Menlove, Manager
New Source Review Section

LRM:JTB:cmn

cc: Uintah Basin District Health Department
Mike Owens, EPA Region VIII

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

INTENT TO APPROVE MODIFICATION OF BONANZA ONE (1) POWER PLANT EMISSION LIMITS, CHANGE IN COAL PILE PARAMETERS, AND RUGGEDIZED ROTOR PROJECT

Prepared By: Tim Blanchard, Engineer

INTENT TO APPROVE NUMBER

DAQE-086-98

Date: January 30, 1998

Source

Deseret Generation & Transmission

Ursula K. Trueman
Executive Secretary
Utah Air Quality Board

Abstract

Deseret Generation & Transmission Co-operative. (DG&T) is proposing to modify Approval Order (AO) DAQE-706-97 (dated August 4, 1997) by modifying certain emission limits, modifying the Coal Pile parameters, and installing a ruggedized rotor at the Bonanza Power Plant Unit One (1) located in Uintah County. Uintah County is an attainment area for all pollutants. New Source Performance Standards (NSPS) Subparts A and Da apply to this source. National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations do not apply to this source. DG&T is requesting a modification in federally enforceable emission limits which will limit the potential to emit (PTE) for this source. These emission limits are being imposed to demonstrate that any net increase in emissions from the approved facilities will not exceed the threshold emission levels which trigger additional review under state New Source Review (NSR) and Prevention of Significant Deterioration (PSD) programs. Because 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 4381 MMBtu's/Hr to 4578 MMBtu's/Hr. DG&T also proposes to increase the total area of the coal pile to 22 acres and the active reclaim area to 11 acres. The net effect of these projects will be an overall reduction of Bonanza 1's potential emissions, with a significant reduction in NO_x emissions and relatively minor increases in other emissions. DG&T proposes to reduce its potential NO_x emissions by 528.17 TPY and increase the following emissions: particulate emissions 22.60 TPY, PM_{10} 14.11 TPY, SO_2 38.21 TPY, CO 91.60 TPY, VOC 10.68 TPY. A 30-day public comment period is required for DG&T's proposal.

The Notice of Intent for the above-referenced project has been evaluated and has been found to be consistent with the requirements of the Utah Air Quality Rules (UAQR) and the Utah Air Conservation Act. Air pollution producing sources and/or their air control facilities may not be constructed, installed, established, or modified prior to the issuance of an Approval Order (AO) by the Executive Secretary of the Utah Air Quality Board.

A Notice of Intent to issue an AO will be published in the Vernal Express on February 4, 1998. A 30-day period following the publishing date will be allowed during which the proposal and evaluation of its impact on air quality will be available for both you and the public to review and comment. If anyone so requests within 15 days of publication of the notice, a hearing will be held. The hearing will be held as close as practicable to the location of the source. Any comments received during the 30-day period and the hearing, if held, will be evaluated.

Please review the proposed AO conditions during this period and make any comments you may have before its closure. The proposed conditions of the AO may be changed as a result of the comments received. Unless changed, the AO will be based upon the following conditions:

General conditions:

1. This AO applies to the following company:

   HOME OFFICE:

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

The equipment listed below in this AO shall be operated at the following location:

PLANT LOCATION:

Bonanza Power Station Unit 1
12 kilometers northwest of Bonanza, Utah
Uintah County

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

2. Definitions of terms, abbreviations, and references used in this AO conform to those used in the Utah Air Conservation Rules (UACR), Utah Administrative Codes (UAC), New Source Performance Standards (NSPS) and Series 40 of the Code of Federal Regulations (40 CFR). These definitions take precedence unless specifically defined otherwise herein.

3. Deseret Generation & Transmission (DG&T) shall operate the 500 est. Megawatt (MW) gross Bonanza Power Station Unit 1 according to the terms and conditions of this Approval Order as requested in the Notice of Intent dated December 24, 1997 and additional information submitted January 5, 1998.

4. At least once per calendar year, all employees who operate equipment (operator) that produces and/or controls emissions to the air shall receive proper training as to their responsibilities in operating that equipment according to all relevant conditions of this AO. The training for each operator shall be for all equipment that operator operates. The equipment shall include all of the associated equipment listed in Conditions # 7, 8, and 9. Within 60 days of every time this AO is modified or reissued, those employees who operate equipment that produces and/or controls emissions to the air that is affected by the AO changes shall receive proper training as to their responsibilities in operating equipment according to all relevant conditions of this AO. Within 60 days of a new operator being employed or assigned with the job responsibility to operate any of the equipment that produces and/or controls emissions to the air, the new operator shall receive proper training as to their responsibilities in operating the equipment according to all relevant conditions of this AO. Records of operator training shall be made available to the executive secretary or executive secretary's representative upon request and the records shall include the two-year period prior to the date of the request. This AO shall be made available to all employees who operate the equipment listed in this AO.

5. The approved installations shall consist of a 500 est. MW coal fired steam electric generating station and associated equipment.

6. This AO shall replace the AO DAQE-706-97 dated August 4, 1997.

Limitations and tests procedures

7. Sulfur Emission Control

A. Bonanza 1 shall not discharge to the atmosphere sulfur as SO_2 at a rate exceeding 0.0976 lb/MMBTU 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 rolling 12-month average. On the first day of each month a new 12-month average shall be calculated using data from the previous 12 months.

B. Bonanza 1 shall achieve at least 90% SO_2 removal efficiency based on a 30-day rolling average.

C. Bonanza 1 SO_2 emissions shall not exceed 0.15 lb/MMBTU heat input as averaged over 30 successive boiler operating days.

D. To achieve the limits above, DG&T may use scrubber slurry additives (such as adipic acid etc.) to increase the dissolved alkalinity of the slurry reagent used in the FGD scrubber.

E. Compliance with the SO_2 removal requirements shall be based on data from outlet SO_2 continuous emissions monitors (CEM), and either inlet SO_2 data from CEM or coal analysis data, over a 30-day rolling average. The total percent removal may be computed using the total available sulfur from the coal analysis and overall sulfur removal. Compliance shall be determined by calculating the arithmetic average for all valid hourly emissions rates for SO_2 for the 30 successive boiler operating days.

8. Nitrogen Oxides Emission Control

A. Bonanza 1 shall not discharge to the atmosphere nitrogen oxide (NO_x) at a rate exceeding 0.50 lb/MMBTU heat input on an annual average. Compliance with this emission limitation shall be determined in accordance with 40 CFR 76.5(b).

B. Bonanza 1 shall not discharge to the atmosphere nitrogen oxide (NO_x) at a rate exceeding 0.55 lb NO_x/MMBTU heat input as a 30-day rolling average value averaged over 30 successive boiler operating days. Compliance with this emission limitation shall be based on CEM data and fuel heat input. Compliance shall 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.

9. Particulate and PM_{10} Emission Control

A. Unit No. 1 shall not discharge to the atmosphere particulate matter at a rate exceeding 0.0297 lbs/MMBTU BTU heat input as determined by 40 CFR 60, Appendix A, Methods 1-5 and 19.

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, 5-5e and 19.

C. Visible emissions from any source shall not exceed 20% opacity as determined primarily by CEM equipment, except for one six-minute period per hour of not more than 27% opacity for the tall stack, as determined by CEM equipment. However, EPA Method 9 may be used when the opacity CEM equipment is not operating.

D. Dust collectors DC-1 through 5, LDC 1 and 2, and the fly ash silo dust collector shall be maintained and operated per manufacturer's recommendations.

10. Stack testing to show compliance with the emission limitations stated in the above condition shall be performed as specified below:

A.

Emission Point	Pollutant	Testing Status	Test Frequency
Unit No. 1			
600 foot stack	TSP	*	@
	PM_{10}	*	@
	SO_2	*	@
	NO_x	*	@
DC-4 and DC-5	PM_{10}	**	#

B. Testing Status (To be applied above)

* Compliance testing is required. The initial testing shall be done in 1995. Alternatively, data from testing done in conjunction with the installation, calibration and certification of the new CEM system in 1994 may be used.

** No initial testing is required. However, the Executive Secretary may require testing at any time in accordance with R307-1-3.4.1, UAC. The source shall be tested if directed by the Executive Secretary.

\# Test if directed by the Executive Secretary. Tests may be required if the source is suspected to be in violation with other conditions of this AO.

@ Test every five (5) years

C. Notification

The applicant shall provide a notification of the test date at least 30 days before the test. A pretest conference shall be held if directed by the Executive Secretary. It shall be held at least 30 days before the test between the owner/operator, the tester, and the Executive Secretary. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approvable access shall be provided to the test location.

D. TSP

40 CFR 60. Appendix A, Method 5

E. PM_{10}

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5A, 5D, or 5E as appropriate. The back half condensibles shall also be tested using the method specified by the Executive Secretary. The portion of the front half of the catch considered PM_{10} shall be based on information in AP-42, Appendix C or other data acceptable to the Executive Secretary.

The back half condensibles shall not be used for compliance demonstration but shall be used for inventory purposes.

F. Sample Location

40 CFR 60. Appendix A, Method 1

G. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2 or any alternative method that has the approval of UDAQ or EPA.

H. Sulfur Dioxide (SO_2)

40 CFR 60, Appendix A, Method 6, 6A, 6B or 6C

I. Nitrogen Oxides (NO_x)

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D or 7E

J. Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide and Nitrogen Oxides Emissions Rates

40 CFR 60, Appendix A, Method 19

K. Calculations

To determine mass emission rates (lbs/hr, etc.), the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary to give the results in the specified units of the emission limitation.

L. Existing Source Operation

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum capacity unless approved by the Executive Secretary.

Roads and Fugitives

11. Coal and limestone conveyors shall be enclosed and all drop points shall be vented to fabric dust collectors.

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

    A. Times of testing.
    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.)

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 by 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. A log of operation shall be kept. The log shall include:

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

14. The long term limestone storage shall be sealed with a surfactant as dry conditions warrant or as determined necessary by the Executive Secretary.

15. The limestone receiving hopper shall be partly enclosed with a wind break.

16. The fly ash/FGD sludge mixture at the end of the conveyor and prior to being completely covered in accordance with landfill procedures, shall be water sprayed to minimize fugitive emissions as conditions warrant.

A record/log of stabilizing done shall be kept which includes dates, type of stabilizing agent, amount applied, and area of application.

17. All unpaved roads and other unpaved operational areas that are used by mobile equipment shall be water sprayed and/or chemically treated to control fugitive dust. The application of water or chemical treatment shall be used. Treatment shall be of sufficient frequency and quantity to maintain the surface material in a damp/moist condition. The opacity shall not exceed 20% during all times the areas are in use or unless it is below freezing. If chemical treatment is to be used, the plan must be approved by the Executive Secretary. Records of water treatment shall be kept for all periods when the plant is in operation. The records shall 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 shall be made available to the Executive Secretary upon request and shall include a period of two years ending with the date of the request.

18. Visible emissions from haul-road traffic and mobile equipment in operational areas shall be controlled by use of a dust control plan.

Fuels

19. DG&T shall use only coal and/or natural gas as a primary fuel and fuel oil and/or natural gas during startup, shut down, upset conditions and flame stabilization. DG&T may burn on-spec used oil, off-spec used oil and small quantities of self generated hazardous waste (<850 gallons/month) as specified in State and Federal regulations. If any other fuel is to be used, an AO shall be required in accordance with R307-1-3.1, UAC.

20. The sulfur content of any fuel oil or diesel burned shall not exceed 0.5 percent by weight. Sulfur content shall be decided by ASTM Method D-4294-89, or approved equivalent. The sulfur content shall be tested if directed by the executive secretary.

21. Boilers burning used oil for energy recovery shall comply with the following:

    A. The concentration/parameters of contaminants in the used oil shall not exceed the following levels:

1.	Arsenic	5	ppm by weight
2.	Cadmium	2	ppm by weight
3.	Chromium	10	ppm by weight
4.	Lead	100	ppm by weight
5.	Total halogens	1,000	ppm by weight
6.	Sulfur	0.5	percent by weight

B. The flash point of all used oil to be burned shall not be less than 100 °F.

C. The owner/operator shall provide test certification for each load of used oil received. Certification shall be either by their own testing or test reports from the used oil fuel marketer. Records of used oil fuel consumption and the test reports shall be kept for all periods when the plant is in operation. Records shall be made available to the executive secretary or her representative upon request. The records shall include a period of three years ending with the date of the request.

D. Used oil (off-spec) that does exceed any of the listed contaminants content may be burned, but owner/operator shall notify the Division of Solid and Hazardous Waste and EPA. The owner/operator shall record the quantities of used oil burned on a daily basis.

E. Used oil that contains more than 1000 ppm by weight of total halogens shall be considered a hazardous waste and can be burned at a maximum rate of 850 gallons/month. The used oil shall be tested for halogen content by ASTM Method D-808-81, EPA Method 8240 or Method 8260 before used oil fuel is transferred to the boiler fuel tank and burned. Small quantities self generated hazardous used fuels are regulated by 40 CFR 266.108(a) "Small Quantity On-site Burner Exemptions".

F. Sources utilizing used oil as a fuel shall comply with the State Division of Solid and Hazardous Waste in accordance with R315-15, UAC "Used Oil Management Rule".

Federal Limitations and Requirements

22. In addition to the requirements of this AO, all provisions of 40 CFR 60, NSPS Subparts A and Da, 40 CFR 60.40a to 60.49a (Standards of Performance for opacity, SO_2, and NO_x) apply to this installation.

Monitoring - General Process

23. All air quality monitoring must conform to the requirements of 40 CFR, Part 58. As part of the air quality monitoring program, a quality control program shall be used and it shall consist of policies, procedures, specifications, standards, and documentation necessary to:

A. Meet the monitoring objective and quality assurance requirements of the Executive Secretary.

B. Minimize loss of air quality data due to malfunction or out of control conditions.

24. The owner/operator shall install, calibrate, maintain, and operate a continuous emissions monitoring (CEM) system on the 600 foot stack. The owner/operator shall record the output of the system, for measuring the opacity of emissions, the SO_2 emissions, the NO_x emissions, and diluent. Procedures to be followed for (1) testing, monitoring, and reporting of excess emissions of particulates, opacity, sulfur dioxide and nitrogen oxides, and for (2) the purpose of demonstrating compliance with the emission limitations of Conditions (7), (8), and (9) are

specified in the applicable section of 40 CFR 60.7, 60.8, 60.11, 60.13, Subpart Da, Appendix A, Methods 1-7, Appendix B, Performance Specifications 1, 2, and 3, Appendix F, and the state CEM policy document (all applicable sections of R307-1-4.6, UAC).

25. A quality control/assurance plan/manual for the continuous monitoring system shall be developed and implemented. As a minimum, the quality control program shall have written procedures for each of the following activities:

    A. Installation of CEM's
    B. Calibration of CEM's
    C. Zero and calibration checks and adjustments for CEM's
    D. Preventive maintenance for CEM's (including parts inventory)
    E. Data recording and reporting
    F. Program of corrective action for inoperable CEM's
    G. Annual evaluation of CEM system

Records & Miscellaneous

26. All installations and facilities authorized by this AO shall be adequately and properly maintained. All pollution control vendor recommended equipment shall be installed, maintained, and operated. Instructions from the vendor or established maintenance practices that maximize pollution control shall be used. All necessary equipment control and operating devices, such as pressure gauges, amp meters, volt meters, flow rate indicators, temperature gauges, CEMs, etc., shall be installed and operated properly and easily accessible to compliance inspectors. A copy of all manufacturers' operating instruction for pollution control equipment and pollution emitting equipment shall be kept on site. These instructions shall be available to all employees who operate the equipment and shall be made available to compliance inspectors upon their request.

27. The owner/operator shall comply with R307-1-3.5, UAC. This rule addresses emission inventory reporting requirements.

28. The owner/operator shall comply with R307-1-4.7, UAC. This rule addresses unavoidable breakdown reporting requirements. The owner/operator shall calculate/estimate the excess emissions whenever a breakdown occurs. The total of excess emissions shall be reported to the Executive Secretary as directed for each calendar year.

All records referenced in this AO or in applicable NSPS or NESHAP, which are required to be kept by the owner/operator, shall be made available to the executive secretary or her representative upon request and shall include a period of two years ending with the date of the request. All records shall be kept for a period of two years (used oil records are to be kept for a period of three years). Examples of records to be kept at this source shall include the following as applicable:

    A. Test results .... Conditions 7,8 & 9
    B. Maintenance records .... Condition 26
    C. Upset, breakdown episodes .... Condition 28
    D. Fugitive emission control .... Conditions 12, 13, 16 & 17

E.	CEM records	Conditibn 24
F.	Fuel consumption	Condition 21
G.	Training	Condition 4

Any future modifications to the equipment approved by this order must also be approved in accordance with R307-1-3.1.1, UAC.

The Executive Secretary shall be notified in writing if the company is sold or changes its name. The notification shall be submitted within 30 days of such action.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including the Utah Air Conservation Rules.

Annual emissions for this source the entire plant are currently calculated at the following values:

	Pollutant	Tons/yr
A.	Particulate	962.56
B.	PM_{10}	925.76
C.	SO_2	1,968.11
D.	No_x	10,029.83
E.	CO	602.45
F.	VOC non methane	70.89
G.	Arsenic	0.34
H.	Beryllium	0.01
I.	Cadmium	0.07
J.	Chromium	4.00
K.	Lead	0.70
L.	Manganese	3.45
M.	Mercury	0.08
N.	Nickel	2.19

These calculations are for the purposes of determining the applicability of Prevention of Significant Deterioration, nonattainment area, and Title V source requirements of the UAC R307.

In accordance with the requirements of Title V of the 1990 Clean Air Act, the following pollutants may be subject to an operating permit fee. Emissions of the following pollutants from all sources, including pre-November 29, 1969 sources, may be subject to the operating permit fee. Both the fees rate and the class of pollutants are subject to change by State, the federal agencies, or both.

	Pollutant	Tons/yr
A.	PM_{10}	925.76
B.	SO_2	1,968.11
C.	NO_x	10,029.83
D.	VOC non methane	70.89
E.	HAPs	10.84

The Division of Air Quality is authorized to charge a fee for reimbursement of the actual costs incurred in the issuance of an AO. Unless public comments are received which require additional work, the fee for this AO will be $1,200.00. An invoice will follow. You may pay this fee prior to the end of the comment period. If there are comments or additional fees, you will be notified.

Sincerely,

Lynn R. Menlove

Lynn R. Menlove, Manager
New Source Review Section